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The Day The Piña Coladas Melted

The turmoil this year in the California power market has led some states to put their plans for deregulation of electricity supply on hold. Chadbourne hosted a debate in Colorado in late June on the topic "Resolved: Electricity is too important to be left to a free market." There were eight debaters. The following are excerpts from four of their statements.

The speakers are Jerome P. Peters Jr., senior vice president and head of project finance for United Capital, Dennis P. Alexander, senior vice president and general counsel of Cogentrix, Lynn Hargis, former assistant general counsel for electric utility regulation at the Federal Energy Regulatory Commission, and John Cooper, senior vice president and chief financial officer of PG&E National Energy Group.

MR. PETERS. Once upon a time, in the land nestled between the Great Continental Divide to the Pacific Ocean, there was a great empire. This land was blessed with long summers, and short mild winters, and an abundance of natural resources, and a group of intelligent and forward thinking regulators. It was truly a land of milk and honey.

AUDIENCE MEMBER: A fairy tale!

MR. PETERS: Indeed it is. The citizens of this empire were a demanding lot. They demanded clean air, clean water and no nukes. At the same time, they demanded more cars, and more freeways, and more affordable and reliable energy.

AUDIENCE MEMBER: Without smog!

MR. PETERS: They elected legislators who were regulators who saw to it the citizens' demands were met. They mandated cleaner cars, and they

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In Other News

ELECTRIC INTERTIES receive attention from the IRS.

The Internal Revenue Service will announce this fall whether utilities must report interconnection payments from generators to connect their power plants to the grid as income. IRS policy since 1988 has been not to tax such payments. The agency announced last summer that it has the area under study. In the meantime, some utilities are requiring generators to "gross up" their interconnection payment for taxes. However, most are taking a

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shut down the nukes. When the regulators began to see the energy as a liability that was being threatened by too much reliance on fossil fuel generation, they initiated programs and tax credits to encourage development of renewable energy projects, which led eventually to a substantial and significant increase in the generating capacity of the empire. By balancing in full the means of reliability with affordability, the regulators were able to ensure that the empire was well served with the first mix of reliable and affordable power.

The citizens, relaxed in their air conditioned houses and sipping frozen piña coladas, confident in the knowledge that life was indeed good.

The citizenry of this empire, never being satisfied with the status quo, decided life would be better if it were cheaper. They elected officials who responded by embracing a concept of free market energy where supply and demand would determine the price of generated electricity. Early on, the wise regulators raised concerns about this new free market approach, warning of price spikes and of power shortages once the plan was implemented. The regulators' concerns were brushed aside and, after many years of playing this debate, they got the free market system that they desired. Almost immediately prices skyrocketed. Several of the empire's largest utilities could no longer afford to purchase this free market power. Soon electric prices to the people rose. The lights went out. The houses got hot, and the piña coladas melted.

Then the people cried out: "Who is to blame?" The people blamed the elected officials for flawed legislation, the elected officials blamed the power suppliers for price gouging, and the power suppliers blamed the fuel suppliers and the elected officials. There was plenty of blame to go around. It seems that the desired price benefits the empire had hoped for failed to be achieved.

The point is that electric generators in any given market represent an oligopoly where significant barriers to market entry give a limited number of suppliers market power, enabling them to manipulate price by limiting supply. If anyone doubts this premise, I offer as evidence various actions by members of OPEC over the last 30 years.

The second point is that suppliers seek to minimize production costs of new generating capacity, leading all the suppliers to choose the lowest-cost type of technology that can be developed in the shortest amount of time. The result has been nearly 100% of all capacity additions in recent years have been gas-fired projects. The increased utilization of natural gas as a primary fuel source has put pressure on gas supplies and transportation capacity, and it has pushed prices to levels two and three times what they were several years ago.

A free market leads to a situation where all new power plants use natural gas.

Reliability has suffered for much the same reason with all new electrical generating capacity using natural gas. When there is a shortage of gas supply transportation capacity, there is a shortage of electricity.

There is nothing in the dynamics of the free market system that promotes the development of higher-priced renewable energy. But without such renewable energy sources, wherever will we be in 30 or 40 years? No frozen piña coladas for sure. What we have learned from the California experience lies not in what they did wrong, but in what they did right. Prior to the free market debacle, California maintained an adequate reserve margin that was mandated by the California Public Utilities Commission and was paid for by the ratepayers. After the early 1980s, new capacity was achieved in long-term power purchase agreements between the utilities and the independent power producers. Regulators encouraged the development of renewable energy through mandated standard contracts, making California the nation's leader in renewable energy production.

With the advent of so-called deregulation, which began in the early 1990s, virtually all capacity additions in the state ceased. Little significant new renewable capacity was added and reserve margins plummeted. As soon as the utilities divested their generating assets, prices rose and reliability dropped. Is there any reason to expect that free market approach will produce better results elsewhere?

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MR. ALEXANDER. I am sorry that we have focused on California, because I don't know of a similar crisis that deregulated markets have created anywhere else in the country.

AUDIENCE MEMBER: Hear, hear!

MR. ALEXANDER. We in North Carolina don't have any problems. In Maine where I was recently, they seem to be getting along just fine. So let's call a spade a spade and not condemn the entire nation and the entire industry because of the folly, failures and shortcomings in California.

The perilous situation in California is far worse than anything that could have occurred had the state truly deregulated and let the market work. In the long run, crises do not serve a free market. They may serve the politicians, but they do not serve any of the other players in it.

To argue that there is a need to regulate when markets fail is like saying that there is a need to resuscitate after someone clubs someone unconscious. The other side assumes the current situation is a failure of the market. An assassination of it is the more correct comparison. Left to its own devices the marketplace will, given time, come

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wait-and-see approach and are asking only for a promise to pay any taxes if they arise.

At issue is whether generators make interconnection payments in their capacities as "customers" of the utilities. An amendment to the US tax code in 1986 requires utilities to pay tax on any contribution of money or property by "a customer or potential customer." Generators argue the payments are not income because generators are not utility customers as Congress used the term and, moreover, the utility has no "income" in the sense of an increase in wealth. The utility cannot put the intertie in its rate base, and it does not earn a profit from its use.

Walter Woo, an IRS lawyer assigned to the issue, said he expects the IRS to publish a notice announcing its decision this fall. Chadbourne sent the Treasury Department 11 fact patterns at the end of May that it asked the IRS to be sure to address in the notice.

CALIFORNIA is moving to increase property taxes on power plants.

The State Board of Equalization voted unanimously at the end of June to instruct the staff to draft an amendment to shift responsibility for assessing utility property from local governments to the state. There is also a bill in the state legislature to do the same thing. Cogeneration facilities and small power plants that generate 50 megawatts or less would be exempted from the change. State assessment means power plants will no longer be covered by Proposition 13, which limits increases in assessed values to 2% a year.

Repeal of the current system is expected to place 41 power plants under state jurisdiction. An independent power group has organized to fight the change.

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into its own balance and the value from the taker will be matched with value to the provider, and there will be a stable situation created, albeit there will be fluctuations from time to time.

We know in our business that there are fluctuations because it takes time and circumstance to adjust to needs. But artificial governmental interference merely frustrates the ability of the market to react.

Transmission is something we haven't really talked about. Distribution is a natural monopoly and is a vital service that must be regulated and controlled. Perhaps the delivery of the product must be regulated, but it does not follow that the product itself must be regulated.

What California does not need is to exacerbate the situation by imposing more regulations to fix the ones that are not working.

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MS. HARGIS. They say if you don't know history, you are doomed to repeat it. In 1930, we actually had in this country a free market in wholesale electric rates. The governor of a very important state became concerned about this because he could not keep down the electric rates in his state. One of the things he tried was to start a public power authority. Even that was not completely successful. So this governor, when he became president of the United States, got enacted an act that would regulate wholesale electric rates and also the holding companies that own them.

Many people now say that this president, Franklin D. Roosevelt, saved capitalism by regulating it, and I propose to you that he also saved investor-owned utilities by regulating them. If you look around the world, you will notice that, until recently, most other countries own the electric power supply system. Far from causing them to be taken over by the state, I submit that FDR saved privately-owned utilities.

Alfred Kahn, the guru of deregulation, testified recently before Congress. Many people are insisting that price caps never work. They point as an example to Nixon and the oil price caps in the 1970's. Kahn said that cost-based regulation of electricity did work — did really work — from 1945 to 1995.

I saw a headline the other day and it said, "Brazil Power Crisis, Another California?" I can remember a time when it would have gone the other way. If we had some trouble in California they would say, "Are we going to be like Brazil?"

Electricity is different from other commodities. The most important reason why it cannot simply be left to a free market is all voters have one thing in common: they pay utility bills. I knew there was trouble when I went to the Federal Energy Regulatory Commission a few years ago for the first time in a long time and saw a sign that the Federal Energy Regulatory Commission "promotes competitive markets, protects consumers." And I thought, that's curious. I know all the statutes under which FERC operates. None of them says its job is to promote competitive markets. Someone had put this ahead of what the statutes do require, which is to protect consumers. What happened next is FERC ignored its own constituency, and Senator Robert Smith, a Republican, introduced a bill jointly with Senator Diane Feinstein, a Democrat, to impose price caps that would have passed both houses of Congress if FERC had not imposed a price cap on its own.

The California situation is not so much a failure of the market as an assassination of it.

Finally, let me say a word about a real market — the stock market. The stock market is regulated in this country under New Deal regulation passed by President Roosevelt. My husband works for the Securities and Exchange Commission, and he goes to countries like Bulgaria, Hungary, and Brazil and helps them with their stock market regulations. There is one interesting thing about those unregulated stock markets — nobody uses them. It is front page news if a share is traded in Bulgaria. I believe there were two shares traded there recently. And yesterday over a billion shares were traded in the United States stock market.

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MR. COOPER: Our worthy opponents have tried to push this debate to the absurd. We are not talking about deregulating the whole electricity supply chain. We are talking about electricity the commodity.

Nobody in his right mind would propose deregulating all the components of the electricity supply chain or natural monopolies. We are not arguing for deregulation of interstate transmission. We are not proposing deregulation of the guy who puts the wires in your house. We are talking about electricity the commodity — the wholesale supply of electricity and the retail purchase of electricity.

Electricity has unique aspects that no other commodity has and that basically require the careful management and transition from regulation to deregulation. We maintain that deregulation doesn't exist anywhere in the county yet, and what we are seeing are basically efforts at moving toward deregulation, some more successful than others.

Why have we been talking in this country about the deregulation of electricity the commodity? It is because regulation has failed. This is not just an academic exercise. People believe that the prices and cost of power should be lower than under the regulatory regime.

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THE US AND GREAT BRITAIN signed a new tax treaty on July 24. The treaty will help British companies with investments in the United States.

It eliminates US withholding taxes on dividends that are paid by a US subsidiary to its British parent. This is the first time that the United States has agreed with any country to a 0% withholding rate. Some commentators expect the treaty to lead to use of the Great Britain as a staging post for investments into the United States. In order for the 0% rate to apply, the British parent must own at least 80% of the voting shares in its US subsidiary. In addition, it must jump through several other hoops. The hoops are easier to get through if the US subsidiary has been owned since September 1998.

The treaty must be ratified by the US Senate and the British Parliament before it takes effect.

SPAIN is making a push to persuade US power companies to run investments into Latin America through Spanish holding companies.

The country enacted a "participation exemption" regime similar to the one in Holland, and it has a wide network of tax treaties with Latin American countries. Tax treaties often reduce the withholding taxes on cross-border payments. They can make it less expensive to withdraw earnings from the project country.

The fact that Spain has a "participation exemption" means that it does not tax Spanish holding companies on their returns from equity investments outside Spain. For example, a Spanish holding company owning all the shares in a project company in Mexico would not be taxed in Spain on dividends from the project company or on capital gains when shares in the project company are sold.

MAURITIUS revamped its companies law at the end of May.

The new rules are expected to take effect in

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Where, in fact, has the push for deregulation been greatest? It has been in California and New York and New England — the highest price power areas in the country. And why have those prices been so high? Because of failed regulatory efforts in the past.

Electricity supply and demand must be in balance at every given instance and this needs to be managed by a centralized dispatch system that signals which units are going to run to meet supply and provide stability to the system. Clearly there is some regulatory role. Right now, the regulators have failed to perform that role properly in the West, and the rules in some regions are more stable than in others, which is one reason why the new supply under development varies in different parts of the country. The price signals must be capable of providing for excess supplier reserve margins at all times.

There is one interesting thing about unregulated markets — no one uses them. It is front page news if a share is traded in Bulgaria.

Right now, the way to regulate supply without direct capacity payments is to turn off the lights. Essentially, the retail market operates on inaccurate price signals. In order to have true deregulation, you must have consumers understand what they are paying for — what the price of their commodity is — to allow behavior to adjust on the demand side as well as over time on the supply side.

The transition process has failed in California, but is being successfully undertaken in New England and New York where various types of transition arrangements have brought forth a flood of new investment that every economist in the industry is predicting will lead soon to an overbuild situation. Competition is what is going to provide the best value and the best pricing for consumers over the long term. ■

US Government Moves To Cap Electricity Prices

by John Tormey, in Washington

The US government moved on June 19 to cap electricity prices in an 11-state area, including California.

Meanwhile, California asked the Federal Energy Regulatory Commission to order $9 billion in refunds for the amount it claims electricity generators overcharged for power since May last year. Utilities in the Pacific Northwest have also demanded refunds. In late July, the commission said it can only order refunds for California power sales on or after October 2 last year. The commission announced a methodology it would use in the future to decide when generators are overcharging for power. It said any refunds ordered could be retroactive only back to December 25 last year for power sales in the Pacific Northwest and back to July 2 this year for power sales in other western states.

Price Caps

The order imposing price caps on June 19 modified a price cap order that had already been in effect for California power sales since April and extended it to an 11-state area in the western United States called the WSCC. The 11 states are New Mexico, Arizona, Colorado, Utah, Nevada, Oregon, Washington, Idaho, Wyoming and Montana. The area also includes small portions of

Texas, South Dakota and Nebraska.

Last April, FERC set a "soft" price cap for California power sales during reserve deficiency hours. Reserve deficiency hours are periods when electricity supply falls below a 7% reserve margin. This was later clarified to mean only during periods when the California independent system operator, or "ISO," has declared a "stage 1 emergency." The price cap is a "soft" cap in the sense that sales can still take place at prices above the cap but only if the seller can justify the higher price.

The June order extending the price caps to the rest of the WSCC means that price caps will be in effect throughout the WSCC whenever there is a stage 1 emergency in California. However, FERC also imposed caps — at 85% of the stage 1 emergency level — during other periods.

The June order also imposed a "must-offer requirement" and said the price caps and must-offer requirement will apply not only to public utilities — defined broadly to include investor-owned utilities, independent generators and power marketers — but also to municipal utilities.

FERC calls the price caps and must-offer requirement a price mitigation plan.

Under this plan, everyone across the WSCC will be subject to the same price caps based on the price at which electricity is being sold in the California ISO. During stage 1 emergencies, the cap for a particular reserve deficiency hour will be a hypothetical amount, called the "proxy price," for the last unit of electricity to be bid into the ISO during that hour. This marginal proxy price will be the cap for that hour for the entire WSCC region. The cap will apply not only to sales in spot markets, but also to bilateral sales. Sellers selling outside the ISO will receive the prices they negotiate up to the cap.

Sales during non-reserve deficiency hours will also be subject to a cap. The maximum price for spot market sales during non-reserve deficiency

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October. Suzanne Gujadhur with the Mutual Trust Management Group in Port Louis reports that "there will not be a great difference between the old regime for the offshore sector and the new." US companies often use holding companies in Mauritius to make investments into China, India and Pakistan.

HOLLAND suggested a way to pull dividends out of a Dutch holding companiy without paying withholding taxes.

The suggestion is in a decree the Dutch state secretary of finance issued in early July. It relies on Dutch tax law rather than tax treaties.

It works as follows: The key is that the foreign parent of a Dutch holding company must cause itself to have a "permanent establishment" in Holland to which shares in the Dutch holding company can be attributed. There is no withholding tax on dividends paid by a Dutch holding company to the permanent establishment, or "PE," of a foreign parent. The foreign parent must have a genuine business in Holland. This gives it a PE. The activities of its Dutch holding companies should be directly related to the PE so that they can be attributed to it. This could be done, for example, by having the foreign parent place a small staff in Holland to manage its investments or project development activity in Europe. The staff would have to have independent decision-making authority.

The Dutch tax authorities will confirm by ruling that the technique works.

MEXICO should no longer collect withholding taxes on "grossed up" dividends. The Mexican Supreme Court said the practice is unconstitutional.

Mexico collects a 5% withholding tax on dividends, but the tax is levied on 1.5835 times the dividend, resulting in an effective withholding tax

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hours will be no more than 85% of the highest ISO hourly market clearing price established during the hours when the most recent stage 1 emergency was in effect. Sellers through the ISO will receive the hourly market clearing price up to this maximum price, while for sales outside the ISO — that is, bilateral sales in California and the rest of the WSCC — sellers will receive the prices they negotiate up to the maximum price.

Generators will be divided into two classes. During reserve deficiency hours, all spare generation capacity in California must be offered to the ISO. Spare generation capacity in the rest of the WSCC must be offered into a spot market of the generator's choosing. This applies only to non-hydroelectric generation. It applies whether the power plant is owned or is under contract — for example, a tolling agreement — to the extent the output is not scheduled for delivery or committed for minimum operating reserves. All such must-offer sales of power are subject to the price mitigation detailed above just as with all other sales.

FERC imposed three further restrictions on sellers. First, power marketers are required to bid as price takers, which means that they cannot bid higher than the market clearing price. Second, FERC required sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas for generation plus variable O&M costs. Third, FERC instructed bidders to invoice the ISO directly for the costs of complying with emissions requirements and for start-up fuel costs. In other words, these costs are outside the cap. Sellers other than power marketers are allowed to justify bids or prices above the maximum prices.

Electricity sellers in an 11-state area in the West are now subject to price caps tied to adjusted spot prices in California.

In an earlier order issued April 26, FERC required each gas-fired generator in California to file with the commission and the ISO the heat rate and emission rate for each generating unit. The ISO would use the heat rates to calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and an adder for the variable O&M cost in order to calculate the clearing price during periods of reserve deficiency. All generators would be paid a single market clearing price reflecting the proxy price for the last unit dispatched during periods of reserve deficiency.

In its June 19 order, FERC determined that the spot gas prices to be used in the formula should be the average of the mid-point of the monthly bid-week prices reported by *Gas Daily* for three spot market prices reported in California (SoCal Gas large packages, Malin, and PG&E city-gate). FERC also eliminated NO_X costs from the calculation of the mitigated market-clearing price and set the O&M adder at $6 a megawatt hour. Finally, FERC also instructed the ISO to add 10% to the market clearing price paid to generators to reflect credit uncertainty.

The new price mitigation plan took effect on June 20, 2000 and will remain in effect until September 30, 2002.

FERC applied the plan to municipal utilities as a condition for municipal utilities selling into the spot markets and as a condition of using the interstate transmission grid.

Possible Refunds

On April 26, the FERC launched an investigation into the rates, terms and conditions of sales for resale of electric energy in the WSCC other than sales through the ISO. This was in addition to the

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ongoing investigation commenced by FERC the previous year into wholesale sales of electricity in California.

FERC stated in its June 19 order that refunds would not be ordered for California sales before October 2, 2000. FERC also said in that order that it expected refunds arising from its investigation of rates in the WSCC other than sales through the ISO would be rare because of the market mitigation implemented WSCC-wide in the June 19 order.

On July 25, FERC issued another order explaining the methodology it will use to decide when sellers overcharged for electricity. The immediate focus of the refund investigation is transactions in the spot markets operated by the ISO and the California Power Exchange and power sales in the Pacific Northwest. Most interestingly, FERC insisted its refund authority is limited to 60 days after filing of a complaint or institution of a "section 206" investigation. Also, of interest was the FERC's determination that it had authority to order refunds from municipal utilities because of its authority over the subject matter of the sales at issue.

FERC said it would calculate overcharges by reference to the price caps, with several slight modifications. The actual heat rate of the last unit dispatched will be used to calculate the market clearing price. The June 19 order established a price cap of 85% of the market clearing price established during the most recent stage 1 reserve deficiency for hours in which no reserve deficiency exists. However, FERC elected not to use this price for such hours in testing for overcharges.

The gas proxy used to determine refunds will be daily spot prices rather than monthly bid week prices. Further, if the marginal unit was located north of "path 15," the spot price would be the average of the PG&E city-gate and Malin spot prices, while if the marginal unit was located

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of 7.69%. Critics charge that the practice violates tax treaties limiting dividend withholding taxes to 5%. The Supreme Court has now declared it unconstitutional. Hacienda, the finance ministry, is analyzing whether it will make refunds to companies that have been withholding taxes at the higher effective rate.

CHILE is considering increasing its corporate tax rate from 15% to 17% over three years. The government proposed the change to the Chilean Congress as a way to pay for lower tax rates for individuals.

THE WORLD TRADE ORGANIZATION said legislation the United States enacted late last year to replace the "foreign sales corporation" regime is an illegal export subsidy.

The decision is expected to be made public on August 13. The United States will have 60 days to decide whether to appeal. The Bush administration is consulting with Congress. However, Rep. Bill Thomas (R.-California), chairman of the House Ways and Means Committee, said "Dragging out the process through extensive appeals or cosmetic changes to our tax system will not solve the problem." Thomas called the US tax system antiquated and said the decision by the World Trade Organization should serve as a catalyst next year for Congress to overhaul US foreign tax rules.

The United States has had rules since the 1970's that allow US companies to reduce taxes on income from exports of US-made goods by as much as 21% by running the sales through an offshore subsidiary. The provisions have also been used to reduce US taxes on rent under outbound leases of US-made equipment like aircraft and turbines.

The World Trade Organization declared the foreign sales corporation regime illegal last year.

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south of path 15, the spot price would be the SoCal gas-large packages spot price. Path 15 is the corridor that runs north and south between PG&E and SCE's territory and is the backbone of California's transmission system. In addition, the spot price for gas will be determined by using the simple average of spot prices published in several sources.

The federal government may order refunds for electricity overcharges in California and the Pacific Northwest back to late last year.

The O&M adder of $6 a megawatt hour is the same as that used for the price cap and the 10% adder for creditworthiness issues is to be used for calculating the refund, but only in calculating market clearing prices after January 5, 2001 (the date that the bond ratings of PG&E and SCE were downgraded). This gives the ISO a baseline against which to calculate whether there were overcharges hour by hour from October 2, 2000 through June 20, 2001.

FERC determined that the most orderly and expeditious method of determining how much in refunds to order is to convene an evidentiary hearing. Once the ISO calculates the hourly baseline prices using the refund methodology, the ISO and the PX must rerun their settlement and billing processes and penalties. The ISO has been given 15 days from July 25 to recreate the price caps using the refund methodology. Within 45 days thereafter, the administrative law judge is to make findings of fact regarding the mitigation price, the amount of refunds owed, and the amount owed to each supplier by the ISO, the investor-owned utilities, and California.

FERC also instituted a conference to be overseen by an administrative law judge to establish the volume of transactions, identification of net sellers and net buyers, price and terms and conditions of the sales contracts, and the extent of potential refunds for the period between December 25, 2000 and June 20, 2001 in the Pacific Northwest. The refund period for the Pacific Northwest commences December 25, 2000 because Puget Sound Power petitioned FERC for refunds in the Pacific Northwest last October.

The refund methodology for any retrospective refunds in the Pacific Northwest is less clear. FERC will probably have to reconstruct all spot sales made during the potential refund period. However, on a going-forward basis, the Pacific Northwest spot market will be subject to the same mitigation as the rest of the WSCC as described in the June 19 order. ■

The Impact Of Electricity Price Caps

The following are excerpts from a discussion about the electricity price caps and ongoing developments in California that took place at a Chadbourne conference in late June.

The speakers are Dr. Robert B. Weisenmiller, one of the leading experts on the California electricity market and a founder of MRW Associates, Inc. in Oakland, California, Jan Smutny-Jones, executive director of the Independent Energy Producers, the trade association for California power producers, and chairman of the board — until earlier this year — of the California ISO, Vincent P. Duane, vice president and general counsel of Mirant Americas, Eric McCartney, head of project finance lending in North and South America for KBC Bank, a Belgian lender, Robert J. Munczinski, managing director of French bank BNP Paribas Group, *Howard Seife, head of the bankruptcy practice at Chadbourne, Ross D. Ain, a former lawyer at the Federal Energy Regulatory Commission and now a consultant for Caithness Energy, and Lynne H. Church, president of the Electric Power Supply Association, the national trade association for the independent power industry. The discussion was moderated by Robert F. Shapiro from the Chadbourne Washington office.*

MR. SHAPIRO: Let us start with a fundamental question. Many of you have read that the Bush administration and the chairman of the Federal Energy Regulatory Commission have said that the only solution to the mess in California is to build new power plants. Yet yesterday, the federal government imposed price controls. The question is will the price controls discourage developers from building new power plants in California?

MR. SMUTNY-JONES: It is hard to say. There are currently more than 9,000 megawatts of power plants that have been licensed to be built in California. A number of these are already under construction, and we have to assume that those plants will be completed. On the other hand, there is a history of unfinished power plants in California. I don't think we are going to know the impact of price caps for some time. That is the negative side.

On the positive side, there is always the hope that price caps might dampen the rhetoric. Unfortunately so far, the effect appears to be that the California governor has merely moved from talking about price caps to calling for refunds. It would be a shame if we move next to a debate about refunds rather than focus on how to fix what everyone agrees is a dysfunctional market.

MR. SHAPIRO: Vince Duane of Mirant, do you have a view about the impact that price controls will have on willingness of generators to add capacity?

MR. DUANE: They are a serious concern. If the question is whether they will put in jeopardy

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Congress then tinkered with the provision in a way that US businesses hoped would meet WTO objections.

The latest decision by the WTO gives the European Union the right to impose 100% ad valorem duties on up to $4.043 billion a year in US exports to Europe. Retaliation is not expected before next year. The European Union issued a list in November 2000 of US goods that may be subject to retaliation. The US will try to negotiate a settlement with the Europeans.

An estimated 6,000 US corporations have benefited from FSC tax breaks. US airplane manufacturer Boeing alone saved an estimated $130 million in taxes in 1998, or about 12% of its earnings for the year.

SOME MEXICAN COMPANIES can no longer be included in US consolidated tax returns.

Section 1504(d) of the US tax code lets US corporations treat some subsidiaries in Canada and Mexico as part of their consolidated tax returns as if the subsidiaries were in the United States. This is true of any subsidiary that is "organized under the laws of a contiguous foreign country [and is] maintained solely for the purpose of complying with the laws of such country as to title and operation of property."

The IRS confirmed in 1970 that a US parent can consolidate a Mexican subsidiary that owns real estate. That's because Mexican law required local ownership of land. However, Mexico dropped the ban against foreign ownership of land on December 25, 1996. As a result, US companies can no longer consolidate Mexican subsidiaries that were formed to own land, the IRS said in August. It said consolidation has not been allowed since the law changed in Mexico in 1996. The announcement is in Revenue Procedure 2001-39.

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Impact of Price Caps

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some of the 9,000 megawatts that are planned, the answer is yes. Power companies looking at building in California look at a risk-reward equation that has some pretty considerable uncertainties and other unquantifiable political risks. We operate in a national if not global market in which there are plenty of opportunities.

California is certainly an important market. It is one that deserves a lot of attention from developers. But there is a misconception that the decision whether to invest is made in corporate boardrooms based on what is the best allocation of capital, or is made by credit unions and banks about where they are willing to lend. What gets lost is the perspective of Wall Street. At Mirant, we are faced regularly with having to answer questions about our California exposure. Anyone who is paying attention to stock prices will appreciate that that constituency is extremely important to public companies. It is something that we are not able to ignore. We may feel internally that we can manage the political risks in California, but that cannot be the entire analysis. We must also consider whether we can convince Wall Street that taking on additional "California exposure" is the right thing to do.

Project developers must consider whether they can persuade Wall Street that taking on additional "California exposure" is the right thing to do.

Continuing Bank Jitters

MR. SHAPIRO: Eric McCartney, speaking as a banker, will lenders be willing to finance new construction?

MR. McCARTNEY: First, it is too early to tell what effect the new price controls will have. There is no financing currently in the market to test the reaction of banks. However, in general, the European banks are very concerned about the political risk tied to lending to California projects. On purely an economic level, everyone should be running to California not only to build power projects, but also to finance them, because that is what you are supposed to do in a boom cycle. But when you consider the political risks, the environmental concerns, the transmission constraints, the unavailability of gas — these are wrenches in the machine. They make it increasingly difficult to evaluate the risks of doing business in California.

MR. SHAPIRO: So if a generator came in today with a project that has been fully permitted and is ready to be financed, what would you say?

MR. McCARTNEY: If the proposal is for the bank to take market risk in California, I think that risk is too great. Speaking just on behalf of KBC Bank versus on behalf of a lot of my colleagues in this room, it would be very difficult for us to get credit approval, and I would feel very uncomfortable taking an underwriting risk with such a transaction.

MR. SHAPIRO: Are there other lenders in the room who feel differently?

MR. MUNCZINSKI: One of the real issues is fundamentally where is the credit? A concern that most lenders have in California is what is the credit quality of the Department of Water Resources? The state is planning another bond issue to raise money to buy electricity. How much of the cash collected from California consumers for electricity will go to the Department of Water Resources to pay bondholders and how much to the utility? Until that question is answered, it will be difficult for a lender to assess the credit quality of the proposed bond issue. There is also the issue of what role the court in the PG&E bankruptcy will have in parceling out revenue.

MR. SHAPIRO: Before we get to bankruptcy, which is a very important area, I wonder if Bob Weisenmiller can speak to what the state government wants in terms of playing a power purchase role longer term or getting PG&E and Edison back into that role and what it will take to do so.

DR. WEISENMILLER: I think the state will remain the power purchaser for only a short period of time. The state legislature wants to get out of this business this year. PG&E is not in any position to pick up the responsibility. Edison is not either. Somehow you have to return them to credible entities, which will require assuring the utilities that they can pass through the cost of purchased power. They will also need to settle past debts with their creditors. These debts are on the order of $13 to $14 billion.

MR. SHAPIRO: So there will be no creditworthy entity to which lenders can look as a backstop in the foreseeable future?

DR. WEISENMILLER: Right now the state is in it by default. At some point, if the bond issue doesn't go, the state will have to face whether it can continue in that role. You can certainly paint some pretty scary scenarios.

MR. SHAPIRO: Can you argue that the new price controls will have a dampening effect on electricity prices so that the cost of purchased power will come back into balance with the retail rates the utilities are allowed to charge?

DR. WEISENMILLER: They could. However, if you base your assessment on where electricity prices are in the futures market, they are not yet close.

Ongoing Bankruptcy Issues

MR. SHAPIRO: Howard Seife, which of the two utilities — PG&E, which filed for bankruptcy, or Edison, which did not — is in a better position?

MR. SEIFE: It's a good question. Edison may yet find itself in chapter 11; the situation has not fully played out. However, if you look at the

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OWNERS OF SYNCOAL PLANTS may have won a major battle but the war is not over. The IRS is finding ways to undermine a political settlement.

The US government allows a tax credit of $1.059 an mmBtu for producing "synthetic fuel from coal." The IRS stopped ruling last fall that coal agglomeration facilities — or facilities that add chemical binders to coal fines or whole coal — are producing synthetic fuel. Owners of the plants complained to Congress. Earlier this year, synfuel producers negotiated a compromise with the Treasury Department, and the rulings window reopened in late April.

However, only one minor ruling has been issued since then. Meanwhile, the IRS now says that anyone receiving a ruling must agree to a cap on the amount of output on which he will claim tax credits. The caps under discussion are somewhere between one and two times the "contract capacity" of the plant, or the amount that the manufacturer said the plant was capable of producing when the plant originally went into service. Many synfuel plants are producing at multiples of at least three and four times this amount.

The IRS is also starting to probe on audit whether synfuel plants were in operation in time to qualify for tax credits. Projects had to be placed in service for tax purposes by June 1998.

One industry participant describes the situation with the IRS as a roller coaster on which there will be many more ups and downs before the track levels off. Many transactions to buy or sell syncoal plants appear in the meantime to have been put on hold.

UNWINDS do not always work.

A US power company bought a regional electric company, or REC, in the United Kingdom in the early 1990's when Britain privatized its utilities. In early 1997, the REC made a cash distribution to

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scorecards and see how the two companies have been faring — one in chapter 11 and one out — you see a lot of similarities. There is not a huge difference to the situation of the two utilities. Neither has found a long-term solution yet to its predicament.

MR. SHAPIRO: What about QFs that have contracts with the two utilities? PG&E must make a decision at some point whether to accept or reject the contracts.

MR. SEIFE: In chapter 11, the debtor — in this case PG&E — has the ability either to assume a contract or to reject it. Any contract that it rejects is in effect terminated, and the QF would have a claim for damages in the bankruptcy. Its claim is a "prepetition claim" and will be paid in bankruptcy dollars, or whatever is provided in the plan. That could be 20¢, 50¢ or 80¢ on the dollar — whatever is provided for in the ultimate plan of reorganization.

If PG&E decides instead to assume the contract, then PG&E will have to cure the contract, which means paying all the overdue amounts, even those that accrued before the bankruptcy filing. It is in PG&E's interest to defer that decision for as long as possible.

The problem in California is there is still the question at the end of the day who foots the bill.

Some QFs have gone into bankruptcy court to impress the judge to force PG&E to make a decision soon. As a middle ground, the QFs and PG&E could negotiate a different form of long-term contract. That is always an option.

MR. SMUTNY-JONES: Bob, there is also a cycle of political play here. There is at least an adult in charge now with rules he follows as opposed to the wide-open situation in our legislature. A deal has been done between the QFs and Edison. The odds a very high that the QFs will make a proposal to PG&E. We are in the process of trying to figure out how best to put something like that together. Earlier this year, PG&E was very close and willing to negotiate some sort of long-term arrangement with the QFs that makes sense.

QF Contracts

MR. SHAPIRO: Will the price controls the federal government imposed this week make such negotiations more likely since the QFs might earn less money by selling their power into the market?

MR. SMUTNY-JONES: I don't think so. It is a mixed bag. There are some people who think the vast majority of QFs would prefer to shed their contracts to sell into the market. There are some investors who simply want to be done with the contracts and the uncertainty surrounding them and move on with their lives. Others want a payment structure that make sense. The *Woods* decision was a disaster. *[Ed. The Woods decision changed the gas component of short-run avoided cost pricing to the cost of gas at a delivery point in northern California. This had the effect of reducing contract payments to QFs in southern California, making it difficult, if not impossible, for such QFs to cover their operating costs.]* It is that sort of thing that is more of a driver in terms of motivating QFs to get some stability long-term.

DR. WEISENMILLER: One of the nightmares that I think a lot of QFs are trying to deal with is the scenario where there is no assumption or rejection of contracts in the immediate future. They continue to have to supply PG&E, and they are losing out on the boom cycle of the market.

When ultimately PG&E is forced to make a decision a year or two from now, the market may be very different. What by then may again be a very valuable contract will be rejected by PG&E. The QF will be left with a general unsecured claim on which it will get pennies on the dollar, and it will be at the mercy of a very different market.

Volatility in Prices

MR. MUNCZINSKI: One thing that has happened in California is the volatility brings in traders. People like Mirant or Coral Energy or others come in and assume electricity price risk. I would like to know what other bankers think about that. You would think you would lend against a Coral credit, which has a triple A rating, but isn't the bank still exposed at the back end in case Coral made a bad decision about California risk?

MR. SHAPIRO: Let me ask Vince Duane this question. Are you less inclined as a generator to enter into a volatile market?

MR. DUANE: The problem with California is there is still the question at the end of the day who foots the bill. Until we get some more certainty on that, we will be concerned about exposing our credit rating to that sort of open-ended risk.

Many people have looked at selling to the Department of Water Resources. Many generators and generator-marketing combos have gotten comfortable with the credit, notwithstanding the government's statements that it wants the Department of Water Resources out of the business in a matter of months. I am probably in the minority here, but Mirant has felt uncomfortable about the ultimate creditworthiness of the DWR. Particularly when you look out 10 or 15 years, you must really swallow hard to take that risk. It is not a market risk. It is a credit risk and one with a political dimension.

Ten days ago, *The Los Angeles Times* ran an

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the US power company ostensibly as a return of capital. However, 11 days later, the US power company decided to unwind the distribution and returned the cash. Five months later, the two companies prepared a formal rescission agreement that said the REC was rescinding the distribution after it became clear the company needed the cash to pay UK windfall profits taxes.

The IRS said in a field service advice in June that the US power company had to pay tax on the distribution even though the money was returned.

According to the IRS, the only way the US company could have avoided US tax is if it had a legal obligation to return the money. The US power company failed to establish in this case that it had such an obligation. The IRS said it was taxable under the "claim of right doctrine" that a company is taxed on money over which it has unfettered use even though it chooses voluntarily to give the money back.

A field service advice is a memo by the national office to an IRS agent in the field.

TAX INDEMNITIES in lease transactions are not always enforced by the courts as written.

A federal bankruptcy court in New York refused recently to enforce a tax indemnity claim tied to a safe harbor lease of aircraft to Eastern Air Lines. Eastern entered into safe harbor leases of its aircraft during the early 1980's. A "safe harbor" lease was basically a sale of tax depreciation and tax credits on the aircraft. Congress allowed such transactions in 1981 and 1982 as long as they were structured in form to look like leases.

Eastern later went bankrupt and sold the planes, causing a loss of tax benefits to the lessors. Eastern had agreed to idemnify the lessors against any loss of tax benefits on the planes. The indemnity assumed a value for the tax benefits based on the corporate tax rate at the time of 46%.

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article chastising the Department of Water Resources for committing to long-term contracts at the top of the electricity price cycle. The criticism is bound to increase. Is signing such a contract an unreasonable risk for a generator when you have questions about how long the DWR will remain in this business, and more importantly, if those contracts end up being out of the money for the DWR, there is a risk the state will eventually try to back out of the contract? It strikes us as a no-win situation.

People are raising questions that normally would be raised about Bangladesh in terms of investing money.

MR. SMUTNY-JONES: We are hearing a lot of people raise questions that normally would be raised about Bangladesh in terms of investing money. That signal needs to get to the politicians in California — not from the generators because the message is obviously self-serving, but from the others in this room. Of course, you probably think the situation is stupid now. You have no idea how much worse it could possibly get. It doesn't need to go there.

MR. AIN: One thing the bankers might reflect on in the federal order imposing price caps is it may increase the supply of power. When the government asked the Los Angeles Department of Water and Power, or other public agencies, or out-of-state public agencies, why can't you sell at reasonable prices, they answered we can't be assured we can buy back at reasonable prices. That was a real disincentive for them to be reasonable. Well, one should now say with the federal government having put a price cap in place can they now sell at reasonable prices at least knowing for a period of time they can buy back at "reasonable prices"?

The second point is that, in order to effect a political solution, the body politic in California will have ultimately to finance the undercollections that have occurred. They need to know what the level of that undercollection is ultimately going to be and, while you had no controls or caps on prices, there was a blank check and everybody was terrified in California of what that could be. With this FERC order on price caps in place, there is the possibility that at least some people can begin to estimate with a lot better specificity what the level of ultimate undercollections will be. Having a QF settlement in place would also help so that the treasurer of the State of California, the governor of the State of California, and the legislature can begin to come out of their shells and say, "What do we really need to make these utilities creditworthy again," and this time figure out the answer. That might be the beneficial effect of the price caps.

Effects Outside California

MS. CHURCH: I have a question for the lenders and investors in the room. We just heard that the federal order for the first time expanded price controls beyond California to the entire 11-state WSCC area and, until today, investment in those other states — Arizona, Nevada, and the Pacific Northwest — has been moving forward rapidly because that is at least pretty safe territory and you are also within reach of a huge market in California to sell into. Does this order change anyone's perception of the risk of investing throughout the rest of the WSCC?

AUDIENCE MEMBER: We are developing a project in Arizona , and we have assets in Nevada. One thing that troubled us was that Nevada has had about a 30% to 40% rate increase already without having the full disease that California has had. There have been rate increases throughout the West. As to the creditworthiness, there are still creditworthy buyers and the FERC order, to the extent it immediately caps the top end of the price spectrum, will put less pressure on the incumbent buyers and keep them more creditworthy. So a simplistic answer would be, it's helpful, not hurtful, because you have more credit support than you would have if this conflict figuration spreads to the rest of the WSCC with the same vengeance as in California. ■

House Votes Tax Incentives For Power Projects

by Keith Martin, in Washington

The lower house of the US Congress voted for $33.5 billion in new energy tax incentives shortly before leaving Washington for the August recess.

The outlook for the package in the Senate is unclear.

Senate leaders have said there is no room in the budget this year for any further tax relief, but they are trying at the same time to find "offsets" or ways to raise revenue that might pay for some new energy incentives. No decisions will be made until the fall. In the meantime, the tax incentives in the House bill are at least in play.

Section 45

The House bill would extend section 45 tax credits. These are credits of 1.7¢ a kilowatt hour for generating electricity from wind, "closed-loop" biomass and poultry litter. The current deadline for placing projects in service to qualify for credits

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Congress reduced the corporate tax rate to 35% in 1986. The lessors suffered the tax loss after 1986. Nevertheless, the indemnity let them claim compensation based on a 46% tax rate.

The bankruptcy court called the valuation using the 46% rate an "unenforceable penalty" and refused to enforce it on grounds that it would lead to a windfall for the lessors at the expense of the airline's creditors.

COURTS DENIED INVESTMENT TAX CREDITS to two more companies trying to claim them under a "world headquarters" exception in the Tax Reform Act of 1986.

Congress repealed the investment tax credit at the end of 1985. However, it made a long list of exceptions where companies that had committed to investments before the repeal could still claim tax credits as late as 1990. One such exception was for any company that had signed an "agreement to lease" space for its world headquarters before September 26, 1985. Such a company could claim tax credits on the cost of the buildout and on the equipment and furniture purchased for the space through 1990. Congress intended the exception to cover only Merrill Lynch and Drexel Burnham Lambert, but the provision was poorly drafted and, on its face, applies to many more companies.

Kimberly Clark and Airborne Freight have both managed to persuade courts that they were entitled to the credit.

However, in late July, the courts turned down tax credit claims by two more companies. The US Claims Court denied tax credits to National Data Corp. The company signed a lease for its Atlanta headquarters in 1971 to run through April 1993. The company made $34.8 million in leasehold improvements to its space during the period 1986 through 1990. It did not claim tax credits on the

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Tax Incentives

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is December this year. Credits run for 10 years after a project has been placed in service. The amount is adjusted each year for inflation. "Closed-loop" biomass refers to trees or other plants that are grown exclusively for use as fuel in power plants.

The House voted to extend the deadline for placing projects in service to December 2006. The extension applies to wind and biomass projects, but not to poultry litter.

The House also voted to allow credits for the first time to persons who use "open-loop" biomass or landfill gas to generate electricity. "Open loop" biomass is defined as "solid, nonhazardous, cellulosic waste material which is segregated from other waste materials" and that falls into one of three categories. The categories are certain forest wastes, "solid wood waste materials" (like crates and construction wood wastes), and waste from "agriculture sources." Municipal solid waste of the kind that is usually disposed of in landfills, old growth timber and paper that is commonly recycled are not "open-loop" biomass.

In the past, the taxpayer had to build a *new* facility to qualify for tax credits. However, under the House bill, *existing* open-loop biomass and landfill gas facilities would qualify for five years of credits after the bill is enacted. Credits for such facilities would be at two-thirds of the normal rate.

Cogeneration

The House voted to allow a 10% tax credit for investment in new cogeneration facilities, called "combined heat and power systems." The tax credit is 10% of the capital cost of the project.

To qualify, a cogeneration facility must produce at least 20% useful thermal output, and it must have an energy conversion ratio of at least 70%. That means the energy content of the electricity must be at least 70% of the energy content of the fuel used to produce it. (The conversion ratio is 60% for smaller projects of 50 megawatts or less in size.) The 20% thermal output test may be hard for many companies to meet. The test to be a qualifying cogeneration facility under the Public Utility Regulatory Policies Act used to be only 5% useful steam output, and this was often difficult to reach.

The House voted to allow a 10% tax credit for investment in new cogeneration facilities.

Some projects will have to choose between tax credits and slower depreciation. Any taxpayer who claims a tax credit on his project could not depreciate it faster than over 15 years using the 150% declining-balance method. Thus, there would be no tradeoff for most gas- and coal-fired power plants, but there would be for projects that use waste fuels.

The credit can only be claimed on new projects placed in service during the period 2002 through 2006.

Clean Coal

The House voted two new tax incentives for investing in new "advanced clean coal technology facilities." The two incentives are an investment tax credit for 10% of the capital cost of the project and a production tax credit whose amount varies from 0.1¢ to 1.4¢ a kilowatt hour of electricity, depending on the Btu content of the coal, the heat rate of the power plant and the year the project is placed in service. Production tax credits could be claimed for 10 years after the facility is placed in service.

The list of what qualifies as an "advanced clean coal technology facility" is almost impossibly complicated. The following technologies qualify potentially: advanced pulverized coal, atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion, integrated gasification combined-cycle plants, and other technologies that have a carbon emission rate that is at least 15% less than conventional technology. The project must reduce at least one kind of air emissions — sulfur dioxide, nitrogen oxide or particulates — below levels set in the bill. There are also limits on the number of megawatts of installed capacity of each type of new technology that would qualify for credits. For example, the limit for pressurized fluidized-bed combustion is 1,000 megawatts. There is a separate limit on all projects of 7,500 megawatts. A project would have to be certified by the IRS before the owner could claim tax credits.

The project could be a new power plant or a retrofit or repowering of an existing facility.

Section 29

The House voted to allow more time for taxpayers to place some oil and gas projects in service to qualify for section 29 credits.

Section 29 credits are tax credits for producing gas from coal seams, tight sands, Devonian shale, geopressured brine and biomass or for producing synthetic fuel from coal. The tax credit was $1.059 an mmBtu for such fuels (other than tight sands gas) produced during calendar year 2000. The amount is adjusted each year for inflation. The credit was originally enacted in 1980 after the Arab oil embargo as an inducement to Americans to look in unusual places for fuel. Credits run currently through 2002 on most gas projects. However, the wells had to have been drilled by 1992 to qualify. Credits for most syncoal projects and many landfill gas projects run currently through 2007. Landfill gas and syncoal projects had to be in service by June 1998 to qualify.

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cost of the improvements when filing its original tax returns for those years, but decided later in 1994 to make a claim on the government for a tax refund of $1.7 million on grounds that it was entitled to tax credits. The Claims Court said use of the phrase "agreement to lease" in the headquarters exception contemplates a lease where the taxpayer has not yet moved in.

The Chicago Mercantile Exchange lost a similar case in late July in the US Tax Court. The exchange leased space for two trading floors and its headquarters in a new office building that was under construction in Chicago. The lease was signed in 1981.

BRIEFLY NOTED: The Wisconsin Gas Company is appealing a decision by a federal district court that it cannot claim research and development tax credits on the cost of developing a computer information system "to improve customer service and company performance." The company bought database software to use as a platform for building its own database and hired Andersen Consulting to help. The company has appealed to the court of appeals in the 7th circuit . . . . The New Jersey governor signed a law on June 29 that requires limited liability companies and limited partnerships doing business in the state to get agreement from corporations that own interests in them either to pay New Jersey income taxes on their incomes from the ventures or else the LLCs or limited partnerships must pay the corporate income taxes themselves . . . . Senator Charles Grassley (R.-Iowa), the most senior Republican on the Senate tax-writing committee, said he will try this fall to extend section 45 tax credits to projects that use cattle and hog manure to generate electricity. The tax credit is 1.7¢ a kilowatt hour.

— contributed by Keith Martin in Washington

Tax Incentives

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The House voted to allow more time to place some new projects in service. Taxpayers can drill new wells for producing oil from shale or tar sands or for producing gas from coal seams, tight sands, Devonian shale and geopressured brine. Fuel from such wells drilled after the bill is enacted through 2006 would qualify for credits for four years, but not beyond 2009. The credit would be 51.7¢ an mmBtu. It would be adjusted for inflation starting in 2003.

Taxpayers could also build new landfill gas facilities. Credits could be claimed on landfill gas projects put into service any time after June 1998 through 2006. The credits would run for five years at 51.7¢ an mmBtu. However, the credit would be only 34.5¢ an mmBtu in cases where the landfill is subject to federal new source performance standards. Both amounts would be adjusted for inflation starting in 2003.

There is no extension for syncoal projects.

There would be an annual limit on the amount of production on which credits can be claimed from each new well or landfill gas facility. The limit is 200,000 cubic feet of average daily output.

Section 29 credits would be extended for gas projects, but not syncoal projects.

Indian Reservations

Projects on Indian reservations qualify currently for special rapid tax depreciation and wage credits tied to the number of Indians hired to work on the project. A project must be operating by December 2003 to qualify. The House voted to extend this deadline by another three years through December 2006 for power plants, gas pipelines and a few other assets.

Transmission Grids

The House voted to let any utility that transfers its transmission grid or shares in a transmission subsidiary to a regional transmission organization or other independent transmission company treat the transfer as an “involuntary conversion.” The transfer must occur before 2009. Treatment as an involuntary conversion means the utility would not have to pay tax on any consideration it receives in return. However, it would have to invest the consideration in other utility property within four years. “Utility property” is defined broadly to include power plants and gas pipelines.

Other Provisions

The House voted for a series of other tax changes that affect segments of the power industry.

It voted to let gas companies depreciate their gathering lines at gas fields over seven years and their distribution lines to customers over 10 years using MACRS depreciation. The IRS has taken the position in court that such gas lines must be depreciated over 15 years. The House action would apply to gas lines put in service after the House bill becomes law. The House expressed no view on what the proper treatment was in the past.

The House adopted a compromise that municipal power companies negotiated with the investor-owned utilities concerning when municipal utilities that expand outside city limits in search of electricity customers would be allowed to continue using tax-exempt debt to finance their equipment. The investor-owned utilities complained that they are at a disadvantage when competing against municipalities because they must use taxable financing. The municipal power companies complain, in turn, that private electricity suppliers are poaching their larger customers, thereby undermining their ability to service their existing debts and forcing them to try to broaden their customer bases. ■

New Trends In The Market

Project lenders report they are so busy this year that they can afford to be more selective about what deals they finance. Rates are increasing for project loans at the same time that rates are falling for other lending. The following are excerpts from a discussion about new trends in the project finance market that took place in late June at a Chadbourne conference in Colorado.

The speakers are Andrew Jacobyansky, vice president and senior credit officer for Moody's Investors Service, David L. Hauser, senior vice president and treasurer of Duke Energy Corporation, David H. Wasserman, vice president for development of Sithe Energies, John Cooper, senior vice president and chief financial officer of PG&E National Energy Group, Gail Nofsinger, vice president in the capital markets division of CoBank, Robert J. Munczinski, managing director of the BNP Paribas Group, Steven S. Greenwald, managing director of Credit Suisse First Boston, Andrew C. Coronios, a structured finance partner at Chadbourne in New York, Roy K. Meilman, a Chadbourne tax partner specializing in leasing transactions, and James S. Godry, senior vice president of Dresdner Kleinwort Wasserstein. The discussion was moderated by Keith Martin from the Chadbourne Washington office.

MR. MARTIN. Our focus today is new trends in the market. One recent trend has been that utility holding companies are spinning off their unregulated businesses to shareholders in the hope that the market will assign a higher value to shares in a standalone independent power company than if that business remained tied to a regulated utility. Andy Jacobyansky, how many spinoffs have there been and are more expected?

Spinoffs

MR. JACOBYANSKY: The first major one was NRG, whose stock has held up fairly well, which I think encouraged other companies to follow suit. Mirant then did it. There were also Orion, Reliant and Aquila, and we expect more to follow.

MR. MARTIN: What do the companies expect to gain from this — why do it?

MR. JACOBYANSKY: Investment bankers visit and tell these companies that their stock prices would be a lot higher if investors looked at the value of the subsidiary as a standalone business. The spinoff will lead to a much higher combined stock value.

MR. MARTIN: David Hauser, you have probably heard the pitch from these investment bankers. Is this an appealing concept to Duke?

MR. HAUSER: We have been visited by investment bankers who think we ought to spin off everything we own, whether it is above or below our average multiple. If we followed all this advice, we would manage the pension plan and that would be it. It would be a great job! However, at the end of the day it is a multiples game. It depends on where your multiple is, whether this is a good idea or not.

MR. MARTIN: Have companies that have done spinoffs benefited as expected?

MR. HAUSER: The answers vary depending on the company. The ones that have spun off 100% I would say have been pretty successful as to the original shareholder. Our job is to optimize value for the existing Duke shareholder, not the new shareholder.

MR. WASSERMAN: Sithe was public a number of years ago and then ended up going private. One of the big traps is liquidity. Unless you are willing to spin off at least several billion dollars

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New Trends

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worth of market cap, you have a problem. We had a problem where we spun off a small amount. Sithe wasn't a big company. We had 10 million shares. We had four institutions each owning over a million or a million and a half shares. Anytime one of them wanted to dump shares, the stock price came crashing down and so we weren't getting proper credit from the market. We had all the disadvantages of being public and we didn't have the liquidity, so it's a real trap unless you have enough market cap to spin a lot of shares and keep liquidity.

MR. JACOBYANSKY: I agree with that. It is an all or a none game at the end of the day.

MR. COOPER: I think that another reason for it is the independent generators are growing rapidly and have large development portfolios. They are massive consumers of capital. They need to borrow large sums of money, which you can't do unless you are also able to provide equity. If you see an independent generator that is trading at 25 times earnings and a utility that has an embedded independent generator and the utility is trading at 12, or at the best at 14, clearly the utility's cost of capital is a lot higher to raise equity as a utility — if its regulators will even permit it to do so — than a Mirant or an NRG or an Orion or an AES, whose equity capital is a lot cheaper.

MR. JACOBYANSKY: An example would be NRG and Xcel Energy. If you look at Xcel, the holding company, it receives and pays dividends and has some financing in place. To the extent it wants to put more money into NRG, its only real choice, without compromising its credit quality, is to issue more stock, which is a fairly unattractive option. NRG has announced a very aggressive growth plan, and there is really no good way for money to come down from Excel.

Growing Demand for Capital

MR. MARTIN: John Cooper made the point that companies are driven to search for higher share price multiples by a voracious demand in this industry for capital. What is driving the demand for capital, in addition to the obvious point that we are building more power plants?

MR HAUSER. Electricity trading is a huge user of credit if not long-term capital. It is a huge consumer of credit because you have to post margins with your counterparties. Those margins move around in a very volatile manner. Ours can move around $500 million in a day pretty easily, and they have been as high as $2 1/2 billion that we have to post either in cash, or letters of credit, or in some cases surety bonds.

MR. MARTIN: Two and a half billion in a single day. What is the credit line at Duke Energy?

MR. HAUSER: We are up in total now to about eight billion. As the banks merge and consolidate, our ability to get credit from banks becomes harder. This is true even with our credit rating, which is higher than a lot of other companies'.

Electricity trading has become a huge user of credit if not long-term capital.

MR. MARTIN: Many of us are developers or financiers of power plants and not that familiar with trading. My understanding is that mark-to-market accounting — or the notion that trading positions must be reflected on your books at the end of each day at their market value — is what is creating a lot of this huge demand in the power industry for credit. John Cooper?

MR. COOPER: Yes. Trading companies typically enter into master agreements with counterparties with whom they would like to trade over time. For example, PG&E Energy Trading might enter into a master agreement with Duke Energy Trading. The master agreement would provide for various types of physical or financial trades of gas or power. The master agreement gives the green light to the trader to enter into individual transactions. These individual transactions are probably evidenced by slips of paper. At the end of each trading day, you mark all of your positions to market. This is basically the price at which you could liquidate that position within a 24-hour period in the market. Not all positions are liquid, so some of them are more difficult than others to mark.

With every single one of your counterparties, you basically balance what they owe you, and you owe them, and you also value your open positions. The net position at the end of the day remains within the credit limits you have established.

Let's say Duke and PG&E established an open account for $50 million back and forth. That is with parent guarantees or with investment grade credit quality — triple B or better — $50 million. It sounds like a lot of money. Your traders enter into positions. Two things can change the value of those positions. One is the quantity of contracts that you have open, and the other is the daily volatility in the price of the commodity. The value of your trading positions bounces up and down.

What has happened over the last three or four months, is that even though volumes of trading have not really grown that much over the last year, the volatility has increased incredibly. When you see electricity trading for $3,500 for a megawatt hour in California, it is not just the guy who is selling that power who is affected, but everyone's trading positions in electricity are marked at that price. Your position in electricity may have been valued yesterday at $100. Suddenly it is $3,800. People who are short and long rebalance their positions. It may be that my $40 million of exposure to you yesterday, and that was inside my limit, is suddenly $400 million.

MR. MARTIN: In one day?

MR. COOPER: In one hour. But you only do it every night. Then the phone calls go out. You have a $400 million margin call that you must cover within 24 hours. If you don't, the positions can be selectively liquidated, which means that the guy who is liquidating can cherry-pick what is best for him, and it can totally disrupt your portfolio.

Even though we may have shown a $400 million net negative to Duke, we have someone from whom we bought the position who owes us $400 million. Our book has not moved at all. We are hedged. Someone owes us $400 million. We owe Duke $400 million. Duke probably owes someone else $400 million. You have this huge volume of credit that has been required and you must either post cash or a letter of credit overnight.

MR. MARTIN: And the trading positions may represent just pennies of profit.

MR. COOPER: They may not represent any profit at all.

MR. MARTIN: But someone makes a margin call for $400 million.

MR. COOPER: It is a big circle and often without any net loss if one considers the entire circle. The only time a loss would be created is if someone defaults and you have to liquidate, then the liquidation leads to a domino effect. The trading system is sound as long as you have creditworthy players who can cover their costs.

Sometimes you can work out a deal. I tell the counterparty that I can't get a $400 million letter of credit by tomorrow, but I can assign this position that I have. This is easier in other commodities than in electricity.

MR. MARTIN: Why?

MR. COOPER: You can't store electricity. You

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don't have a bill of lading. It's not like a cargo of crude oil. There is nothing physical except a piece of paper. The two positions may not match. There is no effective clearinghouse to be able to match up all the counterparties around the table and say everybody put in $5 because the billion dollar positions that each of us holds net into nothing, and so it is a —

MR. MARTIN: Trading operations absorb an enormous amount of credit.

MR. HAUSER: The other piece of this is mark-to-market accounting creates paper earnings that are not matched by cash. Trading becomes an earnings driver. You may have great earnings but no cash coming in from it at that point.

MR. MARTIN: Or big losses on a daily basis.

MR. HAUSER: It could go either way.

Tight Bank Market

MR. MARTIN: Let me move on to a related point. We have this demand for capital created by trading operations. Gail Nofsinger, you mentioned that interest rates are increasing in the project finance market in marked contrast to the trend in the rest of the economy. Bankers are working overtime, and they are becoming much more fussy about what they are willing to finance. Explain this.

MS. NOFSINGER: I think a lot of that is driven by the large number of new power plants under development. There is a huge need for capital. There are many more deals coming to market seeking financing in the domestic market this year than three or four years ago.

The deals are also getting larger. We used to look at $200 million transactions. Five banks could get together, and the deal would be done. Now we are seeing $1 and $2 billion deals. To do one of these, you need every bank in the market to participate in the syndicate, so the larger deals must be priced higher in order to attract everyone in the room. Higher prices in large deals translate into higher prices also for small deals, because no one wants to look at a small deal that pays less. The bottom line is that prices are going up across the board.

MR. MARTIN: We heard yesterday the European banks are reluctant to lend to projects — perhaps even borrowers — with significant California exposure. Are the domestic banks in the same position?

MS. NOFSINGER: Definitely. It is not only the European banks, but I think they are probably in a more difficult position because their parent companies in Europe read the newspaper articles and call back to the States to ask, "What does this mean?" No one really has the answer yet to what it means. People find their time eaten up having to answer questions about what is happening in California. This, in turn, makes people nervous about bringing a deal that has anything to do with California, whether it is ownership or whether the deal is located in California. It is easier just to say no to such deals because you don't have to spend a lot of time answering questions.

A $1 or $2 billion financing requires every bank in the market to participate in the syndicate, so larger deals are leading to higher prices in order to attract everyone in the room.

MR. MUNCZINSKI: I take exception to the generalization that European banks are backing away from this market. We are certainly not backing away. We have multiple tiers of exposures in California from utilities to QFs, and our job has been to manage that process and provide information to people in Paris, and we have spent a lot of time since November or December last year doing that.

I think that the general concern conveyed by credit committees at European institutions is the issue of contagion. Is the problem in California likely to spread to other parts of the United States? We have spent a lot of time on this, and I think we have been able convince our credit people in Paris that it is a WSCC problem for now, one that we are unlikely to find spreading across the country.

Search for Equity

MR. MARTIN: Let me come back to the topic of rapidly growing demand for capital. Trading operations force companies to have larger credit lines. Projects are getting larger. This, too, requires more borrowing. A company can't add indefinitely to the debt side of its balance sheet without also periodically raising equity. What new approaches are companies using to raise equity?

MR. HAUSER: We are doing a couple different things. We think convertibles are —

MR. MARTIN: A convertible is?

MR. HAUSER: A convertible is a debt security that gives the holder a right to convert into common stock. There are a thousand different ways to structure them, but the one we just issued is mandatorily convertible in three years into common stock and, from the viewpoint of — well, I'll let Andy speak from the viewpoint of the rating agencies — we thought we had a positive reaction from the rating agencies on treatment of these instruments as equity or we would not have issued them.

MR. JACOBYANSKY: We see an awful lot of these instruments —

MR. MARTIN: These are instruments that are initially debt with a mandatory conversion to equity in three years?

MR. JACOBYANSKY: There is every single variant that you can imagine, and the one thing that is consistent across them all is the investment bankers tell their clients that Moody's sees them as equity. Quite often we don't.

MR. MARTIN: How do such rumors start?

MR. HAUSER: They saw them as equity until there were too many of them.

MR. JACOBYANSKY: Well, not really. Take, for instance, something NRG did about a half a year ago where they basically issued preferred stock that paid dividends for five years. There was a second feature that required anyone owning the preferred stock at the end of year three to buy some NRG common shares and, at the same time, NRG had to sell the common shares. NRG was told we would put some equity treatment on this.

I look at NRG's coverages and I take into consideration that NRG has an extra fixed charge that the company will have to cover over the five years. Our rating assumes that NRG can make it to the equity markets in three years anyway. It is nice that the company guaranteed it. At the end of the day, the reaction of the rating agency is, "So what?" This is simply a fixed-charge financing. The company will get equity at the same time that we thought it would anyway. The company is hoping we will look at the fixed-charged financing as equity.

MR. HAUSER: That's a really key piece of advice. We are told things about how a product works, but it is important to go back to our friends at the rating agency before issuing something like this and get the straight story.

MR. MARTIN: Do you have any leverage over a person like Andy?

MR. HAUSER: Well, we sat down with Moody's on the one we issued. They have a scale of A to E on the equity, and it's a D. It was that straightforward.

MR. MARTIN: Failing grade?

MR. HAUSER: But we heard it from Moody's.

MR. JACOBYANSKY: Yes, but the point is how you apply the D. We don't look at capital struc-

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ture. We look at cash coverage. We are no different than all the other project people in here. On a GAAP basis, projects have negative equity for years after finishing construction. So when people are told an instrument is going to look like equity, perhaps it looks like equity on the balance sheet, but we don't look at balance sheets. We look at cash coverage.

MR. HAUSER: That's exactly right. We have been told directly by the rating agencies that they don't care if our equity is 10% or 80% of our balance sheet. It is cash coverage that matters. That's the right approach on which to base ratings.

MR. COOPER: Let me add one thing. The major equity driver is not so much to support trading. The amount of credit that is there to support trading is still a very small fraction of what it takes to actually to build assets. One power plant of $500, $600 or $700 million would provide a lot of margin for trading. So the capital requirements are really driven by assets, new construction, acquisitions and things like that.

The rating agencies don't care if equity is 20% or 80% of the balance sheet; it is cash coverage that matters.

Mini-Perms

MR. MARTIN: Other trends? Gail Nofsinger, you mentioned mini-perms. These are short-term loans of, say, five years that require payment of interest only during the term — and perhaps some cash sweeps as the end of the term approaches — and then a balloon payment of principal. It is almost as if the banks are becoming merely transition lenders. The project takes a mini-perm loan as a bridge until it can get into the capital markets. What is behind this?

MS. NOFSINGER: The fact that most deals have some element of merchant risk to them. The banks are less willing to lend long term on a transaction that has an uncertain cash-flow stream. With a mini-perm structure — whether the ultimate financing ends up being bank debt or bond debt — the bank has shorter exposure to the merchant risk — usually construction plus two, although I have seen as long as construction plus eight. You have sweeps to start paying down the principal automatically after the second or third year. The debt is being paid down quickly. If it turns out to be a bank financing in the end, there will be less debt to finance over the remaining period of 10 or 15 years and, therefore, less exposure on the long-term debt to the lender.

MR. MARTIN: If a mini-perm is a bridge to the capital markets, why not go to the capital markets directly?

MS. NOFSINGER: I think part of it is timing. When you are going into the bond market, you have to see if the price is what you want to pay. A bridge loan gives you more time to play the market. Historically, when banks underwrote the transaction, they gave you a firm price and you knew what it was. When you went to the bond market, you didn't really know the price until the day the loan closed. I think we have seen some erosion of this on the bank side. Banks are more likely today to say they were wrong three months ago when the deal was priced and to invoke flex pricing, or the right to reprice.

MR. COOPER: The mini-perm is a sign of the maturity of the industry. We did IPP deals initially with long-term contracts and project financing in which everything was locked up and fixed. The deals were hard to structure, but they were no-brainers. Those financings were also fairly unique.

No other industry, except for the regulated utilities, can raise 25-year debt from banks. What you are seeing now is banks are moving toward a more traditional position, which is providing medium-term financing or backstop for credit support. At the same time, we have gotten access to the capital markets — the long-term debt markets — which we didn't have three or four or five years ago. Therefore, you use a bank as an interim source of finance if the timing isn't right to go into the capital markets. Each of the banks and the bond markets has probably moved into the position it wanted from the start.

MR. MARTIN: Why borrow short-term when rates are at an historic low?

MR. COOPER: We are in an unusual situation, so I can't comment on the bond markets, but the banks are still a lot cheaper.

MR. HAUSER: What Duke is doing is accessing the capital markets for long-term floating-rate debt, normally 10 years. We are also doing a fair number of swaps. We are not borrowing much short term.

MR. JACOBYANSKY: I think there is sort of a myth and a bet going on here with developers. I think the myth is the capital markets are not comfortable with construction risk, but our risk profile for construction is exactly the same as the bank's. We tend to look past construction if there is a good construction scheme and focus on the operating phase. I think the bet is that someday the rating agencies will get religion and all of a sudden become easier on the merchant markets.

MR. GREENWALD: Two points. We all learned that you don't finance long-term assets, fixed assets with short-term liability. Look at companies that just went belly-up in the past and that is probably the reason why it happened.

Number two, the argument of the negative arbitrage is spurious because most of these projects have short construction periods. What rate are you thinking you are going to get a year or two years from now in the capital market? People are checking the interest rate when they go into the bank market to fund these projects, and they are keeping their fingers crossed that things are going to be great a year or two years from now when they decide to do the long-term takeout in the capital market. If you look into the cost of implementing the forward interest rate swap — and that is the key — you will see the swap adds 80 to 90 basis points to the cost of a deal for one year and 130 to 140 basis points for two years. What the guy does is decide against doing the forward rate swap. This puts him back in the position of betting on where interest rates will be a year or two from now and that he will, in fact, have access then to the capital market.

MR. HAUSER: Just one more comment. We do not look at debt on a project-by-project basis, but rather put all our debt into one view and determine how much of it we are going to allow to be floating, and how much as we are going to allow to be fixed because this can have a big effect on earnings. How much you allow to be fixed affects the volatility of your earnings.

Synthetic Leases

MR. MARTIN: That's a perfect bridge to our next topic. Some of the other people at this table work on products that help with earnings. Synthetic leasing is one. Andrew Coronios, what is a synthetic lease?

MR. CORONIOS: A synthetic lease is a form of off-balance sheet financing. It is treated like an operating lease on the balance sheet, which means the company shows neither a debt nor a corresponding asset. Because there is no asset on the balance sheet, there is no depreciation. Depreciation reduces earnings.

MR. COOPER: But the company remains the owner for tax purposes.

MR. MARTIN: Let me give a tax lawyer's perspective. A synthetic lease is a short-term loan, but it is drafted to look like the lender is leasing

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the asset to the borrower.

MR. CORONIOS: You tax people keep looking at substance. The accountants focus on the form of the transaction. It is the perfect disintermediation to create a product.

MR. MARTIN: And the reason this helps with earnings is . . . ?

MR. CORONIOS: Because the borrower does not own the asset for book purposes and has no book depreciation to reduce earnings.

MR. MARTIN. What about the rent payments on the lease? Aren't these the equivalent of depreciation?

MR. CORONIOS. If you think of a synthetic lease as a short-term loan, the lease requires payment of interest only. The rent payments are a small fraction of the book depreciation the company would have had if it had to put the asset on its books.

MR. COOPER: It is a form of 100% debt financing. It helps you leverage up earnings without having to raise true equity capital.

MR. MARTIN: Synthetic leasing is appropriate only in limited situations in the power business. What are they?

MR. CORONIOS: The accountants have taken the position that a power plant is real estate for accounting purposes. This means, in turn, that a company cannot do a synthetic lease of an asset that it already owns.

MR. MARTIN: The company cannot own the asset before the lease financing is put in place?

MR. CORONIOS: That's right. And that is the major challenge in these transactions. Others at this table will talk about leveraged leases, which are basically a way to take assets that a company already owns off the balance sheet. But the cost of a leveraged lease is you give up tax ownership. In a synthetic lease, the company keeps the tax ownership of the asset, but a synthetic lease can only be done on an asset that the company does not already own.

MR. MARTIN: Let me stop you there. A company planning to build a power plant normally goes about setting up contracts, obtaining a site, ordering turbines — things like that. You say the company cannot own the asset if it wants to do a synthetic lease. At what point in the development process does it cross this line?

MR. CORONIOS: The synthetic lease turbine deals that everyone reads about are set up exactly to address this problem. The synthetic lease must be in place before the company gets to the point of making irrevocable payments on the turbines. Such payments would put the turbine on balance sheet and taint the entire project.

MR. COOPER: The turbines have become the driver because they have the longest lead time. However, the point is a company cannot spend money on any hard costs to develop the project and still do a synthetic lease.

A company cannot have spent money on hard costs to develop a project and still do a synthetic lease.

MR. CORONIOS: That's right. No spending on hard costs. People think when they hear this that it means putting a shovel in the ground. It doesn't. It means ordering and starting to pay for key equipment like turbines.

MR. COOPER: It could also be paying for an interconnect. It could be paying in advance to build the waterline. There are myriad things that can cause developers to trip over this rule if they aren't careful.

MR. MARTIN: David Hauser, you have not done any synthetic leasing. Why?

MR. HAUSER: We have certainly looked at the product, but we have a serious tainting problem because our own construction subsidiary builds all our power plants, making them tainted from the very beginning. The other thing that has pushed us away from it is we believe in asset optimization in the sense that we are buyers, builders and sellers of assets. If you have a power plant that you may decide to sell in a year or two, it is questionable whether it is worth the effort to structure a synthetic lease.

MR. MARTIN: Andrew Jacobyansky, are synthetic leases off-balance sheet for rating purposes?

MR. JACOBYANSKY: If a company must make cash payments, they are part of the coverage ratio.

MR. COOPER: Well, he doesn't look at debt to capitalization. The other rating agency looks at debt to cap as well as coverages and so, from their perspective, synthetic leases are not debt.

MR. MARTIN. John Cooper, your company was one of the first to use a synthetic lease.

MR. COOPER: It was the flavor-of-the-month last year, but we are no longer doing them for a variety of reasons.

MR. MARTIN: What is the major reason?

MR. COOPER: Well, these things are driven by a forward equity commitment or a forward takeout in three to five years after the power plant commences operating. Since the creditworthiness of our parent has deteriorated, banks are no longer comfortable with lending us a five-year forward commitment. We still have two existing synthetic leases we put in place, which we have restructured, but we are not really doing any new ones.

MR. MARTIN: Andrew Coronios, how does synthetic leasing compare in terms of cost of capital to straight borrowing or a leveraged lease?

MR. CORONIOS: It depends on how the synthetic lease is structured. John Cooper's company did a variation on the theme. A basic synthetic lease requires an investment-grade company that puts its full faith and credit behind the deal — to the extent the accountants permit it — so that you are basically looking at the company's corporate borrowing rate plus a slight premium for a structured deal.

The deals that John Cooper did were hybrids. Basically, a portion of the deal was financed on a project finance basis — let's say 50% — and this part was assigned a nonrecourse debt rate.

MR. COOPER: Traditional synthetic leases are 85% guaranteed, and ours was 40% or 50%.

Leveraged Leases

MR. MARTIN: Let's move to leveraged leasing. Roy Meilman and Jim Godry, it seems like there has been a resurgence of interest in leveraged leasing for power plants. Why?

MR. MEILMAN: To me, it's a little like David Hauser's comment about convertible debt. Leveraged leases have been around for a long time. There were a lot of leverage leases of power facilities in the 1980s. They were less common in the 1990's — until the last couple of years.

MR. MARTIN: Why the renewed interest?

MR. MEILMAN: The two drivers are tax and accounting. On the tax side, one way to look at a leveraged lease is it is a tax-advantaged loan where the tax advantage reduces your interest rate. There have been some developments that add to the tax profile of power plants. That helps. Companies that cannot use the tax benefits that come with ownership may be better off having someone else own who can use the tax benefits and then share in them indirectly in the form of lower rent. Many power companies cannot use foreign tax credits. Such companies are better off paying rent than interest. Additional interest payments will make their foreign tax credit positions worse. As for accounting reasons, perhaps Jim can address that.

MR. MARTIN: Jim Godry, what else explains the renewed interest in leveraged leasing for power plants?

MR. GODRY: Earnings management, but just to stick with the tax side for a moment, there are

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a couple of power plants being financed this year in the lease market because they are on Indian land and qualify for 12-year MACRS depreciation rather than the normal 20-year. The developers cannot use the tax depreciation on a current basis. That is the primary reason for them to lease — the desire to give them to someone else who can use them in exchange for better terms on the financing.

Turning to the earnings game, a company can boost its earnings per share by doing a long-term lease. Take the cash rent and divide it by the number of years in the lease term. That determines you annual rental expense. Many people are doing extraordinarily long-term leases to stretch out that rental expense and reduce it on an annual basis and, therefore, increase earnings per share.

MR. MARTIN: People used to do a lease-buy analysis to determine whether it made sense to do a lease or straight borrowing. The breakpoint was leasing made more sense if the tax benefits were at least 10-year MACRS depreciation or perhaps longer depreciation but with a tax credit. Does that analysis still hold?

MR. GODRY: You know, we never looked at it that way. People are looking at a conventional lease-versus-own analysis in some cases, but I think what drives many people to leasing is the cost of capital. If the developer or IPP's cost of capital is significantly higher than the lease equity investor's cost of capital, then leasing will make sense from purely an economic standpoint.

MR. MARTIN: John Cooper, your views on leasing?

MR. COOPER: We've done a bunch of them. Ours have been purely earnings driven. Bear Swamp is a pumped storage project with a very long useful life — over 60 years. We got a 43-year lease with 20-year debt. The rents during the last 23 years of the lease after the debt is repaid are very low. As Jim Godry said, if you levelize the rent over the entire 43 years, you end up with a much lower rent expense profile in the first 20 years than if you had borrowed to purchase the asset.

These are accounting earnings, so they don't really count in your ratios and things like that. You still have to pay cash rent. You may be paying $40 million a year in cash rent to service the lessor's 20-year debt, but the accounting charge for that may be only $15 million a year.

MR. HAUSER: We have done a fair amount of leasing, although not so much in power plants as in other assets, like buildings. We have leased one power plant — actually in California. We have done synthetic leases on airplanes. We have done a lot of different things. You need to be looking at your total arsenal of weapons all the time.

I don't think it is as simple as a lease-buy analysis like it used to be. If you are looking at a lease, you better be figuring out where you are with foreign tax credits, where you are with the alternative minimum tax. All these factors play into the decision. You are going to reach a different decision at different points in time.

MR. MARTIN. One more leasing question — can one do a lease on a project credit or must one have a creditworthy parent standing behind the lease rentals?

MR. GODRY: It really is only doable with creditworthy entities. Having said that, you can do a project backed by power purchase agreement or tolling agreement with a creditworthy party. I can think of three or four projects that have been done on that basis this year. The creditworthy entity must be a triple B or better.

Merchant Ratings

MR. MARTIN: Let me ask a series of rapid-fire questions in the time we have left. Andy Jacobyansky, is there a trend in ratings for merchant power plants? Are the rating agencies getting more comfortable with merchant risk?

MR. JACOBYANSKY: We get investors asking us if we are loosening our standards because recent ratings have been higher than in the past. However, the reason for the higher ratings is recent ratings have been on assets that are moving over from one part of the company to another with no real debt. These are not assets that were bought at an auction where somebody paid more than anyone else wanted to pay and had to put a lot of equity in and lever up as much as he could.

An example is where a utility has $550 million in coal-fired power plants on its books. It has owned them for a long time. It moved them recently to a sister Genco and took back an extremely subordinated note. The transfer was blessed by the public service commission. The subordinated note is essentially equity. It is a significant coal-fired portfolio of 2,500 megawatts that is essentially being moved over with no debt on it.

MR. MARTIN: What about ratings for greenfield merchant plants — are they improving?

MR. JACOBYANSKY: No. If we looked at a project today that is identical to a project two years ago, we would come to the same rating.

MR. MARTIN: What about a California-type risk? Are companies with California exposure under pressure from the rating agencies?

MR. JACOBYANSKY: There are many companies with California exposure. We looked at all the corporates — like Calpine and Mirant and Duke and Reliant — and decided they did not have enough California exposure to warrant bringing down their ratings.

We took all the projects in California down to Caa2, which is the unsecured rate for utilities, but just two days ago, recognizing what is going on in California, we put all except one on a list for possible positive upgrade and said the upgrade could be more than one notch. So I think we may start to see some of them move up.

California Premium

MR. MARTIN: What effect has California had on the ability to get financing for projects outside California?

MR. HAUSER: We have had moments when it was very difficult to get financing for merchant power plants. We are all having these peaks and valleys. Things will settle down and then someone like Gray Davis will say something or FERC will do something and the banks pull back to assess what it means. The markets get tough for a little while. Our biggest challenge this fall will be refinancing a portfolio of assets, including in the portfolio some assets in California, but I expect this will get done on schedule.

MR. COOPER: There is what several people said is a headline premium. The bankers must go back to their credit committees and explain after every headline why the latest news story has nothing to do with this deal. It's kind of the aggravation premium. It means that deals are taking a lot longer to syndicate because the bankers have to explain a lot more. When an international monetary crisis hits in an emerging market, the entire country is hit and dries up. It is that sort of phenomenon that we are seeing in the United States. ■

Rules Change For Registering Corporate Tax Shelters

by Keith Martin, in Washington

The Bush administration made changes in early August to rules that require corporations to attach forms to their tax returns disclosing details about transactions that the US authorities will probably want to examine on audit.

The revisions make it less likely that corporate tax shelters will have to be disclosed in the future.

US Treasury officials were very concerned during the Clinton administration about the

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growing market in "tax products" being peddled by the big accounting firms and investment banks. Last year in March, the Internal Revenue Service issued regulations requiring greater disclosure of the details of corporate tax shelter transactions in the hope that this would act as a deterrent to the marketing of such products. The regulations also require promoters of corporate tax shelters to register them with the IRS before the shelters are offered to corporations and to keep a list of companies they persuade to invest in case the IRS wants to see it.

The disclosure regulations came under fire from the business community.

In early August, the Bush Treasury made a number of revisions. Most are clarifying in nature. However, the government has dropped the fact that a transaction is a "hybrid" — meaning that it is expected to be characterized differently by the tax authorities in the US and a foreign country — as a factor suggesting it might be a tax shelter. In addition, the government will no longer require promoters to register transactions merely because they produce an insignificant profit in relation to the tax benefits. The rules, as revised in August, are now as follows.

Promoters are no longer required to register transactions merely because they produce an insignificant profit in relation to tax benefits.

Disclosure

Any corporation that participates "directly or indirectly" in a "reportable transaction" must attach a form with the details of the transaction to its tax returns for each year the transaction affects its US tax position. A copy of the form must also be sent the first year to a special office the IRS has set up to monitor aggressive tax schemes.

Two things must be true before a tax maneuver rises to the level of a "reportable transaction."

First, either it must appear on a list of transactions the government considers abusive — so-called "listed transactions" — or it must possess some of the following characteristics. Any two of these characteristics will require reporting.

- The corporation participated in the transaction "under conditions of confidentiality." An example is where the transaction was pitched to the corporation as a proprietary idea by an outside tax adviser.
- The corporation has contractual protection against the possibility that some of the tax benefits will be disallowed. Examples of contractual protection are an unwind clause, a right to a partial refund of fees, fees that are contingent in the first instance on the tax benefits from the transaction, or a tax indemnity. However, a tax indemnity from another participant in the transaction who had no role in promoting it — such as the tax indemnities that lessees typically give lessors in big-ticket lease transactions — are not a problem.
- The advisers who "promoted, solicited or recommended" the transaction to the corporation are expected to receive more than $100,000 in aggregate fees. For this purpose, fees only count if they are contingent on closing the transaction.
- The expected treatment of the transaction for tax purposes is expected to differ from its book treatment by more than $5 million in any single year.
- One of the other parties to the transaction

is in a different tax position — like a tax-exempt entity or foreign person — and this lets the corporation realize tax benefits that it could not have gotten otherwise.

Second, the expected tax benefits from the transaction must be large enough to warrant IRS attention. A "listed transaction" satisfies the dollar thresholds if the corporation expects to reduce its federal income taxes by more than $1 million in a single year or more than $2 million in any combination of years. The thresholds for other transactions are more than $5 million in a single year or more than $10 million in any combination of years.

The IRS published an initial list of "listed transactions" in February 2000, but has updated it several times since then. The list now has on it 16 items. They include LILOs, or lease-in-lease-out transactions where a foreign entity or US municipality leases a power plant, gas pipeline, railcars or other equipment to a US investor and subleases it back, certain tax plays involving foreign tax credits that are described in IRS Notice 98-5, "lease strips," and ACM Partnership-type transactions.

There is one important exception from disclosure. A transaction does not have to be reported if the corporation "participated in the transaction in the ordinary course of its business in a form consistent with customary commercial practice" and either would have participated on substantially the same terms irrespective of tax benefits or "there is a generally accepted understanding" that the transaction works from a US tax standpoint. The exception does not cover "listed transactions." The exception exempts plain-vanilla lease transactions from disclosure, whether they are domestic or cross-border. Other more exotic lease transactions — such as defeased deals — would seem more problematic.

The disclosure requirement applies to tax maneuvers entered into after February 28, 2000.

Companies are barred from disposing of any documents "that are material to an understanding of the facts of the transaction, the expected tax treatment of the transaction, or the corporation's decision to participate in the transaction." The new disclosure regulations are "temporary and proposed" and may undergo some further revision before they are reissued in final form. They are effective as written in the meantime.

Tax Shelter Registration

IRS regulations also require promoters of corporate tax shelters to register them with the Internal Revenue Service before the shelters are offered to corporations.

Three things must be true about a transaction before registration is required.

First, it must have "avoidance or evasion" of federal income taxes as a "significant purpose." So-called listed transactions fall into this category automatically. Other transactions where federal income tax benefits are "an important part of the intended results" do also, but only where the promoter expects to offer the transaction to more than one potential participant. Thus, unless the transaction is a one-off deal that will never be repeated, it will trip this "avoidance or evasion" test.

Second, the transaction must be offered "under conditions of confidentiality." The IRS said there can be implied confidentiality for a transaction — for example, where an accounting firm, investment banker or other promoter leads the company to believe the idea is proprietary. The IRS effectively issued a challenge: a transaction is *not* offered under conditions of confidentiality if the promoter signs a written agreement with everyone with whom he discusses possible participation "expressly authoriz[ing] such persons to disclose every aspect of the transaction with any and all persons, without limitation of any kind."

Finally, the promoters must be expected to

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receive more than $100,000 in total fees. Fees from all "substantially similar" deals the promoter does must be aggregated. Thus, if he expects to repeat the deal several times with other companies, the fees add up to a much larger number.

Registration applies to tax shelters offered after February 28, 2000. If a shelter was offered before, registration will be triggered the first time it is offered again after February 28. Registration must occur before interests in the transaction are "offered for sale."

Many tax shelters were already subject to IRS registration, but tax schemes offered to corporations often escaped these rules The new regulations broaden the net. Registrations are filed on IRS Form 8264.

Tax maneuvers engaged in by foreign companies may have to be registered. These will be viewed as involving indirect participation by a US company — and, therefore, as potentially involving the "avoidance or evasion" of US taxes — if a US company owns at least 10% of the shares by vote or value of the foreign company that is the direct participant in the scheme. If the foreign company is a partnership for US tax purposes, ownership by the US company of at least a 10% capital or profits interest, or expected receipt of at least 10% of loss allocations, will be enough to require US registration.

Investor List

Promoters must also keep a list for seven years of companies they persuade to invest in corporate tax shelters in case the IRS wants to see it.

Lists are required even for corporate tax shelters that do not have to be registered. As noted above, three things must be true about a corporate tax shelter before the promoter has to register it. However, he must keep a list of investors in any transaction that has US tax "avoidance or evasion" as a significant purpose, regardless of whether it was offered under conditions of confidentiality or the amount of fees paid. ■

More Turkish Power Industry Reforms

by Kimberly Heimert, in Washington, and Begum Durukan, Birsel Law Offices in Istanbul

Turkey has taken three more important steps to reform its power industry.

The Turkish parliament passed a new "Natural Gas Market Law."

TEAŞ — the state-owned electricity trade, generation and transmission company — is being split into three separate joint stock companies. Companies holding contracts with TEAŞ may face some issues.

The Turkish parliament has extended the deadline for the transfer of rights for remaining TOR projects from June 30 to October 31, 2001. A "TOR project" is an existing power plant that is owned by the government, but that needs upgrades. The government transfers the project's operational rights to a private party in exchange for a transfer fee and its agreement to make the upgrades. The private party then has the use of the facility for an extended period, after which it must transfer it back to the government.

Natural Gas

The country adopted a new "Natural Gas Market Law No. 4646" that now regulates the import, export, transmission, distribution, storage, marketing, and trade of natural gas. The only significant gas activity not on this list is gas production.

The new law applies to the natural gas market many of the same reforms that were made in the electricity market in the "Electricity Market Law" last March. These include identification of a regulatory body to oversee the gas market, establishment of a new licensing regime, and introduction of the concept of "eligible consumers." The new law also attempts to encourage the development of Turkish natural gas capabilities and to discourage monopolistic behavior.

The Electricity Market Law last March established an independent regulatory authority called the Electricity Market Regulatory Authority to oversee the electricity market. The new gas law renames this body the "Energy Market Regulatory Authority" and gives it the authority to regulate not only the electricity market but also the gas market.

Under the new gas law, companies engaged in natural gas market activities must be licensed by the regulatory authority for each "market activity" they intend to carry out. "Market activities" are the transmission, storage, wholesale sale, export, import, and urban distribution of natural gas. If a legal entity intends to engage in more than one market activity or a single market activity at different facilities, it must obtain a separate license for each market activity or facility. The new gas law also requires companies to have a "qualification certificate" from the regulatory authority before they may engage in design, construction, revision, repair, supervision, rehabilitation, maintenance, or control activities for anyone in the natural gas market. The terms of these licenses and certificates generally are between 10 and 30 years.

The new gas law introduces an "eligible consumer" concept. Eligible consumers may enter into natural gas purchase contracts directly with any production, importation, distribution, or wholesale company within the country. In the past, such direct agreements were not permitted. Four categories of persons qualify as "eligible consumers." One category is consumers and user unions, such as coops or other organized industrial groups that supply natural gas to members and whose annual natural gas purchases are more than one million cubic meters. Another category covers companies purchasing natural gas to generate electricity. Another is for cogeneration facilities that generate both electricity and steam. The last category is generation companies producing natural gas in Turkey for production activities.

The new gas law also contemplates the restructuring of the state-owned Pipelines and Petroleum Joint Stock Company, called "BOTAŞ." BOTAŞ will be broken into separate transmission, storage, sale and export companies after 2009. All of those companies, except the transmission company, will be privatized within two years from the date of formation.

To prepare for the restructuring, the new gas law takes steps to reduce BOTAŞ 's share in the natural gas market to no more than 20%. The law establishes strict limits on the purchase and sale of natural gas by BOTAŞ. BOTAŞ may not enter into new gas purchase agreements — most of which are import agreements — until its natural gas imports are reduced to 20% of the national consumption of natural gas. After a transition period over the next 12 to 18 months, BOTAŞ must conduct tenders and transfer its natural gas purchase and sale contracts to other qualified import companies until it imports no more than 20% of its current natural gas consumption.

The new gas law also attempts to prevent any other single company from controlling more than 20% of the country's natural gas requirements. No single market player will be allowed to import or sell wholesale more than 20% in national consumption of natural gas each year.

Finally, the new gas law permits existing build-operate-transfer and build-operate natural gas-fired projects — called BOT and BO projects — to purchase natural gas from any source. Most of the current projects have contracts to sell their power to TEAŞ, the state-owned generation and transmission company. Such contracts are often supported by a treasury guarantee of the obligations of TEAŞ. However, the new gas law

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states that if a company purchases natural gas from any source other than BOTAŞ, its sale contract to TEAŞ may lose the benefit of the treasury guarantee.

TEAŞ Restructuring

Articles of association have been issued for the three new companies that will succeed TEAŞ. Those companies are the Turkish Electricity Trade and Undertaking Joint Stock Company, the Electricity Generation Joint Stock Company, and the Turkish Electricity Transmission Joint Stock Company.

Two of the articles of association clearly state that TEAŞ will be dissolved when the new companies are formed, which will be when their respective boards of directors are constituted. Each of the boards of directors will consist of a general director and four other directors, all of whom will be appointed jointly by the Prime Minister and the Minister of Energy and Natural Resources. Although there is no indication of when these appointments will occur and, therefore, when the new companies will be formed, it is generally believed that the appointments will occur in the relatively near future.

The articles of association generally require each of the new companies to assume the rights and obligations that TEAŞ has under any contracts (including internal and external credit arrangements), lawsuits and enforcement actions. However, with one exception, they simply state that each new company will incur the rights and obligations that are associated with the activities of that new company. Therefore, confusion and disagreements are possible over which new company assumes which rights and obligations of TEAŞ.

The articles of association of the new trade company specifically state that the energy sales agreements that were executed prior to the adoption of the Electricity Market Law will be assumed by the new trade company. They also state that the new trade company has the authority to "amend . . . the energy sales agreements . . . in line with the changing sector conditions and legislative regulations by also obtaining the affirmative opinion of the Undersecretariat of the Treasury." There is some concern that the new trade company will use that authority as a justification to demand that certain project companies discuss the renegotiation of their energy sales agreements.

The Turkish Electricity Distribution Company is not directly affected by this restructuring, except that it now must enter into new agreements with each of the new companies regarding the tariffs for goods and services supplied to each other.

TOR Projects Deadline

Turkey had directed earlier that the transfer of rights in all remaining TOR projects must occur by June 30, 2001. The Turkish parliament has now extended that deadline until October 31, 2001. However, the extension may not provide enough time for existing projects to overcome their many legal and practical hurdles.

No single player will be able to import and sell wholesale more than 20% of natural gas consumption for the year.

It is still difficult for project companies to find officials to execute the necessary contracts on behalf of the government, even if they have already been negotiated and agreed. This difficulty is largely because of the on-going "White

Energy" corruption scandal and investigation.

In addition, many project companies are in danger of losing their rights to their TOR projects because of their ownership of television and radio stations. Turkey's radio and television law prohibits anyone with more than a 10% share in a radio or television company to participate in a tendered contract with the government. This includes TOR contracts. Although many of the project companies affected by this 10% limitation are fighting the restriction, it is unlikely that their legal challenges will be resolved by October 31, 2001. ■

Cuban Sanctions

by Samuel R. Kwon, in Washington

President Bush decided in July to continue blocking civil suits by US persons against anyone dealing in property confiscated from Americans by Cuba during and after the 1959 revolution.

The so-called Helms-Burton Act, enacted in 1996, allows US persons to sue in the US courts for damages against anyone — a US person or otherwise — "trafficking" in property confiscated by Cuba on or after January 1, 1959. However, it also allows the President to suspend the provision at six-month intervals. President Clinton suspended the provision soon after it was enacted after Canada and various countries in Europe complained about the extra-territorial reach of the prohibition. The Bush administration decided in July to continue this policy.

However, other US sanctions remain in place against companies doing business in Cuba. These sanctions fall largely into three categories — the Cuban assets control regulations, the Helms-Burton Act and travel restrictions.

Cuban Assets Control Regulations

A US person is prohibited from engaging in any transaction (other than transactions of academic, informational or humanitarian nature) involving Cuba unless it receives a specific authorization from the Office of Foreign Assets Control within the US Treasury Department.

The Cuban assets control regulations prohibit US persons from engaging in any financial transaction on behalf of Cuba or a Cuban national or any transaction involving property in which Cuba or a Cuban national has had any interest at any time after July 8, 1963. A "transaction" broadly includes transfers of credit, payments between banks, dealings in foreign exchange, and exportation or withdrawal from the US of gold or silver coin or bullion, currency or securities. Furthermore, US persons may not deal in any security registered in the name of a Cuban national, whether by acquisition, transfer, disposition, endorsement or guaranty.

The regulations also prohibit exports and imports of Cuban goods. Specifically, US persons may not purchase, transport, import or otherwise deal in any merchandise of Cuban origin or transported from Cuba. Merchandise of Cuban origin includes merchandise made or derived in whole or in part of any article that is the growth, produce or manufacture of Cuba.

Finally, any transaction whose purpose or effect is evading or avoiding any of the prohibitions under these regulations is also prohibited.

US persons subject to these prohibitions include any US citizen, a US resident, any person physically within the US, and any legal entity organized under US laws. It also includes any foreign legal entity owned or controlled by a US person subject to these prohibitions.

If a US person violates any of these sanctions, criminal penalties of up to 10 years in prison and fines may be imposed. Corporate fines are up to $1 million and individual fines are up to $250,000. Civil penalties of up to $55,000 per violation may also be imposed.

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A US person wishing to engage in a transaction prohibited by these regulations must obtain an authorization from OFAC. OFAC will issue an authorization after reviewing a written application only if it decides the transaction does not frustrate the basic goal of the sanctions, which is "[t]o isolate the Cuban government economically and deprive it of US dollars."

Helms-Burton Act

Unlike the Cuban assets control regulations, the Helms-Burton Act applies to *everyone*, including foreign companies. Therefore, foreign companies, as well as US companies, that violate the prohibitions of the Helms-Burton Act will be subject in theory to its penalties.

The Helms-Burton Act prohibits *anyone* from "trafficking" in "confiscated property." "Trafficking" means any kind of dealing — direct or indirect — to derive a benefit of any sort (for example, possession, use, profit, lease or investment). "Confiscated property" refers to property seized by the Cuban government on or after January 1, 1959 without adequate compensation.

US law prohibits anyone — not just US companies — from trafficking in Cuban property.

The Helms-Burton Act provides two penalties for anyone trafficking in a confiscated property.

First, the US person who has a claim to the confiscated property may sue the person trafficking in that property for money damages in the US courts. The recoverable amount of the damages is the larger of the settlement amount certified by the Foreign Claims Settlement Commission plus interest or the current fair market value of the property, plus costs and reasonable attorney fees.

However, the enforcement of this provision was continually suspended by the former President Clinton for the last five years. President Bush has also suspended the enforcement until at least February 1, 2002.

Second, the US will deny visas to any person who trafficks in confiscated property. If an entity was involved in trafficking of a confiscated property, its corporate officers, principals, and controlling shareholders will be denied visas. The denial of visas extends to such persons' spouses, minor children and agents as well.

Travel Restrictions

US law broadly permits travels to Cuba by US and foreign government officials, journalists, academic researchers, humanitarian aid providers, professionals attending international conferences and athletes participating in athletic competitions. Otherwise, US persons wishing to travel to Cuba must obtain a specific authorization from OFAC.

Implications

Under the Cuban assets control regulations, a US power company may not build a power plant in Cuba to generate and sell electricity to the Cuban national utility absent a specific authorization from OFAC. Such a project would involve transacting in property (*i.e.*, contracts and services) in which Cuba or a Cuban national has an interest — a prohibited transaction.

A US power company taking a minority (*e.g.*, limited partner) position in a partnership with a non-US company to do a power project in Cuba may also violate US sanctions. Under this structure, a US person may still be transacting in property in which a Cuban national has an interest — the partnership. This risk exists because the foreign partnership itself may be a Cuban national. A Cuban national includes "any person acting…directly or indirectly for the benefit" of Cuba or a Cuban national. OFAC declines to describe circumstances in which a foreign entity becomes a Cuban national by acting "for the benefit" of Cuba. However, it insists the term "Cuban national" will be read as broadly as necessary to achieve the goal of these sanctions — economic isolation of Cuba.

OFAC elaborates in its release with the following example: "[P]ersons subject to US jurisdiction (including US overseas subsidiaries) may not…sign a contract with a UK firm if the contract term includes Cuba-related provisions (even if those provisions are contingent upon the lifting of the embargo); and may not provide accounting, marketing, sales, or insurance services to a Cuban company or to a foreign company with respect to the foreign company's Cuba-related business."

Finally, both forms of doing a power project in Cuba expose the US company, as well as the non-US partner, to the risk the project would traffick in confiscated property and violate the prohibition of the Helms-Burton Act. ■

Growing Market Expected In Carbon Trades

by Andrew A. Giaccia, in Washington

Carbon trades are on the increase. By some accounts, publicly-disclosed deals in recent years have already totaled as many as 150 million metric tons of carbon dioxide, or CO_2, equivalents. Informal carbon exchanges have been developed in several countries and, perhaps most significantly, a number of investment funds potentially exceeding $2 billion in assets have been announced or formed to focus upon developing tradable carbon credits worldwide.

Much of this activity reflects a growing perception that out of the chaotic beginnings of the global warming regime substantial opportunities may be seized.

At the heart of most carbon trades are two carbon credit mechanisms that were present in the original Kyoto agreement on global warming. The first involves an emissions trading approach that would use market forces to allow countries to achieve their emissions targets. Countries with excess or surplus emissions assigned to them based on 1990 emission levels — Russia is in this category — can sell some of their allocated emissions to other countries. The second approach involves a so-called "clean development mechanism," or "CDM," under which rich countries can earn credits by investing in emissions-reducing projects in developing countries.

These two programs — whose rules are still being developed at the international level — will provide the basis for most international carbon credit trades. Despite news stories to the contrary, the renegotiation of the Kyoto agreement that took place in Bonn in late July did not substantially change the general outlines of these mechanisms, although the delegates to Bonn were still working on the details for implementing carbon trading as the *NewsWire* went to press.

Contract Terms

The absence of clearly defined criteria and authority supporting such transactions makes

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the contract the trading parties negotiate all the more important. The terms of the contract must be not only clearly defined, but also sufficiently flexible to deal with a variety of potential outcomes and intervening factors. A would-be purchaser also has the burden to ensure his carbon credits can be transferred.

Any contract for sale of carbon credits should be sure to address at least six issues.

- The contract should take into account the applicable elements of the Kyoto protocol, as amended in Bonn, and the applicable country-specific requirements, such as requirements for qualification as a "clean development mechanism" project, proof that the reductions would not have occurred without the CDM project, and any potential limitations on the use of the carbon credits.
- In situations where a carbon transaction involves only private parties, attention should still be paid to the host government. If possible, the government should provide certification to the purchaser that the seller has ownership and clear title to the carbon credits. It might be a good idea to give the host government an ongoing share of future emissions credits created by the seller to ensure that it will continue to support and enforce the emissions reductions that are crucial to creating the credits.
- The contract should indicate the source and basis for the carbon credits that are being sold. With the first commitment period for Kyoto essentially ten years away — from 2008 to 2012 — the factual predicates for the carbon credits must be clearly established in order to stand the test of time.
- The contract should explain the scientific basis for measuring the credits, and it should also allow enough flexibility to make changes both in the business arrangements and the methodologies for measuring and recording the credits to the extent that the relevant rules in the Kyoto protocol and the relevant countries evolve or change in the future.
- The contract should explain whose risk it is if some of the data on which the credits were based proves faulty, or the calculations were wrong, or something else goes wrong. In this regard, a number of insurance products are available or under development that might provide useful support for carbon trades.
- The contract should ensure, to the extent possible, that the relevant reductions have the necessary permanence and are binding not only on the seller but also any successors or other parties that might be in a position to undo the relevant reductions or attempt to sell them to a third party.

A number of investment funds potentially exceeding $2 billion in assets have been formed to trade carbon credits.

These are the main legal issues, but others will also have to be addressed in the contract. The complexity of the applicable risks and, therefore, of the contract itself will be proportional to the degree of discount in the value of the carbon credits being purchased and the nature of the underlying project. Certain types of CDM projects — such as coal-bed methane gas projects — can be structured more easily than others. For this reason, carbon credits from such projects are already being actively traded, and their pricing is likely to increase with the increased demand that will accompany eventual ratification of the Kyoto treaty.

Outlook

In Bonn last month, 178 countries committed to take steps to reduce greenhouse gas emissions that contribute to global warming. Nevertheless, development of a uniform and reliable market for carbon trading on the scale contemplated by the Kyoto agreement still faces many significant hurdles. The Kyoto protocol must still be ratified by 55 industrialized countries representing more than half of global greenhouse emissions.

Some people question whether a viable market can exist without participation by the United States. According to the International Energy Agency, a potential greenhouse gas market of roughly $42 billion a year would thrive with full US participation in Kyoto but might be worth as little as only $3 billion a year without US participation.

Even after ratification, Kyoto will need to be implemented by the individual countries. That process has already started, especially in Europe, but it has produced and will likely continue to produce important variations in how each country chooses to implement the accord. In some countries like Canada, implementation will even be left to provincial governments. There is also the prospect of further amendments to the Kyoto agreement, possibly to gain US participation, that might change the scope and timing of the required reductions. ■

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One hundred seventy eight countries meeting in Bonn at the end of July reached agreement on several open issues that were preventing implementation of the Kyoto accord on global warming. The United States is the only major country that is not participating.

Global Warming

Some commentators predicted that the Bush administration's outright rejection of the Kyoto protocol earlier this year would deal a crippling blow to the agreement. However, the Bonn accord is now expected to lead to a number of additional countries ratifying the agreement.

The agreement will enter into force once it has been ratified by at least 55 countries. The 55 must include industrialized countries that account for at least 55% of the total reduction in carbon dioxide or CO_2 emissions that are required from the industrialized group. To date, 36 countries have ratified. They include one industrialized country, Romania. Germany has announced it will also ratify soon.

The goal of the Kyoto protocol is to reduce global greenhouse gas emissions by 5.2% from 1990 levels during the "first commitment period" of 2008 through 2012.

The European Union countries and the so-called Umbrella Group nations — which include Australia, Canada, Japan, and Russia — brokered a compromise in Bonn on a number of major implementation issues.

Credit for "carbon sinks" — or land use and forestry activities that absorb carbon from the atmosphere — will be awarded on a country-by-country basis based on changes in land use since 1990. Forest management, cropland management, grazing land management, and revegetation will be recognized as eligible carbon sink activities.

"Clean development mechanism," or "CDM," rules were adopted that specifically allow energy efficiency, renewable energy and forestation projects to be credited. (Developed countries may earn credit for under-

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taking projects to reduce greenhouse gas emissions in developing countries. These are called CDM projects.)

Penalties were adopted for countries that fail to meet emissions reduction targets during the first commitment period of 2008 through 2012. These countries will have to reduce an additional 1.3 tons of emissions for every ton they are over the target starting in 2013.

These concepts — carbon sinks, CDM and compliance penalties — were already part of the original Kyoto protocol, but there was room for disagreement because the agreement was lacking in detail. The parties agreed in Bonn on some of the important details. However, specific rules to implement the core concepts still need to be developed.

Although the United States has rejected the Kyoto protocol, US positions on the three issues were considered during the negotiations. For example, the US has been a longtime advocate for granting credit for carbon sinks.

US companies with operations in other industrialized countries, such as in Europe and Japan, will ultimately have their facilities in those countries subject to greenhouse gas emission reduction requirements since these nations are expected to ratify the protocol. These requirements may result in significant costs to achieve CO_2 emissions reductions at power plants and other industrial facilities. Such costs could include the installation of more energy efficient and lower CO_2-emitting equipment or purchasing CO_2 emission credits or undertaking CDM or similar projects.

The Bush administration has said it is committed to addressing the problem of global warming, but it charges that the Kyoto protocol is flawed because the agreement does not require emissions reductions for developing countries like India and China. The United States is currently conducting a cabinet-level review of global warming and is expected to outline an approach for dealing with the problem later this year, possibly in time for the next meeting of the environmental ministers scheduled for October 29 to November 9 in Marrakesh, Morocco.

Carbon Trading

A group of twenty-five companies and nonprofit organizations — including Alliant Energy, Cinergy, Calpine, Midwest Generation, NiSource and PG&E National Energy Group — committed in June to participate in a design phase of a pilot CO_2 trading system.

The pilot exchange — called the Chicago Climate Exchange — is being developed by Environmental Financial Products and is intended to create a market for trading voluntary CO_2 reductions within a framework that provides for methods to monitor and track CO_2 emissions and determine what constitutes approvable reductions and offset projects. Under the pilot trading program, participating companies will be issued tradable CO_2 allowances and each participant must agree voluntarily to reduce its CO_2 emissions by 2005 by 5% from 1999 levels. Participants would be able to buy allowances to offset CO_2 emissions or they could reduce their own CO_2 emissions directly.

Regional Haze

The Environmental Protection Agency formally proposed new guidelines in late July for implementing "best available retrofit technology," or "BART," to comply with its regional haze rules. The new guidelines could trigger costly retrofits of pollution control technology at older power plants located near national parks and federal wilderness areas. These are called "Class I areas."

Under the new guidelines, pollution retrofits may be required to comply with BART standards at power plants that were constructed between 1962 and 1977 and emit more than 250 tons a year of any of five pollutants that contribute to impaired visibility in national parks and wilderness areas. The affected power plants are upwind from Class I areas. The five pollutants are sulfur dioxide, or SO_2, nitrogen oxide, or NO_x, particulate matter, volatile organic compounds, and ammonia.

The new guidelines appear to establish flue-gas

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desulfurization or scrubbers as the presumptive BART standard for utility boilers. Installing a scrubber at a large electric generating unit usually costs from $50 million to $100 million.

As proposed, the BART guidelines would set a presumptive SO_2 control level requiring emissions reductions of 90% to 95% compared with uncontrolled operations. This is an SO_2 control level that is significantly more stringent than the existing federal acid rain program requirements. While the guidelines call for states to conduct a case-by-case BART analysis for affected sources, states would be required to justify any deviation from the stringent presumptive BART control requirement.

The Environmental Protection Agency has asked for written comments on the proposed new guidelines by September 18, 2001. These guidelines were originally scheduled to be proposed earlier this year by the outgoing Clinton administration, but were delayed for further review. The Bush administration made only minor changes to the proposed rule.

States have until the period 2004 to 2008 to submit their regional haze plans. BART-level controls would have to be in place at affected plants within five years after EPA approves a state's plan. A number of industry groups are challenging the regional haze rule in court. The case is still pending in the US court of appeals for the District of Columbia.

Air Permits

The Environmental Protection Agency is taking a hard look at US rules for new construction and modification of power plants and other industrial facilities that potentially increase air pollution. It is expected to suggest wholesale revisions in the program — called "new source review," or "NSR," later this year.

The current NSR program requires major new and modified sources of air emissions to undergo a complicated and extensive permitting review process, including the selection of control technology to meet stringent emission limits. NSR permitting reviews have been notoriously costly, time-consuming and fraught with potential pitfalls.

The energy plan that the Bush administration issued in late May directed the Environmental Protection Agency to report within 90 days on the impact of the NSR program on investment in new utilities and refineries, energy efficiency, and environmental protection. The recommendation to review the NSR program was an outgrowth of longstanding complaints that the NSR permitting regime stifles new and modified plant construction.

EPA issued a 90-day review background paper in June. It has been holding both public and private meetings to collect comments. It hopes to submit a finished report to President Bush by August 17, but the deadline could slip into September.

Meanwhile, the Department of Justice is reviewing its NSR enforcement actions at the same time to ensure consistency with the Clean Air Act and its implementing regulations. EPA's high profile NSR enforcement initiative has caused consternation in the regulated community, and generated allegations that the agency has changed its interpretation of certain NSR rules over time. A number of NSR enforcement actions are pending against electric utilities, refineries, and other industries. The industry is hoping that some of these cases might be dropped as a result of the review.

New York

The New York Department of Environmental Conservation, or "DEC," released draft regulations in June that would drastically reduce SO_2 and NO_x emissions at New York power plants.

The draft regulations would reduce SO_2 emissions by an additional 50% below federal Clean Air Act requirements by 2008. They also call for reducing NO_X emissions by 70% from current levels by extending summertime NO_X controls to year-round status starting in 2004. Once implemented, New York power

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plants will be facing some of the most stringent SO_2 and NO_X emission limits in the country.

New York hopes to reduce SO_2 emissions by 130,000 tons a year and further reduce NO_X by 20,000 tons per year. The draft regulations would create an in-state trading program for New York SO_2 emission allowances. Under the new SO_2 regime, New York power plants would still need to hold enough federal SO_2 allowances to comply with the federal Clean Air Act. However, compliance with the New York program should generate an annual surplus of federal SO_2 allowances for New York sources. The NO_X reduction proposal would also expand the existing New York trading program for NO_X allowances.

The draft regulations are currently under review by the governor's office. His staff is holding meetings with stakeholder groups. The regulations are expected to be formally proposed this fall and will be subject to a public review and comment period. They are expected to take effect in time to implement next year.

California

Both environmental groups and the City of San Francisco filed lawsuits recently challenging an agreement that would let a power plant in San Francisco increase electricity output from three diesel-fired peaking units by operating beyond its annual hours-of-operation limits. Under the arrangement between the Bay Area Air Quality Management District and the plant, the peaking units are allowed to exceed air permit restrictions in exchange for payment of a \$20,000 mitigation fee for each ton of excess NO_X generated by the units.

The local air districts were given authority in two executive orders issued by Governor Gray Davis earlier this year to exceed annual hours of operation provided mitigation fees are paid.

The plaintiffs charge the agreement between the plant and local air district violates the federal Clean Air Act because the plant failed to undergo a new source review permitting process to modify its air permit and to obtain emission offsets to compensate for the increased NO_X emissions from the units. The lawsuits are pending before a federal district court in northern California.

Since the beginning of the year, Governor Davis has taken a number of steps to increase the state's electricity generating capacity. Davis issued a new executive order on June 12 that allows natural gas-fired power plants to operate at maximum capacity. The order authorizes local air districts to permit gas-fired plants to exceed hourly, daily, quarterly, and annual emissions limits so long as the power is sold to the California Department of Water Resources or to an in-state utility and mitigation fees are paid to the air district. The order provides for mitigation fees of \$7.50 per pound of NO_X — or \$15,000 a ton — and \$1.10 per pound of carbon monoxide — or \$2,200 a ton — emitted in excess of the permit limits.

Approximately 1,200 megawatts of additional electric generation capacity is expected to be available this summer as a consequence of the governor's June 12 action. EPA Region IX is expected to cooperate with the California air districts to ensure that federal administrative consent orders are issued to authorize the temporary lifting of air permit limits. Local environmental groups may also challenge actions by local air districts to implement the order.

— contributed by Roy Belden in Washington.

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