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California Chaos: The Implications For Generators And Banks

The disarray in the California power market has the potential to bankrupt the utilities, engulf neighboring states, and put the state government in the business of generating and transmitting electricity. The following are excerpts from a panel discussion in New York in late January about the implications for independent power companies and for banks that have loaned money to finance their facilities.

The panel included Dr. Robert B. Weisenmiller, one of the leading experts on the California electricity market and a founder of MRW & Associates, Inc. in Oakland, California, Lynn Hargis, former assistant general counsel for electricity utility regulation at the Federal Energy Regulatory Commission, Howard Seife, the head of the bankruptcy practice at Chadbourne, Robert F. Shapiro, who has negotiated numerous "qualifying facility" contracts and tolling agreements and been involved in a large number of projects in California, Chaim Wachsberger, head of the Chadbourne project finance group, Bruce Rader, an experienced bank lawyer, and Bill Monsen, a former utility economist for the Pacific Gas & Electric Company who is currently with MRW & Associates. The discussion was moderated by Keith Martin from the Chadbourne Washington office.

MR. MARTIN: This is a story that has more twists and turns than the Florida recount. Bob Weisenmiller, everyone has read in the newspapers about how the situation came about, but I think it helps to state for the record that there are three things California did to itself and two external factors that are also contributing to the mess. What are they?

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CORPORATE ACQUISITIONS got a little easier.

The Financial Accounting Standards Board voted unanimously on January 24 to bar future use of the "pooling-of-interests" method of accounting for business combinations. In the future, all mergers and acquisitions will have to use purchase accounting. The difference is a buyer using purchase accounting must ascribe the premium paid above hard asset value to goodwill.

FASB proposed earlier that the goodwill value had to be amortized for book purposes over a

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DR. WEISENMILLER: First, there is a retail rate freeze. The utility is essentially acting as the balancing point between the wholesale price and the frozen retail rate and, as a consequence, the utilities collectively have run up deficits of $12 billion. That is the difference between what they must pay to purchase power and what they are allowed under the rate freeze to charge their customers.

Next, the California utilities are buying — on average across all three — about one-third of their electricity in the spot market . . . . [U]nder the California structure, the utilities are not allowed to sign long-term contracts to buy electricity and have no ability to hedge against price volatility.

Third, no major new power plants have been built in California in 10 years. This was during a period when demand for electricity increased dramatically.

MR. MARTIN: What about external factors?

DR. WEISENMILLER: California is on the margin a gas-based system Gas prices have gone up substantially. Gas prices have gone from what used to be $2 or $3 at the California border to somewhere between $8 and $15 on the forward markets, and some of the daily prices have been as high as $50. Gas prices have gone up by at least a factor of three. That would have translated into a much higher price for electricity whether or not California had deregulated.

Southern California has very strict pollution control laws. The price for tradeable emission credits for NOx emissions has gone from approximately $2 a pound to something like $40 or $50. This translates directly into higher electricity prices in the south.

The third point is California has always imported a lot of its power. Approximately 25% to 30% of its electricity comes from out of state — much of it from the Pacific northwest. The Pacific northwest is short itself — due primarily to low water levels in rivers — and has less electricity to export. This has had to be replaced with more gas generation in California, and has led in part to the escalating cost of emissions credits.

MR. MARTIN: So in assessing whether this problem can happen in other parts of the country, one needs to understand that the mess is due partly to things California did to itself and partly to external factors.

There is a conspiracy view held by some people. What is this conspiracy view, and what is your assessment of it?

In assessing whether California's problems can happen elsewhere, one needs to understand the mess is due partly to things California did to itself and partly to external factors.

Conspiracy Theories

DR. WEISENMILLER: There are two variations on it. Probably the better discussion is a paper by Paul Joskow and Eddie Kahn. Joskow is an economist at MIT. They looked at the operating levels of the different divested plants and tried to pick hours when it would be economic for those plants to operate. Some of the analysis that has been done on the topic of withholding has not looked at whether the market price was above or below the operating cost of the projects. However, the Joskow paper corrected for this and found that during some high-priced periods — when prices were over let's say $125 a megawatt hour — plants were not operating even though their variable costs would have been covered.

There are several reasons why this could have occurred. The plants could have been down for maintenance. The plants could have reached air

emission limits. It could have been a time when the transmission lines running between southern and northern California were congested. Or the plants could have been withholding power to result in a higher price. They could not tell from their data which of those four factors was leading to the undergeneration.

One aside: the week that report came out, AES was assessed a record fine for running its power plants in California at levels above its emissions limits. The Joskow/Kahn report identifies the AES plants as some units that may have been withholding.

Similarly, Duke was also identified in the Joskow report as another generator who may have been withholding. Yet Duke reports that its plants in California are producing 70% more power this year than the year before, and the plants generally are operating at the second or third highest level for the 30 or 40 years of their existence.

The point is it is difficult to untangle things. This will probably be in litigation for years. You have plants that are 30 to 40 years old, that should be operating at an intermediate or peaking level, that are being operated a lot more than before, and that are running into more outages. The question is: is it outages or is it strategic gaming or what?

MR. MARTIN: You told a story of a day in the life of an AES plant operator. Tell us that.

DR. WEISENMILLER: One of the plant operators was trying to explain to his people what it was like operating in California. The company had a bomb threat at its plant. They were trying to figure out whether to shut the plant down to look for the bomb or to keep operating. It's a very stressful environment. There is remarkably poor communication and suspicion between the regulators and independent generators and also between the regulators and the utilities. The distrust and lack of communication among all the parties are staggering.

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period no longer than 20 years. Such deductions would reduce earnings. The proposal set off a firestorm of protests.

When FASB reaffirmed its decision in late January, it said it would no longer require that goodwill be written off, except to the extent that the goodwill actually loses value in a year. This "impairment" approach to writing off goodwill should help ease the pain from having to use purchase accounting.

FASB is expected to release more details in mid-February.

HART-SCOTT-RODINO filings will be significantly more expensive starting February 1.

US antitrust laws require that a notice be sent to the Federal Trade Commission and the Justice Department whenever one company buys another company or its assets for a purchase price of at least $50 million. (The threshold used to be $15 million. That is also being increased as of February 1.) The parties must then wait at least 30 days before they can close the transaction. However, the government sometimes waives the waiting period upon request.

The filing fee was $45,000. It will remain at that level for sales for less than $100 million. However, it increases to $125,000 for sales for $100 million up to a price just below $500 million, and to $280,000 for sales for $500 million or more.

The new fees may put pressure on lawyers to come up with deal structures that avoid the need to file. The options are fairly limited. A sale of LLC or partnership interests escapes the filing requirement, provided the sale is of less than the entire LLC or partnership.

MOST TURBINE MAINTENANCE costs should be deductible.

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MR. MARTIN: Power prices have gone up. One of the biggest problems is that the utilities have to pay more for power, but they can't pass through the cost to their ratepayers. Is there any evidence that power prices have been pushed up artificially or is it all driven by rising gas prices?

DR. WEISENMILLER: Certainly when you go through the fundamentals and look at how much of the increase is coming from higher gas prices, how much of it is coming from higher air credit costs, and various other pieces, the runups are not explained entirely by the increase in production costs.

MR. MARTIN: Of course, rising prices may be a function simply of too little supply and too much demand. There is no conspiracy; it is just the way the market works?

DR. WEISENMILLER: The FERC staff report suggested it is impossible to untangle how much of the increase this summer was due to scarcity and how much to market power. You will hear a lot of allegations that it is market power. You will see numbers thrown around for the amount. The figures always assume a world where the plants only charge their variable costs of operation, or at least the market-clearing price is always set just by the variable cost of operation, which then leads to the question how peaking or intermediate units cover their fixed costs. It's a very strict standard. No market reaches that or matches that standard.

Measuring the Problem

MR. MARTIN: The measure of the problem: the problem at heart is utilities pay more for power than they can pass through to their customers. Edison and PG&E buy how much of their power in the spot market?

DR. WEISENMILLER: If you look at the three utilities in the aggregate, a rough rule of thumb is they buy a third of their power in the spot market. They get about a third of their power from QFs. They generate about a third of their power themselves. Across the three utilities, those percentages obviously differ.

MR. MARTIN: Another measure of the problem is that PG&E and Edison still have rate freezes, do they not, while San Diego can pass through?

DR. WEISENMILLER: Special legislation was passed last summer that put in place a rate freeze for core customers of San Diego Gas & Electric of 6.5¢ a kWh. There is no freeze for noncore customers. And for core customers with 6.5¢, the California Public Utilities Commission has not resolved whether San Diego will be able ultimately to pass those rates through or be forced to absorb them or what happens to the shortfall.

For PG&E and Edison, there is a hard freeze. For PG&E, it is 5.5¢ or 5.7¢. The public utilities commission just gave them an extra penny, taking it to around 6.5¢ or 6.7. Edison was 6.2¢. The extra penny takes them to 7.2¢. You have 7.2¢ relative to a spot market price that was on the order in December of 25¢ to 30¢.

MR. MARTIN: Just an anecdote: one of the Chadbourne associates in Washington went home to San Diego for Christmas. His parents live in a condo that has two bedrooms. Their electricity bill for November — when the air temperature during the day was 75 degrees — was $550.

What's the situation with QFs who supply electricity to these utilities? When did the various utilities stop paying them?

Payments to QFs

DR. WEISENMILLER: I believe QFs selling to San Diego are still being paid. Edison defaulted on payments to QFs for their November power production. PG&E paid for November. However, PG&E has just recently sent letters to QFs claiming force majeure will prevent future payments.

MR. MARTIN: The state is making an effort to reduce the revenue that is being paid to QFs. Before you address that, let me just mention that

most of these QF contracts are in a so-called cliff period. The contracts set the price for electricity during the first 10 years. After that, prices move with the market.

DR. WEISENMILLER: During the cliff period, prices move with the short-run avoided cost. The short-run avoided cost is based on a formula that basically starts with electricity prices in the year California deregulated and indexes this price to the border price of gas. QFs also could elect to receive a price tied to the PX, or spot market, price. A number of QFs in northern California chose the PX price. The PX is winding down, and the volumes are dropping. The question is what happens to QFs that made this election. The price they are supposed to be paid under their contracts is now unclear.

MR. MARTIN: There is a negotiation going on between Edison and its QFs and PG&E and its QFs. What is that all about?

DR. WEISENMILLER: FERC put out the notion that a reasonable price for bilateral contracts between the generators and utilities would be 7.4¢ a kWh. The California Public Utilities Commission grabbed that number, backed out the inflation adjustment, and said — based on that — it believes there should be a cap of 6.7¢ a kWh for QFs. The commission was prepared last week to adopt that number and say no QF — whether it is gas-fired and the border index is 16¢ or it elected to receive the PX price — will be paid more than 6.7¢. Under that gun, the QFs began negotiating with the utilities to try to agree on a different approach.

At the same time, from the utility or state perspective, if one-third of your power is coming from QFs and you are in a stage 3 emergency with shortage problems, the last thing you want to do is to shut down the QFs. So, there have been attempts to negotiate among all parties something, although the negotiators appear to want the legislature ultimately to bless those agreements.

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The Internal Revenue Service let the commercial airlines know in early January when it will let them deduct the cost of major maintenance on airplanes. The agency is expected to use the same guidelines with power companies for maintenance on power plants. The guidelines come after years of negotiation — and litigation — between the IRS and the airlines over this issue. They are in Rev. Rul. 2001-4.

The new guidelines address when the airlines can deduct the cost of heavy maintenance of the kind that is done once every eight years and involves stripping down the airplane to inspect parts and replace ones that are worn. Large commercial airliners are expected to last 25 years. The airlines argue that this maintenance merely gives the aircraft its expected life and does not extend it or enhance the value of the plane.

The IRS posited three situations. In one, an airline spent $2 million overhauling an airplane that it bought new for $15 million 16 years ago. The airline "extensively disassembled" the airframe and replaced an unknown number of parts. The maintenance took 45 days to complete. The IRS said the full cost could be deducted because there was no material upgrade of the plane. The work merely "maintained the relative value."

In the next case, the IRS said the situation was identical except that the belly of the airplane fuselage was so corroded that the airline had to replace all the skin panels, and it also used the opportunity to upgrade the plane by installing a new ground proximity warning system, new fire prevention equipment, and phones for passengers. The IRS said the cost of the upgrades — the new belly for the fuselage and the other equipment — had to be added to the tax basis in the plane. However, the other maintenance costs could still be deducted.

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MR. MARTIN: Is this a single negotiation with all QFs or do the utilities do a deal with one QF at a time?

DR. WEISENMILLER: Generally they have been with all, although it has been like herding cats. It has been a fairly fluid negotiating environment.

MR. MARTIN: If the negotiations fail, will the CPUC reduce the revenue QFs receive under their contracts to 6.7¢ a kWh?

DR. WEISENMILLER: My understanding is there are votes at the commission to put out the draft decision. The commission has held it in abeyance to see what the negotiations produce.

MR. MARTIN: This means a reduction in revenue for QF projects measured against today's high prices. Is it a reduction if one looks at what the QFs were being paid six months ago?

DR. WEISENMILLER: Generally it is above the numbers six months ago, but it would leave gas-fired cogeneration projects with too little revenue to cover their fuel costs, let alone other expenses.

California's effort to cap the price paid to QFs for power at 6.7¢ a kWh would probably not stand up in court.

MR. MARTIN: Gas-fired QFs are what percentage of the market?

DR. WEISENMILLER: About two thirds of QFs are gas fired and one third use renewable fuels.

MR. MARTIN: So, if the CPUC follows through on its threat to set the price for QFs at 6.7¢ a kWh, gas-fired QFs may find themselves unable to produce because they lose money at that level?

DR. WEISENMILLER: Exactly.

MR. MARTIN: Lynn Hargis, a question for you. Does California have the authority to tinker with prices under QF contracts or is this power reserved to the federal government?

MS. HARGIS: The CPUC said in its order that the avoided cost paid to QFs would be based on adjusted gas prices. The CPUC clearly has authority to decide the avoided cost.

However, the CPUC went on to suggest that it has also an obligation to ensure that the amounts paid to QFs are "just and reasonable." The CPUC used a FERC order as a benchmark for what would be "just and reasonable." The federal government decides whether the prices charged are "just and reasonable." The CPUC will exceed its authority if it insists QFs must be paid a price that is below the avoided cost on grounds that to pay them a higher price would be unreasonable.

MR. MARTIN: At the end of the day, California probably has the authority to push down QF revenues in this manner?

MS. HARGIS: No. If a QF sued California, it would probably win. However, the case would take a couple of years to move through the courts.

MR. SHAPIRO: I would say California has the authority administratively to set a new short-run avoided cost. However, the arbitrary nature of picking a number that is so clearly below the cost for gas-fired QFs or the utilities to produce electricity is so suspicious that a court would probably overrule the CPUC.

California Government's Plan

MR. MARTIN: Let's go back to Bob Weisenmiller. California's response to these problems — what is it doing?

DR. WEISENMILLER: The governor has essentially three objectives. Number one: he does not want the utilities to go bankrupt. Two: he does

not want any increase in retail rates above the penny per kWh that has already been approved by the CPUC. Three: he doesn't want to bail out the utilities.

MR. MARTIN: This is a magnificent failure of self government.

DR. WEISENMILLER: It is hard to achieve all three at the same time.

The state legislature is considering legislation that would do a variety of things. The utilities still have valuable hydro systems and transmission grids. There is a thought that the state should grab these assets before they fall into the hands of creditors in a utility bankruptcy proceeding.

The thought is the state might issue or guarantee bonds to cover the $12 billion undercollection with repayment of the bonds to occur over 10 or 12 years. The quid pro quo — so that this is not considered a utility bailout — is that the state would get the hydroelectric and transmission systems. Obviously, the end result is the state would become much more involved in the power business. A state power authority might be set up. The state might move into the business of generating electricity. There is talk even of acquiring all the generation and transmission in California through condemnation proceedings.

The state also has an RFP out today for power. The idea is the state would enter into bilateral contracts with generators to buy electricity and give it or resell it to the utilities. Bids are supposed to come in by noon today. The political situation is very unstable. Things could go in a couple of different directions depending on what sorts of bids the state gets in the RFP.

One thing is clear: the situation will be very bad next summer unless we get a lot more rain in California and the Pacific northwest than we have now.

MR. MARTIN: The power shortages this winter will look mild by comparison to what is possible next summer?

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In the third fact pattern, the airline made "extensive modifications" to a 22-year old plane that was near the end of its useful life in order to give it new life. The cost of all this work — even maintenance that would have been deductible under the other two fact patterns — had to be "capitalized" or added to basis.

Reaction from the airlines has been muted.

SALE OF A POWER CONTRACT can yield capital gain, provided the transaction is properly structured.

Before the huge runup in electricity prices in California, utilities across the country had been looking for ways to cancel long-term contracts to buy electricity from "qualifying facility" projects. Utilities offered large buyout payments to QFs to get out from under the contracts. Some QFs reported the payments as capital gain (rather than ordinary income). The IRS has challenged this treatment on audit. Individuals prefer capital gains because they are taxed at a lower tax rate. Corporations are indifferent, unless they have capital losses to use as an offset.

A recent "technical advice memorandum" sheds new light on the issue. This is a ruling by the IRS national office to settle a dispute on audit between a taxpayer and an IRS . The IRS made the ruling public in December.

In it, a QF sold its contract to a power marketer rather than accept a payment from the utility directly to cancel the contract. The power marketer then renegotiated the contract with the utility.

The IRS let the QF treat the payment from the power marketer as capital gain. One must make a "sale or exchange" of "property" to qualify for capital gain. The IRS conceded that a power contract is "property" because it has an independent value that fluctuates with the market. A transfer of the contract back to the utility would not

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DR. WEISENMILLER: Exactly.

Generators May Be Ordered to Pay Refunds

MR. MARTIN: Let me move to Lynn Hargis. As you can imagine, this crisis has led to a blizzard of litigation. Let's talk about what the lawsuits are aimed at doing before I ask the big question, which is, "Will any of these lawsuits matter at the end of the day or will everything be decided ultimately in the bankruptcy court?"

Last fall, the Federal Energy Regulatory Commission announced a "soft" price cap and also put generators on notice that they might be ordered to refund some of their profits. What was that all about?

MS. HARGIS: In a December 15 order, FERC refused to set any kind of real price caps on the market. FERC still believes in letting the market work. But it did tinker with the market. For example, it freed utilities from having to sell electricity they generate themselves into the PX and buy it back at spot prices. FERC said the utilities could sell this electricity directly to their customers. That's when it suggested a benchmark price of 7.4¢ a kWh might be considered reasonable.

MR. MARTIN: Is this the "soft cap"?

MS. HARGIS: The soft cap was a little different. The soft cap was 15¢ a kWh for sales into the ISO or PX. The generators were assured that sales at that price would not be examined. However, sales above that price would be examined. The generators presumably would have to justify the higher prices later to FERC and might have to make refunds if the higher prices were found subsequently not to be "just and reasonable."

The only problem is that FERC has admitted several times that it doesn't know what is "just and reasonable" in the context of a free market.

MR. MARTIN: Back up one step. FERC told generators it will not order retrospective refunds, but it put them on notice that there might be refunds going forward from what date?

MS. HARGIS: October 2, 2000.

MR. MARTIN: Until when?

MS. HARGIS: Until the end of 2002.

MR. MARTIN: But the only guidance it gave on what standard it might use to decide whether to order refunds is the prices at which generators sell electricity must be "just and reasonable," and nobody knows what that means?

MS. HARGIS: They said there is a zone of reasonableness. The bottom end of the zone is the rates are confiscatory, and the top end is that they are excessive.

MR. MARTIN: These refunds might be ordered only on sales to the ISO or into the PX — not on sales under QF contracts?

MS. HARGIS: Not on sales under QF contracts. FERC did say that generators would be allowed to cover at least their costs, plus a reasonable return, and maybe an opportunity cost. Thus, there should not be a concern that if refunds are ordered, they would leave generators with too little revenue to cover their costs. The hard part is to determine what cost is.

MR. MARTIN: Would refunds be ordered only by generators selling into the California market or does the warning about possible refunds apply to other parts of the country?

MS. HARGIS: This applies only to generators selling to the California ISO or into the California PX.

Lawsuits Challenging Rate Freeze

MR. MARTIN: Another set of lawsuits is aimed at forcing the California Public Utilities Commission to let the utilities pass through their costs of buying electricity to their customers?

MS. HARGIS: Both PG&E and Edison have gone into federal district court to argue that the doctrine of federal preemption requires the CPUC to pass through wholesale rates that have been accepted by the federal government. Traditionally, under normal law, that is correct. Bob Shapiro has argued this very forcefully in the *Freehold* case. But there is nothing traditional or typi-

cal about what is happening in California.

I think there is little chance of the utilities getting the relief they are seeking retroactively because they not only agreed several years ago when the state deregulated to the rate freeze, but it was also part of an overall package that — as some of the parties have pointed out — FERC itself approved.

Going forward, there is a rule of preemption that FERC-accepted wholesale rates must be passed through in retail rates.

MR. MARTIN: The federal government has control over wholesale rates, and the state has control over retail rates, or the rates charged to consumers, but the federal government has an interest in requiring that the retail rates reflect the wholesale rates? This is a federal-state dynamic that President Bush may not have grasped yet when he said the federal government will not become involved? [Laughter]

MR. SHAPIRO: You don't have to answer that.

MS. HARGIS: Traditionally, about 10% of all electricity rates are wholesale rates and 90% are retail rates. What happened in California is, by deciding to run all electricity sales through the PX, all electricity sales became wholesale sales in interstate commerce, giving the federal government jurisdiction over essentially 100% of the rates in California. That's why Edison went immediately to court to ask for a writ of mandamus ordering FERC to decide what are "just and reasonable" rates, asserting that FERC has admitted the market is not setting such rates and, therefore, if FERC has no other plan, it should go back to setting rates based on cost of service. If FERC does not change something on rehearing of its order in the California case, it will certainly be sued on this issue.

MR. MARTIN: How long does a case like this take to work through the courts?

MS. HARGIS: Normally, it would take a couple of years.

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have qualified as a "sale or exchange." That's because when contract rights are extinguished, they simply disappear. The key in this case was the contract survived the sale to the power marketer.

It did not matter that the power marketer traded the contract immediately to the utility for a new contract.

SYNCOAL PROJECTS remain in limbo at the IRS.

Such projects qualify in theory for a tax credit under section 29 of the US tax code of $1.035 an mmBtu for converting coal into synthetic fuel. The IRS said in October that it would no longer rule that syncoal projects are producing a "synthetic" fuel, except in projects that use waste coal. However, in practice, the rulings window has remained closed to all projects.

Treasury officials now say it will be another couple months at least before there is any progress. The issue has become highly politicized. Clinton officials felt it was better to leave it for the incoming Bush administration to handle rather than try to rush a decision. Bush will need time to fill the top tax positions at Treasury and the IRS.

MEXICAN PRESIDENT VICENTE FOX said he will seek an increase in withholding rates for interest paid to foreign banks.

The nominal withholding rate is currently 15%. However, most actual withholding is at 4.9%. Fox wants to impose a 10% rate. This will affect interest paid to banks lending from Belgium, Canada, France, Germany and Japan. Banks in other countries should still qualify for the 4.9% rate under tax treaties between Mexico and their home countries.

MUNICIPAL UTILITIES are arguing with the US Treasury over whether a scheme to prepay for gas

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US Order to Generators to Sell

MR. MARTIN: Another area of legal controversy is the federal government has ordered generators to sell electricity to California. That order was renewed yesterday for another two weeks. Can you elaborate a little more on that?

MS. HARGIS: These are really emergency war powers. They were set up in 1935 for a crisis like war in which there just wasn't enough electricity. Secretary Richardson first invoked them in December. When the California ISO says it is short electricity, generators are required to sell.

There is an equivalent order on the gas side that was invoked for the first time last week because PG&E said its suppliers were not selling it natural gas.

MR. MARTIN: Generators must sell. Is there anything in the order about the price at which they must sell?

MS. HARGIS: The buyer and seller must agree on a price. If they cannot, then FERC will set the price for electricity.

MR. MARTIN: These orders are aimed solely at dealing with the credit problems of the utilities? Generators are reluctant to sell because they are not sure they are going to be paid?

MS. HARGIS: At this point, that seems to be one of the main problems. But there may be an actual shortage of gas.

Market Abuse Investigations

MR. MARTIN: Another area of legal process is the investigations into market abuses. I suppose these could lead ultimately to criminal charges and to racketeering, or RICO, charges. Where are those occurring — at the federal or state level?

MS. HARGIS: A number of cases have been brought. I think mostly in state court. There are two kinds of cases. One set of cases charges that the gas pipelines have created an artificial shortage by selling to affiliates. On the electricity side, the city of San Francisco, a number of water districts and others have alleged that there was an exercise of market power by generators in order to withhold supplies and drive up prices. Those may be more political than legal.

Can QFs Suspend Contracts?

MR. MARTIN: Let me move now to the entire group, but with a heavy bankruptcy input. This is a question for Howard Seife, but the rest of the group should feel free to weigh in. Assume for a moment the utilities in California do not file for bankruptcy. The QFs are not being paid. Can QFs suspend deliveries of electricity and sell their power elsewhere?

MR. SEIFE: That's an analysis that QFs are doing now. Some QFs have not been paid since November. A lot of these are facing cash shortages. They have bills coming due for gas. One thing such a QF could do would be to declare a default on its power sales contract with the utility.

Can the QF go further and terminate the contract? I think there is a very strong argument that failure to pay two months running, plus an announcement publicly that there is an inability to pay, is a material breach under the contract. That would entitle the QF legally to stop supplying power.

There is an alternative solution, and that is to suspend performance. However, there is a question under California law whether such a right exists. That's because it has not been established

All it takes to push the utilities into an involuntary bankruptcy is a filing by three creditors who together are owed more than $10,000.

under California law whether the delivery and sale of electricity are covered by the Uniform Commercial Code. To be covered, electricity must be a "good."

MR. MARTIN: What difference does it make if electricity is a "good" under the Uniform Commercial Code, or UCC?

MR. SEIFE: The UCC provides very clear remedies for breaches of contracts involving sales of goods. One of the remedies is to suspend performance. A generator would be able to suspend performance without terminating the contract. Many QFs are reluctant to terminate their contracts because the contracts are valuable assets.

MR. MARTIN: Bruce Rader or Bob Shapiro, any other views on whether the QFs can walk away from their contracts?

MR. SHAPIRO: Obviously, the UCC question is a very big issue. However, on top of that, you have a threat every day of blackouts. If a large group of QFs was to suspend performance, it would create a worse blackout situation and probably leave the Bush administration with no choice but to invoke section 202(c) of the Federal Power Act to force QFs to continue to serve.

DR. WEISENMILLER: One other point — many of these QFs have long-term contracts with capacity payments that run for as long as 30 years. If a QF were to terminate now at year 12, it would have a substantial liability for the capacity overpayments that have been made to date. The contract would have to be viewed as a 12-year rather than a 30-year contract. That's a very strong deterrent against termination.

MR. SHAPIRO: Another complicating factor is that the standard offer contracts typically in use in California were negotiated, political documents. Consequently, they lack certain key provisions — for example, default and termination provisions. [Laughter] Ordinarily, one would read the default section to find out what is a default

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under long-term purchase contracts works.

The utilities borrow the money for the prepayments in the tax-exempt bond market. They then protect against a drop in gas prices by entering into a separate hedge or swap transaction. The IRS is wondering whether this is not impermissible "arbitrage." Arbitrage bonds do not qualify for tax exemptions. An arbitrage bond is a bond that someone uses to borrow at low rates in the tax-exempt market in order to put the money into a higher-yielding investment. The American Public Gas Association sent the US Treasury a policy memo recently arguing that the scheme does not run afoul of arbitrage rules.

If it works, the idea probably warrants looking again at an idea independent power companies planning to supply power to municipal utilities explored in the early 1990's. The idea was to have the municipal utility borrow to prepay for capacity under a long-term contract. The independent power company would then use this capacity payment as a form of tax-exempt financing.

TAX INDEMNITIES may be barred by the statute of limitations.

Companies with possible indemnity claims should make a formal claim for payment, even if they are contesting with the government — at the request of the idemnitor — whether the taxes are owed.

Tax indemnities are common in lease financing transactions and in mergers and acquisitions. In a lease financing, the lessee usually promises the lessor — or institutional equity — that it will receive certain tax benefits from the transaction. In corporate acquisitions, it is customary for a parent company selling a subsidiary to indemnify the buyer against any taxes that relate to events or periods before the sale.

Norfolk Southern was the lessor in a "safe-

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and what the cure rights are and what happens after a cure period. The contracts are silent on this subject.

What Happens In Bankruptcy

MR. MARTIN: Let's move to a slightly different topic — bankruptcy. Howard Seife?

MR. SEIFE: The utilities could find themselves in bankruptcy in one of two ways. One would be involuntarily. All it takes are three creditors who together are owed more than $10,000 in claims, and all they need to allege is the company is not generally paying its debts as they come due. The companies have already admitted as much in their public filings. Thus, we are faced with a situation where any three creditors could — as we speak — run to the courthouse and put the utilities into an involuntary bankruptcy.

Another scenario would be a voluntary bankruptcy. The implications of a voluntary bankruptcy are significant. Number one, the utilities would be able to resume borrowing and, thus, have the cash to pay their bills. It sounds contrary to common sense that, by filing bankruptcy, one gains access to the credit markets, but that's exactly what happens.

The banks are already lining up to offer DIP financing, or debtor in possession financing. Before any utility puts itself voluntarily into bankruptcy, it would want to be assured that such financing is available and locked in so that it would have access to the credit markets the day after filing.

MR. MARTIN: Back up. Aren't there a couple of other things that happen in bankruptcy? One is creditors cannot continue to pursue collection of past debts?

MR. SEIFE: There are several potential benefits to the utilities from filing for bankruptcy. One is what you just mentioned, which is an automatic stay. Your creditors are enjoined, or stayed, from taking any enforcement actions against you. They can't sue you. They can't attach your assets. They can't even harass you.

MR. MARTIN: Is another effect of a bankruptcy filing by the utilities that the QFs would be obligated to continue performing their contracts?

MR. SEIFE: Yes, to the extent the QFs have not terminated their contracts before a utility bankruptcy, they are going to be locked in. They are going to have to continue to supply power under those power purchase agreements. That is one of the protections that the bankruptcy code gives to the utilities.

MR. MARTIN: At what price would they be required to continue performing?

MR. SEIFE: That raises an interesting question. The normal rule is that, if a debtor still wants to get the benefits of a contract, he must continue to perform according to the terms of the contract. So in this case, if the utilities want to continue to be supplied with power the QFs, they would have to pay for it according to the contract terms.

There is one exception that I don't think has been focused on to any significant degree. If the QFs are determined to be "utilities" for purposes of the bankruptcy code, then the rules change. It it not hard to imagine some smart lawyers representing utilities are going to argue that the QFs are themselves utilities.

MR. MARTIN: What happens if they are utilities?

MR. SEIFE: If they are utilities, then number one, the QFs are required to continue to supply power. Number two, you don't necessarily look at the contracts to determine the rates that the QFs must be paid for their power. You look at something that's more akin to a market rate. A QF could be better or worse off, depending on what its contract provides currently.

MR. MARTIN: The newspapers are full of reports that bankruptcy might be a good idea because a bankruptcy judge could order the CPUC to allow the utilities to pass through their costs. Could a bankruptcy judge do that?

MR. SEIFE: Some of the headlines in the papers have intimated that a bankruptcy judge can unilaterally impose new rates. I think that's far from the case. Bankruptcy courts are very reluctant to step on a regulator's toes. They generally defer to the regulators. You are not going to see a bankruptcy judge unilaterally setting rates.

However, what the bankruptcy court can do is bring all the parties together, give a focus to all of competing claims, and really start imposing some moral suasion and pressure to get a deal done. A bankruptcy judge will not determine what is a fair and reasonable rate.

MR. MARTIN: Is there any reason to believe that these parties — who have already met in one room with the Secretary of Energy, the Secretary of the Treasury, the FERC chairman, and the California governor — are going to be any more likely to reach an agreement in a bankruptcy court than they have already?

MR. SEIFE: I would think not. But it does buy time, and it may diffuse the crisis atmosphere. The utilities will be able to resume borrowing. They will be able to pay future bills. This will buy time.

MR. MARTIN: This is an odd situation for bankruptcy. Normally when a company files for bankruptcy, it starts over with a clean slate. But here, with every electron the utilities buy, they lose more money. How would they be able to borrow going forward in that circumstance?

MR. SEIFE: The magic of bankruptcy is the new lenders will have first priority. They will be the first ones to get repaid on any process. So this is generally a safe loan.

MR. MARTIN: Only if the bank is willing to take assets for repayment. The utilities are losing — and will continue to lose — a million dollars an hour.

MR. SEIFE: There will be cash flow.

MR. MARTIN: If a bankruptcy judge cannot order the regulators to increase retail rates, is

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harbor" lease of 38,000 shipping containers in the early 1980's. The lessee was Flexi-Van. The IRS took the position that Norfolk Southern was not entitled to investment tax credits or accelerated depreciation on the containers because Northern Southern could not prove they were used to carry cargo "to and from" the United States. The IRS let taxpayers who could not prove this settle on the basis that half the containers qualified. Norfolk Southern rejected the settlement at the request of Flexi-Van and — also at Flexi-Van's request — pursued the case all the way to the US Supreme Court.

It lost. Flexi-Van then refused to pay a tax indemnity on grounds — among other reasons — that the indemnity claim was barred by the statute of limitations. A formal claim for payment must be made within six years after the claim arises under a tax indemnity governed by New York law. A federal district court in New York said Norfolk Southern made a timely claim, but just barely before the six years had run. The court said the six years begins to run from when the tax is paid to the US government. The court released its decision in December.

The lesson is to make a formal claim early in the process. A notice to a lessee that the IRS disallowed the tax benefits is not a claim for payment of an idenmnity.

CONGRESS made several changes in tax law in early December that will affect power companies and project developers.

It increased the "volume cap" — or the amount of tax-exempt bonds that a state can issue each year to finance private projects — to $225 million or $75 times the population, whichever is greater. The limit had been $150 million or $50 times the population. The new limit takes effect in 2002. The limit for 2001 is $187.5 million or $62.50 times the population. A state can carry unused volume

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there a risk in bankruptcy that he could order the QFs to accept less?

MR. SEIFE: If the QFs are determined to be utilities, then the judge could try to fix rates. Apart from that, the utility will not get immediate relief from the rates that it is being charged by the QFs.

During the bankruptcy process, the utilities will able to decide whether they want to assume contracts, including these PPAs, or reject them. If they assume the QF contracts, they will have to cure all the back payments. If the utilities think electricity can be purchased elsewhere at better rates, they can reject the contracts. Then the QFs will be left with general unsecured claims.

MR. MARTIN: If the bankruptcy judge rejects the QF contracts, won't this be an ironic outcome? The utilities have been trying to buy them out for several years. Do the QFs get any compensation if the contracts are rejected?

MR. SEIFE: The QF will get to stand on line with all the other creditors. They will have prepetition general unsecured claims, and it will be up to the bankruptcy court to determine the contract damages.

MR. MARTIN: What about the value of the contract itself going forward?

MR. SEIFE: That will be part of each QF's prepetition claim.

MR. MARTIN: At this point, I would like to bring in the rest of the panel. One way to get into bankruptcy is for the generators to force the utilities into it. Do generators have any interest in doing this? Do they gain or lose?

MR. SEIFE: One ironic benefit for the QFs if the utilities go bankrupt is payments will resume under their contracts. The utilities will be able to borrow money. A bankruptcy judge will require the utilities to pay currently for power being supplied by the QFs.

MR. MARTIN: Are there downsides?

MR. SEIFE: The flip side is the risk for QFs that their contracts will be rejected. QFs also have to deal with their own lenders. Each of these QFs has its own bank debt. A bankruptcy filing by a counterparty to the power purchase agreement will be a default under the QFs own financing agreements.

MR. MARTIN: Any other views on the panel?

MR. SHAPIRO: I don't see any of this as realistic. If the state will not allow the utilities to pass through their costs of electricity, the utilities will continue to lose money. Eventually, one will have a situation where the generators must either stop serving or declare bankruptcy themselves. There will have to be a political solution that involves some combination of utility bailout and rate increases. Bankruptcy provides no ultimate solution.

There will have to be a political solution . . . bankruptcies do not solve anything.

MR. MARTIN: So in your view, there is nothing to be gained by bankruptcy?

MR. SHAPIRO: No. Eventually, you will end up in the same place.

MR. MARTIN: Any other views on the panel?

MR. SEIFE: The advantage of the bankruptcy is to buy time for the utilities. A political solution is not in view. This crisis cannot go on much longer in its current mode. I think a bankruptcy is virtually inevitable.

DR. WEISENMILLER: Can utilities shield their unregulated businesses from the bankruptcy court by erecting a "ring fence," or will the bankruptcy ripple out to these affiliated companies?

MR. SEIFE: That's a key question. Will this work? S&P and Moody's think it will because they have given investment grade ratings to these companies that have moved over behind the ring fence. Will it be challenged in a bankruptcy court? I think probably it will be.

What QFs Should Do

MR. MARTIN: If you are a QF and expect the utility to whom you sell power to file for bankruptcy, is there anything you should be doing now in anticipation of this?

MR. SEIFE: If I think I might lose the ability to sell or want to terminate my contract, I would start looking now for another buyer for my electricity.

DR. WEISENMILLER: In California, a QF — under very limited circumstances — can sell on the retail market without becoming a utility, but the sale must be just over the fence. Therefore, I would say over 99% of QFs would have to look at the wholesale market. You then look at the ISO and PX. If you were to try to participate in them now, there would a time lag of maybe 60 days. Obviously, one can't predict whether the PX will be around in 60 days. So, you are looking at the wholesale market — municipal utilities and wholesale entities — trying to figure out if you have any way to get your power to them either through the ISO or through any pre-existing transmission agreements they have. I am not sure "dismal" is the right word, but it is a complicated analysis. I fear most people will find themselves trapped.

MR. MARTIN: One effect of a utility bankruptcy is the QFs become locked into supplying power. Some QFs have talked about filing for bankruptcy themselves. This would set up a dueling bankruptcy scenario. What would happen? Why would a QF do this?

MR. SEIFE: One benefit for a QF to file for bankruptcy is the ability to reject its power

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cap over to the next year.

Congress also extended a tax deduction for the cost of cleaning up Superfund sites. The deduction had been scheduled to expire at the end of last year. It has been extended for spending on cleanup through 2003.

Finally, Congress restored the installment sale method that lets the seller of property report its gain from sale ratably over the same period that installment payments of purchase price are received. Unfortunately, sellers must pay an interest charge on the taxes that are considered "deferred" as a result. However, the option to pay taxes over time can still be useful, particularly in section 29 deals where most of the purchase price is paid as tax credits are earned over time.

BRIEFLY NOTED: Turkey increased a "temporary" corporate surtax from 20% to 25% in December . . . . China cut the tax rate from 33% to 15% for projects in the western provinces effective January 1 . . . . The IRS said in a letter to Senator Jon Kyl (R.-Arizona) that taxpayers who qualify for refundable state tax credits may have to report part of the tax credits as income. Kyl asked about a case where a taxpayer qualified for a $5,000 tax credit in 2000 for purchasing an alternative fuel vehicle. The taxpayer will claim the credit on his 2000 tax return filed in April 2001. He can only use $500 of it on the 2000 return. He has the option of getting a check from Arizona for the balance or carrying it backward or forward to use against other taxes he owes the state. The IRS told Kyl the $4,500 must be reported as income in 2001. It does not matter whether the taxpayer has it refunded to him or uses it as a carryback or carryforward. ■

— contributed by Keith Martin and Heléna Klumpp in Washington and Marta Pulaski-Kelly in New York.

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purchase agreement. It would get out of the obligation the utility bankruptcy imposes to continue supplying power. Obviously, this would entail a lot of risk. A QF would only do it if it wasn't getting paid and knew it could enter into a long-term agreement to sell to someone else.

MR. MARTIN: If a QF waits to file for bankruptcy after the utility does it, would it be released from its obligation to continue serving or is it too late?

MR. SEIFE: I would think it would still be obligated to deliver power to the utility, even though it filed for bankruptcy. However, you would have a conflict between two bankruptcy judges, one of whom wants to do everything possible to protect the utility and the other who wants to do everything possible to protect the QF.

MR. MARTIN: Are there other effects of a utility bankruptcy? Is this an automatic default for QFs under their own bank loans?

MR. RADER: Clearly it is. One other thing we should mention is QFs are looking at forbearance agreements with the utilities as a way of forestalling any utility bankruptcies. The QFs are hoping to get forbearance agreements back to back with gas suppliers and then also with their lenders.

MR. MARTIN: A forbearance agreement is what?

MR. RADER: It is an agreement that the QFs would forebear from trying to collect from the utility for past debts. The utility could suspend payments — namely the next two payments under the PPA. The utility would pay the QFs on April 1 with some concept of default interest built in.

MR. MARTIN: So, suppose a generator expects a utility bankruptcy. What ought it to be doing? Bob Weisenmiller mentioned looking for other outlets for the power. We talked about the possibility of the QF itself filing for bankruptcy. We talked about forbearance agreements. One should probably also let one's lenders know the situation because this could be an automatic default under the QF's financing agreements. Are there other things that QFs ought to be doing now?

DR. WEISENMILLER: This is a major political poker game in Sacramento. QFs ought to make sure that they are represented at the table.

MR. SEIFE: One of the issues that QFs are struggling with is whether to shut down. Right now they are incurring huge costs for gas, and they are not getting any revenues in. That hole just gets deeper and deeper. One of the things they are considering is going dark.

MR. MARTIN: That seems suicidal given the current political environment.

MR. SEIFE: It depends whose suicide you are talking about. [Laughter] One of the issues for the bankers in the audience is what do you do when your borrower — the QF — sends you a notice that it is out of cash, its utility hasn't paid it in two months, and it can't afford to buy more gas to operate. There is very little banks can do. This is not mismanagement. It is not malfeasance. The banks are not going to be able to take over the facilities and run them any better than the QF can. Everyone has to sit on his hands until the political solution is sorted out.

MR. MARTIN: Twenty to 30% of independent generators are selling through power marketers into the spot market or selling their power under tolling agreements. Are generators who are doing this in the same fix that the QFs are? Bob Shapiro?

MR. SHAPIRO: Generators that have tolling agreements with creditworthy offtakers are okay. They are not selling directly into the spot market. There is no regulatory out clause in those contracts. They are protected to the extent that the power marketers to whom they sell power remain creditworthy. The power marketers and tolling gas companies are the

ones with the problem.

MR. MARTIN: Are those power marketers and tolling gas companies putting the credit of the parent company on the line or were these contracts signed by special-purpose subsidiaries?

MR. SHAPIRO: In every case where there is a project financing, the toller has to be itself creditworthy or have a guarantee by a creditworthy entity.

What Banks Should Do

MR. MARTIN: Let me ask Chaim Wachsberger, since you often represent banks, what ought a lender to be doing at this point?

MR. WACHSBERGER: I have to be a little careful in answering that because we have clients who are lenders and developers. The starting point is to know what your loan agreements say. Many of the possible QF actions discussed today will require lender consent.

However, at the end of the day, this is probably one of the most difficult scenarios you could have dreamt of. It's very complicated. It's big. It's in flux. You take a look at some of the power companies in California — these are some of the best companies this business has ever seen. I have to believe the bankers in the audience are thinking I should look at what my rights are, but if these guys can't figure out other options this week, I'm not sure I can figure it out any better. It's not a question of mismanagement. I think it is healthy to know what your borrower is doing and thinking. Keep a close eye on what's going on. Once the situation changes enough so that people begin to have options, you try at that point to have your say.

Risk of Expropriation

MR. MARTIN: Let's move on. There has been talk about the possibility of San Francisco and other municipalities taking over the power plants or seizing capacity. Let me ask Bill Monsen, is this a very likely scenario?

MR. MONSEN: A number of cities in California have been looking at this. The reality is they don't really have any generating assets located within city limits. As a result, it would be very difficult for them to become municipal utilities.

DR. WEISENMILLER: One of the issues the state is facing with its RFP for power is whether it has good enough credit to support long-term contracts. A municipality that goes into the power business would have the same issue, particularly if the only assets nearby to municipalize are distribution lines so that it would still have to buy power in the wholesale market. It is surprising to see the city of San Diego — a very conservative city — looking at municipalization.

In all of the California chaos, the municipal utilities have been isolated from the problems. However, it is a very simplistic solution to say that if Los Angeles — which is served by the LAPD — has done so well, why not do the same thing on a statewide level or at least for the city of San Francisco. The first question is where do you get the excess generation. The heart of the problem in California is there is too little supply in relation to demand. Does the city of San Francisco want to allow the siting of new power plants in San Francisco?

Is California Unique?

MR. MARTIN: One big question, can this happen elsewhere?

MR. WACHSBERGER: It never could have happened here. [Laughter]

MS. HARGIS: I think that's the answer. One of the problems in California is the utilities are not allowed to pass through the high prices they are having to pay for wholesale power. These high prices can be found in other parts of the country. Indeed, GPU in Pennsylvania has a rate cap, and it said recently in a regulatory filing that it has

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run up $42 million in excess costs for power that it has been unable to pass through. I think California is the worst case, but a fair number of states are starting to feel discouraged about whether deregulation reduces electric rates.

MR. MARTIN: Other views on whether this can happen elsewhere?

MR. SHAPIRO: A number of states that have gone far down the road in restructuring have done a much better job than California. In many of those states — for example, Nevada and Ohio — the selloffs of generation have been accompanied by transition power sales agreements back to the utilities that essentially match in price the retail rates the utilities are allowed to charge during the freeze period. There won't be the situation that occurred in California in these states.

The real question is going to be is there enough incentive — are the markets robust enough and is the climate good enough —- for new generation so we won't get into a capacity crunch as California has done. To the extent regulators and governments in other states understand the need to encourage new generation and for supply to grow with demand, over the long-term the pricing will reach equilibrium.

MR. MARTIN: Other views? Bob Weisenmiller?

DR. WEISENMILLER: If you think back to what I identified at the start as the five or six factors that contributed to the situation in California, I think you can find one or more of these problems in other parts of the country, but not the whole combination. You can find jurisdictions that have rate freezes. You can find jurisdictions that have a high reliance on gas or imported electricity. So, you will certainly have rate spikes in other states with utilities being caught at least temporarily in the middle, but I don't think you have quite the same sort of perfect storm where everything goes wrong at the same time. ■

Turkey Overhauls Electricity Laws

by Kristin Meikle, in Washington, and Begum Durukan with the Birsel Law Offices, in Istanbul

Turkey is in the process of overhauling its electricity laws. The government submitted a bill to parliament in mid-December. The measure is expected to pass in early February.

The new rules should eventually open up opportunities for private developers. However, the reforms are not expected to be completed until 2003. In the meantime, developers may find themselves in limbo while waiting for two new regulatory bodies to come out with regulations.

Privatization

The legislation is supposed to address a number of conflicting goals of the Turkish government, including adhering to the debt ceilings prescribed by the International Monetary Fund while at the same time liberalizing the energy market to attract investment in order to address the projected rapid — by some estimates, as high as 10% — annual growth in electricity consumption.

The first set of changes is primarily organizational. As anticipated, the Turkish Electricity Generation and Transmission Corporation, or "TEAS," will be broken up into three entities: a marketing firm, a generation company and a transmission company. The transmission company will be the successor to TEAS and will remain state controlled. Generation and distribution assets are expected to be sold in a state-run auction. The privatization is expected to get underway by 2003, but to take past 2003 to complete.

The bill allows for competition between the state-controlled marketing and generation companies and private entities. Consequently, once the draft law becomes effective, all electricity-related activities — other than transmission — will be carried out by some combination of authorized

private legal entities and a state-run company that consists of remnants of the state-controlled marketing firm and generation company.

Private companies that enter this business will be subject to some restrictions.

First, foreign entities are prohibited from taking a controlling interest in any company that has a monopoly over electricity distribution in a particular region. Second, no private generator can have more than a 20% market share comparing its output in the current year to generation and consumption nationwide the year before. Finally, private companies are restricted to performing activities in one sector only. For example, a company that generates electricity will not be allowed also to distribute it. However, subject to certain limitations, a company will be able to own shares in companies that provide other types of services, provided that this is not a controlling interest.

Amendments are possible to the government's draft bill before it passes parliament. The two most likely areas for amendment are the rules governing foreign ownership and the percentage of market share that a private generator may have.

New Regulatory Bodies

Two new regulatory bodies will be established: the Energy Market Regulatory Authority, or "EMRA," and the Energy Market Regulatory Board. The board will be an arm of EMRA.

EMRA will be responsible for issuing regulations governing the sale, trade, import and export of electricity by private companies.

The board will license private companies to operate in Turkey and assess penalties where companies fail to comply with their obligations. The board will have seven members. They are expected to be appointed within three months after the draft law takes effect. However, the board will not start issuing licenses until 2003.

There will be a transition period of 18 months after the draft law is published in the "official gazette" before it takes effect. The council of ministers has discretion to extend this period by an additional six months. Many government officials believes the transition period in the bill is too short and that 36 months may be more realistic. During the transition period, private companies currently operating in the Turkish energy market are permitted to continue their operations without a license. However, all private companies — including owners of existing power plants — will have to apply for licenses before the end of the transition period.

EMRA will have the final say over the prices at which electricity can be sold. The method for regulating electricity prices will be established through a separate piece of legislation; the government has not yet released the draft. However, regulations on electricity pricing are expected to be in place before the end of the transition period.

Government Guarantees

The draft law will eliminate guarantees of private projects by the Turkish government. The Treasury Department currently guarantees certain payments to be made by TEAS under contracts with private companies. Any projects already completed will continue to be guaranteed. Projects under development will be guaranteed, provided that they are commissioned by the end of 2002. The undersecretariat of the State Planning Organization and the Ministry of Energy and Natural Resources released a list of 29 power projects in January that will be covered by Treasury guarantees, provided that they are commissioned by the end of 2002. Guarantees on these projects are still expected despite the government's promise in a letter to the International Monetary Fund that projects announced after January 1, 2001 would no longer qualify for guarantees.

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The lack of a Treasury guarantee will have considerable short-term impact on the appeal of the Turkish generation sector for private investors. However, once the transition period has been completed, the more liberal and competitive energy market should engender new interest in such investment. ■

Municipal Power Deals

by Keith Martin, in Washington

Anyone who has tried to do a deal with a municipal utility knows that the municipal utility must be careful not to allow too much private use of its assets or it can lose the tax exemption on bonds issued to finance the assets.

The Internal Revenue Service issued guidelines in January showing how far such deals can go before they cross the line.

The new rules will affect anyone trying to wheel his electricity across municipal transmission lines or buy electricity from a municipal power plant. They will also affect schemes to finance merchant power plants in the tax-exempt bond market by making a municipal utility nominally the owner. However, they do not address what terms are allowed for someone seeking to operate a municipal facility. The IRS discussed operator or management contracts in a separate "revenue procedure" in 1997.

One can view the new rules as limits. Alternatively, they can be seen as a road map for creative thinking.

New IRS guidelines show how far deals with municipal utilities can go before they cross the line.

The new guidelines are in "temporary and proposed" regulations. The IRS wants comments on them by July 12. Temporary regulations — unlike regulations that are merely proposed — have legal effect in the meantime.

They leave municipal utilities somewhat in limbo. All utilities are under pressure from the Federal Energy Regulatory Commission to transfer at least operating control over their transmission lines to regional transmission organizations, or RTOs. The IRS said it is still studying what effect such transfers will have on municipal utilities.

Background

Municipalities can finance schools, roads, hospitals and other public facilities in the tax-exempt bond market. This gives municipal utilities an edge over private power companies because they can borrow at lower interest rates. They are also not subject to income taxes on their earnings.

Privilege comes at a cost. The municipality must be careful not to allow more than 10% "private business use" of its assets or the bonds issued to finance the assets will lose their tax exemption. Private business use ordinarily means use in a capacity other than as a member of the general public. Thus, for example, a municipality cannot agree to a special deal to sell power from one of its power plants to an industrial customer or a power marketer on terms that are not available to the general public.

The utility must also be careful not to permit more than $15 million in bond proceeds spent on an "output facility" from being put effectively to private use. Output facilities are not only power plants, but also transmission and distribution lines.

Line Drawing

A deal with a municipal utility goes too far if it has the effect of transferring "substantial benefits of owning the facility and substantial burdens of paying the debt service on the bonds" used to finance the facility. The deal must do both before it is considered private use.

Some situations where a private party has ownership benefits are obvious. An example is where a facility is leased to a private party.

The new rules the IRS issued in January address what one can say in "output contracts" — or contracts to buy power or use transmission lines — without crossing the line.

Ownership Benefit

The IRS said that a contract giving the holder a preferential right to capacity — ahead of the general public — transfers the benefits of owning the facility.

The amount of private use in that case is the percentage of capacity reserved. For example, if a power plant has a capacity of 800 megawatts, a contract to sell 40 megawatts to a private party is 5% private use.

The percentage for a power plant is determined by multiplying the annual nameplate capacity by the number of years to maturity of the bonds. However, if the bonds are issued before the project goes into service, then one counts only the years from the in-service date to when the bonds mature. Thus, if the bonds for the project will mature in 12 years, the project has a nameplate capacity of 800 megawatts, and 40 megawatts have been contracted for three years, the percentage of private use is only 40 x 3 = 120 divided by 800 x 12 = 9,600. In other words, the amount of private business use is only 1.25%. The way this formula works leaves room for planning.

The nameplate capacity must be adjusted for physical constraints – like the fact that a river has too little water to run a hydroelectric project at full capacity – but not for economic constraints. An economic constraint is the fact that a plant loses money because fuel prices are too high in relation to what the plant can get for its power. The IRS said it will calculate private use as a percentage of the expected average *actual* output — rather than nameplate capacity — in cases where there would be less than 10% private use using nameplate capacity but more than 20% such use by looking at actual output.

Debt Service Burden

The burden of paying debt service is borne by a private party to the extent of any payments under a contract that the private party is "substantially certain" to have to make. Payments that are forecast to be made are considered "substantially certain"; they do not have to be legally required.

All payments under an "output contract" — for example, a power purchase agreement or wheeling contract — count as going toward debt service if the contract is pledged as security for the bonds. It does not matter in that case how likely the payments are to be made. However, this is true only if the contract cannot be substantially amended without consent of the bondholders.

The percentage of the debt service that a private party will bear is determined by comparing the present value of the payments under the contract to the present value of the debt service. The discount rate for this calculation is the yield on the bonds.

What happens if there is a 10% transfer of ownership but only 5% support of debt service? The contract is okay because one needs more than 10% private use on both counts to have crossed the line.

$15 Million Limit

Municipal utilities must also be careful not to allow more than $15 million in bond proceeds to be put effectively to private use. If a power plant

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is considered put 15% to private use, then 15% of the bonds used to finance the power plant are considered put to private use. Thus, for example, if the plant was financed with a $600 million bond issue, 15% of the bond issue is $90 million.

Some merchant plant developers try to tap into tax-exempt financing for their projects by stitching together a number of contracts from an "excluded list."

One must take into account all outstanding bonds for the same "project." Generating units placed in service more than three years apart are not part of the same project. Transmission lines are not part of the same project if placed in service more than two years apart. Improvements are not part of the same project if they were not contemplated in the original design and work on them commences — and the bonds to finance them are issued — more than three years after the original project went into service.

Take or Pay

A contract to "take" or to "take or pay" for output is a lost cause. The IRS will treat the facility as put to private use to the full extent of this contract. IRS regulations define a contract to "take" as one where the purchaser agrees to pay for output if the facility is capable of producing it.

Requirements Contracts

Requirements contracts — where someone commits to buy his requirements for electricity or transmission — may or may not be private use depending on the facts. It is a bad fact where the customer commits not to cease business operations (so that he would still have to make payments under the contract for breach of a covenant after a business shutdown).

Opportunities

The following kinds of contracts are ignored; they are not considered private use.

Some merchant plant developers have tried to give a municipal utility nominal ownership of a facility, but to operate the facility and to stitch together a number of output contracts from the following list in order remain below the radar screen on private use.

- Small volume contracts — The payments each year under the contract must not be expected, when the contract is signed, to exceed 0.5% of average annual debt service on the bonds used to finance the facility.
- Swaps and pooling agreements — The purpose of the swap must be to "enable each of the parties to satisfy peak load demands, to accommodate temporary outages, to diversify supply, or to enhance reliability." The swapped output must be expected to be approximately equal in value from year to year.
- Short-term contracts — The contract, including renewal options, must not last more than a year. It must either be a negotiated deal at arm's length or be based on generally applicable and uniformly applied rates.
- Excess capacity — Excess capacity at a power plant or on a transmission grid can be offered under contract for a term of up to three years. Renewal options are counted as part of the term. The municipal utility must apply any payments received from such sales to pay down the bonds issued to finance the power plant or grid. It cannot borrow in the tax-exempt market in the meantime to add capacity.

- Power marketers — Output can be sold to a power marketer without being considered private use as long as the power marketer acts solely as a conduit. The contract would probably have to be structured so that the power marketer acts as an agent for the municipal utility in placing the power. ■

Tax Opinions Face Scrutiny

by Keith Martin, in Washington

Tax opinions may be harder to get from US tax advisers in the future in tax shelter transactions under new rules the Internal Revenue Service proposed in January. The new rules are part of a government campaign against aggressive tax planning.

"Tax shelter" is a somewhat nebulous term that catches many transactions that are done at least partly to reduce federal income taxes.

The new rules are guidelines that US tax advisers must follow when giving any written advice about tax shelter transactions. The aim is to prevent tax advisers from leaving the impression that such transactions work by assuming away inconvenient facts or by failing to flag all the legal issues.

They will have two main effects. One is to force the law and accounting firms rendering such opinions not only to go into greater detail about why they concluded the transaction works, but also to recite the facts on which the opinion writer is relying. Short-form opinions that merely recite the documents the opinion writer reviewed and his conclusion will no longer be permitted. They will also require tax advisers to inquire more deeply into whether the taxpayer has a meaningful business purpose for the transaction or expects any real economics apart from tax benefits and bar reliance on outside appraisals that seem questionable.

Tax partners at law and accounting firms face public reprimands from the IRS — and possibly even suspension or disbarment from practice before the IRS — unless they take steps to ensure their firms are complying.

The rules are merely proposed. The agency has scheduled a hearing on them for May 2.

Tax Shelter

The new guidelines apply to any written advice on the consequences of a "tax shelter" transaction. Written advice includes not only formal opinion letters and tax discussions in offering circulars, but also legal memoranda.

The words "tax shelter" have not been clearly defined. The new guidelines adopt the same definition for the term as in section 6662(d)(2) of the US tax code. The words are defined there as any transaction or entity that has as "a significant purpose" the "evasion or avoidance of Federal income taxes." Thus, a big-ticket leasing transaction or a tax structure to defer US taxes on an outbound investment is potentially a tax shelter. However, the implication is that the taxpayer aims not simply to reduce his taxes, but to do so in a way that is arguably aggressive. IRS regulations under section 6662 say the following:

> "Typical of tax shelters are transactions structured with little or no motive for the realization of economic gain, and transactions that utilize the mismatching of income and deductions, overvalued assets or assets with values subject to substantial uncertainty, certain nonrecourse financing, financing techniques that do not conform to standard commercial business practices, or the mischaracterization of the substance of a transaction. The existence of economic substance does not of itself establish that a transaction is not a tax shelter if the

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Tax Opinions

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> transaction includes other characteristics that indicate it is a tax shelter."

This is broader concept of tax shelter than the IRS used in regulations last year that require any corporation participating in a "reportable transaction" to attach a form with the details of the transaction to its tax return for each year the transaction affects its US tax position.

Law firms are likely to be conservative. The new rules are guidelines for anyone who wants to practice before the IRS. The IRS drew up the rules; it can interpret them as broadly as it wants. This is not a case where the tax adviser can argue that the IRS is misreading what Congress said in the tax law.

Opinions

Opinions about tax shelters will have to explain in a lot more detail in the future why these transactions work.

Opinions about tax shelters will have to explain in a lot more detail in the future why these transactions work.

Different rules apply to opinions that conclude a tax shelter has a better than even chance of working than to weaker opinions. What follows is a description of the rules for opinions that conclude a transaction is at least more likely than not to work.

Under the new rules, the opinion will have to recite all the material facts of the transaction. The tax adviser cannot assume facts. However, he can ask the taxpayer to represent certain things and rely on those representations as long as what is being represented sounds reasonable "based on all the facts and circumstances" and the person making the representation is in a position to know the inside story.

For example, the tax adviser can rely on a credible representation that the transaction serves a real business purpose. However, the representation must explain the business purpose. He can rely on a representation that the taxpayer expects a profit from the transaction apart from tax benefits. However, the taxpayer must provide credible factual backup to support it.

Appraisals and financial projections may be relied on only if they appear sensible and the person doing them is "reputable and competent." The tax adviser must inquire behind any appraisal of the fair market value of assets to make sure the appraiser used an acceptable approach for determining market value.

Turning to the legal discussion, only "reasoned" opinions will be allowed in the future; the opinion cannot simply state a conclusion without explaining why. It must address every tax issue on which there is a reasonable possibility of challenge by the IRS. It must state the likelihood that the taxpayer will prevail on each issue individually, and also give a bottom-line conclusion on the entire transaction. The opinion must also state that

> "the practitioner has considered the possible application to the facts of all potentially relevant judicial doctrines, including the step transaction, business purpose, economic substance, substance over form, and sham transaction doctrines, as well as potentially relevant statutory and regulatory anti-abuse rules, and the opinion must analyze whether the tax shelter item is vulnerable to challenge under all potentially relevant doctrines and anti-abuse rules."

If the tax adviser is relying on an opinion from another law firm, he must identify the firm, give the date of the opinion, and describe its conclusions.

Taxpayers sometimes ask for an opinion only on a narrow issue. A tax adviser will be able to give such an opinion in the future only if someone else competent is opining on the broader issues. He should see the broader opinion.

Penalties

Tax advisers who violate the new rules face public reprimands and possibly even suspension or disbarment from practice before the IRS.

Other tax partners at the same law or accounting firm are also at risk if the government can show that the firm has engaged in a pattern or practice of failing to comply. However, the government is expected to take this action only against any tax partner who knew of the violations and failed "consistent with his or her authority" within the firm to rectify the situation.

Contingent Fees

Some law and accounting firms collect fees based on the amount their advice saves the taxpayer. The new rules bar fees in the future that are tied wholly or partly to success in sustaining a position with the IRS or in litigation. The ban extends to indemnity agreements, guarantees, rescission rights and other arrangements where the taxpayer would be entitled to some money back if the position is not sustained.

However, the ban applies only to fees for advice about positions the taxpayer plans to take on an original return, and not to fees for refund claims or positions on amended returns if the refund claim or amended return is expected to receive "substantive review" by the IRS. ■

Holland Alters Its Approach To Tax Rulings

By Waldo Kapoen with Loyens & Loeff, in The Hague

The Dutch government is moving – under pressure from the European Union – to change its approach to issuing advance tax rulings. This may have an effect on companies that hold their offshore investments through Holland.

Background

The European Union issued a report in 1999 targeting 66 potentially EU "harmful tax regimes" that were in use in EU member countries. Ten of the 66 regimes identified were in Holland. They included the Dutch government's practice of issuing advance rulings to companies that invest through holding companies in Holland to confirm that the investments qualify for the "participation exemption." Dividends received on an investment qualifying for the participation exemption are exempted from Dutch tax. This is also true for capital gains upon disposal.

In late November, the underminister of Finance – who is responsible for taxation – said he expects the EU to drop eight of the 10 Dutch regimes from the harmful tax practices list. This was the tradeoff for new measures the government announced in a letter to parliament. The new measures will take effect from April 1, 2001. The new measures cover not only advance tax rulings, but also advance pricing agreements in transfer pricing cases.

Advance Tax Rulings

The underminister said the government will continue to issue advance tax rulings on the tax classification of international structures — for example, to confirm that the participant exemption applies to offshore investments and on whether the taxpayer will be treated as having a "permanent establishment" in Holland or abroad.

Tax rulings have not usually been published in

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the past. Rulings that deviate from the standard rulings are — with only a very brief description of the facts — published from time to time. This will change. The underminister of Finance said that the policy-related aspects and circumstances underlying the conclusion of both advance tax rulings and advance pricing agreements will be systematically published in the future. So, too, will the government's decision not to rule or enter into a pricing agreement. Publication will be in an anonymous form or in a summarized form.

The underminister said the Dutch government is also studying whether to impose a substance requirement to discourage the location of activities in The Netherlands that are purely tax driven. The government does not want any such requirements to lead simply to migration of the activities to other countries in Europe.

Obtaining an advance tax ruling usually takes about four months currently. The underminister agrees that this is too long, and he has taken measures to improve the organization of the rulings practice and reduce the time required to issue a tax ruling to, in principle, a maximum of eight weeks. Furthermore, the backlog of ruling requests will be halved within six months, assuming that the inflow of requests remains constant. These are goals. It remains to be seen whether they will be met.

Advance Pricing Agreements

The Ministry of Finance will issue an advance pricing agreement decree. Although the Netherlands prefer so-called bilateral APA's, unilateral APA's are also possible. The duration of an APA will be four years, although a longer period is possible. An APA team is being set up within the tax department in Rotterdam.

Holland will follow the internationally-accepted arm's-length principle in the OECD rules on transfer pricing. This will be adopted by statute. The government will also publish a decree dealing with the calculation of transfer prices.

Exchange of Information

The Dutch government notifies taxpayers before turning over information to foreign tax authorities. The government intends to shorten the notice period to 10 days. If the taxpayer lodges an objection within this period, the exchange of information will be suspended. Within the set term, the taxpayer can appeal to the courts to seek provisional relief — for instance, if it fears that release of the information would damage its interests. The court would then rule on the merits of the objection. The information will not be released before the court has ruled on the provisional relief procedure.

Changes in tax ruling procedure may have an effect on companies that hold their offshore investments through Holland.

Transition Rules

Tax rulings that are submitted before April 1 this year will be handled under the old rules.

Rulings are issued for a limited time period and must be renewed. The underminister said any rulings issued under the old rules will be given effect through December 2005, unless the taxpayer prefers to stick with the expiration date given in the ruling.

Taxpayers who do not have to obtain an advance ruling, but who file tax returns in accordance with the existing ruling practice, can continue to do so through December 2005, provided they conduct activities that fall under the present published ruling practice and they currently file tax returns in accordance with the mentioned practice.

In order to get a standard ruling dealing with the

application of the participation exemption or financing or royalty activities, action before April 1, 2001 is needed, although it may be advisable to wait for more information on the new ruling practice before submitting such ruling requests. It may be worthwhile to have such ruling requests prepared in the meantime to avoid a "time is up" situation. ■

Claiming R&D Tax Credits On Projects

by Keith Martin and Samuel R. Kwon, in Washington

The Internal Revenue Service issued final rules in January on how to define "research" that qualifies for a 20% federal tax credit.

The definition is important to power, mining and telecoms companies experimenting with new technologies. The more tax benefits a company can build into its project, the less the project will cost at the end of the day.

The tax credit will be difficult to claim for most projects.

In order to claim a credit, a company must show it spent money on experiments that have the aim of improving technology. The company will have to jump through four hoops to do this.

First, the aim must be to discover new information. The IRS gave the example of a manufacturing company that makes widgets, but wants to use a new material. The company lacks experience with the material, but how to use the material is within the common knowledge of other skilled professionals in the industry. This is not "research." However, where a company wants to build a bridge that can carry a higher volume of traffic than other bridges without deterioration, its work on the technology to build the bridge does qualify. The IRS said it does not matter if someone else has already built such a bridge if the technology is a closely-guarded secret.

Second, research is a process of experimentation. The company should have more than one hypothesis for how to achieve a result and be uncertain which is better. It should run tests to determine which hypothesis is better.

Third, the activity must precede commercial operation. Activity after a project is in commercial operation is not research. The IRS said tooling up for production, trial production runs and trouble shooting are not research. Thus, a power company could not claim the cost of a turbine as research on grounds that the turbine was the first of its kind off the production line. However, the turbine manufacturer might claim that it was still engaged in research if it ran a test model before the model was in production.

Fourth, it is not research simply to adapt an existing product or process to a company's needs. An example is customizing software so that a utility can use computers to dispatch electricity.

The cost of computer software developed for a company's own internal use never qualifies for credits, except to the extent the software will be used in research. The IRS said it would not allow tax credits to be claimed for fixing year 2000 problems with computer software.

If a company qualifies for an R&D credit, then it can compute the credit in one of two ways. Under one approach, the credit is 20% of the amount by which the company increased its research spending above a base. For example, if research spending in 1999 is $6 million, but the company's "base" spending on research was $4 million, then the credit is computed against the $2 million increase. The base is gross receipts for the year times the fraction of the company's gross receipts that it spent on research during a five-year period from 1984 through 1988. Companies that had no research during this period are arbitrarily assigned a base of 3% of annual gross receipts. Research spending must exceed this amount before there is any credit.

Calculations are done by treating all business

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R&D Tax Credits

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entities that are more than 50% owned as a single taxpayer.

The government will not let a company treat more than half its research spending in a year as an increase in its research spending. For example, if research spending mushroomed one year, the government would limit the credit for that year to 20% of half the research spending that year.

The other way to compute credits is under a sliding formula. A company would have to spend more than 1% of its gross receipts in a year to get a credit. The credit would be 1.65% of research spending above 1% of gross receipts, 2.2% of such spending above 1.5% of gross receipts, and 2.75% of research spending above 2% of gross receipts.

The R&D tax credit expires on June 30, 2004, but there is growing support in Congress to make it permanent. ■

Tax Incentives For Burning Local Coal

By Samuel R. Kwon, in Washington

State tax credits to electricity generators for burning local coal may be unconstitutional because they favor in-state coal producers to out-of-state ones.

Other state tax or regulatory schemes that discriminate against out-of-state businesses - for example, higher disposal fees on solid waste from other states or a requirement that utilities use a minimum amount of in-state coal - may also be unconstitutional for the same reason.

State Tax Credits

At least seven states currently give tax credits for burning in-state coal: Arizona, Kentucky, Maryland, Ohio, Oklahoma, Virginia and West Virginia. Alabama and Utah are considering similar incentives. Washington's incentive - a sales tax exemption for generators that use 70% or more in-state coal - was dropped after a lawsuit by coal companies in Wyoming and Montana.

Under these schemes, the states usually give tax credits to generators to offset their overall tax liabilities if they burn coal produced in-state rather than coal purchased from out-of-state producers. The amount of the credit ranges from $1 to $3 per ton of in-state coal burned. Other forms of incentives also exist. For instance, Arizona gives tax credits in an amount equal to 30% of the sales tax paid on the purchase of the in-state coal. In Kentucky, the credit is available only for Kentucky coal burned in excess of a base amount. These credits are nonrefundable.

US Constitution

The commerce clause of the US Constitution grants Congress the power to "regulate commerce . . . among the several States . . . ."

From this clause, the courts have drawn both a positive and a negative implication. Positively, the clause means Congress has the power to enact laws governing interstate commerce and such laws trump conflicting state laws. Negatively, the clause means a state may not enact laws designed to benefit in-state economic interests by burdening out-of-state entities. If a state law affecting interstate commerce benefits in-state entities at the expense of the out-of-state competitors, that law violates the negative implication of the commerce clause and may be unconstitutional.

A state law can affect interstate commerce in at least two ways. It may discriminate overtly against out-of-state entities by giving economic benefits only to in-state entities or imposing economic burdens only on out-of-state entities. Alternatively, the burden on out-of-state entities may simply be a side effect of trying to carry out another objective.

In *Philadelphia v. New Jersey*, the US Supreme Court said, "where simple economic protectionism is effected by state legislation, a virtually *per se* rule

of invalidity has been erected." In that case, a New Jersey statute prohibiting importation of most solid or liquid waste originating outside New Jersey was held unconstitutional.

In subsequent cases, the Supreme Court struck down all but one state law that conferred benefits only on in-state entities or imposed burdens only on out-of-state entities. For instance, the Supreme Court struck down an Oregon statute that imposed an additional fee on solid waste generated out-of-state and brought into Oregon for disposal. It struck down a North Carolina intangibles tax on corporate stock owned by its residents, whose amount was reduced in proportion to the level of business activity the corporation was engaged in business in North Carolina. It struck down a New York local ordinance requiring that all solid waste generated in that locality be processed by a local recycling plant.

Only once has a state law that discriminated on its face been upheld. In *Maine v. Taylor*, the Supreme Court examined a Maine statute that prohibited any importation of live baitfish into Maine. Maine argued such a measure was necessary because it needed to protect Maine's wild fish from being placed at risk by certain parasites prevalent in out-of-state baitfish, but not common to wild fish in Maine. Maine also argued non-native species inadvertently included in shipments of live baitfish could disturb Maine's aquatic ecology significantly. The Supreme Court upheld Maine's legislation, explaining the interests Maine attempted to protect were legitimate and there was no physical alternative to the total ban that would protect Maine's interests.

Even if a state law does not discriminate against out-of-state entities on its face, it may burden out-of-state entities as a side effect of trying to do something else. Such laws are more likely to be upheld. However, the state must show the harm done to interstate commerce is outweighed by the larger goal the statute is trying to serve.

In *Pike v. Bruce Church, Inc.*, the Supreme Court said "where the statute regulates even-handedly to effectuate a legitimate local public interest, and its effects on interstate commerce are only incidental, it will be upheld unless the burden imposed on such commerce is clearly excessive in relation to the putative local benefits." In that case, the Supreme Court struck down an Arizona law that prohibited Arizona producers of cantaloupes from exporting the cantaloupes to out-of-state entities unless their packaging complied with Arizona regulations. The Supreme Court explained the benefit to Arizona — preserving the reputation of Arizona growers by prohibiting deceptive packaging — was not important enough to justify the effective requirement that certain Arizona producers build and operate packaging plants in Arizona to comply with state regulations.

Implications

Because most state tax credits for burning in-state coal discriminate overtly against out-of-state coal producers, they are almost certainly unconstitutional.

The Supreme Court has struck down similar measures as unconstitutional. For instance, in *Wyoming v. Oklahoma*, the Supreme Court struck down an Oklahoma statute that required coal-fired electric utilities to burn a mixture containing at least 10% Oklahoma-mined coal. This law unconstitutionally "reserve[d] a segment of the Oklahoma coal market for Oklahoma-mined coal, to the exclusion of coal mined in other States. Such a preference for coal from domestic sources cannot be characterized as anything other than protectionist and discriminatory, for the [Oklahoma statute] purports to exclude coal mined in other States solely on its origin."

State tax or regulatory measures that deal with solid waste disposal or other types of state level taxes may also be problematic. So long as they impose a greater economic burden on out-of-state entities than they do on in-state entities, those measures are susceptible to constitutional challenges. ■

Environmental Update

The Clinton administration managed — shortly before leaving office – to propose new rules for reducing air emissions that contribute to haze in national parks. However, these and other rules were blocked by the incoming Bush administration.

Regional Haze

The US Environmental Protection Agency proposed new guidelines in mid-January for states to follow in setting "best available retrofit technology" – or what environmental experts call "BART" – for a wide range of facilities, including existing power plants. The new guidelines could affect power plants located near national parks and federal wilderness areas – so-called Class I areas – where there are already regional haze problems due to local industrial sources. The proposed guidelines appear to establish flue-gas desulfurization or scrubbers as the presumptive BART standard for utility boilers. This could have the effect of reducing sulfur dioxide, or "SO2," emissions at such boilers below the levels currently required by the federal acid rain program.

The new standards would apply to power plants that were constructed between 1962 and 1977, that emit more than 250 tons of SO2, nitrogen oxide (NOx), particulate matter (PM), volatile organic compounds (VOCs) or ammonia, and that are located upwind from Class I areas.

Under the new rules, states would have to submit their regional haze plans to EPA between 2004 and 2008, and the BART-level pollution controls would have to be installed within five years after EPA approves a state's plan.

The Bush administration put a halt to implementation of all regulations issued in the final weeks of the Clinton administration to give the new Bush appointees time to assess what was done. The haze proposals have not appeared yet in the *Federal Register* because of the freeze.

Hazardous Air Emissions

Also trapped by the Bush freeze is a guidance document that the US Environmental Protection Agency was on the verge of issuing that would have explained what releases of hazardous air emissions are federally permitted and, therefore, are exempted from having to be reported under two federal laws: Superfund and the Emergency Planning and Community Right-to-Know Act, or EPCRA.

The final guidance reflects heavy industry input after EPA was sued to bar implementation of its original proposals.

The final guidance is expected to provide that releases of constituent hazardous substances that are subject to permit limits or federally-approved state rules – including those designed to limit VOCs, PM and NOx – are exempted from reporting. Emissions above the permit or rule limits are not exempted.

The final guidance is not expected to exempt "grandfathered" air emission sources from the Superfund reporting requirements, unless they have a federal permit or federally-approved regulatory standards in place that limit the plant's hazardous air emissions. Many older grandfathered utilities do not meet this requirement and may have to report such emissions as "continuous releases" under section 103 of Superfund and section 304 of EPCRA.

Mercury

One announcement that EPA managed to make before the Bush freeze is word that the federal government plans to regulate mercury and other hazardous air pollutants from coal- and oil-fired steam generating plants. The announcement appeared in the December 20 *Federal Register*. Owners of such plants are bracing themselves for what are expected to be expensive new rules.

The EPA announcement sets the stage for new maximum achievable control technology standards – or what environmental experts call "MACT" – that will

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apply to all new and existing coal and oil-fired utility units. EPA estimates that the cost for industry to comply could be between $1.9 and $5 billion.

Control technologies that might form the basis of establishing new MACT standards include wet flue-gas desulfurization scrubbers, fuel switching – for example, from coal to gas – coal cleaning, and certain particulate control devices like electrostatic precipitators and baghouses. Newly-developing mercury removal technologies include activated carbon injection and spray cooling.

EPA is expected to issue a proposed rule by December 2003 and to have the final rule out by the end of 2004. Power companies should expect to have to comply by the 2007 to 2008 timeframe.

Congress

The Senate Environment and Public Works Committee hopes to report legislation this year that will impose new multi-pollutant emission limits on power plants. The targeted pollutants are NOx, SO2, mercury and carbon dioxide. Committee chairman Robert Smith (R.-N.H.) is expected to introduce a multi-pollutant bill that will include national emissions caps and emissions trading as two of its key components.

California

The California Energy Commission issued emergency regulations in mid-November that will accelerate licensing of new power plants that are larger than 50 megawatts in size. CEC review and licensing of such plants is now supposed to take only six months.

The main impediment to quick licensing is environmental review. Six months is probably the minimum time the CEC needs to do the review required by the California Environmental Quality Act, or CEQA.

The emergency regulations are full of pitfalls, and the CEC has, as of presstime, received no takers from the development community.

Meanwhile, the California EPA is making efforts to promote a more informal program called the "Green Team" to facilitate permitting and development of power plants that are smaller than 50 megawatts in size. Such projects are too small to be subject to review by the CEC. According to the California EPA, 26 such projects are slated for construction in 2001. Such projects rely upon local permitting authorities, with the assistance of California EPA, to complete the CEQA review process more efficiently than under the CEC program.

President George W. Bush said in mid-January that one way to address the power crisis in California may be to roll back environmental standards. Bush told CNN that "to the extent that we can help California maximize power production in its plants, we need to do so. If there [are] any environmental regulations, for example, that [are] preventing California from [maximizing output at power plants,] like I understand there may be, then we need to relax those regulations."

Coal Ash

A federal appeals court in late January rejected efforts by environmental groups to force the US Environmental Protection Agency to regulate ash from burning fossil fuels as a hazardous waste.

EPA issued a determination in April 2000 that most categories of fossil fuel ash should be regulated only as a non-hazardous waste under the Resource Conservation and Recovery Act, or RCRA. The decision came after years of study. EPA said then that it would still issue non-hazardous waste regulations to establish standards for managing coal ash that is disposed in landfills or surface impoundments. These regulations are expected later this year. Regulations on such ash used to fill mines are not expected until 2003.

The federal appeals court in late January dismissed the environmental groups' petitions on

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purely jurisdictional grounds. Therefore, this is unlikely to be the last word on the issue. The groups can simply refile in the appropriate court.

Migratory Birds

The US Supreme Court struck down a rule in January that the US Army Corps of Engineers has used to assert federal wetlands jurisdiction over non-navigable and isolated intrastate waters.

The Army Corps has used this "migratory bird rule" to claim jurisdiction over wetlands and water bodies, such as power plant cooling water ponds, that "are or would be used as habitat for migratory birds that cross state lines." Federal jurisdiction under laws like the Clean Water Act requires the government show an effect on interstate commerce.

Justice Rehnquist, writing on behalf of a narrow 5-4 majority, did not go so far as to say that such a migratory bird rule was beyond the jurisdiction of Congress, but he did conclude that there had to be a clear statement of Congressional intent to establish jurisdiction that "invokes the outer limits of Congress' power."

The decision by the US Supreme Court means that federal wetlands restrictions and permits would not be required for isolated wetlands that are not at least adjacent to an interstate waterway.

Power Plant Upgrades

The US government reached an agreement in principle with midwestern utility Cinergy in late December on how to resolve an enforcement action that the government brought against Cinergy for allegedly modifying its coal-fired power plants in a way that increased air emissions. The government charged the utility with failure to go through the so-called new source review permitting requirements required by the Clean Air Act before making the improvements.

The agreement in principle covers 34 coal-fired generating units at 10 Cinergy sites. The utility agreed to install selective catalytic reduction on nine units, add four new flue-gas desulfurization systems or scrubbers, and repower nine units with natural gas.

The pollution controls are expected to cost Cinergy $1.4 billion over the 2001 to 2012 time period. In addition, Cinergy will pay a civil penalty of $8.5 million, fund $21.5 million in environmental projects, and surrender between 40,000 and 50,000 SO2 allowances.

The agreement in principle is similar to agreements between the US government and two other utilities –- a November 2000 agreement in principle to resolve an enforcement action against Virginia Power and one in February 2000 with Tampa Electric Company.

The US Environmental Protection Agency has stepped up its new source review enforcement activities. The US government filed a complaint against Duke Energy on December 22, 2000 targeting eight of its plants for alleged violations. Several other utilities across the country that burn coal have also received Clean Air Act section 114 information request letters recently and are under investigation for suspected new source review violations. ■

— contributed by Andrew Giaccia and Roy Belden in Washington.

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