CHADBOURNE
& PARKE LLP

PROJECT FINANCE
NewsWire

December 2001

Fallout From Enron

by Keith Martin, in Washington

Chadbourne asked many thoughtful people in the project finance community in the few days before and after Enron filed for bankruptcy what effect they foresee from Enron's struggles on the independent power industry. Here are the main points that came out of the survey.

Tighter Debt Market

Project developers expect to have to pay more to borrow money at least for the next six to 12 months. One senior banker summed up the situation as "delays, higher costs and more scrutiny." The head of structured finance at a large energy company said, "We will all pay a direct price for Enron's failure."

One investment banker predicted that energy companies will have to pay 10 to 35 basis points more to borrow money in the future as an Enron premium. Another investment banker trying to place a Rule 144A debt offering in early December called that "a modest assessment." At least one debt private placement risked a delay in closing because the road trip had to be extended to call on more potential buyers for the debt issue.

Lenders are reassessing how much leverage projects can support. Watching the seventh largest corporation in the United States in terms of sales collapse in the space of just a few weeks makes lenders worry that the worst-case / *continued page 2*

IN THIS ISSUE

IN OTHER NEWS

YEAR-END DEALS may qualify for more generous tax depreciation.

The IRS said in November that it will give most taxpayers the option of claiming a half year worth of depreciation for assets placed in service during the remainder of this year. The government hopes this will boost investment.

Ordinarily, assets placed in service at any time during the year qualify for only a half year of tax depreciation. In the past, there was always a rush in late December to close transactions in order to enable companies to claim a half year of depreciation for assets that they owned for only a few days. Congress took steps to discour- / *continued page 3*

Enron Fallout

continued from page 1

The market adjusted surprisingly smoothly to the Enron collapse for traders, but perhaps more unevenly for others.

scenario in their deals could be worse than they imagined before. A consequence of making the downside case more severe is it will not support as much leverage. This has a ripple effect through the power business. It changes the calculus for smaller developers who lack their own equity to put into deals. They may be unable to hold on to as large an ownership share in their projects as before. The higher cost of capital means some projects will be deferred. Turbine prices will continue to decline.

Closer attention will be focused than before on who is the offtaker for a project. The head of project finance lending for a bank that has been in the lead on many recent merchant plant financings in the US market said he expects to face a lot tougher questions from his credit committee about the strength behind the offtake contracts, but that "in speaking to other bankers, it seems that they are already recognizing the difference between Enron and other power marketers who have physical assets to back their trades."

"This is probably not the moment to run a new name past the guys in risk management," said another senior banker. "Every marketer will be getting a new level of scrutiny on existing exposure as will any new requests if the originator has the guts to ask." This banker sees an "opportunity" for power marketers to provide more capital — equity, mezzanine — to projects under development. He suggested that power marketers try to use the next few months to firm up trading activities with more physical assets.

Another factor that may lead to longer lead time to close deals is the market is not as confident as before about investment grade ratings. Just six weeks before the bankruptcy filings, Enron put out an earnings release projecting strong pro forma profits. Two of the three big rating agencies reaffirmed Enron's rating of triple-B plus. Moody's remained skeptical. It put the rating under review, but hinted that the danger was a downgrade of one notch. Ratings are a timesaver for lenders, but only if they are credible. However, it is not clear that banks gain any better insight into credit risk by spending more time on due diligence themselves. They may have no realistic alternative other than to continue with the existing system but charge a higher risk premium.

One banker predicted some smaller banks that merely tag along in lending syndicates would withdraw from the market for a while.

Financial officers at project developers echoed the bankers. The chief financial officer of a large independent power company said, "The ashes are still falling from the volcano, but clearly given all the shocks to the industry this year, bank financing will become more difficult as those bankers who were already worrying about the merchant business may use this as another excuse to reduce commitments or exit the market altogether. Ditto for bond buyers who will likely take enormous losses on the Enron structured and supposedly secured off-balance sheet financings."

How long will these effects last? A leading banker with many years of experience in the market said, "Liquidity in the marketplace will be affected, but I think this is a short run issue, as these markets are very deep, broad and resilient." At the end of the day, the more significant issue is the demand and supply for power — how long it will take the economy to pull out of recession and whether there was already an oversupply of merchant plants headed for construction even before the Enron collapse.

Uneven Effects

The market adjusted surprisingly smoothly to the Enron collapse for traders, but perhaps more unevenly for others.

Enron had a very broad reach in the economy. The company accounted for 14.7% of electricity trades, much of it on its own electronic trading floor, EnronOnline, according to the last trade figures in early October. Enron owns 7.5% of total capacity on gas pipelines in the United States. About 25% of its income came from overseas assets.

One trader said after the bankruptcy filing, "The jury is still out on the effects, but at this point, it doesn't appear that there will be as large a domino effect as may have been expected. We are watching two companies closely to see if we need to restrict trading with them due to Enron exposure. All of the large trading firms seem to have exposures within the $100 million range, which is manageable. I'm not sure yet if we will see smaller firms go down as a result. The banks seem to be the worst hit."

Perhaps consistently with this view, one banker complained, "How can Enron have been the number one trader and almost no one — with the sad exception of us banks — has any exposure to them?" Traders had three to four weeks after the first signs of trouble to reduce their exposure. One banker spoke of a ripple effect among banks. The banks are "scrambling to review their exposure and to make sure we are taking the necessary appropriate steps to protect our positions." An analysis by Lehman Brothers published soon after the merger talks with Dynegy collapsed predicted that the ultimate recovery on senior unsecured notes, bonds and debentures would be in the range of 25¢ to 35¢ on the dollar. Lehman Brothers advised Dynegy on the merger.

The collapse left many project developers in a bind. At least 17 projects have contracts with the Enron affiliate, NEPCO, to build gas- or waste-fired power plants both in the US and abroad for completion in 2002 or 2003. Projects that are already under construction are in a different position than ones that have not yet gotten financing. One senior banker said, "Certainly we see NEPCO EPC contracts that we were going to take earlier stopping deals." Another said, "The biggest issue I have seen thus far related to NEPCO, which is building several power plants for clients and whose balance sheet, when revealed for the first time a few weeks ago to one who insisted on seeing it after Enron's problems grew greater revealed — surprise — NOTHING! No real assets, no liabilities, just a shell company to take orders. This may be a bit of overstatement, but not much."

One harried general counsel at a developer, when asked about the effects of the Enron col- / continued page 4

IN OTHER NEWS

age this in 1986 by adopting a "mid-quarter convention" that reduced the depreciation that could be claimed on late-year asset purchases. Since 1986, companies that place more than 40% of their total assets for the year in service in the last quarter have been limited to only a month and a half worth of depreciation on assets they put into service in the last quarter.

In November, the IRS said in two notices that it is waiving this mid-quarter convention for the rest of 2001. Companies sometimes use odd tax years. The waiver applies to any company for whom September 11 falls in its third or fourth quarter.

Any company wanting to take advantage of the waiver must write "Election Pursuant to Notice 2001-70" across the top of the Form 4562 it files with its 2001 tax return. This is the form on which depreciation and amortization are reported.

SOME CONVERTIBLE DEBT INSTRUMENTS have come under fire.

Lee Sheppard, a writer read by many tax policymakers in Washington, urged the Treasury Department in November to prevent borrowers from deducting more than the stated interest rate on loans that the lender can convert into shares in the borrower.

Many corporations have been issuing zero coupon or other debt with a stated interest rate that is below the current market rate. The lender has a right to convert into common shares of the borrower, thereby making up for the lower interest. The loans are structured intentionally with contingent features that increase the stated interest paid in certain events. This has the effect of causing the instruments to be treated as having been issued at a discount for US tax purposes. The result is the borrower can deduct not just the stated interest it actually pays, but also deduct / continued page 5

Enron Fallout

continued from page 3

lapse, responded: "Up to my eyes dealing with the problems being created with lenders, EPC contracts, and other interested parties." He said he would say more when he could find "a few spare moments to collect my thoughts."

Flood of Questions

The collapse led to a flood of questions.

Chadbourne quickly put up an internal distribution list on e-mail to keep project finance and bankruptcy lawyers who were fielding questions about the situation better informed about what issues the firm was being asked to address. The list grew quickly to 50 people.

Clients inundated law firms with three types of questions.

Chadbourne lawyers reported fielding three main types of questions from clients.

One set of questions had to do with the options for developers who are saddled with Enron contracts. This is an especially difficult problem for developers whose projects are not yet financed and may never be unless they can break free of the contracts. Unfortunately, once a company has filed for bankruptcy, the law does not let the other party to the contract simply walk away from the contract for a "status default" — a clause that says the Enron contractor has defaulted on the contract if it goes bankrupt. The developer's only remedy in such a case would be to persuade the bankruptcy court that there was a true substantial performance default. The bankruptcy judge is unlikely to allow the contract to be cancelled at such an early stage in the proceedings, according to David LeMay, a bankruptcy partner in the New York office. However, LeMay said "one of the chinks in the armor that Enron created by filing for only [21] companies is they left themselves open to cancellations involving nonfiled entities."

Another set of questions revolved around projects where other companies have minority interests and in which Enron is either the majority or managing partner. Neil Golden, a project finance partner in the Washington office, advised looking first at the shareholders or partnership agreement. "Sometimes if a shareholder goes into bankruptcy, he loses the right to vote or other shareholders may have a right to buy him out." (Provisions like those are sometimes invalidated by bankruptcy courts, LeMay noted.)

Golden said there are two potential problems created by Enron's troubles. One is the bankruptcy filing may be a default under the project financing agreements or may trigger an obligation on the part of other partners to post guarantees. This may not be a problem if the Enron partner was not included in the bankruptcy filing. There is also the issue whether the project company can be run efficiently if Enron personnel lose their jobs or their attention is diverted or if decisions involving the project must be run by a bankruptcy judge. Golden said that, in such situations, the other partners may have few real options.

Questions also came from companies that want to buy Enron assets. Enron reported receiving three to four calls a day from interested purchasers in some of its assets. At least in the case of assets belonging to "filed entities," David LeMay said, the debtor usually signs an agreement with a "stalking horse bidder" to sell it the assets subject to overbids and then takes the agreement to bankruptcy court for approval. Bidding procedures are set by the court and a breakup fee is approved for the stalking horse if it loses ultimately to another bidder. An auction is then held and the winning bid is presented to the court for approval.

An interesting question is whether many Enron assets may be harder than appears at first glance to sell. One banker cautioned, "They haven't been doing much project financing. They often put their guarantee on risks, and they took cash from projects in return . . . . Now they will have difficulty selling some of those assets."

Enron Europe Limited and six affiliates filed separately for "administration" in London, the UK equivalent of chapter 11 bankruptcy. Denis Petkovic, a partner in the London office, said the filing "operates to stop secured and other creditors from trying to liquidate or take other proceedings against the company." Petkovic said the action will also lead to scrutiny of past transactions and their possible vulnerability to court orders, effectively cancelling some contracts entered into up to two years before the onset of insolvency. This could happen if the administrator can prove that a contract was "at undervalue," meaning the company received significantly less value from the contract than it had given. Also, payments to affiliates and other creditors will be scrutinized and will be at risk if they are "preferences," meaning that the payor was influenced, when making the payment, to put the recipient in a better position than other creditors in the event of insolvent liquidation.

Estimates are for the bankruptcy proceedings ultimately to take six years. Enron has a sprawling corporate structure. A large part of the complication will be sorting out the priority of creditors of its 3,500 subsidiaries and among any litigants who win suits against the company or managers whom the company may be required to indemnify.

Regulatory Backlash

Many people speculate that the Enron collapse might lead to a regulatory backlash. A lot will depend on how the story ultimately plays in the press.

The *New York Times* said in an editorial, "There is a certain irony that Enron, a champion of deregulation, now becomes a poster child for the need for strong regulation on Wall Street." Both houses in the US Congress announced hearings to look into the financial collapse. A banker said, "I am a bit fearful that the politicians will read more into this than there really is, and try to do something." The Senate has put energy policy on the agenda for debate starting in January. However, the Bush administration has no interest in rolling back deregulation, and an omnibus energy policy bill that the opposition party introduced in early December in the Senate made no move in that direction, either.

The main effect is likely to be more subtle. Enron had probably the largest and most effective lobbying staff working for open markets — not only at the federal level, but also in state capitals. It will take a while / continued page 6

IN OTHER NEWS

the discount as it accrues over time. Some borrowers also deduct the premium paid at conversion into shares as additional interest.

The loans go by such names as LYONs.

Sheppard suggested four ways the government can deny interest deductions on the instruments and urged the US Treasury to act quickly before corporate America is awash in such instruments.

According to Investment Dealer's Digest, *"$77.4 billion in new converts had priced as of October 17, a record-smashing number." The number of convertible bonds issued in the first two weeks of October was $4.1 billion.*

SYNFUEL PLANT owners are breathing more easily after the IRS resumed ruling that the projects qualify for section 29 tax credits.

The US government offers a tax credit of $1.059 an mmBtu for producing "synthetic fuel from coal." The agency stopped ruling in the late summer 2000 that coal agglomeration facilities that add chemicals to coal particles qualify for the credits. It reopened the rulings window in theory in late April, but no rulings were issued in practice while the IRS tried to get plant owners to agree to low limits on output in exchange for future rulings.

The IRS backed off this effort on October 9.

Most projects were originally designed to glue together coal fines to form briquettes or pellets. However, a majority of facilities have dispensed with making pellets. The IRS takes the position that projects that omit this step must be able to show that the omission did not result in a significant increase in output. The agency said on October 9 that it would resume ruling that the projects qualify for tax credits and essentially defer any argument with taxpayers about whether output increased until audit.

The IRS had a backlog of some 25 ruling requests. By early December as the NewsWire was going to / continued page 7

Enron Fallout

continued from page 5

before other companies can fill the gap. "Enron was the pied piper of restructuring: its loudest, boldest and often most eloquent champion," said one veteran of Capitol Hill. The head of the Washington office of one of the largest US independent power companies said, "Enron's legislative staff are smart, aggressive and hard working . . . . I think we all relied on their ability to cover a lot of members when contact had to be made. The other independent power companies are growing their legislative capacities, but it will take a while to make up the difference."

Final Thought

On Tuesday, December 4, perhaps to provide some sense of perspective, the following e-mail arrived from someone in an office building across the street from Enron headquarters in Houston:

> *I've been looking out of my 7th floor office window at a very dismal day. Dismal, not just due to the weather, but dismal also because since 10 a.m., I have been watching 4,000 dedicated and loyal Enron employees stream out of the buildings with boxes, bags and briefcases in tow, in some cases maybe their life's work.*
>
> *These are hardworking Houstonians, our neighbors, our fellow bus riders, our children's Sunday school teachers, piano teachers, coaches, etc. Today, they not only lost their jobs and some, if not all, of their retirement money, they don't even know if they have medical insurance. Until the bankruptcy hearing at 4 p.m. today, there's no word even on any severance pay.*

"I have been watching 4,000 dedicated and loyal Enron employees stream out of the buildings."

FERC Adopts New Test For Market Rates

by Robert F. Shapiro, in Washington

The Federal Energy Regulatory Commission issued two orders at the end of November that mark a significant change in its tests for approving market-based rates for public utilities.

With a few exceptions, all public utilities in the lower 48 states must have their wholesale power rates on file and accepted at FERC. "Public utilities" include not only vertically-integrated investor-owned utilities, but also power marketers and independent power producers. The exceptions are municipal or other state or federal systems, utilities in ERCOT in Texas and certain electric cooperatives.

In recent years, FERC has been permitting these utilities to file to make wholesale sales under a market-based rate tariff instead of a traditional cost-of-service tariff if they could demonstrate an absence of market power in generation and transmission. Under a market-based rate tariff, the seller can sell at any rate that it can negotiate with any wholesale power purchaser, that is, whatever the market will bear.

In the November orders, FERC jettisoned a "hub and spoke" test that it has used until now for determining whether the applicant has too much market power to be allowed to sell at market rates. The commission introduced in its place an interim, supply margin assessment or "SMA," test. The commission also sought comments on a proposal to modify all existing market-based rate tariffs and to include in new tariffs a requirement that each utility agree to give refunds if it exercises anticompetitive behavior. Finally, it imposed a refund condition on all existing market-based rate tariffs beginning on January 28, 2002. This is clearly not your grandfather's Republican administration.

The scope of the decisions took the power industry by surprise.

The declared rationale for these actions was the concern that the dysfunctional California power sector was subject to potential market manipulation and that other markets could face similar problems. However, FERC itself never completed an investigation of market manipulation by power sellers in any other market in the country. Moreover, the new, interim market test was announced in the context of a triennial rate review of the market-based rates of three power marketers who, not coincidentally, happened to be affiliates of the three of the largest vertically-integrated public utility holding companies controlling vast transmission assets.

The FERC chairman made no effort to conceal the fact that the commission's actions, which applied the new market test to the detriment of each of the three applicants, were designed to prod these entities to join large regional transmission organizations, or "RTOs."

Interestingly, the commission did not invite interested persons to comment on its new market test, the SMA, which it announced in the order that conducted the triennial review of the three applicants. Rather, it issued a companion order that sought comments only on the modification of existing tariffs and the inclusion in all new tariffs of the requirement for refunds in the event the power marketer engages in anticompetitive behavior. Parties who were not involved in the triennial rate review proceeding will probably file for late intervention in that proceeding and submit requests for rehearing on the new market test.

SMA – The New Market Test

Under the old hub-and-spoke analysis, the commission usually approved market-based rate tariffs if the applicant could show that it had less than a 20% share of installed and uncommitted generation in the relevant market, and either owned no transmission or had an open-access transmission tariff — called an "OATT" — on file. Under this new SMA test, the commission intends to determine "whether an applicant is pivotal in the market," and the applicant will be deemed pivotal, and thus denied market-based rate approval, "if its capacity exceeds the market's surplus of capacity above peak demand — that is, the market's supply margin." The commission will also consider transmission constraints in the relevant market.

The SMA test appears to boil / continued page 8

IN OTHER NEWS

press, seven rulings had been issued, and the agency had worked through ruling requests filed by September 2000.

The IRS will be on the lookout on audit for projects that are not making pellets. Joseph Makurath, the IRS official who signs section 29 rulings, said the IRS will not bother such projects on audit if the taxpayer voluntarily limits his output to the "contract capacity" of his facility. Contract capacity means 50 tons an hour for Startec plants, 70 tons an hour for Covol plants, and 150 tons an hour for Earthco plants.

Taxpayers who do not do this should expect to be asked on audit to prove the plant did not significantly increase output by failing to make pellets. Makurath said the IRS will accept as proof the fact that annual output at the taxpayer's plant did not exceed the actual output at which the taxpayer's plant or a "comparable" facility operated for a full year while making pellets.

Many tax counsel question whether the IRS has authority to enforce production limits. Meanwhile, most projects are debating at what level to operate.

MULTINATIONAL CORPORATIONS have been making retroactive elections to increase foreign tax credits. The IRS said in late October that it will fight most such elections.

US multinational corporations must allocate the interest they pay each year on loans partly to their foreign operations on the theory that money is fungible. Interest expense is allocated between US and foreign operations in the same ratio as assets are deployed at home and abroad. The more interest allocated abroad, the fewer foreign tax credits a company will be allowed to claim in the United States.

Historically, most US companies have allocated between US and foreign assets based on the "tax bases" of their assets. However, in recent / continued page 9

Market Rates

continued from page 7

down essentially to this — if the capacity that the applicant controls in the relevant market exceeds the reserve margin in that market, then the applicant cannot sell at market-based rates but must use a form of cost-based rates. So, for example, if the reserve margin in a region is 20% and the applicant's capacity in that region exceeds 20% of the total available capacity, the applicant will not pass the screen. However, the SMA screen *will not apply* to any applicant that makes its sales in a market that utilizes an independent system operator or an RTO with a FERC-approved market monitoring and mitigation plan. Thus, this new interim approach to market analysis is clearly intended to serve as an incentive for big utilities to join RTOs, since only big utilities with a large capacity portfolio are likely to violate the new test.

The three utilities evaluated by FERC — affiliates of American Electric Power, Entergy and the Southern Company — were each found to have a capacity portfolio in the regions in which they have franchised service territories — their "control areas" — that exceeded the region's reserve margin by between one and one-half times and four times. Accordingly, they each flunked the market screen.

For the uncommitted capacity, each applicant was required to use a "split the savings" approach — a method traditionally used by investor-owned facilities when making spot or economy energy sales to each other. Under a "split the savings" approach, the rate is the average of the seller's incremental operating costs and the buyer's decremental operating costs. For example, if the seller's incremental cost is $30 a mWh and the buyer's decremental cost is $50 a mWh, the split-the savings-rate is $40 a mWh.

It remains to be seen whether this cost-based approach will cause heartburn for the investor-owned utilities that fail to satisfy the new test. However, there is little doubt that it will produce major ulcers for power marketers, who have traditionally refused to disclose their fuel and other operating costs to anyone for competitive reasons.

The commission went on to find that the uncommitted capacity that each of the three applicants owned and sold *outside* its control area satisfied the SMA screen and thus the applicants can continue to sell such power at market-based rates.

The three applicants have until early January to file revised tariffs that include the new rate mitigation plan. Further, Mirant, which was formerly an affiliate of the Southern Company but is now wholly independent, was directed to submit a standalone SMA analysis.

One of the FERC commissioners wrote a dissent to the decision in which she argued that the move to the SMA was premature since it was adopted without any industry input and the commission has already initiated a rulemaking into the continued viability of the "hub and spoke" market analysis. She was also disturbed that the SMA was created for use as a "stick" to encourage large, investor-owned utilities to join RTOs. Again, she would have preferred to use a rulemaking approach to mandate participation in RTOs.

If an electricity seller controls more capacity than the local reserve margin, it will not be free to sell at market rates.

Whether FERC's requirement that a refund condition for anticompetitive actions be added to all market-based rate tariffs will prove to be a significant, added risk for power marketers will depend upon FERC's willingness to investigate market irregularities and to place responsibility on individual market participants. Thus far, FERC's track record has been primarily to try to stop the bleeding in California rather than to try to target specific market manipulators.

It should be noted that these orders do not affect existing, long-term agreements in which the capacity is committed to specific offtakers.

IRS Clarifies Tax Treatment Of Electric Interties

by Keith Martin, in Washington

The Internal Revenue Service said on December 6 that utilities do not have to report interconnection payments from independent generators in most cases as taxable income.

The decision is important because some utilities had been insisting that independent generators pay not only the cost to connect their power plants to the grid, but also a "tax grossup" that added in some cases millions of dollars to the cost.

The IRS announcement came in the form of a "notice" on which all taxpayers can rely. The notice will be published in the *Internal Revenue Bulletin* on December 24.

The IRS said it has decided to extend its existing policy of not taxing interties at qualifying facility, or QF, projects to interties at merchant plants. The problem had been that merchant plant interties failed certain tests that the IRS set up in 1988 for QF interties to escape tax. The IRS said it is relaxing those tests.

Background

Power plants must be connected to utility grids in order to deliver their electricity to market. It is market practice for the owner of the power plant to pay the cost not only of any radial lines and substations needed to connect to the grid, but also the cost of any upgrades to the grid itself to accommodate the extra power.

The utility insists on owning those parts of the intertie that come in contact with the grid.

The generator usually either constructs the intertie and conveys title to the utility or reimburses the utility for the cost.

Ordinarily, when one company pays money or transfers property to another, the recipient must */ continued page 10*

IN OTHER NEWS

years, many companies have moved to allocate based on the relative fair market values of assets, and many companies have elected to do this retroactively in amended tax returns covering several years in the past.

The IRS said in a "coordinated issues paper" in late October that it plans to challenge companies on these retroactive elections. The agency said it would only allow a change in allocation method to be made up to the due date for the original tax return for the year in question.

Courts sometimes allow retroactive elections in other circumstances, but the IRS suggested that, if necessary, it would fight this issue in court.

CALIFORNIA decided to assess power plants for property tax purposes at the state level, but delayed implementing the decision until January 2003.

The delay gives the legislature time to decide how to allocate property taxes collected by the state among counties and cities. The municipalities want the revenue to go back to the same counties or cities that would have collected it had assessment remained at the local level.

The move to state assessment should mean higher property tax bills for many power plant owners. Local assessors are barred by Proposition 13 from claiming more than a 2% a year increase in property values unless the property is sold. This limit does not apply at the state level. Some power plants that are qualifying facilities under the Public Utility Regulatory Policies Act and power plants with nameplate capacities of less than 50 megawatts are exempted from the change and will continue to be assessed locally.

Some developers wonder what the shift will mean for special deals negotiated with local officials when power plants were under development. */ continued page 11*

Electric Interties

continued from page 9

report the value as taxable income.

Interties paid for by generators have historically never been reported by utilities as taxable income. However, in 1986, Congress changed the law to say that property supplied to a utility by a "customer or potential customer" must be reported.

QF Interties

At the urging of the independent power industry, the IRS issued a notice in 1988 to make clear that QF interties do not have to be reported by utilities, but there were conditions. First, the QF had to have a power purchase agreement with a term of at least 10 years to sell electricity either to the interconnecting utility or to another utility to which the electricity would be wheeled. Second, the utility could not put the intertie into rate base. QFs argued that utilities had no income in the sense of an accession to wealth because the utility lacked unfettered use of the property, at least during the period of the power contract with the QF, and the utility could not earn a profit from its use because the intertie was not put in rate base. These rules are in Notice 88-129.

The 1988 notice said that if the utility retains title to the intertie after the power contract with the qualifying facility ends, then it would have income to report at that time. The utility would have income equal to the then-fair market value of the intertie less any "basis" the utility has in the intertie on account of having paid the QF something for it. In 1990, the IRS said in a second notice that it would determine the value at contract termination based on "all facts and circumstances, including the age and condition of the property and whether the property is needed to serve the utility's customers." Thus, if the utility has no further use for the intertie, the intertie would have no value. The agency also said it will ordinarily accept whatever value the local public utility commission attaches to the intertie for purposes of setting compensatory payments.

Equipment that is required *solely* for the utility to sell power to the QF did not qualify for tax-free treatment.

"Dual-use interties" were subject to special rules. A dual-use intertie is one that is used both to carry power to the grid and supply it back to the generator. An example is where an intertie is equipped to carry backup power to a power plant for purposes of startup. The utility must show that it expects that no more than 5% of the total power flowing in both directions over a dual-use intertie will be power flowing back to the generator during the first 10 years after the intertie is put into service. If in fact this proves untrue, then it can lead to a "disqualification event" where the utility would have to report the portion of the intertie used to supply power to the QF as income.

In the early 1990's, the IRS issued a large number of private letter rulings extending the policy in Notice 88-129 to non-QF interties, gas pipelines and interconnections between utility grids. However, some IRS officials began to question by the late 1990's whether the policy ought to apply to merchant plant interties. At issue was whether merchant plants are "customers" of the utilities with whom they interconnect and, if so, whether this meant that the change in the tax code in 1986 that utilities had to report contributions from "customers or potential customers" as income meant they must report the value of merchant plant interties.

The IRS made clear that most merchant plant interties do not have to be reported as income.

Notice 2001-82

The new notice makes clear that most merchant plant interties do not have to be reported as income. Merchant plant interties will be treated the same as QF interties. Some of the tests in the 1988 notice are being changed to fit the new fact patterns found in the merchant power industry.

The new notice creates essentially a "safe harbor." Interties that fall within the safe harbor will not have to be reported as income. Parties to transactions that are outside the safe harbor must apply for private letter rulings.

The tests for tax-free treatment remain the same as in the 1988 notice for QF interties, with the following changes. First, the generator does not have to be a QF. Second, it does not need a contract to sell electricity to a utility; a long-term interconnection agreement will suffice. The IRS said that an interconnection agreement that has no fixed term but is tied to the period the generator will remain in commercial operation is considered long term. Third, ownership of the electricity must pass from the generator "to the purchaser prior to its transmission on the utility's transmission grid." The IRS said this requirement is satisfied if title to the electricity passes from the generator to the purchaser at the busbar for the power plant. The industry urged Treasury before the new notice was issued to allow transfers at other points along the intertie before the power goes on to the grid. The final notice allows such downstream transfers. It also makes clear that the transfer can be to a power marketer who is affiliated with the generator.

The generator must recover his interconnection payments for tax purposes over 20 years using the straight-line method. The IRS insisted on this as a tradeoff for concluding that interties are not income to utilities.

The notice is prospective. It applies to interconnection payments made pursuant to interconnection agreements signed after December 24, 2001. Projects that already signed interconnection agreements will have to apply for private rulings. The IRS said it will waive its usual policy of not ruling in cases where the issue already appears on the utility's tax return in order to deal with past cases.

Wind Projects Advance In California

by William A. Monsen, David Howarth, and Heather Vierbicher with MRW & Associates, Inc. in Oakland, California

As California emerges from the power crisis of the past year, windpower is uniquely positioned to benefit from a new focus on power supply, although some barriers to more widespread development remain. */ continued page 12*

IN OTHER NEWS

LOUISIANA will have to defend in court its view that owners of new merchant power plants built in the state qualify for a 10-year tax holiday from parish and local property taxes.

A state legislator — Rep. Kip Holden (D.) — filed suit challenging an announcement by the state Board of Commerce and Industry last August that merchant power plants qualify potentially for the tax holiday. The tax holiday applies to all improvements that are part of a "manufacturing" process.

Holden won a similar suit against waste incinerators in 1998.

He has temporarily withdrawn the suit, at least as it applies to merchant plants, until after the state formally approves the first application from a merchant plant developer for the tax holiday. Until then, the suit is premature. He is pursuing the suit in the meantime against the state on the issue whether salt and other chemical processing plants "manufacture" a product.

Eleven companies have asked the court to intervene on the side of the state tax authorities.

WIND DEVELOPERS got good news from the IRS.

The US government offers a tax credit of 1.7 cents a kilowatt hour for generating electricity from wind. The tax credits must be reduced to the extent the project benefits from government grants, tax-exempt financing or other tax credits.

The wind industry has been working hard at the state level to persuade legislatures to enact their own tax credits to encourage windpower development.

The IRS had been of the view that these state credits reduce the federal credit. It is not clear the IRS is right when the state credit is tied to the amount of output at the power plant rather than its cost. Cost-based credits clearly reduce the federal credit. */ continued page 13*

California Wind Projects

continued from page 11

One significant barrier that is common to all power projects in California is the issue of securing a power purchase agreement with a creditworthy entity. Because California's financially-crippled investor-owned utilities are unable to provide the necessary level of credit support, the state has stepped into this role. The Department of Water Resources or "DWR" is responsible for procurement, and a new Consumer Power and Conservation Financing Authority has been formed to ensure supply adequacy.

Windpower has proven competitive in recent state solicitations for long-term power supply. The state sees an opportunity to reduce price volatility by including in its supply portfolio renewable energy sources like windpower that have little or no fuel price risk. Somewhat offsetting the fuel price risk mitigation benefits of windpower is the supply uncertainty associated with intermittent renewable resources. Because of the uncertainty associated with the timing of deliveries from wind projects, wind developers typically enter into non-firm, as-available power sales agreements. This has been the case with recent DWR contracts for wind generation.

California will eventually take ownership of wind projects from which it buys power.

Even though wind developers can get as-available power sales agreements that have fixed commodity energy prices and no firm power delivery obligations, the owners of these projects may still face price uncertainty. Under current market rules, generators incur imbalance energy charges when their deliveries deviate from scheduled levels. Since wind generators have highly intermittent supply, they can be subjected to significant risks of imbalance energy charges. However, these issues are now being addressed through a collaborative process between the windpower industry and the California Independent System Operator or "ISO."

DWR: The Only Game In Town

DWR has stepped into the role of procuring power for the investor-owned utilities in California. Among the more than 40 projects with which DWR has executed contracts are three windpower projects with a total capacity of 174.6 megawatts.

A PG&E National Energy Group project, with 66.6 megawatts of installed capacity, began operating in early October. The project's contract is for a term of 10 years and has a fixed price payment of $58.50 per mWh.

Two Whitewater Energy Corp. projects are scheduled to begin operation by the end of 2001. These projects have contracts for 12 years at a fixed price of $60 per mWh. In each case, DWR takes energy as delivered, with no firm capacity requirements. The sellers retain any state or federal subsidies, including the production tax credit, as well as rights to any "green credits" associated with renewable generation that may be sold in a secondary market. Interestingly, these contracts specifically address the issue of imbalance energy charges, with DWR taking responsibility for paying such charges.

California Power Authority: Major Owner of Wind Projects?

The Consumer Power and Conservation Financing Authority was created last summer under Senate Bill 6X, which passed in direct response to California's supply adequacy problems of the past year. The power authority is charged with ensuring reasonably priced, long-term availability of reliable supply of electricity and natural gas, promoting environmentally friendly supply and demand solutions, and achieving adequate capacity reserves by 2006. The legislation allows the authority to issue up to $5 billion in revenue bonds to finance projects to be owned and operated by the authority itself. S. David Freeman, former head of the Tennessee Valley Authority, Sacramento Utility District, and Los Angeles Department of Water & Power, was selected as the power authority chairman. Freeman has a long history of promoting and implementing conservation and renewable energy.

The power authority announced a goal of acquiring 1,000 megawatts of renewable energy projects to be part of a total 3,000 megawatt resource portfolio by next summer. Toward this end, the power authority has already signed letters of intent with developers for more than 2,200 megawatts of renewable generation projects. More than 1,700 megawatts are windpower facilities, with all but 300 megawatts to be located in southern California.

The power authority intends to own and operate all non-windpower projects in its supply portfolio; however, for windpower projects, the authority will instead enter into 10-year fixed-price power purchase agreements with the project developers. At the end of the contract period, the power authority would take ownership of the facilities for a negotiated price. The reason for this arrangement is to preserve the federal production tax credit for private owners. The credits, which run for 10 years after a project is first placed in service, are of no value to public agencies. The power authority expects to sell the power from its projects to DWR.

Although no contracts have been executed to date, the power authority has agreed in the letters of intent to prices for power ranging from $40 to $50 per mWh. These prices are competitive with other sources and are well below prices seen in the market during the past year.

Notwithstanding the agreement on prices, it is unclear when, or even whether, actual contracts between the project developers and the power authority will be signed. Since the DWR is supposed to be the purchaser of power from the power authority's plants, the creditworthiness of DWR must be assured. DWR has yet to issue revenue bonds to back its past and future power purchases. Until the bonds are issued, the power authority's contracts with DWR will probably have to remain on hold.

Imbalance Energy Charges

Unlike the credit problems, progress has been made in the effort to address another barrier to the project financing of windpower projects in California. The intermittent nature of windpower has made it difficult to participate in ISO markets because of the difficulty in hour-ahead and real-time scheduling. To the extent that actual deliveries deviate from the scheduled amount, generators scheduling through the ISO are responsible for imbalance energy / continued page 14

IN OTHER NEWS

At last count, five states — Arizona, Hawaii, Montana, North Carolina and Oregon — allow a tax credit that is a percentage of the cost of a wind project. Minnesota has a tax credit that is tied to output. Tax credit proposals are pending in North Dakota and Pennsylvania.

In late October, the IRS released a private ruling in which it said that the owner of a wind project did not have to reduce his federal tax credit on account of receiving "renewable energy credits" — or RECs — from the state where the project is located. The state requires local utilities to accumulate a certain number of RECs each year. Generators of electricity using renewable technologies are awarded credits by the state and then sell them to utilities. The credits are based on output.

Investors in windpower projects should be careful to check for state credits as part of their due diligence.

HUNGARY will overhaul its income tax system and make tax cuts in 2002, the finance minister said in October. The government also plans to overhaul value added taxes with the aim of reducing the top rates and increasing the lowest rates to make them more compatible with rates in the European Union. The VAT changes are expected to take effect in 2003.

DESIGNATING A SALES CONTRACT AS A HEDGE does not change the timing of when the seller must report income under the contract.

A mineral producer contracted to sell minerals over several years, but the pattern of sales varied. The seller could decide not to make sales for an extended period. It designated the contract as a hedge. The IRS said income did not have to be reported until actual sales occurred under the contract. The fact that the seller / continued page 15

California Wind Projects

continued from page 13

charges. The financial impacts of these charges, and the uncertainty introduced by this issue, have made it difficult for California wind projects to secure project financing.

The operational and cost issues associated with integrating intermittent renewable resources into the ISO grid have been addressed by a consensus proposal developed by an ISO intermittent resources working group. This group held weekly meetings over the summer in an effort to develop a structure through which intermittent resources could participate in ISO markets and, therefore, increase their ability to obtain financing while minimizing costs and impacts on ISO operations

The consensus proposal establishes a framework for improving real-time windpower forecasting to reduce schedule deviations and a monthly settlement period for netting out schedule deviations for participating wind projects. The forecasting project will be conducted by independent experts and be administered by the ISO, with funding from a wind generator payment of $0.10 per mWh. Forecasts will be developed for day-ahead and hour-ahead scheduling, and the hour-ahead schedule will be updated by a near real-time forecast. The forecasted amounts will be deemed delivered, so intermittent resources will not be charged for replacement reserves and imbalance energy. These costs will instead be assigned to scheduling coordinators with imbalanced load. A forecasting working group will be established to monitor the forecasting effort and determine the impact of windpower on the ISO system.

The ISO board of governors approved the consensus proposal at its September 20 meeting. The consensus proposal requires certain operational and tariff modifications that must be approved prior to implementation. These steps are underway and will be considered by the ISO board in the near future, probably as part of a broader package of tariff amendments.

The intermittent nature of windpower makes participation in power pools difficult.

Hurdles Remain

While progress is being made on resolving issues regarding the integration of intermittent wind resources into the operation of the ISO grid in California, larger hurdles face wind project developers. The Power Authority could contract for about 1,700 megawatts of new wind capacity. However, the power authority must establish off-take agreements with one or more creditworthy entities prior to acquiring these assets. The DWR is, at the moment, the main creditworthy wholesale power buyer in the state. However, DWR will not be able to enter into additional power purchase agreements until it has solved its bond financing issues. ◎

Current Issues In Construction Contracts

by Paul Weber, in London

A longstanding tenet of project finance dogma is that a project must be constructed pursuant to a lump-sum, turnkey engineering, procurement and construction or "EPC" contract where the risks of delayed completion and failure of the plant to meet performance standards rest squarely on the EPC contractor's shoulders.

Market developments, cost considerations and the changing perspectives of developers have caused some cracks in the doctrinal wall.

Turbine Wraps

Many project developers placed large orders for gas turbines with Siemens Westinghouse Power Corporation, General Electric and other turbine suppliers in anticipation of using these turbines in projects under development. For a long time, turbine slots were in short supply; the situation has now turned around to a point where 100 turbines or turbine slots are reportedly for sale. Developers typically enter into purchase orders for turbines prior to negotiating an EPC contract.

If the developer anticipates financing a project on a limited recourse basis, when it negotiates an EPC contract it typically asks the contractor to assume the turbine purchase order and provide a turnkey "wrap" of the turbine supplier's obligations in the same manner as if the contractor had negotiated and entered into the turbine purchase order itself.

This approach has opened the door to contractor claims that the turbine purchase orders are insufficient in certain respects to allow a full wrap and may lead to negotiations about exceptions to the turnkey wrap. The most significant exceptions a contractor may seek relate to the amount and timing of, and triggers for, liquidated damages payments. For example, if the liquidated damages payable under the turbine purchase order for late performance or for failure to meet guarantees of electrical capacity and heat rate are less than those otherwise payable for such events under the EPC contract, then the contractor may seek to limit its liability under the EPC contract for such amounts to the amounts payable under the purchase order where the turbine supplier is responsible for the delay or performance shortfall.

However, the determination of which party is responsible for a delay or performance shortfall is not necessarily a simple exercise. Project construction involves numerous subcontractors and suppliers performing thousands of tasks. A solution is to allocate responsibility for the delay or performance shortfall between the contractor and turbine supplier and to adjust the liquidated damages accordingly. This is a complex task and is likely to result in delays in finally determining the amounts due. This issue can be partially addressed by providing that the contractor must, at a minimum, pay liquidated damages in the amounts provided under the turbine purchase order.

Other mismatches between the obligations of the turbine supplier and the EPC contractor may lead to other contract adjustments. For example, where guaranteed equipment delivery times under the turbine purchase order do not support the contractor's */ continued page 16*

IN OTHER NEWS

labeled the contract a "hedge" for tax purposes does not change the timing of when income had to be reported, the IRS told one of its agents in a "field service advice." The IRS memo is FSA 200146046.

AN "OWNERSHIP FSC" transaction is under audit.

The IRS released a "field service advice" in late November in which it told the agent handling the audit to disallow the tax benefits claimed by the lessor.

An ownership FSC is a form of cross-border lease where an aircraft or other equipment is leased by a US lessor to a foreign lessee. The transaction is structured to take advantage of US foreign sales corporation rules that allow the US lessor to avoid having to report up to 30% of the rents as income. In the meantime, the lessor also has tax depreciation and interest deductions to claim from the transaction.

Roy Meilman, a leasing expert at Chadbourne, said "there are the usual deletions and the facts are a bit garbled, but it seems fair to say that the transaction structure under audit was substantially more elaborate than in a standard OFSC transaction." For one thing, the transaction involved defeasance arrangements, which are atypical in a FSC lease. The IRS focused on a right the lessee had to buy the airplane at the end of the lease for a fixed price. It concluded that the transaction had been structured to make exercise of the purchase option a foregone conclusion by the lessee so that the lessee should be viewed as owning the equipment for tax purposes from inception. The IRS position is explained in FSA 200145002.

LOAN GUARANTEE FEES from a US subsidiary to its foreign parent are subject to US withholding taxes.

A US company borrowed money. Its foreign parent guaranteed */ continued page 17*

Construction Contracts

continued from page 15

milestone schedule, the EPC contract may provide for a change order if the turbines are not timely delivered. Broader *force majeure* provisions in the turbine purchase order may find their way (as to the turbine supplier only) into the EPC contract.

Most developers expect the construction contractor to "wrap" the turbine contract.

These sorts of exceptions to the turnkey wrap of an EPC contract should not render the contract unfinanceable. Rather, the lenders will analyze the EPC contract in light of the additional risks the exceptions pose and will look to the developer to cover those risks. For example, if the EPC contract contemplates scenarios under which liquidated damages may be payable at the rate provided for in the turbine purchase order, lenders will analyze whether liquidated damages payable at the lower rate adequately cover the costs to the project of delays or performance shortfalls. If they do not, then the lenders will likely require that the sponsor provide a contingent equity commitment to cover potential shortfalls.

Construction Management Agreements

Some developers have been taking a very different approach. They are not looking for the contractor to wrap the turbine contract and in certain instances are not looking for the contractor to provide liquidated damages or minimum performance guarantees. These developers, including those that are the offspring of electric utilities, may have substantial histories of constructing power plants other than on a turnkey basis and managing the construction process. They are accustomed to putting their balance sheets behind the construction effort. The payoff is a substantial reduction in the EPC contract price; contractors charge significant sums for full turnkey wraps. Another payoff may be a shorter period of time to get a contract in place and construction underway.

The clear downside to this approach is that these contracts are not financeable without sponsor support. One way to provide this is through a sponsor construction guarantee or a contingent equity funding commitment in favor of the lenders. Another approach which may avoid balance sheet recognition of the contingent liabilities of a guarantee or equity funding commitment is for the sponsor to enter into a construction management agreement. This agreement is drafted to fill the gaps in the EPC contract — to provide for the payment of liquidated damages or for minimum performance guarantees where the EPC contract is lacking.

The construction management agreement is entered into by the sponsor with the developer— not the lenders — and it makes no mention of project debt. Hence, it is not a financial guarantee or equity funding commitment. This may have the effect of permitting the sponsor to exclude these obligations from its financial obligations for purposes of determining whether certain of its financial covenants are met under its corporate financing agreements. The construction management agreement is collaterally assigned to the lenders. The bargain struck by developers taking this approach is clear: substantial savings on construction costs come at the price of substantial recourse.

The lump-sum turnkey EPC contract is far from dead and is still the preferred approach of developers for managing construction risks. However, where the circumstances require or where the savings of taking other approaches are compelling, developers have shown a willingness to look at other approaches to managing construction risks. ◎

Lender Held Liable For Construction Defects

by Thomas J. Hall and Douglas M. Fried, in New York

Lenders want to be repaid. Taking prudent steps to protect the value of collateral enhances this prospect. In construction financing, lenders have a legitimate interest in assuring that loan proceeds are put to good use and that the construction work is properly performed in a timely manner.

However, where is the line between a lender taking responsible and prudent steps to protect its capital and security, and the lender exercising management over the construction so as to expose itself to liability for construction defects?

A recent jury verdict in the New Jersey Superior Court can be instructive for all types of construction lending.

The Allegations

In 1999, the Ocean County Club Condominium Association brought suit against the developer of its Atlantic City highrise condominium complex alleging, among other things, defective construction work including leaks, deteriorating balconies and building code violations. The developer, in turn, brought suit against its construction lender, Bank of America National Trust and Savings Association, alleging that the bank was responsible for any such construction defects.

The developer's complaint charged that the bank, as a condition to its financing, required the developer to retain Pavarini Construction Company, Inc. as the general contractor. The developer charged further that the bank knew, or in the exercise of reasonable diligence should have known, that Pavarini was not competent to construct or promptly complete the project. The project needed a contractor with experience in highrise, ocean-front construction. The developer claimed that the bank required that Pavarini be hired to further that bank's own business relationship with Pavarini. The developer also claimed that the bank misrepresented the ability and qualifications of Pavarini and induced the developer to accept Pavarini as the contractor.

The Verdict

Following a three-month trial, the jury found the bank liable in late September, concluding that the bank had deviated from accepted standards of banking practice and improperly exercised effective control over the construction. The jury returned a punitive damage verdict against the bank in the amount of $6.6 million. In a procedural quirk, a separate jury will now determine the amount of compensatory damages, if any, to be / continued page 18

IN OTHER NEWS

repayment of the loan. The subsidiary paid the parent ongoing guarantee fees.

The United States normally collects a 30% withholding tax on payments by US companies to persons who are offshore. The rate is sometimes reduced by treaty. Withholding taxes ordinarily apply only to payments that are considered to have a "US source."

The subsidiary argued in this case that the payments are foreign source because they are for services by the parent, and the services are performed abroad. The IRS said that the payments are more in the nature of interest, which is sourced to where the payor resides — in this case, in the United States.

The taxpayer then argued that the withholding tax should be at less than a 30% rate because a tax treaty between the US and the country that is home to the parent company provides for a lower withholding rate on "interest." The IRS said the provision does not apply because guarantee fees are not literally "interest."

The IRS released a "field service advice" in November on the case. The number is FSA 200147033.

ENVIRONMENTAL CLEANUP costs had to be capitalized, a federal appeals court said in October.

United Dairy Farmers, Inc. purchased two stores in Ohio. Both properties had contaminated soil caused by leaking underground storage tanks. UDF spent money to clean up the soil and replace the leaking tanks. The court said the spending had to be capitalized rather than deducted. UDF could have paid more for the property and had the seller clean it up, in which case its costs would clearly have gone into its tax basis in the property.

The court said a company can only deduct cleanup costs if it did the polluting itself and the cleanup is / continued page 19

Lender Liability

continued from page 17

awarded to the developer. These verdicts are subject to post-trial motions and appeal.

The Lesson Learned

There are various ways by which a construction lender can protect its collateral while minimizing its potential liability exposure. The key is to leave decisionmaking with the borrower while establishing certain parameters to protect the lender. For example, instead of requiring the developer to use a particular contractor, the lender could have retained approval rights over the developer's choice of contractor. Alternatively, the lender could have withheld commitment to the financing until such time as the borrower selected a reputable contractor acceptable to the lender, or the lender and borrower might have agreed to a list of acceptable contractors from which the contractor could choose. Variations on these approaches exist. With any of these approaches, appropriate disclaimers in the loan documents would be helpful as well as a contractual obligation that the borrower thoroughly investigate the qualifications of the contractor it chooses. These concepts could also be made applicable to the selection of major subcontractors and other professionals.

What may have doomed the bank in this case is the charge that the bank directed the use of a particular contractor out of its own self interest. The developer alleged — and apparently the jury believed — that the bank imposed the contractor, not to assure that the construction would be satisfactorily performed, but to advance its own relationship with the contractor. In the jury's mind, this may have been where the line was crossed. ◎

Lenders should not select the construction contractor.

Political Risk Coverage: What's New?

by Julie A Martin, with Marsh McLennon, and Kenneth W. Hansen, in Washington

The October *Newswire* carried an article reviewing the core traditional political risk insurance coverages available from the private and public agency insurers, namely coverage against expropriation, political violence and currency inconvertibility. It concluded with a promise to discuss in the next Newswire the cutting edge innovations and other developments in the political risk insurance arena, including developments post-September 11.

The parameters of the traditional coverages have been substantially settled for the past half century. Recent years have seen growing pressure to update conventional coverages, by expanding or enhancing the scope of coverage to encompass more contemporary risks — notably breach of contract by governments and currency devaluation risk.

Breach of Contract

Expropriation cover has traditionally compensated investors for a government's taking of a project without adequate compensation. With the nineties and the fall of the Berlin Wall came privatizations in myriad forms. These included all shades of public-private partnerships and private projects based on public undertakings, such as sovereign guarantees of the performance of state-owned entities that act as offtakers and fuel suppliers. The government became if not overtly, at least for all practical purposes, a partner in the development and success of these projects.

Traditional expropriation cover protected private investors from the government seizing their property, but such coverage was never intended to protect one partner from bad acts of another partner — including the government. Indeed, coverage often explicitly excludes from the definition of expropriation the failure of a government to provide goods, services or cash promised to a project or its investors. Breach of contract by the government may be explicitly carved out from the scope of coverage or simply be unlikely to fall within the boundaries of the more conventional definitions of expropriation.

Yet a government's breaches of obligations upon which the project's economics are founded are clearly a political risk and a critical risk to mitigate if the public-private partnerships that have come to dominate infrastructure development in emerging markets during the past decade are to be successfully developed and financed.

The traditional mitigation for the risk of breach of contract is a lawsuit. Perform or pay damages. As imperfect a remedy as that may be for commercial counterparties, it is scant comfort when dealing with sovereigns — who are substantively omnipotent and, if they choose, immune to suit. Consequently, subject to the relatively minimal constraints of international law, they may be quite free to treat and mistreat their business partners as the mood, or the current administration, sees fit and to do so free from any concern of being held accountable in court.

Thus arose demand for "enhanced expropriation coverage" to cover the risk that sovereign partners will walk away from their promises.

The market demand has been met, at least part way, by both commercial and agency insurers offering variations of "disputes cover."

Under such cover, if a government breaches a contract that has an arbitration provision, the project company or, as appropriate, the project sponsors must invoke that clause. If the government loses the arbitration, including by failure to participate, but fails to pay the arbitral award, then the insurer pays that award. A common theme of these coverages is that the insurer depends upon an arbitral panel rather than its own staff or the insured to determine whether a breach has occurred.

Demand for coverage that avoids the requirement of pursuing arbitration in advance of a claim payment from the insurer has been substantial. Though a number of insurers have agreed to provide such coverage in connection with direct payment obligations of a government or one of its ministries under export sales or other contracts, it generally remains a step beyond the / continued page 20

IN OTHER NEWS

merely to restore the property to its former condition rather than prepare it for a different use.

The case is United Dairy Farmers, Inc. v. United States. *The decision is by the 6th circuit court of appeals. The court cited a similar holding in a case last year in the 4th circuit involving Dominion Resources*

LEASE REFINANCING COSTS must be amortized over the remaining lease term.

In most big-ticket lease financings of equipment, the lessee has a right to cause the lessor to refinance the debt if interest rates fall. Rents are then recalculated to pass through the benefit of the lower financing costs. The lessee pays the cost of the refinancing as "supplemental rent."

The owner of a power plant got into a dispute with the IRS about such a provision recently on audit. The parties amended the participation agreement for an existing power plant lease to give the lessee the right to ask for a refinancing. The lessee then exercised this right. At the same time, the parties agreed to extend the term of the lease. The lessee deducted the cost of the refinancing as additional rent. The IRS said it had to be amortized over the remaining term of the extended lease.

The lessee argued that spending to reduce future costs can be deducted immediately. The IRS said the spending in this case served two purposes — not only to reduce rents but also to extend the lease. The IRS explained its position in a "technical advice memorandum" in November. The number is TAM 200145003.

MINOR MEMOS: The IRS has asked for comments on "disguised" sales of partnership interests. The issue is when should the IRS treat partners whose interests are diluted downward after the admission of a new partner as having sold / continued page 21

Political Risk Insurance

continued from page 19

cutting edge for infrastructure projects. Still, some project developers are currently pressing both commercial and agency insurers to provide such cover in connection with government undertakings in support of infrastructure projects. This is an area where further evolution is likely.

Currency Devaluation Cover

The Asian economic crisis, triggered in 1997, highlighted disappointment in the marketplace with the inability to insure against the risk that a currency would not become technically inconvertible but would suffer a wholesale collapse in its market value. Although forward contracts and other currency hedges exist, in emerging market currencies such instruments are scarce and for, at best, very short terms. Project term lenders would very much appreciate a hedge against the risk of project debt defaults as a consequence of a general collapse in the value of the host country currency.

Until recently, this was generally deemed an insoluble problem. This past May, however, the AES Tiete projects in Brazil closed a $300 million project bond issue supported by a devaluation guaranty from OPIC. (See related article in the June 2001 NewsWire.) The industry has been holding its breath a bit since then to see whether this would prove a unique event or the first in a series.

The second volley sounded in late November. Sovereign Risk Insurance Ltd., a leading commercial political risk insurer, issued a press release indicating that it was prepared to issue devaluation insurance for lenders to appropriate projects. Where this will all lead is an open question, but it is likely that, while the number of transactions may be constrained by short supply of available coverage, a new product line may be taking form in the political risk marketplace.

Capital Markets Cover

One relatively recent development in the political risk market relates not to the scope of coverages but to the beneficiaries. Originally, political risk insurance was very much associated with equity investment. In the 1990s, there was great growth in demand by institutional lenders for such coverage to support their foreign project loans. More recently, such coverage has been sought for bond offerings and has been provided both by agency and private political risk insurers.

Beginning in July 1999 with the Overseas Private Investment Corporation's currency inconvertibility coverage of bonds issued by Ford Otosan in Turkey, many of the other providers have also now issued coverage on such capital markets transactions. More than a dozen bond issues have now been successfully supported with political risk insurance.

More than a dozen bond issues have now been successfully supported with political risk insurance.

The coverage can enable an investment grade project in a non-investment grade country to "pierce the sovereign ceiling" and achieve an investment grade rating. The benefits are greater access to the US capital markets and improved pricing.

Terrorism Cover Post-September 11

Political violence coverage, whether from formal warfare or informal terrorism or insurrection, has been solidly within the core coverages available from political risk insurers for the past half century. And it continues to be available today. Yet the headlines have correctly reported a collapse in the availability of, and escalation of the pricing for, such coverage.

Not surprisingly, the most dramatic developments have been in the arena of property (damage) and casualty (liability) insurers. Though not generally considered part of the relatively narrow fraternity of political risk insurers, property and casualty insurers have conventionally covered war and terrorism coverage as part of their basic coverage, mostly via the lack of specific exclusions, and at little to no incremental premium. The supply of such insurance for aircraft, marine vessels, and industrial and commercial facilities has been dramatically cut back. Reinsurance treaties that expire December 31 of this year pose the prospect for specific terrorism exclusions or very specific sublimits as well as price increases still to come. A number of legislative proposals that are intended to stem the unwinding of capacity for such insurance in the United States are now pending in Congress.

The situation for casualty liability insurance is more dire in emerging markets where, for the moment, some insurers are hesitating to offer coverage for any kind of casualty liability. The likelihood is that markets will soon develop new mechanisms to fill the vacuum and provide casualty coverage generally, but terrorism cover as an element of such cover is no longer automatic, much less free, and its availability post-January 1, 2002, when existing reinsurance platforms expire and remain to be renegotiated, is very much an open question in certain emerging markets.

As for property insurance, many companies with billions of dollars in assets are facing the prospect of no terrorism coverage at all or, at best, coverage with limits of $5 million in total. While some terrorism coverage is being placed in the London market and, with the announcement of a new facility this week, by AIG in the property markets, limits in both facilities remain small and the coverage is expensive.

In late November, representatives of the major multilateral development banks plus a number of US trade promotion and development agencies gathered in Washington to discuss how they might, individually or jointly, act to assure availability of adequate coverage to support infrastructure projects in emerging markets. What products or initiatives may emerge from these agency efforts remains to be seen. But organizations that in the best of times require time to navigate initiatives through a maze of policies, politics and legislative hurdles are not likely to head off entirely availability or cost problems whose severity will probably escalate effective New Year's Day.

Notwithstanding the arsenal of political risk mitigants available in the private and public agency marketplaces, it is clear that the correspondence between risks and mitigants is far from perfect. While / continued page 22

IN OTHER NEWS

part of their interests to the new partner. That could trigger a gain. It would only happen in cases where cash the new partner put into the partnership was effectively distributed to the existing partners. Comments are due by March 31 . . . . The head of the large and mid-size business division at the IRS said the agency is concerned about cases where corporate partners walk away from partnerships with large deficits in their capital accounts and the partnership fails to file its last tax return . . . . Pamela Olson, the number two tax policy official in the US Treasury, said on October 19 that the government is considering waiving penalties for companies who voluntarily disclose their participation in certain aggressive tax schemes that the IRS has targeted on audit. The government will want copies of any marketing materials and the name of the broker who sold them the transaction. It will then go after the broker for his customer lists.

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

Political Risk Insurance

continued from page 21

demand for the products readily available in the market is probably stronger today than at any time in recent memory, it is also clear that important risks spill over the boundaries of the scope of the traditional products. Those risks take careful identification and negotiation — or will quietly go unmitigated and, with some probability, arise to haunt the project and its investors. Commerce, like nature, abhors a vacuum, so it is much more likely that risk mitigants will be found. Who -– that is, which companies, which agencies of which countries, and which multilateral organizations — will step in, with what products and at what price remains to be seen. ◎

Spotlight On Captive Insurance

by Heléna Klumpp, in Washington

More and more companies appear to be setting up captive insurance subsidiaries. In 2000, the number of captives increased worldwide by 31.6% over the prior year, climbing to more than 3,400. Insurance industry specialist A.M. Best predicts that the 2001 figures will show continued strong growth in the number of captives.

Captives became popular as companies sought ways around the skyrocketing insurance premiums that resulted from a tightening of the insurance market in the mid-1980's. Although at first glance self insurance appears to be the best way to cut costs, amounts set aside in a self-insurance reserve are not deductible for tax purposes (as compared to traditional insurance premiums, which are). The captive market boomed as companies figured out arrangements that allowed them to enjoy the best of both worlds: lower insurance costs plus deductibility of premiums.

Captives

In the simplest, or "single parent," captive structure, a parent company establishes a wholly-owned subsidiary to insure or reinsure the parent company or other companies in the parent company's group. The subsidiary, known as a "captive insurance company" or simply a "captive," is incorporated in a US state or foreign country that has a captive insurance statute. Nearly a third of the world's captive insurance companies are located in Bermuda. The next most popular locations are the Cayman Islands, Vermont, Guernsey, Luxembourg, Barbados, the British Virgin Islands, Ireland, the Isle of Man and Hawaii. Washington, DC established a captive insurance regime in 2000.

> Many companies with billions of dollars in assets are facing the prospect of no terrorism coverage at all or, at best, coverage with limits of $5 million in total.

Offshore jurisdictions are popular for several reasons, most notably for the fact that some maintain less stringent regulatory requirements for insurers and reinsurers. For example, many US states strictly regulate the type of investments an insurance company can make. Many offshore captive jurisdictions have no such restrictions. Also, when they first came onto the insurance scene, captives that were established in tax havens like Bermuda or the Cayman Islands were able to avoid income taxes on their underwriting and investment profits. The US tax laws have since evened this playing field, requiring current taxation in the US of the income of most offshore captive insurance companies that are owned by US parents. (There are some exceptions to this rule for offshore captives of US parents that insure risks located in the captive's home country or in any other country but the US. Those exceptions are set to expire at the end of this year, but may be extended by Congress.) Some state premium taxes may still be avoided by incorporating a captive in an offshore jurisdiction.

The captive can be used to insure against the same types of risks for which a corporation would use a third-party insurer or self-insurance program: property and casualty, general and product liability, workers' compensation, etc.

In a different twist on the same basic idea, the captive may *re*insure primary liability coverage written for other members of its group by a third-party insurer. Most captive insurance companies are reinsurers. This is true for a number of reasons, especially the fact that a third party who deals with the insured party — for example, a lender — may be more comfortable if a recognizable insurance name is the company's primary insurer. Also,in many jurisdictions the reporting and capitalization requirements are less onerous for reinsurers than for primary insurers.

Other variations on the basic captive structure include several different types of "group captives," in which a single captive is owned by a number of unrelated corporate parents. The parents are typically similar in size or in the same industry or both.

Benefits

Insuring through a captive may be attractive for a number of reasons.

First, a captive may be able to charge lower premiums based on a company's loss experience. A third-party insurer bases the premiums it charges on industry loss averages. A company whose loss experience is lower than the norm may thus pay a rate that takes into account the higher average. When a company in that position insures through a captive, its loss experience will be viewed in isolation and the premiums will be priced lower accordingly. In other words, the insured's premiums will be based on its particular level of risk instead of an insurance carrier's general view of the market for that type of coverage. Thus, a company whose loss experience is lower than average may benefit from using a captive.

In addition, a captive insurer — particularly a reinsurer — will save on overhead costs associated with commissions, marketing, claims handling and regulatory compliance. These costs can be high for an insurance company and may represent close to half of an insured's premium. By contrast, the overhead of a captive is insignificant. This is especially true in the case of an offshore captive, which is less likely to be burdened with extensive regulatory requirements. However, in many cases, marketing, commission and other acquisition costs will be low or nonexistent for a captive.

Another benefit is that the captive can earn investment income on its premiums and thus potentially reap financial gains for the corporate group that would otherwise be lost to a third-party insurer. This investment income is typically subject to income tax in the US, either directly (where the captive is a US entity) or indirectly through anti-deferral rules that apply to certain offshore entities (where the captive is a foreign entity).

A captive may be able to provide coverage that is unavailable or prohibitively expensive if purchased from third-party insurers. The insurance market is cyclical. Low premiums one year may lead to high premiums the following year to make up for the insurance companies' losses. A captive's risks are more isolated than a traditional insurance company and thus it is less subject to the market's volatility. As a result, it may be able to provide coverage at more stable rates than are typically available in the insurance market, depending on the loss experience of the insured party.

Finally, if the parent company chooses to establish a licensed insurance company (as opposed to a reinsurance captive), that captive can purchase reinsurance in the wholesale reinsurance market directly. It can sometimes be cheaper for a captive to obtain reinsurance than for a traditional insurance company. In addition, a captive can control the extent to which it reinsures its risks. When reinsurance is cheap, the captive can take advantage of the market and buy more coverage; when reinsurance is expensive, the captive can choose to limit its coverage and retain more of the risk itself. There are downsides to this approach, though, as reinsurers may prefer to maintain consistent relationships with insurers.

Tax Deduction

The main reason companies set up separate captive insurance companies rather than simply self insuring directly is that premiums paid to a captive by a US company may be deductible for federal income tax purposes. Case law extending back to the 1920's establishes the principle that amounts set aside in a self-insurance reserve account are not deductible. Conversely, insurance premiums paid to a captive are deductible for federal income tax purposes as ordinary and necessary business expenses if the arrangement is properly structured.

/ continued page 24

Captive Insurance

continued from page 23

Structuring

The tax laws provide a deduction for insurance premiums that are connected with a taxpayer's trade or business. The tricky part of that sentence is the word "insurance." If an arrangement does not meet the Internal Revenue Service's definition of "insurance," then a taxpayer may not deduct its premiums.

Two things must be true to have "insurance." The first is that the arrangement must shift risk. Self insurance is not insurance because it does not meet this part of the test — no risk shifts when a taxpayer sets aside amounts to cover its own potential losses. The second test is that risk must be distributed. This means that the insurer must spread around the risks it assumes. In cases and rulings involving captives, the IRS and the courts have tended to focus more on the first part of the test. The IRS's main concern is that a taxpayer should not be allowed a deduction for an "expense" it pays to itself. If the risk of loss never shifts, the "premium" is not a true insurance expense.

Last summer, the IRS clarified its position on when and how it will challenge deductions claimed in connection with single-parent captive insurance arrangements. The IRS tries to attack such deductions by arguing that the underlying arrangement is not insurance. Previously, the IRS had relied on a fuzzy "economic family" theory to analyze whether such premiums should be deductible. Under this theory, the IRS looked only to the relationships between the captive and the insured parties to determine whether a captive arrangement was truly insurance or not. However, in the 24 years since the IRS first espoused the economic family theory, not a single court that analyzed a captive insurance situation has fully ascribed to it.

Going forward, the IRS said last summer that it will apply a facts-and-circumstances approach to determine whether a captive arrangement is truly insurance and not just a disguised attempt at self insurance.

A few guiding principles emerge.

First, amounts paid to insure a captive's parent are not deductible if the parent is the captive's only insurance customer. For every dollar the parent pays in premiums, it sees a corresponding increase in the value of its stock in the captive. No risk shifts in this scenario. If the captive pays out on a claim for a loss suffered by the parent, then the value of the parent's stock decreases dollar-for-dollar with the amount of the payout, and thus the parent still feels the entire sting of its loss. The risk has not been distributed. This same principle applies to premiums paid to a third-party insurer by the parent where the insurer cedes the underlying risk to the captive and collects reinsurance premiums from it (where the parent's risk is the only one the captive reinsures). However, if a fair portion of the captive's business is written for unrelated companies, then the IRS is more likely to respect the captive's insurance of the parent. In that case, by distributing its risks among a number of clients, the captive effectively shifts the parent's risk of loss because the premiums the parent pays may have to be paid out to any third-party customer of the captive who suffers a loss. The case law suggests that an arrangement is acceptable if at least 30% of the captive's annual business, measured by net premiums, is written for unrelated parties.

Second, the IRS will not challenge an arrangement where a captive insures or reinsures its sister subsidiary, unless factors indicate that either the captive itself or the overall arrangement is a "sham." If not a sham, insuring a sister subsidiary does shift risk and thus constitutes insurance under the IRS's test. Unlike the parent-subsidiary situation, if the captive must pay out on a claim for a loss experienced by its sister sub, then the sister sub suffers no corresponding diminution in its assets. To determine

The challenge is to structure captive arrangements so that they qualify as "insurance."

whether a "sham" exists, the IRS will look at several factors. Any evidence that the parent "propped up" the subsidiary with a guarantee or that the subsidiary was thinly capitalized points to a finding that the captive is a "sham" entity. The IRS will also look at whether the insured parties faced true, substantial risks and whether the premiums charged by the captive are based on market rates. The IRS will investigate the sub's business practices — were its activities kept separate from its parent's? Did it put in place appropriate claims handling procedures as opposed to just paying out on every claimed loss? If the answer is "no" to either question, then the IRS is more likely to suspect that the captive is a sham. The captive also looks more suspicious if it was formed in a jurisdiction in which its activities are loosely regulated — though clearly this factor alone is not dispositive as most offshore captives are located in such jurisdictions.

Third, the IRS said nothing new about group captives in last summer's ruling. Past guidance suggests that the IRS will not challenge deductions for premiums paid to a group captive if the ownership is diffuse enough. For example, the IRS said in a 1978 ruling that the arrangements between a captive and its 31 unrelated owners were "insurance" for tax purposes. No shareholder owned a controlling interest in the captive and no shareholder's individual risk coverage exceeded 5% of the total risks insured by the captive.

Speaking at a conference last summer, the primary author of the IRS's latest ruling on captives described the IRS's new approach to captive insurance companies as a "sliding scale," noting that "the closer [a transaction] resembles a commercial, arm's-length insurance transaction, the better you'll be." This suggests that the IRS will not automatically attack every captive and that a well-structured, sensible arrangement should avoid challenge. ◎

Mega Gas Project Advances In Bolivia

by Luis F. Torres, in Washington

The Republic of Bolivia, Sempra Energy and an international consortium formed by Repsol-YPF, British Gas and British Petroleum signed a memorandum of understanding in early December to develop an approximately $5 billion natural gas project to export 800 million cubic feet a day of gas from Bolivia to Mexico and California.

The Pacific LNG Project

The memorandum of understanding commits the parties to negotiate exclusively with each other with the aim of reaching a 20-year agreement to develop the Pacific LNG project.

The proposed project focuses on the extraction and sale of natural gas from the rich Margarita fields located in the Tarija region in southern Bolivia. The fields have at least 13 trillion cubic feet of certified reserves, an amount of gas that may be sufficient to supply a four-train LNG condensing plant. The operator of the project would separate dry natural gas from the associated gas liquids at the Margarita fields and transport the dry natural gas through a pipeline to a port to be built on the Pacific coast of South America. Other pipelines may be built to transport the associated gas liquids. At the port, the dry natural gas will be condensed into liquids at a two-train LNG plant and then shipped in cryogenic tankers to a receiving terminal in Baja, California. The liquids will be vaporized back into natural gas at the terminal and then distributed to customers in southern California and northwestern Mexico.

The LNG receiving terminal in Baja will have a send-out capacity of approximately one billion cubic feet a day of natural gas and will be built by Sempra Energy and CMS Energy Corporation. The overall cost of this mega project has been estimated at approximately $5 billion. Full operations are expected to begin by 2006. Repsol-YPF is acting as the project manager during the preliminary development phase of the project.

Because this project is still in its nascent stages, many questions remain regarding its development.

Perhaps the most important questions from a project finance standpoint is who will be purchasing the gas and in what amounts. Everyone agrees on the growing need of the California market for natural gas to generate electricity; however, Bolivian gas needs to be priced at an attractive price in order to compete successfully with gas provided from other sources. Bolivian gas should be able to undercut gas from Oceania in the market because of the shorter distance to bring it to the California market.

Technical and regulatory concerns */ continued page 26*

Bolivian Gas Project

continued from page 25

will also be considerable for a project this size.

Perhaps one of the most significant technical challenges will be to build at least one pipeline through the Andes to take gas from the Margarita fields to the Pacific coast of Peru or Chile. In order to accomplish this, the Bolivian government must assist the project sponsors in obtaining all the necessary permits from the governments of Peru or Chile to build the pipeline, transport the gas through their territory and install the port facilities and the LNG plant along their coast. Permitting is also necessary in California and Mexico since the pipeline that will distribute the gas in southern California and northwestern Mexico will need to join the existing distribution infrastructure in those regions. With respect to Bolivian permits, Bolivian authorities, including Bolivian President Jorge Quiroga, have expressed their full support of the project and their intention to issue all governmental approvals by the first half of 2002 by declaring it a project of "national interest".

Last but not least is the question of where the shipping port and LNG plant will be located.

Because Bolivia is a landlocked country, it needs to use a port in Peru or Chile in order to ship the LNG to North America. Both the Peruvian and Chilean governments have expressed their interest in hosting this multi-billion dollar project. The Mejillones port in Chile offers a shorter route than the port of Ilo in Peru for the pipeline coming from Bolivia to the Pacific coast. However, Peru offers a shorter maritime route to ship the LNG to North America. In addition, Peru has close historical ties with Bolivia and is perceived as the favorite of the Bolivian interested parties. The ultimate decision about where the port and the LNG plant will be located will probably be made by the project sponsors.

The consortium that is developing the Bolivian part of the project consists of Repsol-YPF (37.5%), British Gas (37.5%) and Pan American Energy LLC, a joint venture of British Petroleum and Bridas (25%). Repsol-YPF, British Gas and British Petroleum are currently active in the Bolivian hydrocarbons sector and together control Atlantic LNG in Trinidad and Tobago. ◎

The Mega Gas transaction in Bolivia will spawn a host of related projects.

Projects Lose Acid Rain Protection

by Andrew Giaccia and Roy Belden, in Washington

Whenever a power contract terminates or is bought out by a utility or is modified in a manner that allows the owner of the power plant to pass through new costs, it may have the unintended and costly consequence of subjecting the power plant to limits on sulfur dioxide or "SO_2" emissions under the federal acid rain program.

Determining if and when SO_2 emissions reduction requirements are triggered can be fraught with uncertainty and presents the risk of retroactive compliance costs and potential penalties.

The US Environmental Protection Agency has said little about when an amendment to a power contract goes too far, and to date there has been minimal enforcement. Five years ago, the federal government had little interest in enforcing other emissions limits that come into play when the source of the emissions is modified — so-called PSD/NSR violations for past modifications. Then the Clinton administration unleashed its utility enforcement initiative, and this became an issue of critical importance to the power industry. The lesson should not be lost.

Some regional EPA offices have started asking a lot of questions about acid rain program compliance during recent power plant audits.

Background

Certain power plants that had a "qualifying power purchase commitment" in effect as of November 15, 1990 are "grandfathered" from having to comply with the federal acid rain program. This applies to any power plant that is a qualifying facility or "QF" under the Public Utilities Regulatory Policies Act or that is an independent power production facility or "IPP" under the Clean Air Act.

Plants that lose their status as QFs or as exempted IPPs are required to obtain acid rain permits, to hold sufficient "allowances" to cover their SO_2 emissions, to install a continuous emissions monitor or "CEM" that meets federal acid rain standards, and to comply with other monitoring and recordkeeping provisions.

In order to be grandfathered, a plant that uses fossil fuel was required to have had one or more qualifying power contracts or other commitments — for example, a letter of intent — to sell at least 15% of the plant's total net output in place as of November 15, 1990. If a unit is grandfathered as both an IPP and a QF, then it will remain grandfathered until it loses both its IPP and QF status or the qualifying power contract terminates or is amended in such a way that it voids the exemption. The grandfather rules were adopted by Congress — after intensive lobbying by Chadbourne — to ensure that IPPs and QFs that had already entered into fixed-price long-term PPAs (or commitments to sign PPAs) would not be unfairly saddled with unanticipated acid rain compliance costs that they had no ability to pass through to their power purchasers.

Expiring PPAs

If a PPA expires or is terminated, then the power plant will usually no longer remain grandfathered. For example, in the past few years, Niagara Mohawk has bought out or terminated a number of PPAs with cogenerators in New York. EPA's clean air markets division reviewed a number of these plants and concluded that most are now subject to the acid rain program because they no longer have a qualifying power purchase commitment that was in effect as of November 15, 1990. The only exception is a plant that qualified for a small cogeneration unit exemption based on the fact that it sold 25 megawatts or less to the grid in the first year of operation and did not exceed this limit, on average, over each subsequent three-year period.

PPA Amendments

A qualifying PPA or other commitment may be amended without loss of grandfather status; however, certain types of amendments — particularly those involving changes to pricing terms — go too far. EPA regulations provide that if "the terms and conditions of the power purchase commitment. . . [are] changed in such a way as to allow the costs of compliance with the Acid Rain Program to be shifted to the purchaser," then the grandfather status will be lost.

If this language were applied literally, then no PPA amendments would ever threaten grandfather status for the simple reason that no utility would agree to amend a PPA to accept acid rain program compliance costs as part of the price it pays for electricity.

However, EPA's clean air markets division staff has taken the position that any amendment to a PPA that presents an "opportunity" to pass through acid rain program compliance costs may void grandfather status.

EPA Guidance

The scope of EPA's "opportunity" principle is far from clear. Very little agency guidance is available on what specific PPA changes will cause loss of grandfather status. To date, EPA's clean air markets division has issued only one applicability determination that addresses amendments to qualifying power purchase commitments. In a February 11, 1999 applicability determination, EPA concluded that changes to energy and water pricing terms for the KIAC Partners cogeneration project at the John F. Kennedy International Airport did not trigger a loss of grandfather status.

In its analysis, EPA noted that the electricity pricing was virtually the same between the November 14, 1990 letter of intent and the subsequent PPA, except that the PPA had a lower annual dollar cap on an applicable surcharge. EPA concluded that this change would not have allowed for the passthrough of acid rain costs because the dollar cap on the surcharge was *lower* in the executed PPA. Based on this guidance, decreases in the amount the power supplier can charge usually should not trigger a loss of grandfather status. However, the EPA clean air markets division staff has commented that changes from a fixed price to a market-based price would potentially trigger / continued page 28

Acid Rain

continued from page 27

acid rain program requirements even if market-based prices were currently much lower than the fixed price in the PPA. EPA staff reasoned that a market-based price would fluctuate and may eventually allow the passthrough of compliance costs.

EPA also considered whether increases in prices for hot water and chilled water in the JFK airport PPA would have allowed the shifting of acid rain compliance costs. The parties increased the prices for hot water and chilled water so that the power supplier would earn the rate of return contemplated in the letter of intent. Only the letter of intent was signed before the November 1990 deadline. The PPA was executed later. By the time the PPA was signed, JFK airport had scaled back plans to expand with the result that the power plant would not be able to sell as much hot and chilled water as originally planned. The power plant had also not yet secured long-term financing. EPA found that the project was no better able to bear acid rain compliance costs than before, even though it would charge more for hot and chilled water. However,, the agency said in a footnote that its decision "would not apply where price increases occur *after* the execution of the power sales agreement and the obtaining of any long-term financing."

Developers may unwittingly subject themselves to the acid rain program by amending their power contracts.

Although there is not much guidance to rely on, the JFK airport ruling and recent EPA staff statements suggest that power contract amendments will be tested under the following principles:

- Modifications that do not affect pricing or otherwise affect the energy producer's rate of return, either directly or indirectly, may be acceptable.
- If prices decrease, it may be acceptable, provided that the decrease is not a result of converting from fixed prices to market-based prices.
- If one component of the electricity price — for example, the capacity payment or energy payment — increases while another component decreases due to an amendment, then grandfather status may be at risk. The overall effect of the amendment on pricing is the key.
- If fixed prices increase overall as a result of an amendment, then grandfather status will probably be lost.
- If any passthroughs are added — for example, for energy-related taxes — grandfather status is at risk regardless of any compensating decreases in other pricing components.

Penalties

Power plants that have already unwittingly subjected themselves to the acid rain program by amending their power contracts not only face compliance costs going forward for the costs of installing part 75-compliant CEMs and purchasing SO_2 allowances, but the plants may also be hit with penalties.

EPA has the authority to seek penalties of up to $27,500 a day per violation, but typically the agency will calculate a past noncompliance penalty using its "BEN model" for the purposes of settlement. Under this model, EPA will calculate the economic benefits of avoiding compliance, including the costs of SO_2 allowances had they been purchased starting in 2000 (which was the beginning of phase II of the acid rain program) and any other compliance-related costs that were previously avoided like the delay in installing a part 75 CEMs. Under the model, a gravity component may also be added. The penalty amounts could be substantial in theory. However, no EPA regional offices appear to date to have pursued past noncompliance costs in cases where grandfather status was lost because PPAs expired or were amended.

Environmental Update

Environmental issues are receiving little attention from Congress or the Bush administration in the wake of the September 11 terrorist attacks — with two notable exceptions.

The Senate Environment and Public Works Committee is forging ahead with plans to write a multipollutant bill for power plants. The committee is debating whether carbon dioxide or CO_2 should be part of the equation.

The Bush administration appears on track to release its own multipollutant proposals for power plants by the end of January and is also working on administrative fixes to the "new source review" or NSR air permitting regime. The administration's NSR revisions are expected to be issued by the end of the year. While there is a growing consensus that multipollutant reductions from power plants will ultimately be enacted, the scope, effect and costs of how to do it remain contentious and prospects for any bill to become law before the November 2002 elections are questionable.

Multipollutant Legislation

The Senate Environment and Public Works Committee is pressing forward with plans to reduce power plant emissions of nitrogen oxides or NO_X and sulfur dioxide or SO_2 and to impose new limits on mercury and CO_2.

The committee held hearings on November 1 and 15 on a bill that the committee chairman, Senator James Jeffords (I.-Vermont), introduced earlier in the year called the Clean Power Act. The bill would require significant reductions in NO_X, SO_2, mercury and CO_2 from power plants by January 1, 2007. NO_X and SO_2 would have to be reduced by 75% from the 1997 baseline for NO_X and the 2000 baseline for SO_2. Mercury levels would have to be reduced by 90% from 1999 levels. CO_2 would have to be reduced to 1990 levels.

Two "stakeholder" meetings were held in October before the hearings. Many Republicans on the committee oppose the steep emission reductions in the Jeffords bill and object to inclusion of mandatory CO_2 reductions. However, the Republicans are a minority on the committee.

Senator Jeffords plans to have the committee "mark up," or vote on, his bill in February. The prospects for the bill in the full Senate are dim if Jeffords insists on mandatory CO_2 reductions, hard-to-achieve new limits on NO_X, SO_2 and mercury, and layering the new utility emission reduction requirements over the existing Clean Air Act requirements without providing regulatory relief.

While many power generators appear to support the concept of a multipollutant measure that embraces realistic emission reduction targets and provides some regulatory relief from the many emission reduction requirements already in the Clean Air Act, the industry is largely opposed to the provisions of the Jeffords bill. Examples of emission reductions that are already required by the Clean Air Act are the new mercury "maximum achievable control technology" standards for power plants slated to become final in December 2004 and the regional haze requirements that will apply to older power plants starting in the period 2004 to 2008.

The Jeffords bill is also opposed by the Bush administration. The administration says the bill would cause energy prices to increase by 30 to 50% and that coal-fired electricity generation would decline by 20 to 30% with a significant shift to natural gas. The administration is also opposed to mandatory CO_2 reductions as well as a provision in the Jeffords bill that would require all power plants that are more than 30 years old to meet "new source performance standards" and "new source review" modification requirements.

The administration wants a three pollutant bill. The three pollutants are NO_X, SO_2 and mercury. The administration is expected to call for a market-based trading approach, a longer implementation phase for NO_X and SO_2 reductions, more modest mercury reduction targets, and a more integrated approach with currently existing Clean Air Act requirements, including the elimination of some existing requirements.

New Source Review

The head of the US Environmental Protection Agency, Christine Todd Whitman, acknowledged recently that the agency has decoupled "new source review" or "NSR" air permitting reforms from work on the administration multipollutant strategy. This means that the two will not be released at the same time.

A package of NSR reforms is at the White House for review and is expected to be released as early as late December. The NSR permitting pro- */ continued page 30*

gram deals with "prevention of significant deterioration" or "PSD" air permits for sources in attainment or "clean" areas and air permits for sources in nonattainment "new service review" areas. The latter are areas that do not meet federal ambient air quality standards. The NSR reforms are expected to include the following:

- Power plants would be able to make changes without obtaining a major NSR permit as long as emissions do not exceed a plantwide cap and the facility has already installed certain pollution controls.
- Power plants that recently installed state-of-the-art emission controls on boilers and turbines — so-called "clean units" — would be allowed to make certain future changes without trigging NSR permitting for approximately a 10-year period.
- EPA is evaluating a proposal to create a list of "appropriate activities" that would qualify as "routine maintenance and repair" that would not trigger NSR permitting.
- EPA's rule for calculating "emission increases" for power plants that have begun normal operations would be expanded to other industries, including plants with industrial boilers.

Several of the NSR reforms could be implemented as a final rule since they were included in the set of NSR reforms originally proposed in 1996. These include the concept that a power plant could make changes without obtaining a major NSR permit, provided emissions do not exceed the plant wide cap and the facility has already installed certain pollution controls and the exemption for "clean units."

Other parts of the NSR reform package would require formal notice and comment before they could become final.

The NSR air permitting rules have been controversial from the start. Critics charge that they are an overly costly and time-consuming process that hinders plant improvement and expansion projects. The Bush administration's NSR reform package advances some of the less controversial aspects of proposals that EPA made to reform NSR in 1996.

In a related development, the US Department of Justice is reportedly nearing completion of its review of lawsuits the government filed against a number of electric utilities, petroleum refineries and factories alleging violations of NSR rules because the defendants filed to get approval for modifications to their plants. The Justice review is expected to be completed by late December. The agency will make recommendations on what, if any, steps should be taken next to proceed with the existing lawsuits.

Global Warming

The countries that signed the Kyoto protocol on global warming hammered out operational details to implement the treaty at a meeting in Marrakesh in early November. More than 165 countries approved the operational rules. The United States, which also signed the protocol, had representatives at the meeting, but it reaffirmed its opposition to implementation of the treaty as currently written.

Adoption of the rules sets the stage for countries to ratify the Kyoto protocol. Enough industrial countries are expected to ratify the protocol in the next few months to trigger full implementation starting in 2002. The Kyoto protocol will enter into force once it has been ratified by at least 55 countries. The 55 must include industrialized countries that account for at least 55% of the total reduction in carbon dioxide or CO_2 emissions that are required from the industrialized group. Without US involvement, the treaty will need to be ratified by European Union countries, and Russia and Japan, at a minimum, to enter into force. The protocol must be ratified by the Senate to be binding on the United States. To date, 40 countries have ratified the treaty, including one industrialized country, Romania.

US companies operating abroad will be subject to Kyoto limits on greenhouse gases.

The Kyoto protocol calls for the reduction in global greenhouse gas emissions by an average of 5.2% from 1990 levels during the "first commitment period" of 2008 through 2012.

The operational rules adopted at the Marrakesh conference include provisions governing international emissions trading.

Participants at the Marrakesh meeting also agreed on how to implement "clean development mechanisms," or "CDM," under which developed countries can earn credits against Kyoto targets for projects that reduce greenhouse gas emissions in developing countries. They also agreed on "joint implementation" or "JI" projects that allow one country to receive emissions credits for a specific project to help another country meet its emissions target. Emission credits will be transferable as equal units under the emissions trading regime, and CDM and JI programs.

Participants at the meeting also agreed to the consequences for failing to meet emission reduction targets. Countries will have to reduce an additional 1.3 tons of emissions for every ton they are over the target starting in 2013. However, ,the conference participants deferred a decision on whether the consequences are legally binding.

The Bush administration is currently conducting a cabinet-level review of global warming and is expected to outline the US approach for addressing the issue early next year.

US multinational companies with operations worldwide will find that their facilities in Europe, Canada, Japan and other industrialized countries are subject to greenhouse gas emission reductions notwithstanding the fact that the US is refusing to ratify the protocol. Significant costs may be incurred to achieve CO_2 emissions reductions at power plants and other industrial facilities, including the installation of more energy efficient and lower CO_2-emitting equipment. US multinationals may have to purchase CO_2 emission credits.

Carbon Fund

The World Bank recently announced that its $145 million "Prototype Carbon Fund" is investing $7.4 million in CDM projects in Uganda and Chile. The money will be used to purchase CO_2 emission reduction credits. Investors in the fund include the governments of Finland, Norway, Sweden and Canada and private companies in Japan, the United Kingdom, Germany, Belgium, Finland and France. Investors in the fund may use the CO_2 emission credits gained from these CDM projects toward meeting emission reduction targets in their own countries. Alternatively, the credits may be resold.

The fund plans to make a market in carbon credits so that developing countries will have a place to convert their credits into cash. Through the fund, the World Bank will purchase up to $3.9 million CO_2 emission reduction credits over 15 to 20 years tied to a Ugandan west Nile electricity project. The project involves construction of two small hydroelectric facilities. The World Bank has also contracted to purchase at least $3.5 million of emission credits generated by the Chile Chacabuquito hydro project. This is a run-of-the-river hydroelectric power plant with a 25 megawatt capacity. Both the Ugandan and Chilean projects were certified as CDM projects by international inspection, verification and testing companies.

The fund is reportedly also actively involved in CDM projects in Latin America, including Brazil, Colombia, Argentina, Costa Rica and Nicaragua.

Cooling Water

The Environmental Protection Agency signed off on a new rule in early November that prescribes cooling water intake standards for new power plants and manufacturing facilities that withdraw water from rivers, stream, lakes and other waters of the United States for cooling purposes. The new rule will require new facilities to install costly technology to reduce the amount of water they withdraw for cooling purposes.

EPA is required by section 316(b) of the Clean Water Act to develop cooling water intake regulations for both new *and existing* facilities. EPA agreed in a consent decree with the Hudson Riverkeeper environmental organization to develop the cooling water intake rules in three phases — phase I targets all new facilities, phase II will address existing utility and non-utility power plants that exceed a minimum threshold to be determined by the agency, and phase III will consist of those remaining existing facilities that exceed a minimum threshold of water usage, but do not fall within phase II. The phase II regulations must be proposed by February 28, 2002, and finalized by August 28, 2003. The phase III regulations must be proposed by June 15, 2003, and finalized by December 15, 2004.

The rule EPA announced for new facilities takes a two-track approach, and facilities may choose either track. The first track is based on default technol- */ continued page 32*

Environmental Update

continued from page 31

ogy-based performance standards.

Under track one, new facilities with a capacity to withdraw 10 or more million gallons of water a day must meet an intake flow level commensurate with a closed cycle, recirculating cooling system called a "wet" cooling system. There are also limits on intake flow and intake design components intended to minimize the effect on fish and aquatic organisms. New facilities with a design intake flow equal to or greater than two million gallons a day, but less than 10 million gallons a day, must meet similar requirements to reduce water usage and lessen the impact on fish and aquatic organisms, except these plants are not required to install cooling water system technology designed to achieve the intake flow levels of a wet cooling system.

Track two allows permit applicants to conduct site-specific studies to demonstrate that alternatives to the track one requirements will achieve comparable intake flow reductions and meet the same fish and aquatic organism protection standards as under track one.

The new rule defines new facilities subject to the rule as those plants that meet the definition of a "new source" or "new discharger" under the Clean Water Act and commence construction after the effective date of the final rule. Such sources must have a design intake flow greater than two million gallons a day and at least 25% of the water withdrawn must be used for contact or noncontact cooling purposes.

New York

Governor Pataki signed legislation that adds to the environmental requirements for power plants participating in the state's new expedited permitting process for modifications and plant expansions on adjacent or contiguous sites. New York has a one-stop approval process for power plants with a capacity of 80 megawatts or more.

The new law requires that power plants seeking expedited approvals for plant modifications or expansions must install technologies to limit water consumption to no more than 15 gallons a minute per megawatt of generating capacity. The measure is supposed to encourage use of air-cooled condensers or evaporative cooling water systems or other technologies designed to reduce water usage and minimize the danger to fish of being caught on intake screens and of aquatic organisms being sucked into intake systems.

The new law amends existing so-called Article X provisions that authorize approvals for plant modifications and expansions to be issued within six months where the plant owner agrees to reduce NO_X, SO_2 and particulate emissions by at least 75%. The 75% reduction is calculated by comparing the potential annual emissions of the existing facility to the potential annual emissions in the future after the facility has been modified or expanded. The goal is to reward plants that agree to install state-of-the-art cooling water systems and air emission reduction technologies. ◎

— contributed by Roy Belden, in Washington.

Chadbourne & Parke LLP

30 Rockefeller Plaza
New York, NY 10112
(212) 408-5100

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

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

also in London (Chadbourne & Parke, a multinational partnership), Moscow and Hong Kong