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California: The Financial Effects Of The Crisis

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Californians received an early warning in May of what is expected to be a long summer of blackouts. Hot weather pushed up air conditioning loads and plant outages limited supply, forcing the California independent system operator to implement rolling blackouts. More than 225,000 Californians had their electricity cut off on May 7 and 8. The blackouts were a reminder of the four days of blackouts — and numerous "stage 1" and "stage 2" alerts — earlier this year. They are a harbinger of things to come.

Unprecedented levels of outages are expected to hammer California this summer.

Low water levels throughout California and the Pacific Northwest will significantly reduce hydroelectric generation. Fewer customers are available for voluntary interruption than in 2000. Available generation will be limited by concerns about creditworthy buyers, permit limitations, potential gas curtailments and high gas prices, the operational limitations of aging power plants and — possibly — market manipulation. Regulatory and political efforts in California to promote conservation and add peaking plants have been too little and too late. The California supply system has little or no cushion.

The North American Electric Reliability Council predicts California will be forced to curtail customers for up to 260 hours. Other estimates put the number of blackout hours as high as 1,000 if the summer is warmer than normal.

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THE BUSH ENERGY PLAN faces an uncertain future in Congress after the change in control of the US Senate.

The plan calls for several changes in tax law that would affect the project finance community.

The president asked the Treasury Department to work with Congress to allow either an investment tax credit or faster depreciation for cogeneration facilities — called "combined heat and power" plants. A cogeneration facility would have to jump

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Rotating blackouts are the most obvious sign that California has failed to tame the power crisis that erupted last fall. However, once the blackouts are over, the citizens and businesses in California will continue to suffer from the after effects of the crisis.

This article focuses on the longer-term financial impact of the electricity crisis for the state, its citizens and some key players in the market.

Roots of a Financial Meltdown

Pacific Gas & Electric Company, or PG&E, and Southern California Edison, or Edison, were trapped until recently between runaway wholesale market prices and frozen retail rates. The two utilities ran up deficits at a rate of about $1 million an hour in order to buy electricity for their customers. Although both utilities borrowed money to keep up with their mounting losses, the creditworthiness of both evaporated as these deficits climbed. The financial hemorrhaging ultimately led both utilities in January 2001 to default on payments to the California power exchange — or CalPX — and California independent system operator — or Cal ISO — which, in turn, could not make payments to generators and power markets who had sold through them. The utilities also stopped payments to qualifying facility projects — or QFs — gas suppliers and lenders. Eventually, this led to the CalPX filing for bankruptcy.

Electricity suppliers refused to sell to PG&E, Southern California Edison and the Cal ISO due to credit concerns. The state then stepped in to fill the gap.

California's Department of Water Resources, or DWR, is now the single largest power buyer in California. California Governor Gray Davis signed legislation in February authorizing DWR to enter into contracts for the purchase of electricity and to provide power not only to PG&E and Edison, but also to local publicly-owned electric utilities. To date, DWR has negotiated about 25 long-term contracts with terms of up to 20 years; the agency has nearly 10,000 megawatts under contract for the period 2001 to 2010. Few details of these contracts are public.

DWR is covering most of the utilities' "net short" position — the power needed to meet electricity demand after accounting for purchases from QFs and generation still owned by the utilities. DWR's purchases, combined with an average 7% demand reduction due to conservation by consumers, are expected to cover about 70% of that net short position in June and July and 60% in August. In other words, DWR will be forced to buy over 10% of California's power needs in the spot markets this summer. DWR already has spent well over $5 billion for power purchases.

The governor plans to reimburse the general fund and finance power purchases for the remainder of 2001 from the sale of $13.4 billion in revenue bonds. This will be the largest municipal bond issue in US history, dwarfing a 1998 Long Island Power Authority issue. The governor signed legislation authorizing the bond sale in May.

Governor Davis claims the revenue earned from the sale of bonds will be sufficient to replenish state coffers. However, those projections are based on the state paying an average price of $195 an mWh during the hot summer months ahead. Power at that price may be hard to find. Futures prices for power are closer to $300 an mWh for the summer months. This spring, the state paid on average $346 an mWh for power. Thus, there is uncertainty about the ultimate size of the bond issue and whether it will be enough to cover the state's purchases in the months ahead. In addition to these uncertainties, other factors could undermine the state's ability to issue the bonds.

The PG&E bankruptcy is complicating the bond issue. PG&E filed for reorganization under Chapter 11 in federal bankruptcy court on April 6. The utility said it had run up debt of more than

$9 billion by the time of the filing. Its principal creditors are independent generators and power marketers, natural gas suppliers and banks. This is the largest investor-owned utility bankruptcy and the third largest corporate bankruptcy in US history. Robert Glynn, Jr., chairman of Pacific Gas and Electric Company, said of the bankruptcy filing, "We chose to file for Chapter 11 reorganization affirmatively because we expect the court will provide the venue needed to reach a solution, which thus far the state and the state's regulators have been unable to achieve. The regulatory and political processes have failed us, and now we are turning to the court."

The threat of a potential ballot initiative to overturn the revenue bond legislation could also slow or halt the bond sale.

Effect on QFs

One group hit hard by the utilities' financial meltdown is California QFs. More than 600 QF projects provide 20% to 30% of California's power under long-term contracts, with prices below current market prices. The utilities owe these QFs approximately $2.3 billion. Edison stopped making payments to QFs in November 2000. PG&E paid QFs for purchases in November but, starting in December, paid for at most 15% of power deliveries through the end of March 2001. Many of these QFs were project financed. The utility defaults forced many of them to default on payments to their suppliers and lenders.

Not surprisingly, increasing numbers of QFs have had to shut down. Natural gas suppliers demanded cash payments for fuel deliveries and refused to extend credit to QFs. Without fuel deliveries, some QFs were forced to stop generating. As much as 3,000 megawatts of QF capacity went offline. On March 19 and 20, California was hit with rotating blackouts, affecting as many as 450,000 customers.

Some QFs took their cases to the courts and

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through at least two hoops to qualify. First, at least 20% of the energy output would have to be in the form of steam or other useful thermal output, according to a version of the proposal introduced earlier this year by Senator Frank Murkowski (R.-Alaska) in the Senate. Bush has not said yet what percentage he is proposing. Second, the plant would have to have an energy efficiency of at least 70% at normal operating rates, or 60% for smaller power plant of up to 50 megawatts. The energy efficiency is the energy content of the output compared to the energy content of the fuel that went into the power plant.

Bush also wants to extend an existing tax credit of 1.7 cents a kWh for generating electricity from certain renewable fuels. The current credit can be claimed on electricity produced from wind, closed-loop biomass and poultry litter. Bush did not endorse an extension for poultry litter. However, he called for expanding the definition of biomass that qualifies to include most types of biomass and to allow the credit at power plants that co-fire with biomass and coal.

In a surprising development, Bush said he wants to expand the section 29 tax credit — a tax credit currently of $1.059 an mmBtu that can be claimed by producers of synthetic fuel from coal or gas from biomass, tight sands, coal seams or Devonian shale — to cover "new landfill methane projects." Bush said projects at landfills that are already required by federal law to tap the gas might qualify for a lower credit than projects at other landfills.

Finally, Bush said he wants to reward Americans who buy hybrid cars using fuel cells between 2002 and 2007 with a new tax credit.

The plan faces an uncertain future in Congress. Democrats are expected to take charge in the Senate in early June after Senator James Jeffords (R.-

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the Federal Energy Regulatory Commission. Caithness filed suit in a Nevada federal court for authority to place a lien on Edison's share of the Mohave generating station. The Nevada court sided with Caithness, allowing the lien to be put in place until Edison made good on past payments to Caithness. CalEnergy filed suit against Edison for the right to sell power to other purchasers without terminating its power purchase agreements. A California court ruled in CalEnergy's favor, granting it the right temporarily to suspend deliveries of capacity and energy to Edison and to sell to other purchasers. Ridgewood Power and several other QFs asked FERC for permission to sell power in the wholesale market.

QF problems caused by the utility defaults are intertwined with a controversial regulatory proceeding. In August 2000, Edison disputed the use of Topock — a major California gas delivery point — gas prices in a formula used to determine short-run avoided cost, or "SRAC," payments to certain QFs. Edison claimed that use of the formula to determine the avoided cost price results in a price that exceeds Edison's true avoided costs because natural gas market prices were distorted by market power problems in the gas market. While California regulators considered changing the formula, Edison began to withhold payments from QFs.

After the March blackouts, California regulators directed the utilities to resume paying QFs for future deliveries but at the same time approved Edison's request to change the formula underlying the SRAC prices. The new formula lowers the prices the utilities must pay to QFs for their power. California regulators replaced the southern California Topock index with one based at Malin, Oregon — the delivery point for gas to northern California — plus the intra-state transportation tariff rate for delivery within the state. In May, the price paid to QFs was 20% lower than what QFs would have earned for their power under the previous SRAC pricing formula. While California regulators ordered the utilities to pay QFs for power purchases on a going-forward basis, past payments owed to QFs remain in limbo.

The decision by the California Public Utilities Commission to revise the formula underlying payments to QFs brought an avalanche of formal protests and lawsuits. QFs argued that the regulators overstepped their bounds, violated PURPA, violated CPUC statutory authority and due process, and made a decision not supported by evidence. Many QFs did not resume full operation after the CPUC decision.

In response to these protests, the CPUC launched an investigation into whether QFs were meeting contractual performance obligations, pointedly noting that QFs that were not generating power were affecting the state's energy crisis and questioning actions QFs had taken in courts and at FERC to sell power outside of their contracts. A press release issued by the CPUC said, "The QFs are seeking to divert electricity they supply under contractual arrangements with the utilities and instead sell that electricity to third parties at higher 'market' rates." The CPUC directed the utilities to file a report with the CPUC outlining the status of energy deliveries over the past 12 months for each QF supplier and to notify the CPUC of any QFs that have made declarations of intent to withhold future deliveries.

Effect on Ratepayers

California ratepayers will face sticker shock when they open their electric bills in June. The state's utilities are just now implementing a new rate increase approved in late March by the CPUC. The impact of the increase may show up in June bills. The rate increase is supposed to finance the state's power purchases .

In January, the CPUC raised all customers' retail electric rates by 1¢ a kWh. The rate increase, called an "energy procurement surcharge," was allocated to customers on an equal cents per kWh basis. The increase was intended to be a temporary measure, giving the CPUC time to investigate the utilities' financial situation in more depth.

However, time and events did not stand still for the regulators. The utilities' financial condition deteriorated and the state's power purchase bills mounted. In late March, the CPUC approved an additional 3¢ increase and made the January 1¢ increase permanent. The combined increase –- equivalent to about a 40% rate hike –- was the largest rate increase in California history. The increase has not affected all customer classes equally. Residential and small business customers that are heavy users of electricity and medium- and large-size customers will bear the brunt of the rate increase. Residential users who conserve energy and keep use below certain thresholds will see little or no increase.

The CPUC has still not addressed completely the priority among the state government, the QFs and utilities for laying claim to the additional revenue brought in by the rate increase. The state cannot sell bonds unless the bondholders are guaranteed an acceptable claim on a share of the revenue. It is not yet clear whether — even with the rate increases — there will be enough money not only to cover the costs of buying power on a going-forward basis, but also to repay the billions of dollars the state has already spent this year.

Appeals are likely to any CPUC decision on the waterfall for these revenues among competing claims.

The utilities have still not been reimbursed for shortfalls run up last year. Several plans are being pursued to address these shortfalls. California officials and utilities are seeking a FERC decision to require both public and private generation owners and power marketers to refund "overpayments" caused by the high prices paid in 2000. This would reduce the shortfall between utility revenues and costs. However, FERC has found

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Vermont) announced he was leaving the republican party, throwing control in the closely-divided Senate to the democrats. Republicans had said they hoped to move the energy plan through Congress this summer. Things will now take more time.

Another complicating factor is it is not clear there is any money in the budget for additional tax relief this year after the republicans spent the full amount authorized on a $1.35 trillion tax cut for individuals.

A TAX AGENDA is already taking shape for next year.

Rep. Bill Thomas (R.-California), chairman of the House Ways and Means Committee, said recently he expects three items to be on the agenda for next year: depreciation, reform of the "subpart F rules" that deal with US taxes on income earned by foreign subsidiaries, and extensions of expiring provisions.

Utilities are pressing for 7-year depreciation of power plants. Most power plants are depreciated today over 15 or 20 years. In the past when Congress has provided more generous depreciation, a project had to be placed in service after the new law took effect to benefit and then it benefited only on spending on the project after the effective date.

Meanwhile, Senators Max Baucus (D.-Montana) and Orrin Hatch (R.-Utah) are preparing to reintroduce their bill this summer on foreign tax issues. The bill is a laundry list of items sought by business. However, a Baucus aide said that the bill will not deal with "interest allocation" problems that prevent most US power companies from qualifying for foreign tax credits when they bring back earnings from abroad. Any relief in this area would be too expensive.

Baucus will become chairman of the Senate Finance Committee when the democrats regain control of the Senate in June.

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only limited potential "overpayments" to date. Even if FERC ordered refunds of all the charges identified as potentially subject to refund, the amounts identified thus far would make no appreciable dent in the utilities' shortfall.

It is not clear that the $13.4 billion the state plans to borrow this summer will be enough to cover the what it will have to pay to buy electricity or that it will even be able to sell its bonds. California could easily find itself having to increase rates further or to dip further into the budget surplus.

In addition, under a recently-executed "memorandum of understanding" between the DWR and Edison, Edison would sell its transmission assets to the state at a price above book value and apply the extra revenue against past undercollections, in an attempt to avoid bankruptcy. The memorandum authorizes Edison to issue bonds for the remaining revenue shortfall to be paid by customers in the future. Edison's remaining shortfall is estimated to be $2 billion.

The proposed deal between Edison and the state has little support in the California legislature. The deal is opposed by consumer groups and the left wing of the democratic party as a bailout for Edison and by most republicans as a plan to put the state in the power transmission business. The plan addresses electricity problems at most only in southern California. There is nothing to recommend the plan to legislators from the northern part of the state.

At the end of the day, California's ratepayers may already have been hit with record rate increases, but they should expect more increases. Higher rates will eventually dampen electricity demand, thereby reducing future generating capacity shortfalls.

Effect on State Government

The golden state's finances are not looking very golden. The dot.com economy bubble burst. An overall economic slowdown appears likely. Tax revenues are expected to decline. Pending rate increases will disproportionately hit California industry.

Credit rating agencies placed the state on credit watch in January. In April, Standard and Poor's lowered the state's rating on general obligation bonds from "AA" to "A+". It similarly revised other lease ratings and ratings for the California health facilities construction loan insurance fund, known as Cal Mortgage. Only the state's cash reserves, diverse economy, and the planned sale of revenue bonds saved California from a more drastic rating downgrade. Other ratings agencies followed suit with their own credit downgrades.

In May, Governor Davis revised his budget proposal for the upcoming fiscal year. The revisions lowered previous projections by $5.7 billion. The governor proposed cutting spending for transportation, housing, and the environment by $2.5 billion as a result. California's budget surplus is now expected to dwindle to only $1 billion next year, down from over $5 billion this year. Some political observers believe the governor proposed insufficient reductions and an inadequate reserve, leaving the legislature to assume responsibility for another $2 to $3 billion in budget cuts.

According to the state controller, California has paid $5.1 billion through early May to buy electricity. Nearly all was to cover purchases made in the spot market. DWR paid only $36 million for power under long-term contracts. The rest was short-term spot market power. In January, the governor projected the state would only spend $1 billion to address the electricity crisis. In fact, the state is now spending about $70 million a day and $1 billion a month.

The key question is how long California can maintain such spending. The answer may be until November 15, 2001. After that, general fund expenditures for short-term purchases of electricity cannot exceed $500 million in the aggregate. This legal restriction, codified recently by the legislature, is intended to protect the general fund from future energy purchases.

The scenario could hardly be more bleak. Current monthly spending is twice this amount, almost all of which is spent on spot market purchases, but the state will be restricted to spending only $500 million. It is far from obvious that either PG&E or Edison will be financially capable of reassuming the responsibility for power procurement if the state is forced to exit the business.

Effect on PG&E Creditors

The full financial impact of PG&E's bankruptcy filing cannot be known at this point, but it will undoubtedly be far-reaching. There are approximately 100,000 claims against the utility in addition to the top 20 creditors (see table). In addition, consumer advocacy groups and nonprofit groups are seeking their place at the negotiating table.

PG&E's Top 20 Creditors	Name of Creditor
The Bank of New York	$2,207,250,000
California Power Exchange	$1,966,000,000
Bankers Trust Company	$1,302,100,000
California Independent System Operator	$1,128,800,000
Bank of America, N.A.	$ 938,461,000
US Bank, Corporate Trust Services	$ 310,000,000
Calpine Gilroy Cogeneration LP	$ 57,928,385
Calpine Greenleaf Inc.	$ 49,452,611
Crockett Cogen, A CA Limited Partners	$ 48,400,572
Calpine King City Cogen LLC	$ 45,706,378
El Paso Merchant Energy	$ 40,147,245
GWF Power Systems LP	$ 40,122,073
Geysers Power Company LLC	$ 32,867,878
EP Energy Company	$ 29,523,530
Enron Canada Corporation	$ 28,210,551
Chevron U.S.A Production Co	$ 24,178,334
Sempra Energy Trading Corp.	$ 23,849,455
Calpine Pittsburg Power Plant	$ 21,576,506
Wheelabrator Shasta Energy Co. Inc	$ 21,508,087
Sierra Pacific Industries	$ 19,888,348

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ELECTRIC INTERTIES take front and center.

The Internal Revenue Service is expected to issue guidance this year on whether utilities must report as income payments from independent generators to connect their power plants to the grid. The generator usually pays the cost of the intertie. The utility insists on owning it. Such payments have not been reported in the past. However, the IRS put the issue under study because of the view of some IRS officials that the payments should be treated as part of the income the utility earns for wheeling electricity for the generator.

Treasury officials say that this item is near the top of the list. Guidance could come out as early as this summer. They are hoping to use the momentum created by work on the Bush energy plan to tackle it quickly.

THE IRS BUSINESS PLAN has several other items on it this year that could affect the project finance community.

They are "guidance concerning the international activities of partnerships," "guidance on international restructurings," "guidance regarding securitization of the rights to recover stranded costs," and further guidance on transactions the US tax authorities do not like that involve use of hybrid entities. A hybrid entity is a company that is transparent for tax purposes in one country but not in another. Tax planners exploit the differences in treatment to produce a number of benefits. For example, such entities can be used to strip earnings from one country without paying taxes in it while at the same time avoiding taxes in the other country.

NEW "TRUE LEASE" GUIDELINES were issued by the IRS in May.

The IRS has had guidelines since 1975 on when

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One important issue in the early stages of the bankruptcy proceedings is the jurisdictional clash between the CPUC and the court. PG&E is seeking an injunction from the bankruptcy court against part of a March CPUC order. In that order, the CPUC required PG&E to recalculate various transition cost balancing accounts back to 1998. The effect of the order was to reduce PG&E's net undercollections. If upheld, the effect would be to shift billions of dollars of liability from PG&E's ratepayers to shareholders. The CPUC is claiming that it has sovereign immunity from bankruptcy court jurisdiction, and this overrides the PG&E reorganization effort.

The fiscal impact of PG&E's bankruptcy filing on those QFs holding PG&E receivables is another unknown. PG&E wants to delay its decision on whether to assume or reject the QF contracts until it finishes working out a reorganization plan. QFs have filed a variety of petitions with the bankruptcy court including ones asking for the suspension of their obligations under the contracts with PG&E.

Political Muddle

Meaningful solutions to California's electricity crisis have been hard to achieve. Although all parties have solutions, partisan bickering, longstanding animosities, and real conflicting interests hamper the search for a consensus.

The political agenda is dominated by attempts to shift blame to someone else. California officials claim the problem is that the federal government has refused to implement regional price caps while Texas-based generators manipulate energy markets and Federal regulators. Federal officials point to California's decision to implement a flawed restructuring program, hinder the development of an effective regional power market, attempt to repeal the laws of economics and hamper the development of new supplies by a cumbersome siting process.

Governor Davis recently declared "war" on the generators and power marketers and has signed legislation to set up a state power authority.

The state attorney general, Bill Lockyer, who has been investigating the practices of power generators and marketers for almost a year, said recently, "I would love to personally escort [Enron Corp. Chairman Kenneth] Lay to an 8 x 10 cell that he could share with a tattooed dude who says, 'Hi, my name is Spike, honey.'"

The politicians also continue to rail against the state's utilities. Perhaps in response, PG&E appeared to time its bankruptcy announcement so that it was made the morning after the governor went on state television to unveil his plan to tackle the electricity shortage.

Among the few areas of consensus are the need for new supplies and additional conservation.

The California Energy Commission has expedited the applications for several peaking plants. Governor Davis issued an executive order directing the commission to permit new peaking and renewable power plants on an expedited schedule. Power plants that are permitted under this emergency process are exempt from the requirements of the California Environmental Quality Act. California has also relaxed its stringent air emissions limitations for this summer.

Governor Davis also issued an executive order to encourage greater energy conservation. The order directs the CPUC to create financial incentives for conservation by residential, commercial and industrial customers. Under this program, the utilities will provide rate reductions of up to 20% to consumers who reduce their electricity consumption by at least 20% during June to September 2001. The program will be financed through a reduction in the utilities' payments to the Department of Water Resources in subsequent months.

These efforts may provide some help to California this summer, and will certainly bring more relief in 2002.

The California Energy Commission has permitted 24 power plants in recent years, of which nine plants representing over 6,000 megawatts are under construction. The first 3,000 megawatts should be on line by the end of this year.

In the end, the market may be a powerful enough force that it overcomes the political muddle. Californians are just starting — half a year into the crisis — to see meaningful price signals, which should dampen demand. Normal rainfall should eventually return to the West and further increase supplies. Increased gas drilling and expansions of the gas system should dampen the Western gas basis differential. In the longer term, the market will adjust. The forecast in the shorter term is for an intemperate summer. ■

New Product For Devaluation Risk

by Kenneth W. Hansen, in Washington

The first project financing to be guaranteed against devaluation risk closed successfully in mid-May.

AES borrowed $300 million for a 15-year term to refinance its costs of acquiring the recently-privatized Tiete hydroelectric generating stations in Brazil.

The transaction is noteworthy not only because of the way it handled devaluation risk, but also because it is the first project-risk bond in Brazil to pierce the sovereign ceiling and achieve an investment grade rating. The debt was rated Baa3 by Moody's Investors Service and BBB- by Fitch. The rating reflects — in addition to strong project economics — support by the Overseas Private Investment Corporation both with

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it will issue advance rulings confirming that a transaction set up in form as a lease of equipment is in fact a lease for tax purposes. The issue is important to lessors who want to know they can claim tax depreciation on the equipment. The new guidelines are in Revenue Procedure 2001-28. For the most part, they merely repeat the earlier rules.

THE NEW YORK GAS IMPORT TAX is unconstitutional, a New York appeals court said in May. Efforts in the state legislature to fix it have been put on hold after El Paso and other companies with a large stake in the outcome complained.

New York collects taxes on natural gas consumed in the state. The tax is collected by the local distribution company. However, large industrial consumers of gas it can avoid the tax by buying gas directly at the gas field and paying a pipeline to transport it. Therefore, the state imposed a separate gas import tax "on the privilege or act of importing gas services or causing gas services to be imported into this state for [the importer's] own use of consumption in this state." The tax is 4.25% of the gas price.

Tennessee Gas Pipeline Co. owns an interstate pipeline that runs through New York. The company draws on some of the gas it is transporting cross state to operate pumps or compressors along the pipeline. The state assessed it for $1.6 million in back taxes. The court said the tax was unconstitutional because it burdened interstate commerce. The pipeline company argued that there was no mechanism for giving it credit to the extent it had already paid taxes on the same gas to another state. The state legislature had foreseen this potential problem. The tax has a "savings clause" directing a court to interpret it in a way that allowed credit for taxes paid to other states if necessary to

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conventional currency inconvertibility insurance and a new guaranty by OPIC of the US dollar value of local currency net revenues. This is a form of devaluation coverage.

New Product

For the past year, OPIC — the US government agency that since 1971 has provided political risk insurance and financing in support of US investment in emerging markets — has worked with Banc of America Securities on a structure to provide lenders to a project with protection against fluctuations in currency values. The structure can be used to protect any project that generates local currency and is otherwise commercially sound against defaulting on its dollar-based debt because of serious devaluation or depreciation of the local currency.

The AES Corporation proposed Tiete as a test case for this new product.

The coverage is not insurance in the traditional sense but rather is structured as a standby foreign exchange liquidity facility upon which the project company can draw if, as a consequence of devaluation, it would otherwise be unable to make its dollar debt service payments. OPIC disbursements then become a junior loan to the project company whose repayment is subordinated to current payments on the bonds.

The OPIC disbursement must be both necessary and sufficient to avoid a payment default.

It must be necessary in the sense that, if the project company can make the payments due notwithstanding the devaluation or depreciation, then no OPIC disbursement will be available.

The OPIC disbursement must be sufficient to avoid a default. That is, if the maximum amount of the OPIC disbursement available as a consequence of the devaluation, when added to the current dollar value of project revenues or other sources of funds available for debt service, is inadequate to make the payment then due, then an OPIC disbursement will again not be available. In other words, OPIC will not disburse "into a default."

Through use of such triggers, the OPIC coverage distinguishes exchange rate risks from operational risks, with OPIC supporting the former while leaving the project, and its lenders, to other devices to deal with the latter.

Substantial economic and policy analysis supported the development of the devaluation product. The basic economic theory underlying the product is "purchasing power parity" – the proposition in international economics that exchange rates will adjust to reflect the relative buying power of each currency; that is, exchange rates will adjust to inflation.

Economic Analysis

OPIC retained Wharton Economic Forecasting Associates to study the adequacy of relative inflation rates as an explanation of exchange-rate changes in a number of countries, including Brazil. The study confirmed that "depreciation" — or market deterioration in a currency's value — and "devaluation" — or change in currency value declared by monetary authorities — that are not explained by current inflation do occur naturally. In some countries — including in recent years Indonesia, Thailand, Russia, Mexico, Brazil and Argentina — such exchange rate volatility has been substantial. The Wharton analysis was comforting to OPIC because it suggested that significant deviations of currency values from the rates predicted by inflation tend to be of limited duration. While headlines capture dramatic devaluations, they tend not to report the return of rates to more predictable levels.

The Wharton analysis suggested that even dramatic devaluations are likely to pose only a temporary problem for an otherwise healthy project, unless the dollar debt is disbursed at a time when the local currency is significantly overvalued. The consequence for the OPIC product is that draws from a standby facility may occasionally be needed, but a project that is otherwise financially sound in local currency terms should be able to repay those draws in relatively short order.

One motivation for the product has been the observation that, contrary to the expectations of many lenders and developers, dollar-tied offtake agreements may not effectively protect a project and its investors from devaluation risk. When severe devaluations occur, the risk of offtaker default becomes a high likelihood. Consider Indonesia. Offtakers face strong customer resistance at passing on price increases triggered by international currency market events that seem far removed from local life. In contrast, if prices under an offtake agreement are tied to local inflation, then price increases will also be tied and be proportionate to the economic changes surrounding both the offtaker and its downstream customers. For reasons of both economics and politics, such contracts are likely to be less subject to breach or repudiation in times of economic turmoil than are dollar-based contracts.

Where the project revenues escalate in proportion to local inflation, the OPIC facility assures that the local net revenue, together with the OPIC disbursements, will be adequate to meet hard currency debt service payments as long as the project is operating successfully in local currency terms.

Future Uses

This was a pilot project for OPIC and has not yet been adopted as a regular product. That next step will depend, in part, on whether demand exists in the marketplace from appropriate projects. Appropriate projects would be those with strong local currency project economics –- so that repayment of draws on the foreign exchange liquidity facility

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uphold the tax, but the appeals court said it was not its job to rewrite the tax.

Most power plant owners who are importing self-help gas into New York have filed protective refund claims with the state. The governor asked the state legislature in May to amend the tax retroactively to provide for a credit. The measure passed the state Assembly, but stalled in the Senate. The effort has now been put on hold.

GIVING AN ISO OPERATING CONTROL OVER TRANSMISSION ASSETS will not jeopardize tax-exempt bonds that a utility used to finance them, the IRS said.

The IRS made the statement in a private letter ruling made public in May. There are currently five "independent system operators," or ISOs, set up to manage the grids in California, Texas, New York, New England and PJM (Pennsylvania, New Jersey and Maryland). The Federal Energy Regulatory Commission is also pushing utilities to set up regional transmission organizations, or RTOs, to operate the grid in other parts of the country. At a minimum, these entities have operating control over the grids. In some cases, they might take legal title. Utilities worry about the tax effects of transferring their transmission assets.

The utility in the ruling had used tax-exempt debt under the "two-county rule" to finance portions of its grid. This rule let private utilities that serve an area no larger than two contiguous counties use tax-exempt financing for their assets. The rule has since been repealed, although power companies that qualified for such financing at the time of repeal can still use it.

The utility planned to give operating control over its grid to an ISO. This called into question whether

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can be expected as exchange rates return to more "normal" levels. Appropriate projects would necessarily have project revenues that adjust to local inflation. The more often tariffs under an offtake agreement adjust to inflation, the more appropriate would be OPIC's product to protect the project from foreign exchange volatility.

Additionally, appropriate countries would exclude those with currencies generally perceived to be artificially supported at overvalued levels, creating the risk of a one-time devaluation unrelated to current local inflation. ■

Russia Edges Closer To Restructuring UES

by Laura M. Brank and Peter Gloushkov, in Moscow

The Russian government approved an ambitious plan in late May to restructure the national electric utility, RAO Unified Energy Systems.

However, many details of the plan are still in flux, and the government has set a deadline of June 19 for a working group to report back.

The restructuring is expected to occur in two stages. In the first stage, 32 power stations belonging to UES will be divided among five to seven new generating companies, and 73 regional subsidiaries of UES will be consolidated into a smaller number of entities. UES itself will become the core of a new state-owned company that will own the national grid.

UES management estimates that it needs $35 billion in new investment over the next nine years to keep up with demand for electricity.

A report released in May by Arthur Andersen — consultants for the Russian government — warned that there will be severe shortages of electricity by the winter of 2002-2003 unless a radical overhaul of UES is undertaken soon.

Background

Russia's power sector is one of the world's largest, with nearly 200 gigawatts of nameplate capacity and three million kilometers of high-voltage transmission lines. The sector is incorporated and consolidated primarily under one entity — UES — which accounts for over 72% of Russia's electrical power production. UES also owns the high-voltage transmission grid and central dispatch systems, as well as between 14% and 100% of the shares in Russia's 73 regional energy companies — called Energos — and 32 federal generating stations. Together with UES, these companies are referred to as UES Holding, one of the largest holding companies in the country, operating through six unified energy systems: Northwest, Central, Middle Volga, Urals, Northern Caucuses and Siberia. In addition, UES owns 59 research and development institutes, 30 dispatch companies, 22 "non-profile" companies — those not involved directly in the energy business — and construction, repair and other support companies. These companies, plus UES Holding, constitute the UES Group of Companies.

The market capitalization of UES has reached $4 billion with annual sales of $10 billion, according to the latest data published in March.

Given the size of UES and the scope of its activities, its privatization and restructuring have been a major topic of discussion among project developers and lending institutions with an interest in Russia.

Recent operating statistics from UES may also increase the value of its assets in comparison with previous years. For instance, UES reports that power consumption in Russia is increasing. In 2000, the consumption level rose by 3.9%, and an additional increase is likely in 2001. Anatoly Chubais, the chief executive officer of

UES, said that UES managed last year to obtain 100% of its payments in cash. In previous years, including as late as 1998, the cash payment rate was as low as 20% with other payments being made through barter arrangements or through the "shadow" economy. These payment problems discouraged developers and banks from investing in Russian power projects and, as a result, almost no investment has been made in the sector in the last 10 years.

Legal Framework

UES was established in 1992 by the Russian Committee for State Property Management. In May 1998, the Duma passed Law No. 74-FZ, which restricts ownership by foreign states, companies and individuals of shares in UES to 25% of all types of shares. The same law established that 51% of the shares of UES must remain federal property and may not be sold, pledged or otherwise disposed of. The Russian government currently owns approximately 52% of the outstanding shares of UES.

Electricity Tariffs

Wholesale power in Russia is sold on a federal wholesale market called "FOREM." FOREM functions on the basis of an April 1995 law called Law No. 41-FZ and Resolution No. 793 that the federal government issued in July 1996. All power produced by the generating companies of UES and other producers — like the nuclear power plants that are outside the UES umbrella — is supplied to FOREM, where it is then purchased wholesale.

The principles for establishing power tariffs were first outlined in a government resolution No. 121 in February 1997 and were modified by a presidential decree No. 889 in July 1998 and a government resolution No. 915 in August 1998.

Tariffs are set by the Federal Energy Commission, or "FEC," the state regulatory authority for

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the grid would now be used in more than two counties, jeopardizing the tax exemption on the bonds. The IRS said it would not be. The key to the ruling was that the actual use of the grid was not expected to change. The IRS also analyzed the effects of a single rate structure for all transmission over wires controlled by the ISO, and the fact that this meant that the benefits of tax-exempt financing by the two-county utility would be shared to an extent with transmission customers over the entire grid controlled by the ISO, before deciding this was not a problem.

ARGENTINA said it will tax gain from the sale of shares in Argentine companies.

Gain from the sale of shares in "public" companies remains exempted from tax. The new tax was announced by decree in late April. Foreign investors with projects in Argentina will be subject potentially to the tax if they hold shares in an Argentine company through an offshore holding company. The tax will be collected by withholding by the buyer of the shares. The effective rate is 17.5%. However, the seller has the option of filing a return and paying taxes himself.

LOUISIANA wants new merchant power plants being built in the state to commit to supply at least 25% of their electricity in Louisiana in exchange for property tax breaks. Governor Mike Foster (R.) made the announcement in late April on his weekly radio program. The state offers property tax abatements for up to 10 years for new manufacturing facilities. The abatements have to be negotiated with the Board of Commerce and Industry.

CORPORATE ACQUISITIONS will be a little easier to structure as "tax-free reorganizations."

The IRS issued two revenue rulings at the end of

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UES Restructuring

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the energy market. In establishing tariffs, the FEC must ensure — among other things — full compensation of the established costs of power producers along with a return on profit necessary for "self-refinancing." However, in practice, the process for establishing tariffs remains very bureaucratic, heavily influenced by state policy, and non-transparent. Real market conditions are generally not taken into consideration.

The fact is that no real market for power exists in Russia today. Even UES admits that FOREM is not a real market, as sellers are forced to sell power to buyers designated by UES who are largely related to UES.

Restructuring Plan

The plan adopted in principal by the government in late May resembles in part a restructuring proposal that Chubais floated late last year. That plan came under fire from minority shareholders and the Russian communist party who complained that it would "strip the most valuable assets of UES" and deprive shareholders of control over the company.

Details are still in flux.

Arthur Andersen, which has been advising the government, made its recommendations in a report on April 9. Arthur Andersen recommended that the restructuring take place in two stages. In the interim phase, which should begin this year, UES would become a temporary holding company to be created on the basis of UES' current assets and containing several new structures, while retaining UES' current shareholders.

The temporary holding company would own a grid company, a separate holding company uniting the power stations, between one and five federal generating companies, a thermal power station holding company and up to seven guarantor energy suppliers.

The federal generating companies would include those stations currently wholly-owned by UES and the largest thermal stations. The stations, classified as subsidiaries of the generating companies, which form the foundation of the electricity market, would be able to charge market prices, and their activities would be licensed.

The thermal power station holding company would include the rest of the power stations. The guarantor suppliers would receive the distribution arms of UES' current subsidiaries, but the Russian government would continue to set tariffs for these suppliers. The grid company would own the high-voltage transmission lines and dispatch facilities.

During the transition, the UES temporary holding company would own between 51% and 100% of all of the above structures. In the second phase, the temporary holding company would be liquidated and its controlling stakes in the various structures, except for the grid company, would be sold.

The Russian government would retain at least a 51% stake in the grid company, which would remain a monopoly. Shares in the grid company would be swapped for UES preferred non-voting shares.

Under the Arthur Andersen plan, shareholders of all UES subsidiaries would be offered the opportunity to exchange their shares for shares in the new companies. Shareholders of UES would receive shares in each of the federal companies, in each guarantor supplier, in the power station holding company and in the grid company, in proportion to their shares in UES. It is unclear how long this transitional phase will last.

Shareholders in the UES regional subsidiaries are also expected to receive shares in these companies. The plan provides that each new company established would present the minority shareholders of its subsidiaries with specific schemes for exchanging shares six months after establishment of such company.

The Arthur Andersen plan calls for creation of three power markets. The first, the federal market, would deal with the export of power. The second, the guaranteed market, would operate using regulated tariffs. The last, the independent market, would operate on market prices.

The power market would be regulated by a new federal body, which would be in charge of licensing power companies. The Arthur Andersen plan provides that a restructuring would last as long as seven or eight years. It would not be expected to require an increase in current tariffs.

In addition to the Arthur Andersen plan, a working group of the State Council headed by Victor Kress, the governor of the Tomsk Oblast, prepared a proposal that was presented to the Russian president at the end of April. Details of this plan remain mostly unclear. UES itself is also being advised by various consulting firms on different options for restructuring.

At the meeting on May 19, 2001, the Russian government provisionally approved the main principles governing the reform of the electricity market in Russia as set forth in a plan proposed by the Ministry of Trade and Economic Development drafted on the basis of submissions from UES and Arthur Andersen. However, due to certain discrepancies between this proposal and the proposals of the working group of the State Council and the Ministry of Energy, the full restructuring plan was sent back for further revision and additional input from the working group of the State Council.

The government requested that the final version of the restructuring plan be submitted for approval by June 19, 2001.

Andrei Sharonov, deputy minister of trade and economic development, confirmed that in the second phase of its restructuring, UES would be separated into two entities: grid and non-grid holdings. The state would own 52% in each entity (which reflects the current ownership

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In Other News *cont.*

May that relax technical rules on how mergers must be structured in order to qualify as tax-free reorganizations.

One of the rulings — Revenue Ruling 2001-24 — dealt with “reverse subsidiary mergers” where a parent corporation sets up a subsidiary to merge into the target company. The US tax code had been viewed in the past as requiring that the merged subsidiary remain a first-tier subsidiary of the parent after the merger. However, the IRS said in the ruling that the parent could drop the merged subsidiary into another subsidiary — making it a second-tier subsidiary — and the original merger would still qualify as tax free.

The other ruling — Revenue Ruling 2001-26 — dealt with so-called two-step mergers where a parent or subsidiary uses voting stock of the parent first to buy shares of the target company in the market. Then once it owns a majority of the stock, it arranges the merger of its subsidiary into the target. The IRS said it would treat both steps as part of a single tax-free reorganization.

BRIEFLY NOTED: Carolina Power & Light Company continues to insist that a nuclear power plant was placed in service for tax purposes in 1986 even though the plant was not synchronized with the grid or had a full operating license from the US government until 1987. The IRS takes the position the plant went into service in 1987. The case is before the US court of appeals for the 4th circuit . . . . The World Trade Organization is expected to rule on June 22 on whether new US tax law provisions that tax income from exports of US-made products less heavily than other kinds of income are an illegal export subsidy. The US risks retaliatory duties on as much as $4 billion in US exports to Europe. ■

— contributed by Keith Martin in Washington.

UES Restructuring

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structure of UES), and it would eventually increase its stake in the grid company. Non-grid holdings would include five to seven generating companies, and 40 to 60 wholesale-distribution companies. According to various reports, state control over the grid was one of the main issues discussed at the May 19 meeting. Under the Arthur Andersen proposal, the federal grid company would remain a state-owned monopoly. Local grids would be merged with the federal grid company. At the same time, the state would decrease its stakes in regional generation companies. Sharonov also noted that reform of the power sector will likely require that significant legislative amendments be adopted.

Interestingly, Chubais, who was present at the Russian government meeting, said that March 31, 2004 was set as the date when UES will "end its existence."

Whatever plan is eventually adopted, it seems clear that significant attention is now being paid to this issue and that a certain momentum exists in the Russian Federation in favor of restructuring UES. ■

Do Turkish Projects Make Sense?

by Kimberly Heimert, in London, and Ender Özeke with Hergüner, Bilgen & Özeke, in Istanbul

Large additional investments in the Turkish power sector are fairly unlikely in the near future.

However, investors who want to establish a foothold in a market that undoubtedly will be extremely important in the future may consider investing, in the meantime, in inside-the-fence power plants that serve factories that produce for the export market.

Turkey adopted a new electricity law in February 2001 that provides for a new licensing regime and permits bilateral contracts. The new law also sets in motion a transition to a liberal and competitive market environment for the power sector. However, several factors make Turkey a tough place to do a project at the moment. These include the collapse of the Turkish economy, the lack of implementing and regulatory legislation for the new electricity law, the unavailability of government guarantees for virtually all projects, a decline in power demand projections, the declared illegality of certain ownership rights, and a corruption scandal.

Implementation

The legislative framework required to implement the new electricity law has not taken shape as quickly as previously expected. Although the new law contemplates a transition period of two years, it is widely acknowledged that this period actually will be substantially longer. A number of steps must be taken before the new law can be fully implemented. A new regulatory body, called the Energy Market Regulatory Authority, must first be established and then it must issue a number of implementing regulations. TEA, the state-owned electricity generation and transmission company, must be restructured by separating its generation, transmission, and trading functions into new companies.

At this time, no regulatory body has been formed, no regulatory framework is being discussed seriously and the restructuring activities have been delayed.

Government Guarantees

The Turkish government is not expected to issue any additional guarantees for power projects.

The government had been expected for the past several months to stop issuing guarantees in response to International Monetary Fund demands and other pressures. However, until recently, the government was nevertheless expected to issue guarantees for approximately 20 identified projects, all of which are underway. With the deepening financial crisis, the government has had to tighten its belt. Latest indications from the government are that it is very unlikely to provide guarantees for any projects with long-term take-or-pay obligations, although there is some hope that it will provide guarantees for one or two projects that are already fairly developed.

Demand Projections

The projections for huge increases in power consumption for Turkey now appear to have been overstated.

Over the last several years, Turkey has been touted as a huge growth market for power consumption. The original projections for increased power needs were based on the Turkish economy continuing to grow. However, the country's financial crisis has affected the expansion of many industries, including those that are major power consumers. The effect has been severe enough that many now believe that the BO, or build-own, projects currently under construction — including the Intergen projects, which have a total capacity of 3,850 megawatts — will provide enough capacity for Turkey until at least 2005 and possibly beyond.

With the current economic downturn, it is very difficult for anyone to predict what the power needs will be in the next five years and beyond. However, there is concern that if some of the transfer of operating rights, or TOR, projects do not progress, and, therefore, do not receive an infusion of new investor capital, many of the plants that are part of those projects will be forced to close because of severe environmental, safety, and maintenance problems. Obviously, if those are closed, their production will have to be replaced by other projects.

Ownership Issues

A number of distribution TOR projects have been canceled because of their owners' interests in radio or television outlets. Turkey's radio and television law prohibits anyone with more than a 10% share in a radio or television company to participate in a tendered contract with the government. Developers involved in approximately 10 to 15 projects that are affected by this prohibition have challenged the law. One developer has recently exhausted the legal appeal process unsuccessfully.

In addition, the new electricity law requires that the transfer of rights in all TOR projects must occur no later than June 30, 2001. That transfer is impossible for the affected projects until this ownership restriction is removed. Although there is some discussion that the relevant legal provision may be repealed, it is generally believed that none of the affected projects will be able to meet the deadline established by the electricity law.

Corruption

Indictments were issued against several government officials and business people in the energy sector earlier this year, adding to the disarray. Turkey, like most emerging markets, has struggled to rid itself of corrupt business dealings. Although these recent developments have caused some additional uncertainty, there is hope that they will transform the way business is done in the Turkish power industry. Unfortunately, the effect in the short term is to cause an already slow bureaucratic machine virtually to cease all activities in connection with negotiating and developing power projects.

Industrial Projects

Despite all the problems, investments in smaller power plants adjacent to existing factories that produce for the export market may make sense as

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Turkish Projects

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an interim step for developers who hope to play a more major role in Turkey once the economy recovers.

Although exact projections are impossible at this time, there is little doubt that Turkey's power consumption will continue to increase and will increase dramatically at some point in the future. Developers who are already in the market may be in much better positions to invest in attractive projects.

Turkey has industrial zones in almost every large and medium-sized city, which creates consolidated potential consumer bases throughout the country. Many industrial zone companies export a substantial percentage of their production and, therefore, may be sufficiently creditworthy to justify the financing of a project.

Also, we understand that many of the companies in those industrial zones buy electricity off the grid at approximately $.08 per kilowatt hour. Of course, every project has unique economic requirements, but independent power producers often are able to provide electricity from inside-the-fence projects at substantially lower rates.

Finally, a large majority of new generation that will come on line over the next year relies solely on natural gas for fuel. The ever-changing landscape of the potential gas pipelines to Turkey from Russia, Azerbaijan, Turkmenistan and Iran means that a sufficient gas supply is anything but certain. Therefore, the Turkish government should be very receptive to additional production provided by dual fuel capable plants, or plants that are able to run on more than one fuel.

Unfortunately, obstacles to inside-the-fence projects also exist. First, no licensing body currently exists to issue the required licenses. Second, any excess capacity cannot currently and easily be sold into the grid because transmission arrangements are unclear and certain volume limitations exist. Third, because of the financial crisis, many companies in Turkey — including large industrial companies — are downsizing dramatically.

Several existing auto-production facilities are looking for strategic partners to help them expand. Investing in such an existing project may eliminate several of the obstacles facing other investments in the Turkish energy sector. For example, existing projects should have the required licenses, the right and ability to sell power into the grid, and customers with a credit history that justifies such an expansion. ■

IRS Reopens Synfuel Window

by Keith Martin, in Washington

The Internal Revenue Service reopened the window in late April for rulings that output from coal agglomeration facilities qualifies as a "synthetic fuel from coal," but it set a number of conditions with which projects will have to comply in order to get rulings.

The IRS will hold projects that apply for rulings to a cap on output.

The agency also put the industry on notice that it will deny tax credits to investors in syncoal projects in two situations when it finds them on audit.

Coal agglomeration facilities use chemical binders to glue together small particles of coal or to effect a chemical change in otherwise usable coal as it passes through the facility.

The IRS announcement represents a middle ground between coal companies who had lobbied the Treasury Department to deny tax credits to projects that they argued do little more than spray petroleum on usable coal and owners of the syncoal plants who argued that the coal lobby was trying to stifle competition for coal customers by putting them out of business. Both sides had significant political support.

Background

The federal government has offered a tax credit under section 29 of the US tax code since 1980 as an inducement to Americans to look in unusual places for fuel. The aim was to reduce US demand for oil and gas from the Middle East by tapping more domestic energy sources. The tax credit can be claimed by anyone who produces gas from biomass, coal seams, tight sands or Devonian shale, or who makes a "synthetic fuel from coal." Projects to make synthetic fuels from coal had to be in service for tax purposes by June 1998 to qualify. The tax credit last year was $1.059 an mmBtu. It is adjusted each year for inflation. Credits for most syncoal projects run through 2007.

Starting in the mid-1990's, several companies developed chemical binders that could be used for gluing together small particles of coal to make pellets or briquettes. The IRS refused initially to rule that use of these binders resulted in a "synthetic fuel," but later changed its mind. More than 50 syncoal plants that use binders were placed in service by the June 1998 deadline. An active resale market has developed in the projects because many owners of projects cannot use the tax credits. Tax credits cannot be used efficiently by individuals or by corporations that are on the alternative minimum tax. Meanwhile, coal companies in the eastern US where most of the facilities are located have found it hard to compete with the synfuel plants for customers because of the large subsidy for synfuel.

Last October, the IRS stopped issuing private rulings that the projects produce a "synthetic fuel" while it studied the issue.

Future Rulings

The IRS said a number of things in late April when it reopened the rulings window.

It said it has decided not to tinker with the definition of "synthetic fuel." A project is considered to make a synthetic fuel if the output from the project differs significantly in chemical composition from the raw material, or feedstock, used to produce it.

The agency will continue to rule that coal agglomeration facilities make synthetic fuel. However, investors in such projects will have to show three things in the future in order to get a ruling.

The feedstock must consist of "coal fines or crushed coal comprised of particles the majority of which, by weight, are no larger than 3/8 inch." This test is applied at the point where the binder is added. Thus, the raw input to the project can be whole coal, and crushing can occur at the synfuel plant. Joseph Makurath, the IRS official who will sign any rulings, said the reason for imposing this condition is the government believes the greatest chemical change occurs when binder is applied to small particles.

The binder must fit into one of four categories. The IRS will not approve any new processes beyond those on which it had ruled by 1999. The four approved processes are "styrene or other monomers following an acid bath," "quinoline or other organic resin and left to cure for several days," "ultra heavy hydrocarbons," and "aluminum or magnesium silicate binder following heating to a minimum temperature of 500 degrees Fahrenheit."

The project must produce output in the form of a pellet, briquette or "extruded fuel product" or show that omitting this step "will not significantly increase the production output" through 2007. The change in output is measured against what the facility is capable of producing when it slows down to produce pellets or briquettes. The IRS did not say what it considers a "significant" increase in output. However, "significant" has usually meant in the

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IRS Synfuel Projects

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past more than a 10% increase.

Makurath said future rulings will specify the "capacity" of the project. Taxpayers will be barred from claiming credits on output above this capacity.

Audits

The IRS said it will deny tax credits in two situations when it finds them on audit.

One is "spawned" projects. An example is where equipment is added after June 1998 to a conventional coal wash plant to convert it into a facility for making synfuel. Syncoal plants had to be in service for tax purposes by June 1998 to qualify for tax credits. The IRS said spawned projects failed to meet this deadline because they were not in service in June 1998 *for the purpose of making synfuel*.

Tax credits will also be denied on audit where a project is modified after June 1998 in a manner that significantly increases the production capacity or significantly extends the useful life. This is in keeping with past practice of denying tax benefits to projects that are "grandfathered" from a change in tax law if the projects are significantly altered after the deadline to qualify for grandfather relief. In this case, the deadline was June 1998.

It is a modification of a project to add or replace equipment or to move it to a new location.

The revenue procedure says that a project will remain grandfathered after a move only if "all essential components of the facility are retained and the production capacity of the relocated facility is not significantly increased at the new location."

The IRS position in the past was that a move does not cause loss of tax credits as long as the amount spent on the move and reassembly is no more than 80% of the value of the synfuel plant at the new location. A senior Treasury official involved in drafting the revenue procedure confirmed that the IRS has now set up two more hoops through which taxpayers who move their synfuel plants will have to leap: "all essential components" must be retained after the move, and the plant must be reassembled in a way that does not significantly increase production capacity or extend the useful life.

Many synfuel plants have already been moved. Projects that already have private rulings covering the moves should not be affected. However, anyone who moved before getting such a ruling will have to prove compliance with all three tests. ■

California Threatens Windfall Profits Tax

by Keith Martin and Samuel R. Kwon, in Washington

California is moving toward imposing a windfall profits tax on electricity generators and power marketers who sell electricity into the state.

Questions have been raised about its constitutionality.

The tax passed the state Senate and was expected to come for up for a vote in the state Assembly as early as May 31.

Senate Version

Under the Senate version, all "sellers of electricity" in California would have to pay a tax of 100% of their windfall profits. Windfall profit is defined as the sales price above a "base price" of $80 a mWh. However, the California Public Utilities Commission would have authority to reset the base price "based on an industrywide average of the cost of selling electricity, as adjusted for a reasonable allowance for profit margins and maintenance of operational expenses."

The tax would be withheld from the sales price by the California independent system operator, in the case of sales through the ISO, or by the regulated utilities where sales are directly to them.

Sales made under binding contracts that were signed before the effective date of the tax would be exempted. The tax would become "operative" on the first day of the month that is more than 60 days after the tax is signed into law by the governor.

The CPUC would have authority to waive the tax — or reduce the rate — on electricity from "renewable sources."

The Senate directed the CPUC to use its control over rates to try to prevent generators and power marketers from passing through the tax to electricity purchasers.

The revenue collected by the tax would be returned to California residents in the form of a tax credit. The Franchise Tax Board would be directed to figure out the amount of the credit each year. The credit would be "determined in a manner that distributes, in equal amounts among those individuals required to file an income tax return . . . a sum that is equal to the total amount" of the tax collected. Individuals who do not pay enough in taxes to get the full credit would receive a check from the state. However, this "refundability" feature will require a separate appropriation from the legislature to implement.

Assembly Version

A slightly different tax has been proposed in the state Assembly.

Under the Assembly version, a tax of from 50% to 90% would be imposed on the "excess receipts" of anyone selling electricity for consumption in the state. "Excess receipts" are defined as revenue from sales above a "base price" of $60 a mWh. The CPUC would have authority to reset the base price.

The tax would be imposed on a sliding scale. The tax would be 50% of the excess receipts for sales at up to 150% of the base price. It would be 70% of excess receipts for sales at up to 200% of the base price. It would be 90% of excess receipts for sales at higher prices.

There is no mechanism in the state Assembly bill to return the revenue to individual taxpayers.

The tax would be collected by withholding by the purchaser of the electricity. It would be imposed retroactively back to January 2001.

The CPUC would have authority to waive the tax — or reduce the rate — on electricity from "renewable sources."

Constitutional Issues

Critics charge that California does not have a right under the US constitution to apply the tax as broadly as it proposes. In general, a state must have a significant enough connection — or "nexus" — with the taxpayer before the constitution allows it to impose a tax. For example, no state could tax air passengers on a share of their incomes solely on the basis of the amount of time they spent during the year flying over the state.

The Senate bill is silent on nexus. The state Assembly bill says that the tax will only be collected from taxpayers with a nexus to the state, but then defines nexus more broadly than perhaps the courts would allow.

The main constitutional issue is whether the tax California proposes would impede interstate commerce. The US Supreme Court takes the position that — to be constitutional — a state tax must comply with four conditions. First, it must be applied to an activity with a substantial connection to the taxing state. Second, it must be fairly apportioned, meaning that — to the extent that some of the activity generating the income takes place outside the state — California

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Windfall Profits Tax

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can only tax a share of the income. Third, the tax must not discriminate against interstate commerce. An example of a discriminatory tax would be one imposed at a higher rate on out-of-state generators. Fourth, the tax must be fairly related to the services provided in the state.

On its face, the California tax raises questions under at least a couple of these conditions. One is it makes no effort to apportion income from an electricity sale in cases where the electricity is generated across the border and sold into California. The state where the power plant is located will also want to tax income from the sale. Another is there is little correlation between the amount of tax and the services provided in California.

Some California officials have described the tax as a self-help effort to impose a price cap on electricity sales in the state. This would have an effect throughout the West, probably by driving electricity away from California into neighboring states. ■

"Financial Assistance": A Fatal Flaw In Cross-Border Acquisition Financings

by Denis Petkovic, in London

A challenge in many corporate acquisitions is how to finance the acquisition without violating local company law prohibitions against the target providing "financial assistance" for the purchase of its own shares by third parties.

Examples of financial assistance are where the target's assets serve as security for the acquisition debt or where the target agrees to sell off assets after the acquisition to help pay down the debt.

Refinancings after the acquisition can also be a problem.

Prohibitions against financial assistance are littered throughout company law in jurisdictions within the British Commonwealth ranging from England to Australia, Hong Kong, Singapore and Nigeria. Because the rules have as their foundation prohibitions against unauthorized returns of capital to shareholders — prohibitions that are found in civil law countries also — it is prudent to inquire into similar restrictions in civil law jurisdictions as well. An example is Italy.

English Law

The English law prohibition is in section 151 of the Companies Act, 1985. Section 151 prohibits two types of transactions. First, it provides that where a person is acquiring or proposing to acquire any shares in a company, it is unlawful for the company or any of its subsidiaries to give financial assistance, directly or indirectly, for the purpose of that acquisition *before or at the same time* as the acquisition takes place.

Second, *after* a person has acquired any shares in a company and any liability has been incurred by that person or any other person for the purpose of the acquisition, it is unlawful for the company or any of its subsidiaries to give financial assistance, directly or indirectly, to reduce or discharge the liability incurred.

If a company acts in contravention of section 151, then it is liable to a fine and every officer who was involved is liable to imprisonment or a fine or both.

Policy

The financial assistance prohibition dates to 1929 and reflected a view that companies ordinarily ought not to buy back their own shares because this would constitute an unauthorized reduction of share capital. The underlying policy went further, however, and was intended to prevent asset stripping — the process whereby potential bidders borrowed money to acquire a company and then used the assets of that company to finance their borrowings. The concern extended to prohibiting bidders from securing their borrowings against the assets of the target, thereby putting at risk the interests of minority shareholders of the target company and creditors of that company.

There was a general feeling by the 1980's that the law went too far. The statute was amended in 1981 to define more accurately what constituted "financial assistance" and to relax the prohibition so that it did not affect honest transactions.

The prevailing feeling in the United Kingdom is that the present rules still do not work very well, in particular in relation to fundamentally honest transactions. Moreover, companies now can buy back stock, and the era of highly leveraged buyouts often premised on strong economic efficiency grounds lays a valid philosophical challenge to the notion that company law should discourage "asset stripping." For this reason, further changes to the law are proposed from time to time, particularly as the prevailing rules are a minefield of technicalities that can create a fatal flaw in fundamentally honest deals.

Refinancings

A good example of the tripwires created by the financial assistance rules is found in section 151(2). This section prohibits absolutely the target company or any of its subsidiaries after an acquisition is completed from giving financial assistance, directly or indirectly, for the purpose of reducing or discharging the liability incurred. The prohibition lasts indefinitely and catches refinancings.

As discovered in the United Kingdom during the last recession and which one must be mindful of in the light of prevailing economic storm clouds, the prohibition can be particularly problematic when a restructuring is required for a group of companies, one of whom may have been acquired previously, as it continues to be impossible for security to be taken from that company to support the refinancing.

One of the consequences of prohibited financial assistance taking place — even inadvertent — is that any security taken will be void. Thus, lenders are potentially at risk. It is for this reason that calls have been made in the United Kingdom to subject section 151(2) to a time limit so that, for example, nothing done by a target company after a lapse of two years from the date of acquisition of its shares will constitute a breach of the section. To date, these calls have fallen on deaf ears.

What is Financial Assistance?

Section 152 defines what financial assistance is. It is a wide definition. It covers:

- gifts;
- guarantees, securities or indemnities, releases and waivers;
- loans or other agreements under which any of the obligations of the person giving the assistance are to be fulfilled at a time when, in accordance with the agreement, any obligation of any other party to the agreement remains unfulfilled, or by way of the novation of, or the assignment of rights arising under, a loan or such other agreement;
- any other financial assistance given by a company, the net assets of which are thereby reduced to a material extent or which has no net assets.

A House of Lords decision in 1989 held that the definition is to be interpreted widely.

Negative Pledges

Are there any transactions that would not come

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within the parameters of financial assistance?

There are some. The grant by the target of irrevocable negative pledges under seal in favor of a financier does not constitute financial assistance. This is so for two reasons. First, section 151(2) provides that where a person has acquired shares in a company, then it is not lawful for the target or any of its subsidiaries to give financial assistance for the purpose of reducing or discharging the liabilities so incurred. The grant of a negative pledge will not actually reduce or discharge liabilities of a target at all nor of any of its subsidiaries. It is arguably not assistance having a "financial" character.

Second, the grant of a negative pledge in favor of a bank does not actually fall within the definition of financial assistance in section 152.

Territorial Reach

A further area of concern is whether section 151 prohibits a foreign subsidiary of an English company from providing financial assistance for the acquisition of shares in its English parent company, and secondly, whether it applies to an acquisition of shares in a foreign company.

These issues were touched upon in *Arab Bank plc v. Mercantile Holdings Limited* (1994) by Millett J who issued some troubling comments. He was concerned principally with the first issue, whether section 151 prohibits a foreign subsidiary of an English company from providing financial assistance for the acquisition of shares in its English parent.

Millett J concluded that subsidiaries for the purposes of section 151 of the Companies Act had to be construed as limited to subsidiary English companies.

There is a view that Millet J's conclusion is correct, but that his reasoning is perhaps wrong. The view that supports Millett J's interpretation relies on the context of the financial assistance prohibition and asserts that the context requires limiting the reference to "subsidiaries" to locally incorporated subsidiaries rather than foreign subsidiaries. Why is the context so important? It is because section 151 is concerned essentially with capital reduction, protection of shareholders' rights and creditors' rights — matters that are generally dealt with under the law of the place of incorporation of the relevant company. On this view, it is not for English law to legislate whether foreign subsidiaries may give financial assistance for the purchase of shares in their parent companies, but rather it is for the government of the place the foreign subsidiary is incorporated to do so. Indeed, in some jurisdictions, there is no prohibition on giving financial assistance at all. For example, an international business company incorporated under the law of the British Virgin Islands is not restrained by any such prohibition.

On this basis, it should be lawful for an English company to give financial assistance for the purpose of assisting the purchase of shares in its foreign parent company — the foreign parent after all is not a "company" for the purposes of the Companies Act and is not thereby caught within the prohibition. It should also be lawful for a foreign subsidiary to give financial assistance in connection with the purchase of shares in its English parent. However, the Department of Trade and Industry proposes to change the law on this topic to prevent a British company from providing financial assistance for the acquisition of its own shares or those of any British or foreign parent company. Financial assistance by foreign subsidiaries for the acquisition of the shares of a British parent company would continue to be permitted.

Fees

Another question about the ambit of the financial assistance prohibition concerns transaction fees. Quite often, the parties may agree that a target will bear the cost associated with the acquisition of its shares, such as valuation fees for auditors. Some lawyers take the view that such costs may be met by the company because they fall outside the rules if the net assets of the company are not reduced to a material extent. The Department of Trade and Industry proposes to legislate to introduce a specific exemption for lawful fees and indemnities.

Statutory Exemptions

Section 153 of the Companies Act and subsequent provisions provide several bases that one might use to argue a scheme is not prohibited.

Incidental Purpose

Sections 153(1) and (2) permit financial assistance if the company's principal purpose is not to give it for the purpose of the acquisition or to discharge a liability incurred by a person for the acquisition and the financial assistance is given incidentally as part of some larger purpose of the company and in good faith in the interests of the company. These provisions are designed to loosen up the operation of section 151 so as not to catch honest transactions that incidentally involve financial assistance. The problem with the sections is the use of the word "purpose" and the mingling of concepts such as "principal purpose," "larger purpose" and something being an "incidental part of some larger purpose." As far as drafting goes, this wording is truly appalling. Those familiar with the use of "purpose" tests in tax legislation will know that they are difficult to apply. This has been the experience of sections 153(1) and (2).

In the context of a refinancing where only a small portion of indebtedness from an initial takeover remains, it could be said that the "larger purpose" is to obtain new finance rather than to discharge an old acquisition borrowing. Perhaps where the new money was £9,999,000.00 and the amount of old acquisition borrowings remaining was £1,000.00, one could rely on these provisions, but where the split is perhaps £5 million for each, it would be a brave lawyer who would say that the principal purpose exemption was available.

The Department of Trade and Industry proposes — possibly during the next parliament — to recast the exemption so that financial assistance would not be prohibited where the company's "predominant reason" for entering into the deal was not to give financial assistance. When applying this new test, the reason for a transaction should be assessed from the company's perspective — making board minutes of very great importance — and the fact that the transaction or its manner of implementation constituted financial assistance would be disregarded.

Dividends and Other Exemptions

Section 153 also contains numerous other exemptions. The most important is the ability to provide financial assistance by way of dividend, which is one method in which operating profits may be distributed to shareholders. Also, reductions of capital confirmed by the court, redemptions or purchases by the target of its own shares and schemes of arrangement approved by the court are exempted. In practice — apart from the relaxation procedure discussed below — the "dividending up" exemption is the most important exemption used by companies.

Relaxation Procedure

Section 155 of the Companies Act establishes an exemption or relaxation from the prohibitions set out in section 151 that is often applied in highly leveraged deals.

The section permits a private company to give financial assistance where the acquisition of shares in question is or was an acquisition of shares in the company or, if it is a subsidiary of another private company, in that other company

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if certain legal tripwires are avoided. This section does not apply if one of the intermediate holding companies is a public company.

One condition for section 155 to apply is that the company giving assistance must have net assets that are not reduced, or to the extent that they are reduced, the financial assistance is provided out of distributable profits.

This condition is difficult to comply with in practice. If the target company grants a guarantee and charge in respect of its assets to secure a debt, then are the net assets thereby "reduced"? How is the contingent liability associated with the guarantee to be treated? Current accounting treatment looks at whether the guarantee is likely to be called having regard to the viability of the borrower's group and cash flow and other projections relevant to the indebtedness in question. If, on the basis of this examination, it is not foreseeable that the guarantee will be called over say two to three years, then the amount of the contingent liability represented by the guarantee will be discounted completely. On this basis, there is no reduction in net assets. These are judgmental considerations and here lies one of the problems associated with section 155(2); judgment brings with it a lack of certainty.

The relaxation provisions are full of other technical requirements, like the need for an auditor's report and company declarations.

The Department of Trade and Industry has previously proposed to revamp the relaxation provisions significantly. Under the DTI's preferred approach, private companies will be allowed to provide financial assistance if that assistance is not "materially prejudicial" to the company or if the members approved the transaction in advance.

In what circumstances would a transaction not be "materially prejudicial"? The DTI proposed that if the assistance is out of distributable profits and results in a reduction of less than 3% in the company's net assets — assuming in the case of contingent liabilities that they were enforced — that the transaction will not be materially prejudicial.

Lender Concerns

For banks, the major concern associated with section 151 is that they will be punished unduly: the consequence of providing financial assistance in contravention of the statute is, among other things, illegality of any contract (such as a guarantee or security) given in respect of that assistance. Criminal sanctions also apply as mentioned previously. The DTI has previously proposed to change the law in the United Kingdom so that a transaction would not be void solely on the grounds it constituted unlawful financial assistance. Other civil law remedies (constructive trust breaches, etc.) would continue to be available.

Conclusion

The financial assistance prohibition in the statutory form used in the United Kingdom is full of technical tripwires for the unwary and must be approached with caution. The prohibition appears in many permutations around the world. However, these are in no way uniform and each jurisdiction in which a "cousin" to the UK prohibition is to be found should be subject to separate scrutiny.

The issues raised by the prohibition are not peculiar to British Commonwealth or ex-British Commonwealth jurisdictions. Given that the original concerns of the prohibition were to stop unauthorized reductions of capital, civil law jurisdictions may throw up similar issues when target company support is required as a condition to the financing or refinancing of an acquisition of a target's shares by an investor. Indeed, in some recent transactions in continental Europe involving refinancing of acquisition debt, similar concerns have surfaced. ■

Environmental Update

The national energy plan that the Bush administration unveiled in late May includes a number of significant environmental proposals. The administration can implement some without waiting for Congress to act.

Bush Energy Plan

The plan calls for a market approach to controlling emissions of various pollutants similar to the approach used currently for sulfur dioxide, or SO_2, emissions for electric utilities. The Clean Air Act Amendments in 1990 created a fixed number of "allowances" or rights to emit SO_2, and these are traded in a national marketplace. This same approach would be extended to nitrogen oxide, or NO_X, and mercury emissions at power plants. NO_X emissions from power generators are already capped in the northeast but not in the rest of the country, although seven more states will be added to the NO_X control area in 2003 to 2004. There are no federal controls currently on mercury. The plan directs the US Environmental Protection Agency to draft bill language that can be given to Congress to implement such a program. The cap on SO_2 emissions would be ratcheted down from current limits.

The president's support for multi-pollutant legislation may improve the chances of Congress passing a multi-pollutant measure by the end of next year. This would be the first major amendment to the Clean Air Act since 1990. Existing coal and oil-fired plants would probably bear the brunt of the emissions reductions.

President Bush took steps to implement one part of his plan on May 18. The president issued an executive order directing federal agencies to hasten their review of permits for energy projects. The order creates an interagency task force headed by staff of the Council on Environmental Quality to push for greater coordination of the permitting process at the federal, state, local and tribal levels. Project developers with horror stories about permitting delays at least now have an outlet for their complaints.

The plan directs the Environmental Protection Agency to take another look at its "new source review" program. This is a program that requires power plants and other major sources of air emissions to have obtained air permits before starting construction. EPA has been given 90 days to report back to the president on the impact of the program on investment in new utilities and refineries, energy efficiency and environmental protection. Power companies complain that the new source review program inhibits both new plant construction and upgrades of existing plants due in part to the long lead times to receive permits and the uncertainty in how much it will cost to install any pollution control equipment that the government might require as a condition for issuing permits. The EPA review may lead ultimately to an overhaul of current new source review requirements.

The president has also directed the attorney general to take another look at cases the government has pending in the courts against a number of electric utilities and refineries for violations of existing new source review standards. Some of these cases might ultimately be dropped or settled.

The president was stung by criticism over his decision for the US to withdraw from efforts to deal with the global warming problem through the Kyoto protocol. Perhaps for this reason, the Bush plan suggests that the federal government will look for other ways to get to the same place. It directs federal agencies to look for market mechanisms, new technologies and other innovative approaches to address global climate change. There is also a cabinet-level review underway of how the US might address climate change. However, the plan does not recommend any specific reductions in greenhouse gases, and the plan failed to include carbon dioxide, or CO_2, among the list of pollutants that will be covered by draft multi-pollutant legislation being prepared by EPA. Environmental groups are lobbying Congress aggressively to include CO_2 in any multi-pollutant bill.

Section 126 Rule

The US court of appeals for the DC circuit largely upheld a rule the Environmental Protection Agency issued to require reductions in NO_X emissions from specific power plants and industrial plants in 12 states in the eastern half of the United States. The rule is called the "section 126 rule." The court released its decision in mid-May.

The section 126 plants are required to comply with new federal NO_X standards by May 1, 2003. These standards are substantially similar to the government's "NO_X SIP call rule." The NO_X SIP call rule and the section 126 rule will force many existing power plants and industrial facilities to install costly pollution control devices — such as selective catalytic reduction systems — to reduce NO_X emissions. EPA is expected to coordinate implementation of the two rules. Companies required to comply with the NO_X SIP call rule have until May 31, 2004 to do so.

The court took issue with one feature of the section 126 rule. It set aside the rule to the extent it includes cogeneration facilities in the "large electric generating unit" category and sent the question of how to classify cogeneration facilities back to the Environmental Protec-

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tion Agency for further consideration. The court said the government failed to show that cogeneration facilities can meet the more stringent electric generating unit NO_X standards as opposed to the standards for non-electric generating units.

Mercury

The Environmental Protection Agency asked a federal court in May to dismiss cases brought by the Edison Electric Institute and a group of utilities. The groups want the court to overturn a decision by EPA last December to regulate mercury emissions and other hazardous pollutants from coal and oil-fired power plants. The case is before the US court of appeals for the DC circuit.

The skirmishing in court is part of an ongoing debate over whether mercury emissions from power plants should be reduced.

EPA is expected to issue a proposed mercury and hazardous pollutants rule by December 2003 and to finalize whatever rule it proposes by the end of 2004 with industry compliance required during the 2007 to 2008 timeframe. Many coal and oil-fired plants may need to install expensive pollution control devices to comply with the new standards.

Massachusetts

Massachusetts directed the state's six oldest power plants in April to reduce CO_2 emissions. The plants must limit CO_2 emissions to 1,800 lbs per mWh by October 1, 2006 or two years later if they repower. This represents a 10% reduction from the current average CO_2 emission rates for the plants. Massachusetts is the first state to mandate CO_2 reductions from power plants.

Massachusetts also imposes new NO_X and SO_2 emission standards that are expected to reduce these emissions by as much as 50% and 74% respectively from current levels at the six plants. The reductions in SO_2 and NO_X emissions have to be made between October 1, 2004 and October 1, 2008.

Massachusetts also put power plants on notice that it intends to propose limits on mercury emissions by June 1, 2003 with a compliance date of October 1, 2006.

Impaired Water Rule

The Environmental Protection Agency is in settlement talks with industry, the states and environmental groups over the agency's hotly contested rule for setting "total maximum daily loads," or TMDLs, for impaired water bodies. The TMDL rule, issued in July 2000, has been challenged by numerous industry groups in the US court of appeals for the DC circuit. EPA asked the court on May 11 for another 60 days to submit briefs in the case in view of the ongoing settlement talks. The TMDL rule directs states to identify polluted rivers, lakes and coastal waters and set strict wasteload allocations where water bodies are not meeting applicable water quality standards. These wasteload caps will ultimately translate into more stringent wastewater discharge limits for industrial dischargers.

The controversy has spilled over to Congress. Congress passed riders to EPA funding measures prohibiting the use of fiscal year 2001 and 2002 funds to implement the rule. Implementation of the TMDL rule is currently scheduled to start during fiscal year 2003.

California

EPA Region IX recently issued an "administrative order on consent" to a California power plant authorizing it to exceed air permit limits for peaking units at the plant on an emergency basis. The emergency order contains "mitigation fees" or stipulated penalties for exceeding hours of operation permit limits during peak demand periods. A mitigation fee of $20,000 per ton of excess NO_X will be assessed under the emergency order. The order requires that the plant return to compliance by January 1, 2002.

The California independent system operator has identified 37 peaking units that may exhaust allowable annual operating hours prior to this summer's peak demand period, and a number of these plants may be able to seek similar emergency consent orders from EPA Region IX to continue operations. The emergency consent orders are intended to allow plants to exceed federally-approved emission limits and thus preempt potential federal enforcement actions. ■

— contributed by Roy Belden in Washington.

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