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PROJECT FINANCE NEWSWIRE

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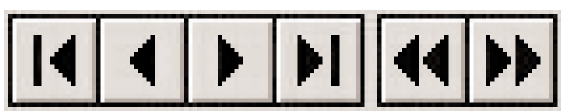

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CHADBOURNE & PARKE LLP

PROJECT FINANCE NEWSWIRE

December 2000

California At Sea: The Perfect Political Storm

by Dr. Robert B. Weisenmiller, William A. Monsen, and Steven C. McClary, with MRW & Associates, Inc. in Oakland, California

Power companies and banks with investments in California had best batten down the hatches: the storm they weathered last summer when electricity prices soared to unprecedented levels is likely to repeat next summer.

The experience holds lessons for regulators and participants in deregulating markets everywhere.

The high prices that rocked the western power markets last summer were caused in part by lack of generating capacity, relatively low hydroelectric generation, high natural gas prices, and high costs for emissions trading credits. Flaws in California's electric market were also to blame.

Background

The California legislature voted unanimously for deregulation of the electricity market in 1996. The plan had support from utilities, large customers, labor unions, independent power producers and small customers, providing what one observer called "something for everyone."

Under the plan, two new entities were created – an independent system operator, called the "Cal ISO," and a power exchange, called the "Cal PX."

The Cal ISO operates the transmission system. It is also charged with assuring reliability of the electric grid by managing transmission congestion through usage charges, administering a real-time market for imbalance energy usage,

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MERCHANT PLANT DEVELOPERS can probably avoid having to pay tax grossups on their electric interties by using a grantor trust structure.

The owner of a new power plant must pay the cost of connecting his power plant to the grid. The local utility usually builds the intertie; the generator reimburses it for the cost. Utilities have not reported these cost reimbursements as income since 1988. However, the IRS said earlier this year that it is studying the issue. A ruling is expected sometime next year. If the IRS decides that the cost reimburse-

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and procuring ancillary services.

The Cal PX is the spot market for buying and selling power that operates day-ahead and day-of hourly energy markets, as well as offering block forward power contracts. The Cal PX currently dominates California's wholesale power market because the utilities have an obligation to buy all of their power requirements and to sell all of the output from their power plants through the Cal PX.

Aside from the creation of the Cal PX and Cal ISO, utilities were allowed to recover generation-related stranded costs through a non-bypassable transition charge during a transition period to end no later than March 31, 2002. Utility plant divestiture was encouraged to mitigate potential market power concerns and to pay down stranded costs. Retail rates were frozen during the transition period, with recovery of stranded costs being inversely proportional to wholesale power prices. Customers were allowed choice in selecting energy service providers.

Calm Waters: 1998 and 1999

The early consequences from deregulation were encouraging.

There are no easy evacuation routes to avoid the storm of 2001.

Power prices were reasonable, if not low. In its first year of operation in 1998, the Cal PX day-ahead market averaged $24 per MWh, while prices the next year averaged $28 per MWh. During those years, the Cal PX accounted for 80% to 90% of the power volume transmitted through the Cal ISO. Meanwhile, the Cal ISO maintained system reliability during a period of record electric demands and four "Stage 2 emergencies" when the reserve margin on the Cal ISO-controlled grid fell below 5%.

Over 186,000 customers – primarily large commercial and industrial customers – took advantage of the opportunity to strike favorable power purchase agreements with third-party providers. Some of these arrangements were short-term deals that were tied to the spot price of power from the PX. Other agreements were longer-term and included hedging against power price volatility.

Industry restructuring opened the floodgates for development of new power generating facilities in California. At present, the California Energy Commission, or "CEC," has more power plant applications pending and expected than at any other time in its history. Five power plants, representing 3,628 megawatts of new capacity, have been approved (but only two are expected to come on line in 2001). There are applications pending at the CEC for another 7,892 megawatts of new capacity. Finally, there are at least four additional plants (representing 2,750 megawatts of new capacity) that are expected to file applications for siting approval with the CEC in the near future.

Over $500 million in funding was pledged to reinvigorate the renewable energy industry in California. So far, over $162 million has been pledged for the development of 500 megawatts of new renewable resources, while customers have received about $76 million in credit against electricity bills for buying power from renewable energy providers.

The state's investor-owned electric utilities — Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric – divested over 17,000 megawatts of capacity, receiving an average of 1.8 times book value for generation assets, or $180 a kilowatt hour. Almost 7,000 megawatts of additional capacity could be divested in the next two years. Relatively high sale prices for generating assets, combined with low power prices, allowed utilities to pay down some or all of their stranded costs. San Diego Gas & Electric was able to pay off its stranded costs by June 1999. This ended the rate freeze in San Diego, which meant that customers' rates would reflect the volatility in spot power prices from the Cal PX unless San Diego Gas & Electric hedged against this uncertainty.

In short, the first two years of the restructured power market appeared to be successful in terms of prices, opening markets, and rationalizing ownership of generating assets.

Storm Clouds Appear: Early 2000

By early 2000, there were small yet noticeable signs that all was not well in California.

These included complaints by a number of market participants that the restructured power market was dysfunctional. The Cal ISO's market surveillance committee also expressed concern that individual generators or power marketers possessed too much market power at least some of the time.

The Cal ISO attempted to respond to these concerns by making over thirty sets of changes to its tariffs, including major changes in the operation of the Cal ISO's ancillary services markets to try to curb very high prices in certain markets. A number of retail energy service providers abandoned the California market because of thin margins, market design problems, and very low market acceptance of their products.

Most municipal utilities, including the Los Angeles Department of Water and Power, declined to cede operational control of their transmission facilities to the Cal ISO. In addition, California was either unwilling or unable to reduce the time or complex regulatory requirements that power project developers

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ments must be reported as income, then utilities will insist on a tax grossup, making interconnection more expensive.

There are ways to structure the interconnection arrangements to avoid this problem — no matter what the IRS decides. The key is the generator should arrange directly with a contractor to have the intertie built. It would then contribute the intertie to a grantor trust with itself as beneficiary and the utility as the trustee. This would give the utility the control it requires over the intertie. It should also not have to report the intertie as income. At the end of the interconnection agreement, the trust would liquidate and the intertie would be returned to the generator.

This approach works with radial lines and other dedicated equipment. It is hard to make work for system upgrades.

BANKS LENDING TO MERCHANT PLANTS ARE STARTING TO FRET about whether the projects might have to refund some money collected for electricity.

The risk is that regulators might order generators to refund electricity revenues during periods when prices skyrocket. Bank loan negotiations are an exercise in risk allocation. At least for new loans to California projects, the borrower takes the risk that refunds will be ordered for revenues the project has already collected before the loan closed. Project sponsors are being asked to enter into capital contribution agreements promising to contribute an amount equal to any refunds to the project company that is the borrower.

Refunds of *future* revenues are the bank's risk. However, some banks ask that a reserve account be established equal to any excess revenue above what the project is projecting to earn. This reserve would remain in place only for a short period — for example, a year — before the revenues in it are released.

The Federal Energy Regulatory Commission warned generators in California in early November

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faced in obtaining permits to site new generation. Finally, the utilities complained about their limited ability to hedge against price volatility through forward contracting. However, because power prices were reasonably low, customers and regulators did not sense any immediate need to resolve these concerns.

The Storm Hits: Summer 2000

The storm rocked California and western power markets with punishing force in the summer 2000.

Power prices moved in ways previously unseen in the west. Not only did power prices soar to unprecedented levels during peak load hours – for example, greater than $1,000 per MWh in certain bilateral markets – prices also were very high during some off-peak periods. Figure 1 shows the Cal PX price versus load scheduled through the Cal ISO. As seen in Figure 1, prices in the summer of 2000 appear to have increased to record levels almost without regard to electric demand.

Loads increased at the same time electricity imports fell. The Cal ISO saw its loads increase by 7% in June and July 2000 compared to the same two months the year before, even though the summer 2000 was not a record-setting demand year. Demand in the Pacific northwest and the southwest also grew, resulting in less excess power being exported from those regions to California. For example, net hydroelectric imports from the northwest into California decreased by more than 3,200 megawatts in August.

Meanwhile, due to construction and regulatory delays, no major new power projects came on line in California in time to help supply the higher loads in 2000.

By July, the average price of power in California had risen to $109 a MWh, with August prices spiking to $166 a MWh. Hourly prices hit $750 a MWh in the Cal PX. Figure 2 shows hourly market-clearing prices since the Cal PX began operation. Figure 3 shows off-peak prices, which also soared in the summer 2000.

Figure 2

CalPX Day Ahead Unconstrained Market Clearing Price (4/1/99 - 9/30/00)

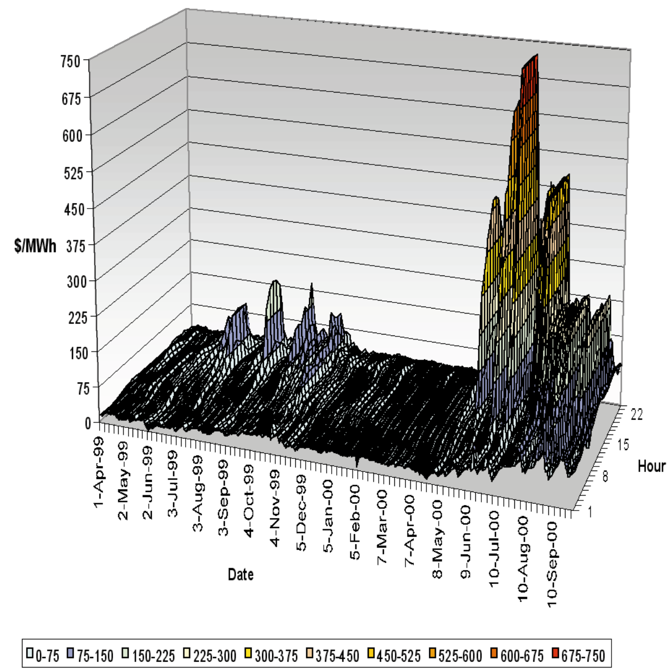
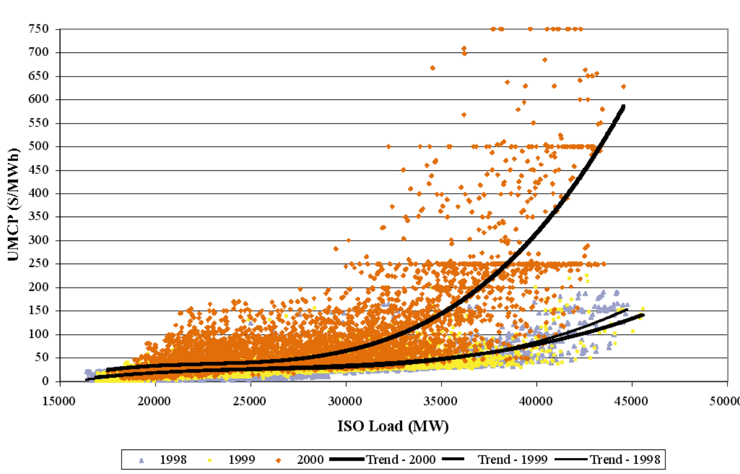


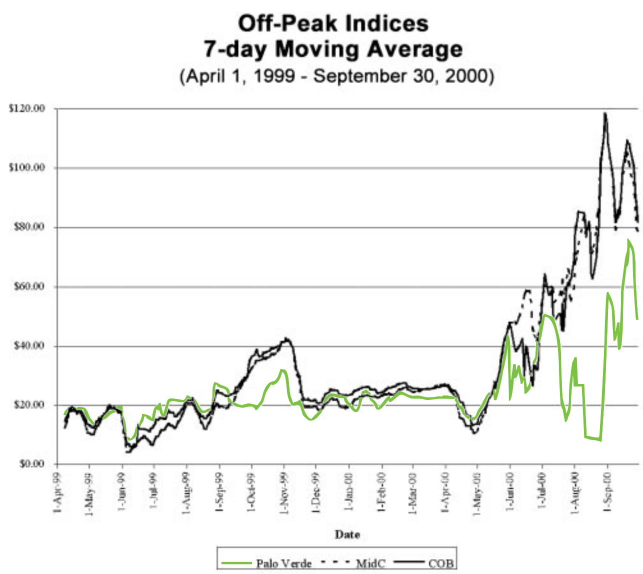
Figure 1

CalPX Day-Ahead UMCP vs ISO Actual Load



The quality of service suffered. In June, the Cal ISO required the involuntary curtailment of power deliveries to about 100,000 customers in the San Francisco Bay area as a result of transmission limitations. This was the first time in history such an action had been taken in California. In addition, the Cal ISO declared 32 “Stage 1” – less than 7% reserve margin – and 17 “Stage 2” – less than 5% reserve margin – emergencies. These emergencies resulted in interruption of service to participants in the utilities’ interruptible load management program. Since the inception of these programs, participants had never experienced this frequency of interruptions.

Figure 3



These gyrations in the power markets had significant impacts on different stakeholders.

San Diego Gas & Electric, having ended its rate freeze, passed along the increased costs of wholesale power to its customers, resulting in rate increases of over 70%. Because of the public outcry resulting from these rate increases, the California Public Utilities Commission initially imposed retroactive rate caps on San Diego Gas &

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that their revenues from power sales for the next two years through the California Power Exchange will remain subject to possible government-ordered refunds. This precedent suggests the same thing could happen in other parts of the country.

COMPANIES THAT HAVE BORROWED MONEY should be careful when changing their tax classifications. It could trigger taxes on the debt instrument.

The US treats any “significant modification” of debt terms as an exchange of the old debt for a new one. The lender may have a gain or loss on the exchange, depending on what the debt is worth at the time of the exchange in relation to his tax basis in it. The borrower may also have tax consequences.

IRS regulations take the position that a mere change in obligor on a recourse debt is a significant modification of the debt that triggers these tax consequences. The analysis for a nonrecourse debt is more complicated.

Companies today can change their US tax classifications simply by filing a form with the IRS. For example, a company treated as a corporation might — by filing a form — turn itself into a “disregarded entity.” It then ceases to exist for tax purposes. If the company has borrowed money, this change in classification means that a different entity is suddenly the borrower on the loan. The tax consequences are easy to overlook.

SECTION 29 TAX CREDITS would be extended through 2012 under bills introduced in the House and Senate in October.

The two Senators pushing the bill in the Senate — Frank Murkowski (R.-Alaska) and John Breaux (D.-La.) — are both on the Senate tax-writing committee and, therefore, they are in a position to move the bill next year if they are serious about it. Dennis Moore (D.-Kansas), a congressman who is

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Electric, with undercollections accruing to a balancing account. These caps were further reduced as a result of passage of Assembly Bill 265. These retail rate caps have resulted in San Diego Gas & Electric being unable to recover its cost of service fully.

The wholesale cost of power for the other two utilities – Pacific Gas & Electric and Southern California Edison – also soared. However, these utilities were unable to pass along the spiraling costs to consumers because they still had frozen rates. This has caused a major cash flow crisis for the utilities. The bond ratings for these companies have suffered as a result. In fact, these utilities – which are subsidiaries of holding companies – have implied that bankruptcy is a possibility if the CPUC fails to grant them additional borrowing authority and other forms of relief. These claims are being investigated by the CPUC, with the utilities being asked to produce extensive documentation of the problems and how affiliated unregulated companies may have profited during the summer 2000.

The Cal ISO imposed much lower price caps on its markets than were in effect before in response to pressure from California governor Gray Davis, the state legislature, utilities and ratepayers. This has created incentives for in-state generation to be sold out of state, where such price caps do not exist, resulting in even less generation being available to meet California's power demands.

The state legislature, the Electricity Oversight Board, the Federal Energy Regulatory Commission, the state attorney general and the CPUC have all opened investigations into the cause of the high summer prices in western power markets. As part of these investigations, a number of owners of generation in California – particularly companies that acquired the utilities' divested generation – have been served with subpoenas to produce documents disclosing their bidding and operating strategies.

Owners of generation in or around California – for example, LADWP, the utilities, the "new generation owners," and other independent power producers – and power marketers have reported very strong quarterly profits as a result of the high prices.

Causes of the Storm

The storm last summer had two causes: structural defects with the market design, and supply and demand issues.

Structural defects

The Federal Energy Regulatory Commission identified three major flaws in California's market structure.

One is the limited ability of the local utilities to purchase forward, requiring almost complete reliance on spot markets. The CPUC required utilities to purchase almost all of their power requirements through the Cal PX, which until recently offered only a day-of and day-ahead market. Thus, the utilities had limited ability to hedge against spot price volatility.

Another structural defect is chronic underscheduling of both loads and supply, requiring the Cal ISO to purchase too much power through the real-time markets. Lower price caps in the Cal ISO than in the Cal PX caused load-serving entities to bid their demand in the day-ahead markets only up to the price cap in the Cal ISO real-time market. As a result, as prices rose in the Cal PX, a greater and greater share of the load-serving entities' demand was being met through the Cal ISO's real-time market. In fact, at its peak, the Cal ISO had to procure over 15,000 megawatts in real time. Purchases of such magnitude were never anticipated in the design of the real-time market.

The third structural defect is lack of demand responsiveness because of frozen retail rates. The CPUC froze rates for retail customers in order to allow the utilities to recover their stranded generation costs. However, when wholesale power prices rose, most customers did not reduce consumption because the high prices had little or no economic impact on them. This resulted in higher bids from suppliers and higher market clearing prices.

The Federal Energy Regulatory Commission proposed several short-term measures to repair these market failures in early November. However, the commission warned that it does not have jurisdiction either to give load-serving entities the right to hedge or to end the retail rate freeze in order to provide some measure of demand responsiveness. Only the CPUC can fix these problems.

Supply and demand issues

A number of market fundamentals also contributed to the soaring prices.

Higher loads: Electric demand in the western region has grown significantly over the past several years. There were several days last summer when temperatures reached unusually high levels – for example, temperatures reached 111 degrees in parts of the San Francisco Bay area on June 14.

Lower hydro generation: Load growth in the Pacific northwest coupled with relatively low hydroelectric production resulted in less power being sent to California from the northwest, which is an area that has traditionally supplied California with low-cost power during the summer.

California power was exported: After the Cal ISO ordered the reduction in price caps in California, prices in markets outside of California were more favorable to suppliers than the markets with capped prices in California. As a result, some marketers sold power into out-of-state power markets. FERC estimates that net imports declined by about 3,000 megawatts from May through August, which is the period over

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not on the tax-writing committee, introduced a companion bill in the House.

The US government offers a tax credit of $1.035 an mmBtu for producing gas from coal seams or biomass, or synthetic fuels from coal, or $0.536 an mmBtu for producing tight sands gas. This was supposed to act as an inducement to Americans to look in unusual places for fuel. The idea was to reduce the need to import as much oil from the Middle East.

The deadline for placing projects in service to qualify for credits has already passed. The deadline for coal seam and tight sands gas projects was 1992. It was June 1998 for other projects.

Frank Murkowski – who, in addition to serving on the tax-writing committee, chairs the Senate Energy Committee – said he was introducing the bill because "we are 56 percent dependent on foreign sources of oil." The bill would push back the deadline for completing all projects – for example, landfill gas, synthetic fuels from coal, coal seam gas, tight sands gas – to 2010. Any such project put into service after the bill is enacted and before the new deadline of 2010 would qualify for tax credits through 2012. However, the amount of the credit would phase out starting in 2009. For example, credits in 2009 would be only $0.897 an mmBtu (before inflation adjustments) compared to $1.035 an mmBtu today. Credits in 2012 would be only $0.276.

There would be no extension of tax credits for projects that are already in service when the bill is enacted.

The bill would also add heavy oil to the list of fuels that qualify for tax credits, and it would permit companies that pay taxes under the "alternative minimum tax" to use section 29 credits for the first time to offset minimum taxes.

LESSEES BUYING ASSETS OUT FROM UNDER LEASES cannot deduct part of the payment immediately as a

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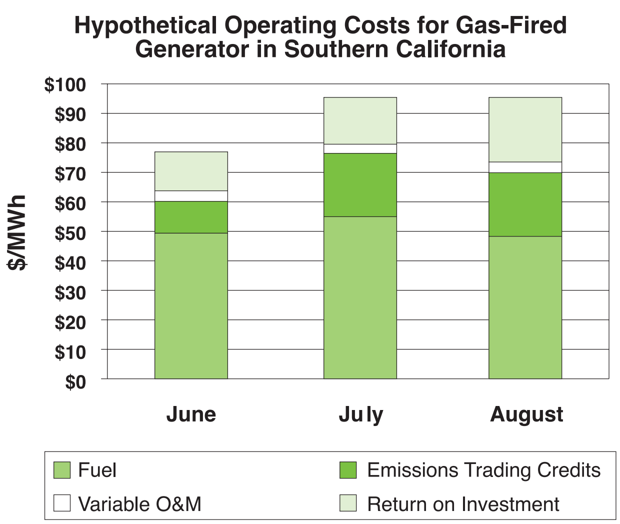
which the Cal ISO reduced its price caps.

Higher variable operating costs for gas-fired generators: Power plant owners saw significant increases in their variable operating costs, resulting in higher bid prices. First, natural gas prices at the southern California border reached an all-time high in the summer 2000, with month-ahead prices reaching almost $7.00 an mmBtu in September. These high prices were a result of greater demand for natural gas and deliverability problems on the interstate gas transportation system. Second, a general tightening on the supply of emissions trading credits in southern California as well as higher demand for these credits – in part a result of greater operation of power plants in California – caused the price for these emissions trading credits to spike. Emissions credits that had once sold for $6 a pound or less were trading for over $40 a pound in August. Figure 4 shows the hypothetical operating costs for generators in the summer of 2000.

Figure 4



The potential for the high prices seen in the summer 2000 existed since the time the California market was restructured. However, because of a lucky series of events – for example, cool summers and high hydroelectric output – prices never reached the prices seen last summer. It was only when electricity demand was "normal," net imports into California were down, and forced outages of thermal generating plants were up that the market structure problems began to take their toll, allowing the "Perfect Storm" to occur.

Warning Ahead

California's battered power market is not yet out of the storm. Many of the root causes of the high prices last summer cannot be changed immediately.

California is working to bring on new peaking capacity in the near term, but it is not clear that this and other stopgap measures will be enough to avoid a replay in 2001. Without significant new generation coupled with improved demand responsiveness, prices next year will be as high or higher than this year absent price caps that the Federal Energy Regulatory Commission is proposing to implement. However, these price caps will weigh heavily on the minds of new power plant developers when analyzing the risks and potential rewards of investments in the western power market versus other locations. There are no easy evacuation routes to avoid the storm of 2001. ■

Opinion: FERC's Failure To Order Refunds Spells Trouble For Generators

by Lynn Hargis, in Washington

Several events in early November spell big trouble ahead for generators in the California market.

The Federal Energy Regulatory Commission said in a November 1 proposal to "fix" the California power market that wholesale rates in California markets last summer were "unjust and unreasonable" – and, therefore, unlawful – under the Federal Power Act, but found that the governing law did not permit it to order any refunds retroactively for that period. However, FERC made all rates in the California Power Exchange subject to refund prospectively from October 2, 2000 through December 31, 2002.

Most generators who sold into the California market breathed a sigh of relief that FERC had not given in to politics just before a presidential election and ordered refunds retroactively. The debate shifted to whether FERC's "soft cap" of $150 per MWh for the single price auction for energy sales was something they could tolerate.

Meanwhile, Governor Gray Davis of California made a nearly unprecedented trip to the Federal Energy Regulatory Commission on November 9 to express his dismay that the commission had found the California rates to be unlawful, but had done nothing about it. State lawmakers threatened a voter referendum that could overturn all aspects of the state restructuring law, putting all power facilities under state – not federal – control. Governor Davis also said he "cannot allow" FERC's proposal "soft cap" instead of a "hard cap."

Further, the two big investor-owned utilities in California, Pacific Gas & Electric and Southern California Edison, made legal moves in an effort to ensure they will not be left holding a bag of many millions of dollars of wholesale power costs that cannot be passed through immediately to their ratepayers because of the rate moratorium in place.

These combined facts could spell big trouble for generators. The Federal Power Act was simply not designed to promote competitive markets or to protect people speculating in the power business. It was enacted to protect wholesale rate consumers and utilities required to serve them.

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cost to cancel the lease, the US tax court said in November.

Union Carbide had a special tanker built in 1983 for carrying liquid chemicals, and it financed the ship through a 20-year lease with Merrill Lynch as the lessor. The lease proved burdensome. Ten years into the lease, Union Carbide wanted out.

The company had separate options under the lease either to terminate for payment of termination value or to buy the ship. It chose to buy it because the purchase price — at a little over $107 million — was about 20% less than it would have had to pay merely to terminate the lease and give back the ship to the lessor. Both Union Carbide and the IRS agreed that the ship was worth only about $13 million in 1993 when Union Carbide bought it.

Under the tax laws, a payment to cancel a burdensome contract is deductible when paid. Union Carbide deducted the amount above $13 million as its cost of getting out of the lease. The tax court said no. It said Union Carbide had to treat the full $107 million as tax basis in the vessel and recover it over time through depreciation.

The court gave two reasons for this conclusion. First, it said that section 167(c)(2) of the US tax code — enacted in 1993 — compels this result. That section says that anyone buying an asset "subject to a lease" must treat the entire purchase price as tax basis in the asset; no part of it is allocated to the lease. Union Carbide argued that it did not take the asset "subject to a lease" since the lease was effectively cancelled when it acquired the ship. The court said the time to test is immediately before the purchase. Second, the court said it would have reached the same conclusion even if there were no section 167(c)(2). It said the weight of authority is not to allow bifurcation of payments.

The case is Union Carbide Foreign Sales Corp. v. Commissioner, *115 TC 32 (November 8, 2000). The taxpayer is considering whether to appeal.*

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Trouble For Generators

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While FERC correctly listed the key cases saying that FERC cannot retroactively change rates and order refunds, one cannot ignore the fact that those cases dealt with vastly different facts. Given the pro-consumer protection rationale of the statute, a way might be found legally to order the refunds that Governor Davis wants.

Only San Diego ratepayers actually had to pay rates that increased by 70% or so last summer. Even so, not only the California legislature, FERC, and the governor of California, but also the president of the United States got into the act because the political uproar was so huge. Once it becomes clear that the customers of Pacific Gas & Electric and Southern California Edison will be hit with similar increases on a delayed basis, the political uproar will be thunderous.

Under these circumstances, what approach should generators take with the Federal Energy Regulatory Commission? The logical reaction would be to take the profits and run, insisting that refunds cannot be made, and simply debating the finer points about whether a single price auction or some other auction is preferable in the future, and what other incentives generators will require to come into California.

Here's a more heretical suggestion: generators should recognize that a market for a commodity as essential as electricity simply cannot, for political reasons, allow prices to rise unchecked indefinitely with no recourse for consumers. Therefore, generators should take it upon themselves to find a compromise method of imposing a ceiling and – if necessary – refunds on customer rates and their own profits.

When I left the FERC staff 14 years ago, I remember a utility lawyer urging me not to work for independent power producers. He told me that investor-owned public utility managements thought of themselves as quasi-public servants and understood the public interest role of their business, but that some of the independents were simply profit-hungry "cowboys." I think the "cowboy" spirit of independence and initiative has done a lot for this industry, but it may be that the public-interest side of the business has sometimes been overlooked.

The independent power business might be practice enlightened self-interest by recognizing that the one true thing about almost every voter is that he or she pays utility bills, and then by taking upon itself as an industry a "public interest" gloss in any public statements to the federal regulators. Unless the industry itself proposes or accepts some limits on what consumers can be charged and thus on its own profits, the possibility is strong that the nascent market for competitive power and market-based rates will be stifled in infancy by the public outcry over unfettered and skyrocketing utility bills. ■

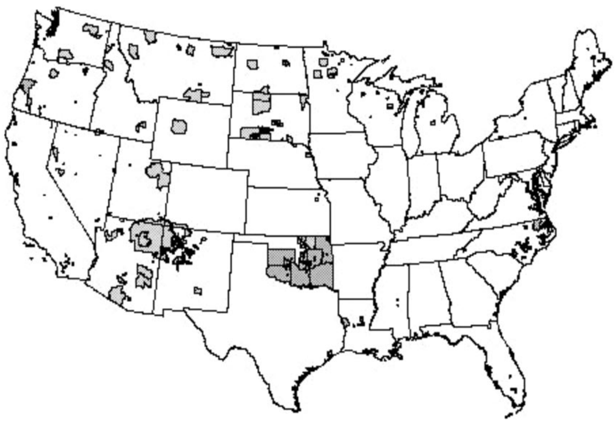
Tax Issues And Incentives For Projects On Indian Reservations

by Keith Martin, in Washington

Projects on Indian reservations qualify potentially for three federal tax subsidies, but time is running out to take advantage of them. The projects must be operating by December 2003. There is always the possibility that Congress will extend this deadline.

The map on the next page shows the location of Indian reservations across the United States.

The three tax subsidies are rapid tax depreciation, a wage credit tied to the number of Indians hired to work on the project, and the possibility of using tax-exempt financing. President Clinton signed a law on November 6 to set up a commission to look into other possible investment incen-



tives. The commission is supposed to report to Congress within a year.

Depreciation

Property that would have to be depreciated over five years if it was built elsewhere — for example, a power plant that burns biomass for fuel and is a "qualifying small power production facility" under the "Public Utility Regulatory Policies Act" — can be depreciated over *three* years if built on a reservation. Most gas and coal-fired power plants are depreciated over 15 or 20 years today. They would qualify for 9- or 12-year depreciation if built on a reservation. Buildings are normally depreciated over 39 years, but 22 years if built on a reservation.

The difference for most power plants is worth about 6¢ for each dollar in capital cost of the project. For example, depreciating a gas-fired power plant over the standard 15 years generates tax savings with a present value of 18¢ for each dollar of investment. Depreciating the project over nine years produces a tax savings of 24¢ per dollar invested. The difference is an extra 6¢. The same calculation for a power plant that would otherwise be depreciated over 20 years – for example, one that burns coal or a combined-cycle gas plant – leads to the same 6¢ in additional tax savings.

These special depreciation allowances apply to

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LILOS come under attack on audit.

The IRS released a "field service advice" in mid-November to an agent handling an audit of a US company that participated in LILOs. The national office told the agent to deny the company the tax benefits it claimed from the transactions.

"LILO" stands for lease-in-lease-out. In the transaction under audit, a foreign government leased equipment that it had owned for a number of years to a US company. The US company then subleased the equipment back to the foreign government. The sublease was scheduled to end before the head lease so that the US company would have a period, in theory, when it had use of the equipment. However, the foreign government had a purchase option — in its capacity as sublessee — to buy out this residual leasehold interest for a fixed price.

The US company paid the first year rent at closing and borrowed an amount on a nonrecourse basis equivalent to the remaining rents under the lease lease. It paid the borrowed money over to the foreign government as a "security deposit." The deposit turned the next year into a prepayment of the remaining head lease rents. The foreign government used most of the security deposit to defease the rents it had to pay under the sublease. It also defeased the fixed-price purchase option. In other words, it put money aside in a bank with instructions to pay the amounts when due. It was not legally released from the obligation to pay the sublease rents. At the end of the day, the money circled back to the original bank that loaned it.

The IRS agent characterized the transaction as a payment of the first year rent plus advisory fees for tax benefits.

In a LILO, the head lease rents are allocated to different periods under the lease in a pattern that decreases over time. The sublease rents have a reverse pattern that starts low and goes high. The lease is supposed to give the US lessee net deduc-

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Projects On Indian Reservations

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property placed in service during the period 1994 through 2003.

There are a few wrinkles: the property cannot be financed with tax-exempt bonds or be leased or used by a tax-exempt or government entity. The taxpayer cannot acquire the property from a related party.

As a general rule, the property must be on the reservation and "not used or located outside the Indian reservation on a regular basis." One issue is whether a power plant on a reservation that sells its entire output to a utility elsewhere is "used" on the reservation. A lawyer with the Joint Tax Committee in Congress – when asked about the issue in 1993 within a few days after the provision passed Congress – said an independent power facility qualifies since the facility is used on the reservation, even if the output is not.

The extra depreciation is worth about 6¢ for each dollar in capital cost of the project.

There is an exception for "qualified infrastructure property." It qualifies for the special depreciation allowances even though it is not on the reservation. This might be a hook for claiming rapid depreciation on transmission lines and other related equipment off the reservation, but property off the reservation must satisfy additional tests, including a showing that it "benefits the tribal infrastructure," "is available to the general public," and "is placed in service in connection with the taxpayer's active conduct of a trade or business within an Indian reservation." These phrases have been left for the Internal Revenue Service to define.

Wage Credit

There is also a separate tax credit tied to the number of Indians employed on a reservation. This credit is 20% of wages and employee health insurance costs paid during the year for employees who are enrolled members of Indian tribes and their spouses. "Substantially all" the work the employee does must be on the reservation. He must also live on or near the reservation where the services are performed.

Again, there are wrinkles. The employer must do better than he did in 1993 to qualify for this credit. The credit is calculated against his increase in wages and employee health insurance costs for Indians in 1993. Thus, if he employed no one in the target group in 1993, then his base is zero, and he is in a position to benefit fully from the credit.

The wage credit cannot be claimed on wages and employee health insurance costs for the following workers: anyone paid more than $30,000 a year, and – if a corporation is the employer – anyone who owns more than 5% of the outstanding stock or stock possessing more than 5% of the total combined voting power or stock representing more than 50% of the value of the corporation, or – if a partnership is the employer – anyone who has more than a 5% capital or profits interest in the partnership. No more than $20,000 in wages and employee health insurance costs per employee can be taken into account in calculating the credit, even if the person is paid more. Also, money paid for an employee who is fired within his first year does not count toward the credit, with certain exceptions where the employee was fired for cause.

Ordinarily, an employer is allowed to take a tax deduction for his payroll costs. However, the deduction in this case must be reduced by the amount of the tax credit.

The credit applies to amounts paid through tax years beginning by December 2003.

Tax-Exempt Financing

Indian tribes have the authority to issue tax-exempt bonds just like state and local governments, but their authority is more limited and would take imagination – and perhaps an assist from Congress – to finance a power plant.

The authority has had a colorful history since it was first granted in 1982. Initially, Congress said tribes could only issue bonds to finance public facilities – like roads, schools or hospitals – and these had to serve an "essential governmental function." It specifically ruled out any so-called "private activity bonds" – that is, bonds that go to finance private property like a power plant that will be privately owned or to finance public property that will be put to private use like a power plant that is owned by the tribe but whose output is dedicated under long-term contract to a private company.

Soon after, the IRS issued surprisingly generous regulations. The IRS said a tribe was fulfilling an "essential governmental function" as long as its borrowing was for a public facility that qualified for financial support from the Bureau of Indian Affairs. The BIA will support practically any project that brings some economic benefit to Indians. This interpretation opened the door to abuse. For example, the IRS ruled privately in 1986 that regular commercial banking is an essential governmental function and could be supported by tax-exempt borrowing as long as the bank was owned and operated by the tribe. It was not long before Indian tribes were issuing bonds to acquire tribal businesses off the reservation and to finance housing projects and factories while arguing that these served an "essential governmental function."

In 1987, Congress declared that the IRS regulations were "invalid." It said that the IRS had

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tions for rent that are equivalent to a depreciation allowance on the equipment, except that the deductions are more accelerated. Since the US lessee borrows most of the amount needed to prepay the head lease rent, it also has deductions for interest.

The agent said any pre-tax economic return in the transaction was, at best, insignificant. The IRS national office told the agent to disallow the rent and interest deductions on grounds that the transaction was so circular as to lack economic substance.

The IRS staked out its position on LILOs in a May 1999 revenue ruling. The transaction described in the field service advice looks like the first generation structures that were in use before June 1996 when the IRS issued proposed regulations under section 467 of the US tax code limiting the degree to which rents can fluctuate in leases.

TURBINE MAINTENANCE COSTS should be easier to deduct after a court decision in October.

A barge company overhauled the engines on its towboats every three to four years. It spent $100,000 on average for each overhaul. A new engine would have cost $1.5 million. A rebuilt engine could have been purchased for $600,000. The barge company inspected about 90% of the parts of the engine and replaced, on average, 21%. The IRS argued that the overhaul costs had to be capitalized because they extended the useful life of the towboat. The US tax court disagreed, saying this was nothing more than routine maintenance.

The case is *Ingram Industries v. Commissioner*. It is a huge win. The airlines have been fighting the IRS for years over whether the cost of periodic major maintenance checks on jet engines can be deducted. IRS agents usually require that such costs be capitalized and recovered through depreciation of the engine over time. Negotiations between the airline industry and the US Treasury over the issue

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Projects On Indian Reservations

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misinterpreted the law and that, when Congress authorized tax-exempt borrowing for essential governmental functions, it meant only to allow it for "activities that are customarily financed with governmental bonds (*e.g.*, schools, roads, government buildings, etc.)."

At the same time that Congress limited what public projects could be financed this way, it opened the door to tax-exempt financing for other projects that do not serve an essential governmental function. The 1987 law allows Indian tribes to issue bonds for projects that can jump through six hoops. Power plants will have trouble getting through three of them. The six hoops are

- the project must be considered a "manufacturing facility" within the meaning of section 144(a)(12)(C) of the Internal Revenue Code. A power plant probably is, but the IRS has never addressed the issue.
- The tribe that issues the bonds must be on an approved list published by the Treasury Department. There are procedures for tribes not on this list to gain approval.
- The project must on land that has been held in trust by the United States for the benefit of the tribe for at least five years.
- It must be "owned and operated" by the tribe.
- The project cannot be put to more than 10% "private business use," or – in the case of a power plant – the share of the bond proceeds put to private use cannot exceed the lesser of 10% or $15 million.
- The face amount of the bonds cannot be more than 20 times the annual payroll for Indians who work at the project.

Tax-exempt financing would take imagination — and perhaps an assist from Congress — to use.

Senator Max Baucus (D.-Montana) made a low-key effort in 1992 to persuade Congress to waive the last three requirements in the case of power plants that use coal or other fuel found on the reservation. Baucus was acting at the request of an independent power company that was looking at building a power plant on a Northern Cheyenne reservation in Montana. Baucus will be the most senior Democrat on the Senate tax-writing committee in the new Congress that convenes in January and in a much better position to effect such changes.

There is no "volume cap" on bonds issued by Indian tribes. State and local governments are limited in the amount of bonds they can issue each year to support private projects – so-called "private activity bonds." The limit is $50 times the population of the state or $150 million, whichever is greater. These limits to do not apply to Indian bonds.

However, there is a tradeoff whenever tax-exempt financing is used. The project must forfeit rapid tax depreciation. In this case, not only would it not qualify for the special allowances for projects on Indian reservations, but it would also have to be depreciated on a straight-line basis over the "class life" of the project. The "class life" for a power plant that burns coal or a combined-cycle gas plant is 28 years. It is 22 years for other gas-fired power plants. It is 10 years for power plants that run on waste fuels.

New Commission

President Clinton signed a new law in early November creating a 21-member commission – called the "Regulatory Reform and Business Development on Indian Lands Authority" – that is charged with reviewing all laws and regulations that affect investment on Indian lands and reporting back to Congress by November 2001. The main focus of the commission is to identify rules that inhibit investment. However, there is nothing to rule out recommending new incentives. The US Secretary of Commerce has until January 6 to appoint the members.

IRS Stops Ruling On Syncoal Projects

by Keith Martin, in Washington

The Internal Revenue Service said in late October that it has decided to stop issuing rulings in syncoal projects on the question whether the output qualifies as a "synthetic fuel from coal."

However, it made two exceptions. It will continue to rule on whether output qualifies for tax credits at facilities that make synthetic fuel from coke or "waste coal."

At issue is whether owners of syncoal projects qualify for a federal tax credit of $1.035 an mmBtu. The tax credit — found in section 29 of the US tax code — is supposed to induce Americans to look in unusual places for fuel. Anyone producing "synthetic fuel from coal" qualifies potentially for tax credits as long as the facility he uses to produce the fuel was placed in service by June 1998. Tax credits run potentially through 2007.

The IRS moratorium applies to all ruling

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have not yet led to an agreement.

WIND PROJECTS may not benefit from state tax incentives.

The US government offers a tax credit of 1.7 cents a kilowatt hour for generating electricity from wind. The credit is in section 45 of the US tax code. However, it cannot be claimed to the extent the project benefits from other government subsidies, including "any other credit allowable with respect to any property which is part of the project." Some states either have or are considering adopting tax credits like the one at the federal level to reward electricity production from wind. The IRS national office takes the position that the federal credit will not apply to the extent states adopt these credits.

There is a good argument the IRS is wrong. The examples of other credits that Congress cited in 1992 when it adopted the federal wind credit were tax credits that subsidize the capital cost of a project — not credits that reward output. Rep. Bob Filner (D.-Calif.) has introduced a bill in the House to clarify the situation, but Filner is not on the right committee to advance the bill. Wind groups need to find another sponsor.

MACHINERY CANNOT BE IN SERVICE for tax purposes until employees of the owner have been trained to use it, the IRS said.

The government took this position in a "field service advice" to an agent who was auditing a newspaper company. The newspaper had new printing presses installed. However, just as it was about to start up the presses, its employees went out on strike. The strike lasted a year. After a while, the newspaper deinked the presses and shut them down. There was never any question that the presses were capable of operating before the employees went out on strike. However, it was months after the strike ended before the newspaper was able to go

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requests, including ones that are already at the agency awaiting action. The announcement is Revenue Procedure 2000-47.

The agency also put out a list of questions on which it is seeking public comment.

Syncoal facilities have come under fire after the Kentucky governor and three congressmen sent the Treasury Department letters in July complaining that some syncoal plants were doing little more than spraying a chemical on coal that would have been burned anyway in utility boilers and claiming they had effected enough chemical change in the coal to turn it into a synthetic fuel.

According to a study last summer by RDI Consulting in Boulder, Colorado, 52 syncoal plants that use chemical binders to bind together coal fines were reportedly put into service in time to qualify for tax credits. Many of the original developers of these projects are too small to have much appetite for tax benefits. Consequently, many projects have been sold to institutional equity participants. The equity usually seek a ruling from the IRS.

Rulings in this area typically cover at least three issues. One is whether the output from the project is a "synthetic fuel from coal." Another is whether the deal with the developer has been structured properly to transfer tax credits. Another – in projects that went into service after 1996 – is whether the project was under "binding written contract" by December 1996 to be built. The deadline for putting syncoal plants into commercial operation to qualify for tax credits was originally December 1996, but Congress extended it to June 1998 for projects to which the developer was irrevocably committed by the end of 1996.

IRS officials have tentatively taken the position that they will only rule – while the moratorium remains in place – on projects that make synfuel* entirely *out of waste coal.

The IRS announcement in late October said the agency has stopped ruling only on the first issue — whether output from the project is a "synthetic fuel." The IRS publishes a list at the start of each year of areas in which it will not rule because the area is under "extensive study." The IRS said it is adding the following item to this list:

> "Whether a solid fuel other than coke or a fuel produced from waste coal is a qualified fuel under § 29(c)(1)(C). Waste coal for this purpose is limited to waste coal fines from normal mining and crushing operations and does not include fines produced (for example, by crushing run-of-mine coal) for the purpose of claiming the credit."

It asked for public comment on five questions. Comments were due by November 27.

The first question is whether the test of whether output is a "synthetic fuel from coal" should remain simply whether it is significantly different chemically from the coal used to produce it and, if so, how to measure chemical change. The next question is whether "additional or alternative tests are needed." The third question is whether tax credits should only be allowed in cases "where domestic energy production is increased." The fourth question is in what circumstances credits should be allowed on output produced from waste coal or coal fines. The last question is whether the IRS should require that the synthetic fuel have a market value significantly greater than the cost of the coal and binder used to produce it. Most projects buy raw coal at a higher price than they can sell the output, but still profit from turning coal into synfuel because of the large tax subsidy. The subsidy amounts to about $25 a ton of coal.

IRS officials have tentatively taken the position that they will only rule – while the moratorium remains in place – on projects that make synfuel entirely out of waste coal. The industry is arguing that it should be enough to make synfuel "primarily" from waste coal. This issue remains under debate. ■

Foreign Multinationals Risk New Lawsuits In The US

by Noam Ayali, in Washington

Multinational companies doing business in the United States run a growing risk of being sued in the US courts for such things as human rights violations and environmental damage caused in other countries.

This fall, a federal appeals court in New York allowed a class action lawsuit to proceed in the US courts against Royal Dutch Petroleum Company of The Netherlands and Shell Transport and Trading Co. Plc of the United Kingdom — which together control the Royal Dutch Shell Group of Companies — alleging human rights violations in connection with the Group's oil and gas exploration and production operations in Nigeria.

Also this fall, a class action lawsuit was filed in federal court in San Francisco against Rio Tinto Plc of the United Kingdom and its sister company

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through the process of restarting the presses and training its employees. The IRS national office said the presses were not in service until the employees were trained. The field service advice was written in 1997, but only just released to the public.

A LOCAL DISTRIBUTION COMPANY has gone to court to challenge the IRS over whether it must pay income taxes on refunds from its gas suppliers.

The suppliers had to make the refunds after regulators said it overcharged for gas. The case has implications for electric utilities — for example, in California — who might receive refunds in the future from their electricity suppliers.

The LDC is Bay State Gas Co. in Massachusetts. The Federal Energy Regulatory Commission ordered upstream suppliers of gas to Bay State to make refunds after concluding that the gas rates charged by these suppliers in 1993 and 1994 were "excessive." Bay State is required by law to pass through the refunds to its ratepayers. However, rather than write checks, it made an adjustment in its cost-of-gas accounts so that there would be less cost of service to pass through to customers in future periods.

The case is before the US tax court.

INTERSTATE GAS PIPELINE COMPANIES are not overburdened by the New York franchise tax, a state appeals court said.

New York taxes the "gross earnings from all sources within this state" of companies in certain businesses, including in the business of supplying gas delivered through mains or pipes. The tax is imposed under section 186 of the state tax code.

Texas Eastern owns 1,900 miles of gas pipeline of which 2.5 miles run into New York to a meter and regulating station on Staten Island. The company had gross earnings during the period 1989 through 1991 of between $1.4 and $2.0 billion a year. New York

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Foreign Multinationals

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in Australia alleging liability for environmental damage caused by a subsidiary's copper mining operations in Papua New Guinea.

Alien Tort Claims Act

The legal basis for these lawsuits is the "Alien Tort Claims Act," which was enacted by the first US Congress in 1789 and provides that "The district courts shall have original jurisdiction of any civil action by an alien for a tort only, committed in violation of the law of nations or a treaty of the United States." "Tort" is a legal term meaning a harm done to another person.

Although the Alien Tort Claims Act has been on the books for over two hundred years, it has been described by one federal judge as "an aged but little-noticed provision of the First Judiciary Act," and as "mostly ignored since its enactment in 1789" by another.

The original purpose of the Alien Tort Claims Act remains the subject of controversy, with some scholars suggesting that its sole purpose was to provide redress for a problem of the times: torts committed by pirates when stopping and boarding vessels at sea. Yet, in the last several years, the Alien Tort Claims Act has found a new lease on life. Initially used in the area of human rights – it served as the basis in 1995 for a landmark decision by a US appeals court allowing Bosnian torture victims to bring a civil action in the US against Serbian strongman Radovan Karadzic – it is now also being used in the hands of activists intent on holding multinational corporations liable in tort for their international operations.

These cases should serve as a reminder to include environmental and social conduct in international operations in the due diligence for acquisitions.

Although other industries have also been targeted under the Alien Tort Claims Act – in 1999, several retail and clothes manufacturers settled a billion dollar claim for unethical labor practices filed on behalf of a class of some 50,000 garment workers in Saipan – it is undoubtedly multinational corporations in the oil and gas industries and the natural resources mining industries that have been feeling the brunt of this trend and that are facing the most highly publicized and potentially damaging claims.

Proceedings have been brought against Freeport-McMoran alleging liability for environmental damage stemming from the company's open pit copper, gold and silver mining operations in Indonesia. The case was dismissed in 1999 on procedural grounds.

Another case filed in federal court against Unocal alleged liability for human rights violations in connection with the Yadana gas pipeline project in Myanmar (Burma). In 1999, the federal court hearing the case denied a motion for class certification following two earlier decisions in which it declined to dismiss the proceedings against Unocal, but held that it had no jurisdiction over the other partners in the project, Total of France and a Myanmar state-owned enterprise, or over the presiding military regime.

Proceedings are also pending against Chevron alleging liability for human rights violations in connection with its operations in Nigeria, and against Texaco alleging liability for environmental damage in Ecuador and Peru.

Each of the companies involved in these cases has vigorously defended itself. So far, none of the cases has led to a decision against the company. Nonetheless, the potential liability must be a source of concern from a financial and business reputation perspective, not to mention the drain on management resources that would otherwise have gone into productive operations rather than time-consuming and costly legal action.

Due Diligence Issue

The threat of class action lawsuits in the United States may speed a trend among large oil, gas and mining companies to view the environmental and social aspects of their international operations as a direct "bottom line" factor and, therefore, an integral part of the business decision-making process, rather than just one of several other, perhaps ancillary, considerations.

It should also serve as a reminder to these companies and their shareholders of the need to include environmental and social conduct in international operations as part of standard due diligence in acquisition and other corporate transactions.

A case in point is the merger announced in October between Chevron and Texaco. Both companies are the subject of separate class action lawsuits based on their international operations. Earlier this year, a federal court in San Francisco allowed a suit brought by several California lawyers representing Nigerians to proceed against Chevron. The plaintiffs allege human rights violations by a Chevron subsidiary operating in Nigeria. Also earlier this year, a federal court in New York declined to dismiss a case brought on behalf of indigenous Amazon rainforest people against Texaco alleging liability for environmental damage caused by a Texaco subsidiary's oil exploration and production operations in Ecuador and Peru. Clearly, representatives of both companies will need to undertake the necessary due diligence to assess the potential exposure and its implications for the proposed merger, and shareholders will need to factor it into the decision whether to merge. ■

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claimed that 7% to 8% of this income was earned in New York. Texas Eastern complained that this allocation looked solely at receipts from sales of gas in New York while ignoring the transportation over long distances that had to occur to bring the gas to New York. The company said the tax acts as an obstacle to interstate commerce because of the way it is imposed in violation of the commerce clause in the US constitution.

A New York appeals court disagreed in October.

ANOTHER UTILITY files a back claim for investment tax credits for the period 1986 through 1990.

The US used to allow companies investing in new equipment to claim as much as 10% of the cost as a credit against income taxes. The idea was to induce companies to invest in new plant and machinery, thereby creating more jobs. Congress repealed the investment credit at the end of 1985. However, a company could still claim investment credits as late as 1990 on any property that it could show it had to build "to carry out a written service or supply contract" in effect at the end of 1985.

A growing number of utilities have argued that they qualify for these tax credits on all their spending on power plants during the period 1986 through 1990 on grounds that their legal franchises to serve local ratepayers required them to invest in new power plants and other equipment. No one has won such a claim yet in court.

Nevertheless, Con Ed filed suit in September to claim back credits. The case is before a federal district in New York.

OWNERSHIP BY VOTE may not be an easy matter to determine.

The US tax laws require that a parent company own a subsidiary at least 80% by vote in order to file a consolidated tax return. Some strategies to defer US taxes on offshore investments — particularly in Latin

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America — require that one own a subsidiary more than 50% by vote. Most companies look simply at the number of board members to determine ownership by vote. For example, if the parent can appoint four of five board members, then it owns the subsidiary 80% by vote.

A decision last year by the 6th circuit court of appeals in *Alumax v. Commissioner* has thrown a wrench into these calculations. In the case, US company Amax controlled eight out of ten votes on the board of its subsidiary Alumax. Japanese interests controlled the other two. However, the Japanese held a veto right in essense over all important matters. In addition, the board had to pay dividends amounting to 35% of its net income; it had no discretion.

The court said the 80% voting control by Amax was illusory.

The case was a focus of discussion at meetings of the tax section of the New York State Bar Association this fall. The bottom line is US companies must look more closely at the details of how control is shared with minority partners.

CAREFUL when selling a subsidiary to a related company.

A Dutch company with operations in the United States sold one of its US subsidiaries — Sub A — to another US subsidiary — Sub B. The IRS invoked section 304 of the US tax code to treat the purchase price paid by Sub B as a dividend to the Dutch parent. It demanded withholding taxes on the dividend. The US collects a 30% withholding tax on dividends paid by US companies to foreign shareholders, although the rate may be reduced by treaty.

The IRS action is described in a legal memorandum the agency released in September.

Section 304 of the US tax code is aimed at preventing end runs around the US tax system by paying out earnings in form as purchase price for a related company. Under this section, money paid to buy a sister subsidiary is treated as a dividend to the common parent to the extent of the combined "earnings and profits" of the two subsidiaries.

BRIEFLY NOTED: Senator Charles Grassley (R.-Iowa), who takes over as chairman of the Senate tax-writing committee in January, has been an advocate for section 45 tax credits for windpower projects and has also wanted the credit to be available for coal-fired power plants that co-fire with biomass . . . . A World Bank report in October said over 80% of businesses in Uganda pay bribes, and 70% of businesses reported paying more in bribes to corrupt officials than they paid in corporate income taxes. The US Foreign Corrupt Practices Act makes it a crime for US companies or individuals to pay bribes to win business. The law holds people accountable for actions by agents or partners that they should have known would occur. The World Bank report will require greater due diligence when doing deals in Uganda . . . . The IRS said in a "field service advice" in September that utilities may not deduct the cost of removing asbestos insulation at power plants. The cost must be capitalized into the tax basis in the power plant.

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

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