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PROJECT FINANCE

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New Energy Incentives

by Keith Martin, in Washington

A package of new tax incentives for energy projects is taking shape in the US Congress. Project developers and equity investors would be wise to take the new incentives into account in their planning.

The tax-writing committees in both the House and Senate approved separate packages of energy tax incentives in early April.

The House package is more expensive than the Senate. It would cost $18.1 billion over 10 years. The Senate incentives would cost $15.5 billion. There is only expected to be room for roughly $15 billion.

The tax incentives will be folded into a larger energy policy bill that is gradually winding through Congress. The energy bill passed the full House on April 11, but it will face greater difficulty in the Senate where it is tentatively scheduled for at least two weeks of debate in May. It must then go to a "conference committee" to iron out differences in approach between the two houses. A similar measure failed to make it to the president's desk in the last Congress because the two houses were unable to reach agreement in conference. The hope is that things will be easier this time with both houses of Congress now under Republican control. However, there is no agreement, even among Republicans, about some of the more contentious issues. The betting by industry lobbyists is a bill will ultimately be enacted, although probably not until late in the year. */ continued page 2*

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CONFIDENTIALITY AGREEMENTS should contain language making clear that the "tax treatment" and "tax structure" of the transaction are not confidential.

This is important if the parties want to avoid having to disclose the details of the transaction to the Internal Revenue Service. Revised corporate tax shelter regulations that the IRS issued in late February identify six broad categories of transactions that the agency considers potential tax shelters. Such transactions must be reported to the IRS. One of the triggers for reporting is where the transaction was "offered to a taxpayer under conditions of confidentiality." */ continued page 3*

CORRECTION

An article in the February *NewsWire* entitled "Lessons From Foreign Investment Disputes" said that a reason to buy political risk insurance for projects in some countries is that this gives the participants the ability to collect on an arbitration award if the government not only fails to honor its contractual commitments to the project, but also refuses to pay the arbitration award.

The article compared the experience of a geothermal project in Indonesia owned by CalEnergy that had political risk cover with the experience of other projects that did not. One of the other projects was the Karaha Bodas project in Indonesia. The article said that the facts surrounding the CalEnergy project and the Karaha Bodas project "start out virtually identical" and that the Karaha Bodas project had been awarded $261 million in damages by an arbitration panel against two government-owned entities in Indonesia in December 2000, but that Karaha Bodas was having to chase Indonesian assets all over the world in complex litigation to collect and that it still seemed "pretty far from recovering anything."

These comments and some of the other information about the Karaha Bodas project in the article were incorrect, according to a spokesman for the project. There are numerous dissimilarities between the CalEnergy and Karaha Bodas projects and the course of their disputes. Most importantly, Karaha Bodas has done much better at enforcing its arbitration award than the article suggested. According to a project spokesman, Karaha Bodas has been able to freeze funds in US banks far exceeding the amount of its award, and the ultimate disposition of these funds is still to be determined by US courts. The article, which was illustrating the advantages of political risk insurance coverage that pays compensation upon obtaining an arbitral award, should not have suggested that Karaha Bodas has not achieved positive results in its collection efforts. The article also said incorrectly that the Karaha Bodas Company was formed in 1994, principally by Caithness Energy and Florida Power & Light. According to a project spokesman, neither of these entities formed the company. Rather, it was formed, and is presently majority owned, by affiliates of these entities.. ◎

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The House and Senate tax packages have many common features that are virtually certain to be in the final bill.

Cogeneration

Both tax-writing committees voted for a nearly identical tax credit for new cogeneration facilities.

A "cogeneration" facility is a plant that produces two useful forms of energy from a single fuel. One of the outputs must be steam or another form of thermal energy. The other can be electricity or mechanical shaft power. The tax credit is 10% of the capital cost of the project.

To qualify, a plant must produce at least 20% useful thermal output, and it must have an energy conversion ratio greater than 70%. That means that the energy content of the electricity or mechanical power must be more than 70% of the energy content of the fuel used to produce it. (The conversion ratio must exceed 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 Senate committee waived both these requirements for plants that "generate electricity or mechanical power using back-pressure steam turbines in place of existing pressure-reducing valves or which make use of waste heat from industrial processes such as by using organic rankine, stirling, or kalina heat engine systems." The House did not provide for a similar waiver.

Some cogeneration facilities will get less generous tax depreciation in the future. Any project for which a credit is "allowed" cannot be depreciated faster than over 15 years using the 150% declining-balance method (or over 22 years using the straight-line method for a project that is financed with tax-exempt debt). This will affect cogeneration facilities that burn culm, gob and other waste fuels.

The credit can only be claimed on new plants that are put into service during a window period that runs through 2006. The House and Senate disagree whether the window period should start with enactment of the bill or on January 1, 2004. As currently drafted, the effective date is a cliff. A project placed in service on the effective date would qualify for a full credit. One placed in service the day before would receive no credit.

Section 45

The energy bill will extend an existing tax credit for generating electricity from alternative fuels.

The credit is currently 1.8¢ a kilowatt hour. It can be claimed currently by anyone generating electricity from wind, "closed-loop" biomass or poultry litter. The deadline for placing projects in service to qualify is December 2003. 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 and other plants that are grown exclusively for use as fuel in power plants.

Both tax-writing committees voted to extend the deadline for placing such projects in service to December 2006. (However, the House extended it only for wind and closed-loop biomass projects — not poultry litter.)

Both committees also voted to add to the list of eligible fuels.

The House bill would add three new fuels: "open-loop" biomass, landfill gas and municipal solid waste. "Open-loop" biomass is "solid, nonhazardous, cellulosic waste material which is segregated from other waste material" 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 agricultural sources. Municipal solid waste and paper that is commonly recycled are not considered "open-loop" biomass.

The Senate would add seven new fuels to the list of eligible fuels: "open-loop" biomass, livestock manure (and straw bedding), geothermal and solar energy, municipal biosolids, recycled sludge, municipal solid waste and small irrigation projects of up to five megawatts in capacity that generate electricity "without any dam or impoundment of water through an irrigation system canal or ditch."

Under both bills, owners of *existing* facilities that use open-loop biomass to generate electricity would be able to claim tax credits for five years after the bill is enacted. An example is a power plant that burns wood. The credits would be at two-thirds the normal amount.

There are numerous complicated special rules in each bill that will have to be reconciled in conference.

For example, the House would allow owners of existing power plants that run on landfill gas to */ continued page 4*

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In order to avoid this trigger, it must be clear that "the taxpayer's disclosure of the tax treatment or the tax structure of the transaction is [not] limited in any manner." However, there can be restrictions reasonably necessary to comply with securities laws.

The IRS suggested that it would be a good idea to have everyone who "makes or provides a statement, oral or written, to the taxpayer about the potential tax consequences" sign an express written authorization substantially as follows: "The taxpayer (and each employee, representative, or other agent of the taxpayer) may disclose to any and all persons, without limitation of any kind, the tax treatment and tax structure of the transaction and all materials of any kind (including opinions or other tax analyses) that are provided to the taxpayer relating to such tax treatment and tax structure."

The IRS wants such authorizations signed within 30 days after the discussions start with the promoter or adviser. When this is done, the deal will not ordinarily be considered confidential.

TRANSMISSION CREDITS receive a favorable tax ruling.

The Internal Revenue Service said in a private letter ruling in late February that a utility did not have to report amounts for which an independent power company reimbursed it for "network upgrades" as taxable income. "Network upgrades" are improvements to the transmission grid to accommodate another power plant. Utilities are required currently to collect the cost of such work from all users of the grid through the rates they charge for transmitting electricity. However, collecting this way takes time, so utilities ask the owner of any new power plant connecting to the grid to advance the funds for the improvements and promise that the amount */ continued page 5*

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claim credits for five years on the electricity generated. The credits would be at two thirds the normal rate. The project could not double up on tax credits by also claiming section 29 tax credits for producing landfill gas (as well as section 45 credits for generating electricity from it). Anyone with an existing landfill gas project should be careful that this ban against doubling up on credits does not inadvertently rule out section 29 credits on which the landfill gas producer was counting. Section 45 credits are claimed by a different party — the company that purchases the landfill gas and uses it to generate electricity.

The House would allow section 45 credits to be used to offset taxes that a corporation owes under the "alternative minimum tax." However, this would only apply to windmills that are put into service after the bill is enacted and then only for the first four years after the windmill commences service.

Lease financing is not used today for projects that qualify for section 45 tax credits. That's because the statute denies any credits at all unless the same company that owns the project is also the "producer" of the electricity. The problem with a lease is the lessor is the owner and the lessee is the producer. Therefore, no one would be allowed tax credits. The House bill would allow the lessee or a contract operator to claim section 45 credits, but only for open-loop biomass projects that are already in service when the bill is enacted.

The Senate bill is a patchwork of special limits that were put in to try to keep the cost of the measure within bounds. It is a case study in how many different groups were able to keep their issues in play for conference with the House by claiming small placeholders that they hope can be fixed later. For example, under the Senate bill, open-loop biomass projects would only qualify for credits if put into service by the end of 2004. Projects that use other fuels would have until 2006.

Geothermal and solar projects would qualify for only five years of credits — not the normal 10 years.

The Senate would freeze the tax credit at 1.8¢ a kWh for all new projects — regardless of fuel type — that are put into service after the enactment date. There would be no further inflation adjustments after 2003 for such projects. This would affect not only projects that use newly-eligible fuels, but also new wind projects.

The Senate would let tax-exempt electric cooperatives, municipal utilities, state and local governments and Indian tribes sell the section 45 tax credits on projects they own to other taxpayers for cash. However, credits could be sold only once. A rural cooperative would have the option to treat the value of its credits as a payment against any loans the cooperative has from the US Rural Electric Service.

Section 29

The energy bill will allow more time for taxpayers to place new projects in service to qualify for section 29 tax credits.

Such credits are an inducement for companies to look in unusual places for fuel. The current credit is $1.095 an mmBtu. Any new credits authorized by the bill will be only 51.7¢ an mmBtu. The House would adjust them for inflation starting with the credit amount for 2004. The Senate would not allow any inflation adjustment.

The bill will also allow additional credits to be claimed at a 51.7¢ rate on output from some existing projects.

The House bill would allow tax credits on output from new wells drilled through December 2006 that produce oil from shale or tar sands, or gas from geopressured brine, Devonian shale, coal seams or a tight formation. Output from existing wells would also qualify. Credits could be claimed on four years of output (but not past December 2009).

Landfill gas projects would also benefit. Gas from collection equipment put into service from July 1998 through December 2006 would qualify for five years of section 29 credits starting after the bill is enacted. (However, the credit would be only 34.5¢ for gas from landfills that are subject to new source performance standards that were issued in 1996 by the US Environmental Protection Agency.)

Taxpayers claiming credits under the House bill would be limited to credits on "average daily production" of 200 mcf over the tax year. An mcf is equivalent to 1.0276 mmBtus.

The Senate bill would allow credits to be claimed on output from new projects put into service after enactment through December 2006 that produce oil from shale or tar sands, gas from geopressured brine, Devonian shale, coal seams, tight formation *or biomass*. Credits could only be claimed for three years after a project is put into service.

The Senate would also allow section 29 credits for the first time for producing four additional fuels: liquid, gaseous or solid fuels from agricultural or animal waste, viscous oil, coalmine gas or "refined coal." Projects to produce these fuels would qualify if they are placed in service during a window period running from the enactment date through December 2006. Credits could be claimed only for three years on the first two fuels, only through 2006 on coalmine gas, and for five years on refined coal.

"Refined coal" is defined as "liquid, gaseous, or solid synthetic fuel" from coal or lignite or fuel derived from high-carbon fly ash. Two things would have to be true for output from a project to qualify as "refined coal." The nitrogen oxide, sulfur dioxide or mercury emissions from burning it would have to be at least 20% lower than the emissions from burning the raw coal used as feedstock, and it must have a "market value" at least 50% higher than the raw coal.

The Senate bill would also allow tax credits to be claimed through 2005 on output from existing coke batteries and coal gasification plants.

Prepaid Gas Deals

Some gas suppliers have been entering into long-term contracts to supply gas to municipal utilities. The utility prepays for the gas and is given a discount off the gas price for doing so. It borrows the funds to cover the prepayment in the tax-exempt bond market. The gas supplier gets access indirectly to money at tax-exempt borrowing rates.

These deals run afoul potentially of rules that bar a municipality from borrowing at tax-exempt rates and then reinvesting the proceeds in a commodity or other "investment-type property" that earns it a higher return than its cost to borrow. The discount off the gas price might be viewed as such an arbitrage profit.

The Internal Revenue Service proposed an exception from the arbitrage restrictions in April 2002.

The US Treasury Department is being actively lobbied to allow a similar exception for prepaid electricity deals — for example, where an independent power company signs a long-term contract to sell electricity to a municipal utility or electric cooperative.

Under the proposed IRS regulations last year, no arbitrage profit will be found as long as the municipal utility uses at least 95% of the gas to supply retail gas customers in its historic service territory or to generate electricity for customers whom it is required by federal or state law to serve. Its historic service territory is the area it served at all times during the five years leading up to when the tax-exempt bonds were issued.

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will be repaid through "transmission credits."

Some utilities worry that they must report the advances from generators as taxable income. The IRS ruled privately in February that they do not. The advances are a loan, and borrowed money does not have to be reported as income.

The ruling is important to any generators who would otherwise have been required by a utility to "gross up" their network upgrade payments for taxes. Such grossups can run into the millions of dollars. Any generator who already paid such a grossup should be entitled to its money back.

In the case addressed by the ruling, the utility awarded the generator transmission credits in the same dollar amount as its network upgrade payments. The credits could be used against future charges for wheeling electricity from the generator's power plant. Any credits that the generator was unable to use in this manner by an outside date were repaid in cash. The generator received back eventually not only its money, but also interest. The utility did not put the network upgrades into its rate base.

The IRS was initially "adverse" on a more difficult fact pattern, but is expected to rule that this more difficult case also involves a loan by the generator to the utility. In it, the utility does not repay the amounts with interest, and there is no deadline by when the full amount must be returned to the generator. The utility also puts the upgrades into rate base at inception when the upgrades are made.

In the meantime, the Federal Energy Regulatory Commission has ordered at least one utility to repay network upgrade payments to a generator — and to do so with interest — even though the interconnection agreement that the parties signed did not require this. It was an old contract. See related article beginning on page 8.

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The parties to such gas contracts usually also enter into a swap at the same time. Under the proposed IRS regulations, such swaps are okay as long as they are with third parties and the swaps stand as independent contracts. The swap will still be considered "independent" even though it terminates after a failure by the gas supplier to deliver gas for which the swap is a hedge.

Both tax-writing committees in the House and Senate voted to put an identical exception for pre-paid gas deals directly into the US tax code.

The exception would apply only to gas deals — not electricity.

Under it, the volume of gas secured by the prepayment in any year could not exceed the average annual gas volume purchased by retail customers of the utility or used by the utility to generate electricity for such customers — plus gas consumed to transport the gas. The testing period would be the five years ending before the calendar year in which the bonds are issued.

The utility would have to reduce the gas it is allowed to buy under the prepaid contract by any gas it has in storage on the date the bonds are issued and gas that it has a right to acquire during the contact term from other sources. This would include gas that the utility has under option. The parties could ask the IRS for a private letter ruling allowing a larger gas volume to accommodate expected population growth in the utility's service area.

Transmission Lines

The energy bill will allow utilities that dispose of their transmission and distribution lines and related assets to pay tax on any gain ratably over eight years. This is called an 8-year spread.

The idea is to reduce the pain to utilities of divesting themselves of their transmission lines. The Federal Energy Regulatory Commission is pressing US utilities to transfer operating control at a minimum — and ownership if they prefer — of their transmission assets to large regional transmission organizations that would operate whole sections of the grid independently. These transfers are supposed to occur by December 2004.

A utility would be able to take advantage of the 8-year spread only on transmission and distribution assets that it sells to a qualified buyer. It would have to sell them either to an RTO (regional transmission organization), ISO (independent system operator) or other independent transmission company that has been approved by FERC. Alternatively, it could sell them to someone else as long as that someone else is determined by FERC not to be a "market participant" — meaning that it does not own power plants in the area served by the portion of the grid that it is purchasing and it assigns operational control over the assets to the nearest RTO or ISO. (There are special rules for transactions in Texas because the state is not part of the national electricity grid.)

Assets would have to be sold by 2006 to take advantage of the 8-year spread under the House bill. The Senate bill would allow another year through 2007.

Under the House bill, the utility would have to reinvest the sales proceeds in other utility property within four years after the sale. The other utility property could include such things as a power plant or a gas pipeline or shares of another power or gas company. The reinvestment could be done through an affiliate.

The sale of a utility company that owns transmission or distribution assets would also qualify for the spread.

Depreciation

Electric and gas companies have been pressing Congress for faster tax depreciation for their assets.

The House bill would allow faster tax depreciation for electric transmission and distribution assets. They are depreciated over 20 years today. Such assets put into service after the bill is enacted could be written off over 15 years. The faster depreciation could be claimed on existing assets that someone purchases after the bill is enacted.

Senator John Breaux (D.-La.) was expected to ask for the same treatment in the Senate, but did not raise the issue in the Senate tax-writing committee. There is the possibility that it could be added to the energy bill as a "manager's amendment" when the measure is taken up on the Senate floor.

Both bills in the House and Senate would allow gas gathering lines to be depreciated over seven years using the 200% declining-balance method in the future. This has been an area of controversy with the IRS. The IRS has been insisting that gathering lines must be depreciated over 15 years. Duke Energy and the True Oil Company won the right to use 7-year depreciation in court. Clajon Gas Co., L.P. and Saginaw Bay Pipeline Co. lost their cases. There would be no inference under the bill about what was the correct treatment until now. Gathering lines are the pipelines at gas fields that bring gas from many different wells to a central collection point.

Both bills would also allow natural gas distribution lines — for example, the gas mains that a local gas utility uses to serve customers — to be depreciated over 15 years rather than the 20 years that is used currently.

The bills would allow the same tax depreciation for all these assets both under the regular corporate income tax and the alternative minimum tax.

Clean Coal

The Senate bill would provide new tax incentives for retrofitting or repowering existing coal-fired power plants — or for building brand new plants — with clean coal technologies. However, the provisions are almost impossibly complicated; they make a mockery of claims by Congress that it wants to simplify the US tax code.

There is no similar provision in the House bill.

There would be three different incentives.

The first is a production tax credit of 0.34¢ a kilowatt hour for generating electricity at existing coal-fired power plants that are retrofitted within the next 10 years to use clean coal technologies. Credits would be claimed on the electricity output for 10 years after a plant is returned to service. The plant could not have a nameplate capacity greater than 300 megawatts. Only 4,000 megawatts of capacity would qualify for this "retrofit" credit. Projects would have to be certified in advance by the Internal Revenue Service. The list of clean coal technologies includes advanced pulverized coal or atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion and integrated gasification combined cycle. The bill imposes other requirements, such as maximum heat rates and emission tests. The project could not have received any clean coal technology money from the US Department of Energy.

The Senate bill would also provide an investment tax credit for 10% of the capital cost of new or retrofitted clean coal plants. (A company whose retrofitted plant qualifies for the production credit of 0.34¢ a kilowatt hour could not also claim this credit.) A project would have to jump through a series of hoops to qualify. The hoops vary depending on the technology. For example, a plant using pressurized fluidized-bed combustion must be placed in service by 2016, and its heat rate and carbon emissions must / continued page 8

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SYNFUEL audits may start to wrap up this fall.

A growing number of projects that make synthetic fuel from coal are under audit by the IRS. The agency is looking at whether the projects qualify for section 29 tax credits. The credits on output at a single synthetic fuel plant can run $50 to $75 million a year.

The IRS will not say how many projects it has under audit currently, but a key member of the team that is coordinating the audits said that the agency expects to get to all projects eventually. At last count, 73 "coal agglomeration facilities" — or plants that make synthetic fuel by applying chemical reagents to raw coal — claim to have been put into service in time to qualify for tax credits. The deadline to be put into service was June 1998.

The IRS is focusing on three issues in the audits, the source said. One is chemical change, or the question whether the output from the projects is different enough from raw coal to qualify as a synthetic fuel. The IRS has not drawn any informal line in the sand. For example, there is no rule of thumb that there must be at least a 15% chemical change in order to qualify as a synthetic fuel. The agency is still formulating its position with the help of Dr. James Speight, an expert in coal chemistry at the University of Wyoming.

The other two issues are what had to have occurred by June 1998 for a plant to be in service and what is the "facility" in cases where a plant has been moved or sold to a new owner and its configuration or conveyor belts, motors and other equipment changed. The audit team has been getting guidance from the IRS national office on these issues.

The source was reluctant to commit to when the first audit will be completed. One taxpayer was told last year that its audit would be closed without any adjustment, but then the audit was reopened at the direction of the coordinating team. The source said he hopes the / continued page 9

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comply with standards set by statute. Only 500 megawatts of pressurized fluidized-bed combustion projects in total could qualify for the tax credit, and only 250 megawatts of such capacity put into service before 2009 would qualify. Projects would have to apply in advance to the IRS for confirmation they fit under the megawatt cap.

Finally, the Senate bill provides a production tax credit for the same projects that qualify potentially for the investment credit. This credit would run for 10 years. The amount would vary from 0.1¢ to 1.4¢ a kilowatt hour depending on when the power plant is placed in service and on its design net heat rate. Plants that produce fuel or chemicals from coal — rather than electricity — could also qualify. The credit would be claimed on each 3,413 Btus of fuel or chemicals produced.

Municipal utilities, electric cooperatives, Indian tribes and the Tennessee Valley Authority could also lay claim to some of the scarce credits. Since these entities do not pay taxes, they would be allowed to sell their tax credits for cash. However, the credits could only be sold once.

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 2004 to qualify. The Senate bill would extend this deadline by another year through December 2005. There is no similar provision in the House bill.

Fuel Cells

Both bills would encourage new investment in fuel cell power plants.

The Senate would allow a tax credit for 30% of the capital cost of such projects. However, the amount claimed as a credit could not exceed $1,000 per kilowatt hour of generating capacity. The fuel cell power plant would have to have a capacity of at least 0.5 kilowatts and operate at least at a 30% generating efficiency. Credits could be claimed on projects put into service through December 2007.

The House bill has the same provision, except that the tax credit would be for only 10% of the capital cost and the project would have to be placed in service a year earlier (by December 2006). ◎

Some Generators Are Owed Refunds

by Adam Wenner, in Washington

Some independent power projects may be owed refunds by utilities for amounts that the projects had to pay utilities for "network upgrades." The amounts involved may run into the millions of dollars.

"Network upgrades" are improvements that had to be made to the grid to accommodate another power plant.

The good news for generators is that the Federal Energy Regulatory Commission is willing to alter existing contracts to require such refunds.

An independent power project signs an "interconnection agreement" with the local utility agreeing to terms under which the project will be allowed to connect its power plant to the utility grid so that it can move its electricity to market. Such contracts require the generator not only to pay for any radial lines, circuit breakers and other costs of the "direct" intertie to connect to the grid, but may also require the generator to advance funds for any network upgrades that will also be needed to accommodate another power plant. Current Federal Energy Regulatory Commission policy is that the costs of network upgrades are not the responsibility of the generator, but instead should be borne by all users of the transmission grid. A utility may require an independent generator to advance the funds for network upgrades, but the amounts must be repaid over time through "transmission credits."

The bad news is that so far, the only situations where FERC has modified contracts entered into before the new FERC policy to require refunds of network upgrade costs are those where the contract has language allowing either party unilaterally to ask FERC to modify the rates the utility is allowed to charge for transmission.

Background

In 2001, as part of an effort to reduce impediments to the construction of new power plants, FERC adopted a policy that allocated the cost of improvements to the network necessitated by the addition of a new generator — so called "network upgrades" — to all transmission customers, rather than solely to the generator, as long as the new or upgraded facilities become part of the utility grid. Previously, and still, the cost of equipment that benefits only the generator, such as the line that ties a power plant to a transmission grid, must be borne by the generator.

Before 2001, FERC had used a "but for" test for determining what costs must be borne by the generator. Under this test, any costs that the utility would not have incurred "but for" the request by the generator to connect his plant to the grid would have to be borne by the generator.

Under the new policy, the cost of network upgrades that benefit all users of the grid are rolled into the rate base that the utility uses to calculate its transmission rates. The utility must return any amounts it collects from a generator for network upgrades through "transmission credits." This means that the utility allows the generator to claim the amounts as an offset against future transmission charges for wheeling its electricity across the grid. However, since many generators transfer title to the power they produce before it reaches the grid, the credits can usually be transferred to the customer, or the generator can opt to have the amounts refunded over time in cash. Some utilities have proposed transmission credit mechanisms that are nothing more than a plan to return the money over a few years in cash.

Originally, FERC did not require that interest be added to the amount of the transmission credits, but in response to complaints from generators, it now includes interest calculated at a FERC rate.

The effect of FERC's new policy is to require generators to finance, but ultimately not to bear, the costs of network upgrades. FERC explains its policy as an extension of its long-established "or" pricing policy, which permits utilities to charge users of its grid either average embedded cost rates or incremental cost rates, but not both. (Interestingly, FERC orders do not discuss the logical policy of requiring the party with the lower cost of capital initially to bear the carrying cost of the new equipment, which would be the most economically efficient approach.)

Recent Decision

In a recent decision involving power plants developed by subsidiaries of Duke Energy and interconnected to the Entergy transmission system, FERC clarified its policies on how it determines whether equipment is part of the direct intertie or a network upgrade. First, FERC confirmed that it will treat all equipment at or beyond the point where the generator connects to the grid as network */ continued page 10*

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first audit will close by September this year, and then the others will begin move in quick succession.

Six projects triggered their own audits by applying for "pre-filing agreements" under a program the IRS instituted in 2001. These six have now "leapfrogged" to the front of the queue, according to the source.

Meanwhile, the IRS announced on April 10 that section 29 tax credits were $1.095 an mmBtu for output during calendar year 2002.

DEPRECIATION BONUS issues should be addressed soon.

The United States offers a "depreciation bonus" as an inducement to companies to invest in new plant and equipment during a window period that started after the terrorist attacks on September 11, 2001 and continues through 2004 or 2005, depending on the investment. The bonus is 30%. In other words, a company can deduct 30% of its cost of the plant and equipment immediately. It depreciates the other 70% of the cost as it would normally. The tax savings from the faster depreciation are worth as much as 5.39% of the cost of a power plant.

Power companies had a number of questions about how the bonus applies to power projects. Most were resolved in a "blue book" that the staff of the Congressional Joint Committee on Taxation issued in late January. However, the industry has been waiting to see what technical corrections Congress makes to the statute and how the IRS addresses other open issues in regulations expected out this summer.

Regulations have been drafted, but have not been reviewed outside the IRS branch that handles depreciation bonus issues. However, Treasury officials — who must review the regulations for policy input — say they intend to get to them by late April or May with the aim of */ continued page 11*

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upgrades. In the Duke Energy cases, the network upgrades included a new, high voltage, 500 kilovolt switch station, upgraded circuit breakers, upgrades to transmission lines and substations, all located on the utility side of the interconnection point for the Duke power plants.

The Duke cases were complicated by the fact that, in accordance with prior FERC policy, Duke had signed interconnection agreements with Entergy that assigned the costs of all the equipment, including equipment that FERC now defines as network upgrades, to the generator rather than to the general body of transmission customers. Moreover, in what has become known as the "Hinds I" decision, FERC ruled initially that the parties were bound to the terms of their interconnection agreement and said the contract could only be changed if it were found adversely to affect the "public interest."

However, FERC later reconsidered its decision. In "Hinds II," it ruled that the interconnection contracts could and should be modified to conform to FERC's new policy of allocating the cost of network upgrades to all transmission customers, thus making available its favorable policies even to generators that had previously agreed to arrangements reflecting FERC's prior pricing policies.

Longstanding US Supreme Court interpretations of the Federal Power Act have left the door open for FERC to modify contracts where necessary to ensure that FERC-jurisdictional power sale and transmission rates are "just and reasonable." The court has held that where parties to a contract reserve the right unilaterally to request FERC to change a contractually-established rate, then FERC will review the proposed change under its normal standard, which is the same as that used for its initial review of rates, to determine if they comply with existing FERC policies. However, if the parties have waived their right to seek FERC review of their contract and have included so-called "Mobile-Sierra" terms (based on the names of two Supreme Court cases), then FERC will only consider requested changes to the rate if the proposed changes are necessitated by the public interest — for example, where the rate is so low that it would bankrupt the utility that agreed to charge the low rate. This is a much higher hurdle.

The contracts that Duke had with Entergy contained contractual language permitting either party to make a unilateral application to FERC for a change in the rates or other terms or conditions of the contract. As a result, FERC agreed with Duke that the lower "just and reasonable" standard for considering modification of the interconnection contract should be used, rather than the "public interest" standard that some courts of appeal have characterized as "practicably insurmountable." Since FERC found the allocation of network costs to the independent power project rather than to all grid users to be unjust and unreasonable, it ordered the contracts to be modified to reflect its current transmission cost allocation cost policies.

FERC later cited the "Hinds II" decision to require similar changes to an existing interconnection agreement between a subsidiary of Calpine Corporation and the Pacific Gas & Electric Company. Eleven Calpine subsidiaries reached agreements with PG&E that conform to the FERC's new policies requiring all transmission customers to pay the costs of network upgrades. However, a 12th subsidiary, the Delta Energy Center, had previously submitted its interconnection agreement to FERC and said in the filing that Delta's entitlement to credit for the cost of network upgrades resulting from its operations would turn on FERC's decision in the Duke Energy Hinds case. FERC review of Delta's contract showed that, like Duke Hinds, Delta had reserved the right to seek unilateral changes to its contract. The agency held that failure to provide Delta with credit for the network upgrades it would initially pay for would be inconsistent with FERC policy and, therefore, would not be just and reasonable. It ordered a change in the contract.

Implications

There are a number of implications from these decisions.

Any generator negotiating a new interconnection agreement should make sure that the agreement conforms to FERC's interconnection policy, which states that all upgrades beyond the point of interconnection are network upgrades the costs of which are the ultimately responsibility of the utility and its transmission customers.

As to contracts entered into prior to the FERC's new policy initiatives on interconnection, based on these FERC decisions, it is clear that any similarly situated generator — that is, a generator who agreed to bear the costs of what FERC now classifies as network upgrades and whose interconnection agreement expressly reserved its rights to seek unilateral FERC changes to its contract — will be accorded the same treatment. What is not clear is the prospect for convincing FERC to change the cost allocation in interconnection agreements where the generator waived its rights to seek unilateral FERC modification. Generators in such cases must satisfy the higher "public interest" standard to have a contract modified.

Ironically, many independent power companies favor having FERC maintain a "nearly insurmountable" standard against changing long-term power purchase agreements for the sale of electricity at a specified rate not subject to requests for unilateral rate changes. Utilities and California have tried to set aside contracts to buy electricity that were signed when electricity prices were high. If FERC were to establish a lower standard for contract modification of this type of contract in the transmission arena, the decision would haunt generators in their roles as power sellers. ◎

Banks May Face Unwanted Regulation If They Foreclose

by Lynn Hargis, in Washington

Lenders to distressed power projects are wrestling with the problem that they may not be able to foreclose on the project assets or take control of the special-purpose entity set up to own the project without subjecting themselves to government regulation as a utility.

The owner or operator of a power plant or power contract is considered a utility under certain federal laws. As long as the owner is a passive lender, it is not likely to be regulated, but once a lender takes active possession of a power plant or power contract, then utility status may result.

In addition, if a lender forecloses on voting stock of a project company that is considered a utility after a default, then the lender could become a "holding company" subject to even broader utility holding company regulation.

Finally, a federal regulator has recently determined that a company designating itself as a "financial adviser" to a power marketer that owns only electric power (and other) contracts, but no physical plant, is nonetheless an "operator" of such power marketer contracts, and therefore a public utility.

Big Deal?

What's the big deal if a bank becomes a / continued page 12

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publishing them this summer. There had been talk of delaying any regulations until Congress finishes revising the statute. Several "technical" corrections are expected. However, Treasury officials have decided not to wait. A meeting is expected with Treasury officials in May to review the remaining list of power industry issues.

The technical corrections to the statute are expected to include an "anti-churning rule" that would prevent a company with a project that does not qualify for a bonus — because construction started before September 11, 2001 — from trying to convert the project into eligible property by selling and leasing it back or by selling it before construction ends to a related party. An open issue has been how "related party" will be defined. The text of the technical corrections is expected to be released this spring.

Meanwhile, IRS officials say they have heard few companies are actually claiming the bonus. They attribute this to the slowdown in the economy.

The most common question the IRS is being asked about the bonus is how to elect out of it. Smaller companies do not want the bonus because it is not worth the trouble of keeping two separate accounts since many states do not allow the bonus to be claimed for state income tax purposes. At last count, 25 states have opted out of the bonus and another six states allow only a partial or delayed bonus.

FOREIGN TAX CREDIT relief is possible.

The United States taxes US companies on worldwide income. It allows credit — in theory — for taxes that were paid on the same income to other countries. However, the foreign tax credit rules are so full of fine print that many US companies are unable to claim such credits in practice. The biggest problem is something / continued page 13

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public utility? Arguably, a bank or other lender should not care if it is deemed a public utility as long as the relevant regulators employ "lightened" regulation as is the current federal trend. However, as discussed below, the Bank of America and UBS, both of which have chosen to become public utilities in order to trade in wholesale electric contracts, have found that even lightened regulation may be too burdensome for their purposes. In addition, a change in the political climate against deregulation could trigger a return to much "heavier" regulation of electric traders.

The potential regulatory consequences of foreclosure on an electric utility or stock are explained below.

Holding Company Act: SEC

Traditionally, the federal utility regulation most feared by non-utilities has been under the "Public Utility Holding Company Act," or "PUHCA," administered by the US Securities and Exchange Commission, which regulates the parent companies of utilities.

PUHCA regulation is to be avoided. Among other things, a parent company required to register with the SEC must divest its non-utility businesses — like banking! — unless they are "functionally related" to the utility business. . It must also limit its utility holdings to a single integrated system, thus precluding geographically widespread utility holdings. PUHCA also provides a comprehensive scheme under which the SEC regulates the corporate organization and financial activities, including acquisitions or sales, of utility parent companies that have to register with the SEC.

If a bank acquires 10% or more of the voting stock of a company considered a utility in the course of exercising remedies upon default of a loan agreement, then the bank will technically become a "holding company" subject to the PUHCA requirements to register and divest its non-utility businesses.

A bank can escape this consequence of foreclosure if the owner of the power plant has been declared to be an exempt wholesale generator, or "EWG." This exemption is found in section 32 of PUHCA. To qualify, the power company must be exclusively in the business of owning or operating a power plant that sells electricity exclusively at wholesale. EWGs are exempted from PUHCA, and the owners of EWGs do not become utility holding companies solely on account of such ownership.

Foreclosure on stock of most power plants considered "qualifying facilities," or "QFs," under PURPA also results in no PUHCA status, as long as the project remains a QF after the bank forecloses. No more than 50% of a QF can be owned by "electric utilities," "electric utility holding companies" or their subsidiaries, as defined in Federal Energy Regulatory Commission rules. Since banks are typically not "electric utilities," they can generally meet this requirement and own or operate QFs without becoming a public utility" or "public utility company." (However, see the discussion below about the Bank of America and UBS as "public utilities" for Federal Power Act purposes and, presumably, "electric utilities" for PURPA purposes.)

If a power plant owner whose voting stock is being acquired by a bank or other lender cannot qualify as an EWG (because the plant also sells electricity at retail or for some other reason) or as a QF, then PUHCA provides a temporary exemption from holding company status to a bank for purposes of liquidation or distribution in connection with a previously contracted bona fide debt. This PUHCA exemption — called a section 3(a)(4) exemption by lawyers — can be obtained by a bank for a period of two years by a simple filing with the SEC. Non-bank lenders, such as insurance companies, cannot use the same filing procedure as banks, but they can apply to the SEC for a temporary exemption for purposes of liquidation or distribution. Banks can also apply for a longer exemption extending past two years. In such a case, the filing of a "good faith" application would exempt the bank or lender until the SEC acts on its merits. (A "good faith" application has traditionally been considered one in which the PUHCA staff at the SEC has acquiesced, but be alert to any new SEC decisions on this question as the issue of what qualifies as "good faith" has been raised in a pending Enron-related PUHCA proceeding.)

In addition to regulating the upstream "owners" of a power plant or power contract, PUHCA also regulates the upstream "operators" of power plants. There is a difference between a typical operating and maintenance contract and status as an "operator" under the statute. If the "operator" carries out day-to-day plant decisions, but is ultimately responsible to someone else, receives a fixed fee or one with appropriate incentive payments rather than profits tied directly to electricity revenues and has no ownership interest in the utility, then the O&M contract will be considered simply a "service contract" that will not subject the contractor's parent company to holding company regulation.

To our knowledge, the SEC has never ruled that a power contract or other utility contract by itself is a "facility" under PUHCA, and its staff has issued numerous "no action" letters to the effect that a contract alone is not a statutory "facility." Thus, banks should be able to foreclose on and acquire the voting stock of electric power marketers that own only electric contracts, not power plants, without concern about becoming "holding companies" under PUHCA.

Federal Power Act: FERC

Financial entities, including banks, that have passive, lender-type interests in wholesale electric contracts (or transmission contracts) are not typically deemed "public utilities" under the Federal Power Act as long as they remain passive lenders. Lenders often obtain declaratory orders from the Federal Energy Regulatory Commission to confirm their non-utility status. The two-part test is that passive lenders must take no part in the ultimate control of the power company that is the borrower, and they must be primarily in a business other than the utility business (such as banking).

Once a lender forecloses and takes control of a power plant or power contract, the lender loses its passive status.

A power plant is not considered a "facility" for purposes of the Federal Power Act (because power plants are regulated by state commissions). However, unlike PUHCA, the Federal Power Act has been interpreted to provide for FERC regulation of entities owning power contracts that are on file at FERC. Thus, foreclosure that results in a bank acquiring only electric wholesale contracts of a power marketer or EWG will subject the bank to FERC jurisdiction. Transmission contracts, as well as transmission facilities, are also FERC-regulated facilities.

Unlike PUHCA, the the Federal Power Act has no specific provisions to exempt banks that foreclose on utility facilities, and EWGs are not exempted from FERC regulation, although that regulation is usually "lightened." Banks that have had to foreclose on utility plants or contracts can set up special-purpose subsidiaries to be regulated as "public utilities" that will hold the utility assets until the bank can sell them.

Public utility status under the Federal Power Act is far less onerous for a bank than "holding company" status under PUHCA because the former does not result in direct upstream regulation of parent companies. Indeed, the Bank of America and UBS have recently become "public / continued page 14

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called the "interest allocation" rules.

Up to 35¢ in credit is allowed for each $1 that a US corporation earns from foreign sources. The problem is US tax rules treat borrowed money as fungible. Thus, if a US parent company borrows large sums in the United States, part of the interest paid is considered a cost of its foreign operations in the same ratio as the company has its assets deployed in the US and abroad. Thus, a US company might earn $X million from its plants in Spain, but it will be treated as having earned much less after a share of its domestic borrowing costs is allocated to the Spanish operations. Many US companies have large overhangs of allocated interest expense that they must burn off — called "overall foreign losses" — before they will be considered to have earned even one dollar abroad.

Congress passed new rules — called "worldwide fungibility" — in 1999. The idea was the principle that borrowed money is fungible ought to apply both ways so that some foreign borrowing costs should be charged partly to US operations. However, the measure failed to become law. Congress seems unlikely to revisit the issue any time soon.

In the meantime, the US Treasury is receiving letters from US companies urging it to take steps on its own to help. Domestic interest expense is allocated currently in the same ratio as a company's assets are deployed at home and abroad by looking either at the relative fair market values of the assets or their "tax bases." Most companies use tax bases because they do not want the hassle of having to have their assets appraised every year. The problem with tax basis is US assets are depreciated more rapidly for tax purposes than foreign assets. This creates distortion: over time, the company looks like it has more foreign assets. The letter writers want Treasury to allow the same slower / continued page 15

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utilities" under the Federal Power Act as power marketers because of their ownership of power contracts. As a general rule, FERC waives its regulations or grants "pre-approvals" wherever possible for power marketers and others selling electricity at wholesale at market rates.

However, these banks have been required to make public, quarterly reports to FERC regarding their marketing activities. Moreover, FERC refused to pre-approve acquisitions by the banks of more than 1% of the securities of other companies considered public utilities without the banks applying to FERC for approval. Thus, these two banks have another step they must go through before foreclosing on borrowers in the power industry.

Also, FERC has in recent years extended its regulation to the upstream owners of public utilities to require FERC prior approval for sales or purchases that result in a change in control over assets that are subject to FERC regulation, such as power contracts. Although FERC approval is generally given for such sales or acquisitions, banks may not want to have to get prior FERC approval for their decisions.

The Bank of America and UBS have asked FERC to reconsider its refusal to grant them certain waivers and pre-approvals, indicating that without those, the banks would not find it worthwhile to enter the power trading business. FERC has indicated that it will act on the banks' request for a rehearing by April 14, 2003.

Other Comments

Just like the SEC does under PUHCA, FERC draws a distinction under the Federal Power Act between a statutory "operator" of assets that it regulates, and one who conducts operations as an agent pursuant to a "service contract," usually an operations and maintenance agreement. However, FERC recently found that a company that purported to be a "financial adviser" to a power marketer that owned power contracts was in fact the "operator" of those contracts. The problem was the entity was more than a mere financial adviser. It had sole discretion to enter into power contracts and to sell electric services on its own. It also owned computer programs to help it determine which contracts to enter. FERC concluded that this indicated the company was the "operator" of the power marketer's contracts and, thus, a public utility in its own right. (The power marketer was also considered a public utility for purposes of FERC regulation.)

There may be state law consequences to becoming an active owner or operator of a public utility, particularly one that sells electricity at retail. However, these consequences vary state to state and are outside the scope of this article. ◎

Argentina Relaxes Exchange Controls

by Aruna Spencer in New York, and Diego Serrano Redonnet and Fernando Zoppi with Pérez Alati, Grondona, Benites, Arntsen & Martínez de Hoz, in Buenos Aires

New Argentine central bank regulations relax some of the foreign exchange controls that were instituted by the Argentine government at the end of 2001 and early 2002 to address the country's economic crisis. Under these exchange controls, most of which are still in effect, transfers of foreign currency outside of Argentina require central bank authorization, with certain exceptions.

The new central bank regulations, issued during the first quarter of 2003, broaden these exceptions, among other things, to allow the payment of corporate profits and dividends and to ease the restrictions on debt repayment to foreign lenders.

In addition, the new regulations provide a termination date of August 8, 2003 for many of the transfer restrictions.

The central bank foreign exchange regulations issued since December of 2001 have been numerous and complex. Moreover, some regulations have expired by their own terms, some short-term regulations have been extended and other regulations have been repealed or amended. At the present time, the cumulative impact of these regulations on the ability of Argentine entities to remit foreign currency outside of Argentina to repay debt or pay dividends prior to August 8, 2003 can be generally understood in the framework set forth below.

Principal Payments

Payments of principal in foreign currency to foreign lenders require central bank authorization unless the loan falls into one of the following seven exceptions:

1 The loan was disbursed and brought into the local financial system after February 11, 2002.

2 The loan was made by an international organization or by banks participating in transactions co-financed by an international organization.

3 The loan was made or guaranteed by an official credit agency or export credit insurance company that is a member of the International Union of Credit and Investment Insurers.

4 The loan was made or guaranteed by a multilateral credit organization of which Argentina is a member or that is party to an agreement affording "most favored nation"-type protections to the multilateral credit organization.

5 The loan was restructured and the restructuring was approved by a court or was effected in accordance with central bank guidelines. A restructuring complies with the central bank guidelines only if it satisfies four tests. First, the restructuring must be evidenced by a restructuring agreement executed after January 2, 2003. Second, it cannot provide for payment of more than 10% of the outstanding principal at the date of execution of the restructuring agreement, more than another 5% of the outstanding principal within the first six months after signing, or more than another 5% in the following six months. Third, the restructured principal must have an average life that is at least five years longer than in the original loan. Finally, the restructured debt must involve notes, bonds or commercial paper, a foreign bank syndicated loan, a foreign bank loan that is not secured by the offshore assets of the debtor or another Argentine entity, or an intercompany loan by an affiliate outside Argentina.

In addition, if before principal is repaid under the existing loan, the local borrower refinances the debt on or after December 26, 2002 through the foreign exchange market and this new financing has an average life of at least five years and is for an amount equal to at least the amount of the original loan, then the conditions in this "restructuring exception" will be deemed met. Therefore, no prior authorization of the central bank will be required.

6 The payment is overdue and the principal amount to be repaid does not exceed US$1 million a month. (This threshold reflects a March 13, 2003 increase by the central bank in the permitted monthly payment, which previously was only US$150,000.) The borrower must make a sworn statement that the repayment complies this rule.

7 The payment is overdue and relates to an obligation that did not exceed US$5 million on December 31, 2001, including both overdue and outstanding / continued page 16

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depreciation to be used for US assets solely for purposes of allocating interest expense.

Michael Caballero, a Treasury lawyer, said the government is studying the suggestion, but no decision has been made yet. The fact that the issue is not on the IRS business plan for this year would not prevent the government from acting.

Meanwhile, the Treasury is also being pressed to adopt worldwide fungibility on its own — without waiting for Congress to act. Ken Kies, a former staff director of the Congressional Joint Tax Committee, argued in an article in the influential *Tax Notes* magazine in late March that the Treasury has authority on its own to ignore the interest allocation rules that Congress wrote into the US tax code. Treasury is not convinced.

Kies cites a statement in section 864(e)(7) of the US tax code granting the IRS authority to flesh in details of the interest allocation rules and even to decide that they "shall not apply for purposes of any provision of this subchapter to the extent the [IRS] determines that [their] application . . . for such purposes would not be appropriate."

NEW TAX TREATIES — or protocols to existing treaties — between the US and the United Kingdom, Mexico and Australia reduce withholding taxes on repatriated earnings.

The new income tax agreements were ratified by the US Senate in March. Anyone with projects in these countries should probably take another look at the ownership structure to make sure it still makes sense given the reduction in withholding rates.

The new treaty with the United Kingdom waives withholding taxes altogether on dividends paid by a UK subsidiary to its US parent — or vice versa — in cases where the parent owned 80% or more of the voting stock of the subsidiary for the 12 months before the dividend was / continued page 17

Argentina

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principal installments. (This threshold reflects a March 27, 2003 increase by the central bank from the previous threshold of only US$3 million.)

Interest Payments

Under a new central bank regulation issued on March 13, 2003, payments of interest in foreign currency to foreign lenders must be authorized by the central bank unless the payment is made no earlier than 15 days before the due date for the amount. Before this new regulation, a borrower had to wait until three days before the due date to make an interest payment. Certain other ministerial requirements may apply, such as verifications that the payments relate to genuine debt, but the existing regulations do not provide detailed information about all of these requirements.

Dividends

One of the more significant changes in the exchange controls, effected by a central bank regulation issued January 7, 2003, is the elimination of the restrictions on corporate profits and dividends payable by Argentine entities to entities outside of Argentina. Argentine entities may now freely purchase foreign currency and transfer it outside Argentina as corporate profits or dividends to the extent such payments are supported by audited financial statements.

Impact

Most of the exceptions to the general requirement of central bank authorization for transfers of foreign currency outside Argentina already existed before 2003. While the removal of restrictions on corporate profits and dividends is important for foreign shareholders, the changes to the restrictions on debt repayment provide limited relief to foreign creditors. Further, despite a February 2003 central bank regulation providing that many of the exchange controls implemented since December 2001 will be lifted on August 8, 2003, there can be no certainty that this termination date will not be extended.

Although the impact of the new regulations may not be dramatic in comparison to the continuing effects of the sweeping foreign exchange restrictions and emergency legislation previously enacted by the Argentine government, the new regulations, implemented in response to international pressures to normalize the country's financial system, may presage future regulations that eliminate other exchange controls with potentially greater import for foreign investors. ◎

FERC Signals Contracts Are Safe

by Adam Wenner, in Washington

A majority of commissioners on the Federal Energy Regulatory Commission suggested at a meeting in late March that the agency is unlikely to set aside contracts that independent generators and power marketers signed to sell electricity to a state agency in California in 2001 when electricity prices were at their peak.

California has asked FERC to set aside the contracts on grounds that electricity prices were artificially high at the time because of "gaming" of the electricity market.

Background

The Federal Energy Regulatory Commission ruled at the end of March on several cases involving alleged market manipulation in California. While the commission focused mainly on whether to order electricity suppliers in California to make refunds to the state on grounds that they had overcharged for electricity, the commissioners — discussed their views about requests by California for FERC to use its authority under the Federal Power Act to modify or cancel contracts for long-term power supplies entered into in the first half of 2001.

The contracts, which were requested by the state in two requests for bids, were priced on the basis of forward curves, which are projections of future prices, used by power sellers and buyers to estimate future electricity prices. After the contracts were executed, projected future prices dropped, and today are significantly below prices projected in the first half of 2001. A year after the contracts with the state were signed, the California Energy Oversight Board and the California Public Utilities Commission filed complaints at FERC in which they charged that the contracts were excessive. California requested that the commission modify or cancel the contracts.

At issue in the FERC proceeding is the question whether FERC can and should exercise its authority under section 206 of the Federal Power Act to modify the challenged contracts.

That section provides that if FERC finds the rates, terms or conditions in a wholesale power sale or transmission contract are not "just and reasonable," it must revise the contracts so that they are just, reasonable and not unduly discriminatory.

Unlike other federal regulatory laws, the Federal Power Act does not require that uniform rates be charged for electricity sales or for transmitting electricity across the grid. Instead, it relies on voluntary contracts entered into by willing sellers and purchasers of power or transmission services to set prices. While recent FERC orders have required transmission system owners to provide nondiscriminatory service to all customers seeking service, power sales remain voluntary and the prices for such sales are established by contract between buyers and sellers. While the Federal Power Act grants FERC the authority to modify voluntary contracts, its longstanding policy has been not to modify contracts where the parties agreed to allocate the future risks and rewards of a transaction, but expectations changed and one party no longer finds the deal to be favorable.

Electric utilities are free to and often do sign contracts in which they reserve the right under section 205 of the Federal Power Act to file requests to increase rates over those established in their contracts. Similarly, customers may retain the right to ask FERC to reduce the contractually-established rates. However, particularly when contracts formed the basis for funding new facilities, sellers and buyers can waive their rights to request FERC to change the rates or terms of their contracts. In two cases in which utilities sought to increase rates in violation of their agreement to waive their rights to do so, the US Supreme Court ruled that their rate filings were invalid. It held that where sellers and buyers waived these rights to seek changes to their contracts, FERC still retained the authority to modify the contracts, but only if FERC found that failure to do so would be against the "public interest" (as opposed to the private interests of the buyer or seller). This type of contract is called a "Mobile-Sierra" contract, based on the names of the Supreme Court cases that established this interpretation of the Federal Power Act.

Several of the contracts between power suppliers and California explicitly prohibit the parties from unilaterally requesting FERC to alter the contract. They also direct FERC to use the higher "adverse-to-the-public-interest" standard for reviewing a proposed change to the contract. Other contracts are silent, but none expressly reserves the rights of the seller or the purchaser to seek rate or contract */ continued page 18*

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declared. The parent must also have owned at least 80% of the voting stock before October 1998. It could have done so indirectly.

The United States agreed to the same 0% withholding rate for dividends between US and Mexican companies as in the UK treaty. In other words, the parent company must have owned 80% of the voting stock in the subsidiary before October 1998 and also in the 12 months leading up to the dividend. (The US promised Mexico earlier that if it adopted a withholding rate below 5% in a treaty with another country, it would extend the same benefit to Mexico.)

The Senate also ratified a protocol to the US tax treaty with Australia. The protocol eliminates withholding taxes on dividends between US and Australian companies. The only requirement is the parent company must own at least 80% of the voting stock of the subsidiary paying the dividend in the 12 months before the dividend is declared. There is no requirement that it must also have owned shares before October 1998. The new Australian protocol also eliminates withholding taxes on interest paid to any financial institution that is unrelated to the borrower.

The Australian protocol also removes rents paid under cross-border equipment leases from the definition of "royalties." This has the effect of eliminating withholding taxes on rents and rendering them taxable to the lessor in the country where the lessee is located only if the lessor has a "permanent establishment" in that country.

TEXAS inched closer to shutting a loophole.

Most companies with projects in Texas set up limited partnerships to own them. The state franchise tax does not apply to limited partnerships, but rather is collected directly from the partners. However, out-of-state companies that are limited partners are not taxed because they are */ continued page 19*

California Contracts

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term changes from FERC.

The California challenges to the contracts signed in 2001 to buy electricity for terms up to 11 years require FERC to address this issue once again. The agency will also have to determine what weight to give to the contractually-established bargain struck by the parties, in a scenario where the prices reflected in those contracts, while extensively praised by the California officials who negotiated them at the time, are no longer viewed as favorable to the state.

FERC Signals

Two of three FERC commissioners suggested in a public meeting on March 26 that they do not intend to set aside the California contacts.

The chairman, Pat Wood, said he agrees with the FERC staff's view that contract sanctity is vital to the industry and suggested the evidence presented so far by California does not constitute a basis for abrogating the contracts. This is consistent with other signals that FERC has given in the case to date. For example, the order the commission issued setting the case for hearing referred to FERC's "long-standing policy" of recognizing the sanctity of contracts. In an April 2002 order, FERC observed that preservation of contracts "has become even more critical" today, since "competitive power markets simply cannot attract the capital needed to build adequate generating infrastructure without regulatory certainty."

The power suppliers and marketers who signed contracts to sell to California and the FERC staff have taken the position in the proceeding that a decision to set aside the contracts would complicate the financing of future power projects. No lender could be certain that the deal the seller struck to sell electricity will last for the full term of the contract. Such a result would be ironic, since the lack of sufficient supply is acknowledged by all of the California parties to have played a substantial role in the spot-market price increases that the long-term contracts were intended to remedy.

Meanwhile, California argues that the power shortages and extremely volatile spot-market prices at the time it agreed to the contracts were extraordinary market conditions that are not likely to recur. A FERC decision to revise the contracts would be a non-recurring remedy to unique circumstances.

Another FERC commissioner — Nora Brownell — said at the March 26 meeting that the contract price is not the only consideration in the analysis, and that the "societal costs" of unwinding a contract must be compared to the benefits of contract modification. She emphasized that contracts form the very basis of the economic system, and also are the underpinning of "infrastructure investment," including "generation vital to the market." She noted that the parties who entered into the contracts were sophisticated and experienced in the power industry, and the fact that California signed contracts and then waited a year to complain about them influenced her view that its complaints should be viewed with skepticism. A more convincing case is made if a party concerned that the other side has undue market power does not wait, but instead files a complaint with FERC simultaneously with the execution of a contract.

The chairman, Pat Wood, said he agrees with Brownell, but wants to finish reading the large volume of materials submitted in a government investigation of alleged market manipulation in Western markets before making a final decision.

Wood and Brownell are the two Republicans on the commission. There is only one Democrat, Raymond Massey. Two other commissioner slots are vacant.

In contrast, Massey said concerns about the sanctity of contracts must be balanced against the staff's finding that flaws in the California spot market carried over to prices in contracts with terms of one and two years. The staff found that prices in longer-term contracts were not materially affected by problems in the spot market.

The commissioners also talked at the meeting about the standard that must be met under the Mobile-Sierra doctrine to justify modification of a contract in which the seller and buyer had agreed to waive their rights to seek changes to the agreed-upon contract rate or terms. Wood and Brownell said they would permit contract modification only on a showing that the contract had a significant adverse financial impact on the purchaser as well as on the purchaser's end users, that the contract was a significant part of the purchaser's portfolio, that the purchaser had no alternative sources of supply (including from other generators), or that other adverse circumstances existed contemporaneously with entering into the contract, and that the purchaser complained to FERC in a timely manner.

A formal decision in the California case is expected this spring. If the decision is consistent with the discussion at the March 26 meeting, then it will be good news for lenders and investors in project-financed energy projects, as the revenue stream for such projects is derived from rates established in contracts. ◎

Current Issues in LNG Projects

Many people expect LNG projects to become an active area of project finance in the next several years. Chadbourne hosted a well-attended workshop on the subject in Houston in February. The following are excerpts from the discussion. The speakers are three Chadbourne lawyers: Dan Rogers, David Schumacher and Noam Ayali. Rogers has years of experience with LNG, some of it as an assistant general counsel at Enron. Schumacher is a longtime project finance lawyer with a special interest in gas projects. Noam Ayali spent several years as a lawyer at the International Finance Corporation in Washington working with the oil and gas division before joining Chadbourne. A detailed outline of the issues in LNG projects can be obtained by sending an e-mail to nayali@chadbourne.com.

MR. ROGERS: I have been designated to give you some key definitions.

"LNG" probably should stand for "little or no golf" — an apt description of the lifestyle of those of us working in the natural gas industry — but its more common use is liquefied natural gas. This is gas that is carried across the ocean on tankers in liquid form and then turned back into gas when it reaches the terminal. The reason it has to be liquefied is because this is the only way at the moment to transport natural gas long distances across oceans. You need a terminal at the other end to convert it back to gas.

"NIMBY" means "not in my backyard." It is a term heard not only by power plant developers, but also by developers of LNG projects. However, in the LNG world, we also have "BANANA" — "build absolutely nothing anywhere near anything." It is one thing to build a power plant in the desert or another place inland where few people are located. You can imagine the siting problems of trying to put an LNG terminal along a coast.

Indeed, the latest acronym is "NOPE," or "not on planet Earth." This describes the position of some of the more extreme environmental and safety groups / *continued page 20*

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viewed as having an insufficient "nexus" with the state to subject them to tax.

The legislature is moving to tax limited partners. Three bills have been introduced — two in the House and one in the Senate. All three would impose a tax retroactively to January 1, 2003. The bills remain controversial, and the legislature is scheduled to adjourn for the year on June 2. It is a close call whether anything will be enacted, according to sources in the state government.

Meanwhile, power companies are pressing for relief from an accounting problem. A company must record as a "deferred tax liability" on its books the difference between the "tax basis" and the "book basis" that it has in its assets. The tax basis is usually lower. The company multiplies the gap by the state tax rate to which it is subject. Thus, if it has a tax basis in an asset of $100 million, but a book basis of $200 million, and the state tax rate is 4.5%, then it would have a deferred tax liability of $4.5 million. This is recorded as an expense. It reduces book earnings. It also appears on the balance sheet as a liability (an additional debt that it will have to pay one day to the state).

Out-of-state companies that invested in Texas projects as limited partners have not been recording any deferred tax liability because their state tax rate was 0%.

If the law changes this year, then they will suddenly have a deferred tax liability show up on their books for the full difference between tax and book basis. This will be a big charge to earnings in a single year.

They want relief from the legislature and are proposing that the amount of the deferred tax liability on December 31, 2002 would become a special "Texas asset" that they would amortize over 30 years for tax purposes. In other words, they would get a tax deduction in Texas spread over 30 years for the amount of the deferred tax liability. Since the company / *continued page 21*

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toward LNG import terminal development plans.

Noam Ayali will describe how deals for LNG import terminals are structured.

Structures

MR. AYALI: There are two key project structures in the market today, and there is a potential third structure that I will call the "fully-integrated LNG import project." We recognize that there really is no third structure yet in the market, but I offer it as something to think about. In a recent discussion with the head of an oil and banking house, this third structure came up and this particular banker thought it might offer a new way through the financing maze for LNG projects.

That said, the focus today is on the two types of LNG import projects. One is called the "downstream integrated import project." Examples of this are the Dabhol project in India, the recently financed AES Andres project in the Dominican Republic, EcoElectrica in Puerto Rico, and most of the Japanese LNG projects. A "downstream integrated import project" is one where the import facilities are tied to one or more specific offtakers, like a power plant, a gas pipeline, or a seawater desalination plant. What distinguishes this type of project is there is common ownership of all the different components of the project, either under a single owner or affiliated ownership within a single group.

The choice of structure has implications for the financing. The key thing to remember in what we are calling the downstream integrated project is that the offtaker is the LNG purchaser, and the LNG supplier, the transporter and the private lenders are all looking to the integrity of the project and the offtaker's end market as the credit support for the financing.

The other common structure for LNG projects is the "standalone or tolling project." Examples are the existing LNG facilities in the United States — at Lake Charles, Elba, Cove Point and Everett. Also, some of the new projects that are being considered by folks like Freeport LNG are this type of project. What we are talking about is an LNG import facility that is designed to serve one or more independent capacity users. The distinction is that the facility owner is not the LNG purchaser, and he is not necessarily the end marketer or end user of the product. You have capacity users paying a tolling fee for access and usage of the storage vaporization and sendout capacity of the receiving terminal. A lender lending into this type of structure must be satisfied with the strength and duration of the charges under the throughput capacity agreement, the reservation charges and the send-out capacity. Another example of a standalone tolling structure is the recently proposed Dynegy Hackberry project. *[Ed: Sempra Energy recently acquired the project from Dynegy]*.

Let me turn next to some general issues in financings, and then we will get into the meatier part of the discussion about LNG-specific issues. What follows is important because it ties into how best to set up a project and coordinate efforts with partners. Some of what I am about to cover probably relates more to jurisdictions outside the United States.

First point: as you are assembling your consortium, find out whether there is specific petroleum legislation and whether there are specific LNG regulations. Also be aware of the political environment and expropriation history. Venezuela is a recent example of what can go wrong, even though the actions there affected only the liquefaction side of projects.

Next point: let's talk about partner selection and due diligence issues. There are often legislative requirements for local partners. This will affect financeability, as there is a danger that the local partner's credit will effectively become the lowest common denominator for your project finance lenders. Be aware that if the local partner is a state-owned entity or host government, it may have restrictions on its ability to grant security interests because of World Bank lending arrangements. Be sure to vet at an early stage in the development arrangements any differing objectives within the sponsor group. For example, one member of the group may be interested only in the fuel supply arrangements. Another may be interested in owning assets. This will affect how issues like sponsor withdrawals, and sponsor rights and obligations are addressed. This needs to be hashed out at a very early stage.

MR. ROGERS: Let me give you a real-life example of the types of problems that can arise when members of the sponsor group have different objectives. Not very long ago, I worked on a fairly large gas pipeline development project where — as a result of a merger — we wound up with a foreign oil major as a partner who was not terribly interested in project financing and saw no need for leverage. As time passed, we found ourselves doing detailed risk analyses with the aim of using project financing, and our partner could not see any value in the exercise. It planned simply to write a check for its share of the project.

The disconnect began to color the relationship among the parties. Things eventually deteriorated. The point is to make sure you are all on the same page, especially about whether project financing will be used.

MR. AYALI: Maybe the last point to make about the preliminary project development arrangements is the choice of local partner may bring into play US Foreign Corrupt Practices Act, transparency and corruption issues. A US developer can be held accountable under the Foreign Corrupt Practices Act for malfeasance by his partners. If the project intends to buy political risk insurance, malfeasance by one of the partners could be grounds for the insurance company to refuse to pay a claim or to terminate the coverage.

That's a 30,000-foot view of some preliminary issues. Now let us move into more LNG-specific issues.

US Onshore Projects

MR. SCHUMACHER: I am going to start with permitting issues. I will talk first about US onshore facilities and the regulatory regime that applies to them, then discuss US offshore facilities, and then talk about the regulatory regime for receiving terminals in Mexico.

Starting with US onshore terminals, as is the case with interstate natural gas pipelines and storage facilities, the Federal Energy Regulatory Commission also has jurisdiction over the siting and construction of gas import and export facilities, including LNG receiving terminals. FERC has essentially regulated LNG import facilities the same way it regulates interstate natural gas pipelines. This is true from a siting perspective and construction perspective as well as the perspective of terms of service. Thus, when determining whether an LNG facility is in the public interest to construct, FERC has applied the same essential standards for determining whether it should issue a certificate for construction of an interstate pipeline. This means applying a cost-benefit analysis or balancing the benefits of a project versus the adverse impacts of the project.

FERC has required LNG receiving terminals to charge cost-based rates, unless there is a showing that the terminal does not exercise market power. This is the same approach it uses for natural gas storage facilities. It requires that there be on file tariffs setting forth the terms and conditions of service. An LNG terminal must provide service on an / continued page 22

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would be able to deduct the same amount as the deferred liability — albeit over time — the two would cancel each other out. There would be no expense or liability to record on the books.

Utilities were given relief from the same problem when they were first subjected to income taxes in other states like Virginia, New Jersey, New York and Ohio.

SALE-LEASEBACKS are becoming more challenging.

Lessees should be careful in sale-leasebacks of power projects not to assign the lessor a contract to sell electricity from the project or pledge such a contract to the lessor as security to support the rents and other lease obligations. Accounting firms are taking the position that this will rule out off-balance sheet treatment for the lease financing. The only arrangement with which the accountants seem comfortable is where the lessor has a pledge of *shares* in the lessee to secure the rents. The lessee can then agree to a covenant not to sell or assign the power contract. The same analysis applies to tolling agreements.

Off-balance sheet treatment will also be a problem if the accountants view the power contract or tolling agreement as, in substance, a sublease of the power plant to whomever is buying the electricity. (For a detailed discussion of the sublease issue, see an article by Leslie Knowlton and Henry Phillips of Deloitte + Touche in the April 2002 NewsWire.*)*

ROTABLE SPARE PARTS can be depreciated

The IRS said in late March that it will let equipment vendors that keep on hand a pool of spare parts to use in servicing customer equipment claim tax depreciation on them without waiting until the parts are put to use. However, this only applies where the parts of "rotable." That / continued page 23

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open-access basis, which means that available capacity must be offered to persons regardless of the source of gas supply.

This approach to regulation has arguably stymied investment in LNG terminals because of the way projects are financed. An LNG project requires long-term commitments to purchase and sell gas and to store it so that it can show potential lenders it has a sure revenue stream to repay the debt.

FERC made an important change recently in an order relating to [Sempra's] Hackberry facility. It signaled with that order that it is willing to dispense with the requirement that terminal operators of new onshore facilities have on file tariffs and charge cost-based rates. Rather, they will be allowed to charge market rates. Operators of new onshore terminals will be allowed to negotiate whatever terms of service they can work out with customers, including rates. And most importantly, the capacities of these new terminals do not have to be subscribed or contracted for on an open-access basis.

What FERC has done in essence is to decide that an LNG terminal should be treated more like a gas production facility than a mere storage facility or pipeline. It must have concluded that because wholesale gas prices have been deregulated for some time now, so too should LNG prices and LNG terminal users can recover costs through the sales price of the gas. This is appropriate because the developer is assuming the risk that it will be able to recover its cost. Also, with the enactment last fall of the "Maritime Transportation Security Act" — which allows so-called proprietary terminals — FERC figured that those proprietary terminals and other onshore terminals should be treated the same.

FERC has retained the authority to remedy future discrimination. It also requires that contracts between affiliates — for example, the sponsor and an affiliated offtaker — be filed.

FERC has probably created more questions at this point than it has answered. One that comes to mind is: what about existing facilities? There is now a dual regulatory regime — one for existing facilities and one for new facilities.

MR. ROGERS: The Hackberry decision didn't purport to supplant the existing regulatory structure. It merely provides developers with another option for how to develop an LNG terminal. Existing facilities remain subject to stricter regulation. It is unlikely the Hackberry decision can be used as grounds to change existing contracts.

MR. SCHUMACHER: An interesting question is whether the owner of an existing project might be able to build an expansion facility and cite Hackberry to charge market rates for use of it. The danger is the regulators might view the expansion as part of an integrated facility.

Another question with no answer yet is whether there is anything in the Hackberry decision that could justify different treatment for terminals in other parts of the country — the Hackberry project is on the Gulf coast — or for projects with offtakers that are affiliates of the sponsor. One of the ways FERC justified the Hackberry decision was by pointing out that the project will operate in a competitive gas market. Can the same thing be said of a project on the East coast in the Northeast?

MR. ROGERS: I'm not sure. I think the market power analysis that FERC used in the Hackberry decision works when you are talking about terminal facilities at the inlet of the gas production and gas supply system where there are a lot of alternatives and a lot of transportation and storage infrastructure. A single terminal owner would probably have a lot less ability to exercise market power in such a location than he would on the East coast.

MR. SCHUMACHER: The Hackberry order does not address this, but it raises the question whether it is possible to draw a related gas pipeline under a Hackberry-type order so that market rates can be charged for the use of it.

MR. ROGERS: That's correct. In December 2001, there was an attempt to try to get transportation service on the Cove Point project's send-out pipeline. It is an 80-mile-plus pipeline. The challenging party was trying to get the cost of the LNG service decoupled from the cost of pipeline transportation. FERC rejected the challenge on the basis that the send-out pipeline was integral to the LNG facility and that by splitting it out, you may wind up encouraging the use of the pipeline to the detriment of the LNG facility. FERC wanted to ensure the economic integrity of the LNG facility.

MR. SCHUMACHER: Another point: in addition to getting FERC approval to site the project, the importer of the LNG must also ask for authority from the US Department of Energy to import the LNG. This is essentially a rubber-stamp approval. It is essentially a reporting requirement. A DOE official said at a conference recently that approvals take about a week.

Next, we want to talk about US offshore projects, and in particular the new Marine Transportation Security Act, which amended the Deepwater Port Act and basically brought offshore LNG terminals under a new set of rules.

US Offshore Projects

MR. ROGERS: That is a mouthful. I am going to refer to the Maritime Transportation Security Act as MTSA.

Last November, the LNG industry received two early Christmas presents. One was the Hackberry decision, and the other was MTSA. MTSA essentially established the United States Coast Guard as a one-stop shop for purposes of applying for authorization to site, construct and operate offshore gas and LNG terminal facilities. The statute also applies to compressed natural gas or CNG facilities.

The Coast Guard was part of the US Department of Transportation. It has now moved to the new Department of Homeland Security. The statute requires the Secretary of Transportation, who used to oversee the Coast Guard, to make certain regulatory decisions. My understanding is that he will continue to do so, notwithstanding that the Coast Guard has been moved to Homeland Security.

The good news is that MTSA is an improvement over the regime for land-based terminals. There is more certainly about the application process. If you get all the paperwork in and the Coast Guard determines that it is in order, then you should know within 351 days from when the complete application was filed whether you will be granted an offshore terminal license. Compare that to onshore terminals, where the process can take a year and a half to two years. So that is a great improvement. It is something that would be nice to have on the onshore side as well.

The governors of the affected coastal states must also give approval before the license can be issued. MTSA sets a time limit for this approval. The Coast Guard will have 90 days after public hearings on the license application to be in contact with the governors of the affected coastal states.

Shifting to economic regulation, offshore LNG terminals are now authorized to be operated on a proprietary closed-access basis. This means they can charge market rates rather than rates that are tied to cost of service. Surplus or excess capacity can be let out to third parties provided that it's let out on reasonable terms and the third-party usage doesn't interfere with the original licensee's usage plans.

There is also a citizen complaint procedure. This may provide some bargaining leverage for potential users of excess capacity in the future. Such users */ continued page 24*

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means the vendor replaces a defective part using one from the pool and then puts the defective part into the pool, after it has been repaired, for reuse with another customer. The IRS announcement is in Revenue Ruling 2003-37.

MINOR MEMOS: Arkansas is considering replacing its corporate income tax with a gross receipts tax for companies selling electricity or natural gas. The state taxes corporations currently at a 6.5% rate on net income. The gross receipts tax would be at a 4% rate on "proceeds from all sales" of electricity or natural gas. The state legislature is scheduled to adjourn on April 17, but the session could be extended . . . . The IRS issued regulations in March that would deny a parent company the ability to claim a loss on the sale of shares in a subsidiary. The regulations — called the "dual consolidated loss rules" — would deny losses where a parent company sells a subsidiary that was part of the same consolidated group for tax purposes in circumstances where there is the potential for the same loss to be claimed twice.

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

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could complain to the Coast Guard that they are not being treated reasonably. It would not surprise me to see lenders insist in the future that the terminal be locked down and not operated in a fashion that allows access by third parties.

Mexican Projects

MR. ROGERS. Now turning to Mexican projects, the Mexican government is still studying what the US has done in MTSA. I don't think there will be any guidance soon from the Mexican government about the rules that will apply to offshore Mexican projects. This is disappointing.

However, there is better news about onshore Mexican projects. First, the government is approaching the regulation of onshore LNG terminals from a traditional Mexican onshore storage regulatory framework. That is to say, they are starting with the regulations that apply to gas storage facilities and altering them to fit LNG. They view LNG terminals as more complicated gas storage projects. Thus, the permit that one must obtain from Mexican is a 30-year permit for a gas storage facility.

The Mexican agency — CRE — does have some special guidelines for the preparation of LNG proposals. It is important to read these. You may also have to apply for a pipeline interconnected permit.

The good news is there actually may be an approval granted next month. Five projects have applications pending. All five seem to be on roughly the same timeline — that is roughly seven months from the initial application, you should get word back, at least on the economic permit, from CRE whether or the project has been approved.

Environmental approvals are also required at the federal level. At the state and local levels, there are land-use issues. However, at least on the 80,000-foot level, it is a relatively expedited application process.

An emergency technical standard for the design, construction and operation of LNG terminals was issued last August. This was part of an emergency regulation. The CRE is busy working on the final regulation. It is due out sometime in late 2003 or early 2004.

We understand that at least 10 foreign companies have expressed a formal interest to CRE in developing LNG terminals along the Mexican coast. To date, five parties have filed applications. All five are presently under evaluation. Unless there is a hitch, it looks like the Marathon consortium permit will be granted in February, followed by the CMS-Sempra authorization in March and then on through the pack.

The jury is still out on the economic regulation of Mexican onshore terminals. The original plan of CRE was to adopt a modified version of the US open-access, cost-of-service tariff, rate-based regulatory structure, but this plan was thrown for a loop in December with the Hackberry decision. The regulators are studying the US decision, but appear still to be leaning toward their original plan.

Turning to site access, direct foreign ownership of land in coastal restricted zones in Mexico is prohibited. Thus, you must either own land through your Mexican local partner or through an approved bank trust. Do not sign an option to acquire land with a local developer. It will not get you very far as a foreign investor.

Next, Dave Schumacher will take us through some of the engineering and construction issues and operations and maintenance issues.

Contractor Issues

MR. SCHUMACHER: We have included an awful lot of information about EPC contract issues in the outline we handed out. Let me just call your attention to a couple of key points, and you can read the rest in the outline.

The first is the issue of contractor responsibility. Project developers in recent years have been moving away from pure turnkey contracts where there is one point of contact, the general contractor, who is basically responsible for completion of the entire project, to arrangements where there are multiple contracts with multiple contractors, each of whom is responsible for a particular aspect of a project. The issue that arises in such arrangements is finger-pointing risk. If something goes wrong, everyone points to someone else. "It's not my fault. It's his fault." How do you manage this risk?

MR. AYALI: This issue is more relevant to the type of project we are calling the downstream integrated receiving terminal. It has many more moving parts — the terminal, docks, storage facilities, vaporization facilities, and a related power plant or a desalination plant. A word of caution to developers of such projects: your lenders will be concerned about the potential for finger-pointing if something goes wrong during construction. You need to make sure your various liquidated damages clauses fit together and that the timing and completion tests in the various construction contracts are in sync. There cannot be any holes when you present the deal to the lenders. You should also be ready to offer credit enhancement, keeping in mind that the reason you have these multiple construction contracts is because you got better prices as a result — you were able to squeeze some more savings out of the project.

MR. SCHUMACHER: Another issue relates to the commencement of project testing. Dan and I were talking recently about the need for one or more so-called cooldown cargos as a precursor to testing.

MR. ROGERS: The issue is the marriage between the EPC contract and the LNG supply contract. In a typical project, you will need an LNG cooldown cargo to test that the facility works. This cargo is usually purchased by the project developer under a long-term, take-or-pay supply contract, albeit with a fair amount of relief at least on the front end for problems during the ramping-up period — perhaps even an excuse from the take-or-pay requirement for the first cargo. The important point is that what the EPC contract says about testing must mesh with the LNG supply arrangements. You do not want to have to start the LNG supply contract in order to get access to the cooldown cargo and then have the testing reveal that the facility really isn't ready to operate yet. Take the time to ensure the two contracts fit properly.

MR. SCHUMACHER: There is also the issue of allocating risks between the EPC contractor and the project sponsor. Who is responsible for purchasing the cooldown cargo? What happens if there is a delay in testing? What happens if the tests show the facility is not yet ready to operate?

MR. ROGERS: If there is a construction defect or other delay, it will affect your LNG supply arrangements because you probably at that point already at least preliminarily confirmed your annual cargos for the year. You have a seller who is anxious to begin delivering cargos to you. Who bears the risk when you find yourself unable to take those LNG cargos as scheduled. That is something you can try to push back to the EPC contractor in the form of delay damages. Otherwise, you will have to absorb the loss yourself. The lender will not take it.

MR. SCHUMACHER: Next, we'd like to talk about operation and maintenance contracts. As is often the case with other infrastructure projects, the terminal operator may want to contract with a third party to provide operation maintenance services. A number of issues arise when drafting and negotiating an O&M contract for an LNG receiving terminal. We could probably talk about them for an hour. Let me just mention a couple of key ones and you can read about the rest in the outline.

One relates to fuel management guidelines. Fuel management is an issue because you have a number of different offtakers or tollers who are delivering or having cargos delivered on their behalf to the LNG terminal.

MR. ROGERS: It is important for everyone to understand who has the final say on scheduling and how it will work. Anyone who has worked with LNG tankers knows that scheduling is much more an art than a science. There needs to be some flexibility. We have seen some projects where the lawyers have tried to reduce scheduling to some type of a mathematical. The formulas will not work in practice.

MR. SCHUMACHER: There is a similar issue at the other end. That is maintaining a good process for nominating sendout and working with the pipelines that are taking the gas that is sent out. Make sure the nomination schedules correlate. Make sure the O&M contractor has the authority it needs to coordinator scheduling between the LNG facility and the downstream pipelines. The process requires some thought to work properly.

MR. ROGERS: That management function is critical to the success of the project.

MR. SCHUMACHER: Another issue is unique to LNG terminals, particularly when compared to gas pipelines or gas storage facilities. It is marine works maintenance. Not enough attention is paid to this in contracts.

MR. ROGERS: The contracts need to address who has responsibility for marine maintenance and what are the consequences for failing to do it.

MR. AYALI: There have been problems in some projects with allocating liability and responsibility among the ship, the project and the port authorities. This is especially relevant in projects where you may not be working with an established port authority. You may be opening up a new port. It might be a private facility instead of a public facility. Who is regulating that? How do you address liability issues?

MR. ROGERS: That's where you get into a very complicated dance between local law, the various international limitation conventions that limit the shipowner's liability for certain types of accidents, and marine insurance, which is a whole topic by itself. This is an area where you need to bring in qualified maritime legal advisors and qualified marine insurance specialists to understand how the liabili- / continued page 26

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ties are being allocated throughout the chain on the ship-to-shore interface.

LNG Supply

MR. ROGERS: The next topic is LNG supply contracts. This contract is obviously central to an LNG project.

Let me start with the difference between reserves availability and deliverability. Just because your supplier is sitting on an awful lot of reserves does not mean he can deliver them. The lenders and their technical advisers are going to look at every aspect of this. Deliverability is what is key to obtaining financing.

For example, there are some supply contracts with sovereign emergency gas reserve allocations that could cut off supply to the LNG terminal in the event of a local catastrophe. Force majeure clauses are important. Have a complete understanding of how they translate all the way through the supply chain. There cannot be any disconnects.

Delivery terms have become fairly standard across contracts. LNG is basically delivered in two ways. It is either delivered ex-ship or FOB at the loading port. The traditional contract structure is a long-term 17- to 20-year take with 100% take-or-pay, perhaps with a little bit of downward flexibility. During the last several years, there has been some movement away from the traditional model with negotiations leading to multi-turnout supplies, differential pricing, and some spot capability. However, lenders are skittish after the energy meltdown in the United States, and there is pressure to return to the more traditional model.

MR. SCHUMACHER: Keep in mind that you are basically trying to match up a long-term, 100% or very high percentage take-or-pay supply contract with gas offtake agreements that here in the States are typically short-term and probably sensitive to spot prices. How you mesh those two things can be a challenge.

MR. ROGERS: Another area of evolution in deal terms is in the allocation of gas price risk. Gas suppliers are not happy in long-term contracts with taking the full price risk. There have been discussions about slicing it up between perhaps an index risk and the basis differential risk and allocating the two tranches of risk to different parties.

MR. SCHUMACHER: Query how willing suppliers will be to tie their prices in the future completely to a NYMEX or Henry Hub or any other spot price index as the basis for their pricing.

If I am buying LNG to sell into the market to Industrial A or Industrial B, how can I match up my pricing with the needs of the LNG supplier? It is a real conundrum.

MR. ROGERS: Those issues are going to keep a lot of us busy in the coming years. On the subject of mitigants to pricing risks, in a contract I saw recently, the supplier had a fair amount of flexibility on the timing of its deliveries as long as it stayed within certain parameters, and it also had the right up to certain volume thresholds to substitute liquid fuel for LNG on very short notice.

Gas specification and quality certification are probably a big issue on the US east coast but probably not such an issue on the US Gulf coast where there is more capacity for pipeline blends. There is also more storage capacity. LNG from the Middle East has an extremely high heat content and is hard to handle on the US east coast. During transit — with some of the boil-off — it actually increases in heat content so that when it reaches land, it is awfully hot gas. You have a customer base on the east coast that is used to low Btu gas and will have problems accommodating very high heat content gas. Ultimately, this comes down to a question of who is going to pay for the treatment. It is an economic issue.

Payment security is another big issue. It applies throughout the chain. Everyone down the supply chain will want an assurance that the next person to touch the gas is creditworthy and can make payment. The world has changed in the past two years. Many gas marketers had very high credit ratings and the ability to purchase a commodity without a lot of letter of credit or parent guarantee support. Now, we are back to a world in which everyone must prove he is creditworthy.

MR. AYALI: Dan, it might be worth spending a little more time on this point, certainly as it relates to issues of private financing. We have seen gas suppliers basically taking a first secured position over all revenues generated by the LNG. They are requiring escrow accounts and other revenue arrangements. The problem is your project lenders will want the same security over the same revenues. That is where the rubber hits the road.

There are different ways to structure around this, but clearly the project lenders will have a lot of heartache over sharing security or cutting out of their security and revenue stream any potential credit enhancement or credit sources that the LNG supplier wants to see supporting his supply contract.

MR. SCHUMACHER: The basic position of lenders in these projects is the gas supplier can be the first to be paid in the waterfall, but if there is an event of default, then all bets are off, and any cash in the waterfall is ours. This does not sit well with a gas supplier, particularly if there is no strong credit support behind the offtaker in the form of a highly-rated guarantor or a letter of credit.

MR. ROGERS: The credit issue is probably the biggest impediment right now to moving forward with the LNG projects that are currently under development.

Terminal Access

MR. SCHUMACHER: The terminal access contract is the key contract for LNG terminal that plans to operate as a tolling facility. It is the contract that is the main source of revenue for such a project. It determines whether the project is financeable.

It is a lot like a gas storage contract. The terminal operator receives gas, stores it and sends it out on demand, all within certain confines of reserve capacity and send-out capacity. Of course, it is more tricky than a traditional gas storage agreement — we are talking about berthing ships and delivering liquid gas, storing it and sending it out — but the idea is the same.

In a typical contract, the services are priced such that the offtakers will pay a revenue or capacity charge based on the amount of capacity that is reserved to hold the liquid and then pay variable charges for sendout and other additional cost charges.

If you look at many of these contracts that are on file with FERC, what terminal operators have tended to do is essentially use their gas storage tariffs as the model for LNG terminalling services. This works more or less, but it requires thought. You can't just pick and choose terms to take from a pure gas storage tariff and plop them into an LNG terminalling tariff.

MR. ROGERS: Exactly. Some LNG terminal tariffs that you see today in the US have their origin in either the storage or the pipeline tariffs that were in existence at the time. They were modified for LNG. There are a couple of areas where, with the benefit of 20 or 30 years of hindsight, it clear this approach has not worked in practice. An example is interruptible LNG service.

MR. SCHUMACHER: This may be a remnant of the fact that FERC regulates LNG the same way it regulates interstate pipelines. Like interstate pipelines, LNG terminals have to provide for an interruptible service.

MR. ROGERS: In a more liquid market with LNG terminals up and down the seaboard, there may be a place for interruptible service, but until that happens, I'm not sure that the pipeline-style capacity release structure works well in an LNG terminal setting.

MR. SCHUMACHER: Another area of concern in LNG projects is how tariffs allocate liabilities.

MR. ROGERS: We did a very, very detailed risk analysis on a particular tariff on behalf of a client where, at the end of the day, we realized that a lot of the liabilities that were allocated to the importer of LNG and the user of the terminal facility under the tariff were of a nature where it was very difficult to find available insurances to cover those liabilities. The risk allocation embedded in the tariff came as a surprise to the client. The tariff had been approved by FERC. Yet, at the end of the day, when you really analyze how it works in practice, there are risks there that are getting pushed back on the user of the facility that the user of the facility has difficulty insuring against. It is important to understand the tariff, and then address issues raised by it in the terminal contract, if you can.

MR. SCHUMACHER: The last subject I want to mention is credit. When talking about a tolling terminal, a lender is going to be looking at the credit of the offtaker or the person who is buying the storage services. If that person or its guarantor is a triple A credit, you probably don't have an issue, but there are almost no triple A credits in this business. So the question is what type of offtaker credit will the lending community require before providing financing?

FERC has traditionally allowed gas pipelines to ask customers for credit support like letters of credit or guarantees that cover approximately three months of service. However, in a number of instances, particularly in project-financed pipelines, FERC has allowed pipelines to ask for credit coverage of up to a year's worth of service. Lenders have been willing to finance pipelines on that basis.

The issue is what lenders will require of LNG terminals. Is triple B credit enough? Will lenders look to downstream sales contracts and do essentially a receivables / continued page 28

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financing where this storage buyer is entering into contracts with downstream buyers and lenders are relying on that revenue stream? This is one of the more interesting questions facing LNG projects. How will lenders get comfortable with the credit? ◎

Insolvency Law Changes Affect English Law Deals

by Denis Petkovic, in London

A new law that takes effect this summer will radically change the law relating to corporate insolvency in Great Britain.

The changes reflect a shift from an insolvency regime previously recognized as being strongly "pro-secured creditor" to one that endeavors to uphold the collective interests of all creditors, particularly unsecured creditors.

The changes raise important issues for project finance lenders. The new rules follow enactment of an "Enterprise Act" last November. The UK government is still in the process of writing rules to implement the changes, although the rules are expected out before the changes take effect this summer.

Background

In most project financing transactions, a facility agreement is entered into between the borrower and a single lender or syndicate of lenders that is obliged to make loans on set conditions.

The security granted to support the loans will usually comprise a security in the nature of a first fixed legal charge over the borrower's real estate interest in the project site that extends to all buildings and equipment affixed to the land, an assignment of project contracts, shareholder's agreements, bank accounts, debts and insurances, and a floating charge over all the borrower's other assets. In addition, separate direct agreements between the lenders and key counterparties of the borrower are typically obtained. These agreements provide for cure periods in the event of the borrower's default or insolvency and for the lenders or their substitute or nominee to be able to "step in" and rectify any defaults in connection with the relevant contract.

A fixed charge over the sponsor's shares in the borrower may also be sought coupled with other possible sponsor support. The security sought by the borrower to the lenders could be granted in a series of security documents or in a composite security on debenture.

Popularity of Administrative Receivership

Prior to the new reforms, secured creditors typically exercised enforcement rights under the security package by appointing a receiver on the occurrence of a default. A receiver is a licensed insolvency practitioner — usually a partner in an accounting firm — and his appointment is over the assets that are the subject of the various securities. The powers of a receiver are spelled out in any applicable security. These powers, which are augmented by other powers under statute, typically include the power to take possession of the property subject to the security and sell it by public auction or private bargain.

The receiver is in an unusual position in that he is an agent for different persons. He owes duties to the borrower and to third parties with an interest in the "equity of redemption" associated with borrower's property managed by him. However, under the common law in England, a receiver is also the agent of the banks or creditors appointing him under a security document and, as such, he owes his primary duty to those persons when selling assets or carrying out his functions. He is "not simply a person appointed to manage the company's affairs for the benefit of the Company," in the words of one court decision.

Receivership has, to date, been the most commonly invoked insolvency procedure involving the continued trading of a bankrupt company or more importantly its business. It is quick, can be implemented out of court and does not require a public auction of assets. In practice, receivers act in close tandem with their appointers. This is also why receivership is a popular procedure with secured creditors. A receiver will be subject to one overriding duty in exercising a power of sale: he must take reasonable care to obtain a proper price. Connected with this duty is an obligation to take account of the effect of a receiver's actions on the value of goodwill of a business and to manage property with due diligence and, of course, to act in good faith. None of these duties is overly onerous, and it is rare for appointing creditors to become liable as a result of any negligent act of breach of duty by a receiver. These are some of the other reasons why receivership has been so popular in Great Britain.

The "Insolvency Act 1986" introduced a new type of receiver to British insolvency law — an administrative receiver. An administrative receiver is a receiver appointed by a secured creditor under a security package comprising not only fixed charges over specific assets, but also a "floating charge" such that the secured package extends to all or substantially all of a borrower's assets.

After 1986, secured creditors invariably included floating charges in their security packages for one important reason: the holder of a floating charge who had appointed an administrative receiver could always block the appointment by a court of an administrator over whom the secured creditor would have far less control.

Administration Under the 1986 Rules

"Administration" has, in the past, often been likened to a chapter 11 bankruptcy proceeding in the United States. That is a proceeding where the borrower gets some breathing space to try to reorganize its affairs.

To date, an administration order could be obtained from a court by, among others, the borrower, its directors or a creditor if supported by an affidavit and accountants' report setting out the grounds for the administration order.

To obtain an administration order from a court, the borrower must be insolvent in the sense of being unable or likely to become unable to pay its debts. Moreover the court had to be satisfied that the making of an administration order would be likely to achieve one or more of a list of four purposes. For example, one might show that by putting the borrower into administration, this might lead to the survival of the company as a whole or any part of its undertaking as a going concern. Alternatively, one might show that putting the borrower into administration might lead to a more advantageous realization of the company's assets than would be effected on a winding up.

The effect of the making of the order is that a moratorium operates to stop secured and other creditors from trying to liquidate or take proceedings against the company until the petition is dismissed or the administration order is discharged or varied.

Among the administrator's powers is the power to dispose of the borrower's property. However, in the case of fixed charge property of a secured creditor, a court order is required and the proceeds must be paid to the secured creditor. Assets that are the subject of a floating charge may be disposed of without a court order, but the administrator must respect the priorities of the secured creditors with respect to proceeds of realization.

The New Regime

There will be fundamental changes under the new regime.

The cornerstone of these changes is the introduction of a prohibition against secured creditors holding of certain "qualifying floating charges" from appointing an administrative receiver to a company. This means that creditors will no longer be able to block the appointment of an administrator by taking a "qualifying floating charge" as part of the security for a loan.

This change in law reflects concerns by the current government that the large number of administrative receivership appointments in the recession of the early 1990s may have represented precipitate behavior by lenders that led many companies to fail unnecessarily.

However, some types of floating charges can still be used by lenders to block the court appointment of an administrator.

First, the regime will not extend to floating charges created before a date sometime this spring or summer when the corporate insolvency parts of the Enterprise Act come into force. Such floating charges are thus "grandfathered" by the new legislation.

Second, the new regime does not apply to floating charges granted in the context of a capital markets arrangement where a party incurs or is expected to incur a debt of at least £50 million and a "capital market investment" is issued. A "capital market arrangement" is defined to involve derivatives. In addition, the security must be held by a security trustee with some obligations being guaranteed by a third party. A "capital market investment" is one that satisfies one of two criteria. The investment must consist of a bond or commercial paper issuance and must be issued to one or more sophisticated investors. Alternatively, the investment must be a debt instrument that is or is "designed to be" rated by an internationally-recognized rating agency, listed on the official list of the Financial Services Authority, or traded on certain approved and "recognized invest- */ continued page 30*

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ment exchanges" or "foreign markets." Securitization transactions are a main intended target of this exemption.

The third exception to which the new regime will not extend is the appointment of an administrative receiver of a "project company" of a project that is a public-private partnership project and that includes qualifying step-in rights.

A "project company" includes a company that holds property for a purposes of a project, or has sole or principal contractual responsibility for carrying out a project, or is one of a number of companies that together carry out a project, or that has the purpose of supplying finance to a project or is the holding company of any of the foregoing.

Companies that also perform activities unrelated to the project in addition to the foregoing do not qualify as "project companies."

A creditor has qualifying step-in rights if it provides finance in connection with a project and has a conditional contractual entitlement to assume sole or principal contractual responsibility for carrying out all or part of the project or to make arrangements for carrying out all of part of a project.

The fourth exception extends to certain designated utility companies in sectors such as electricity, water and sewerage, rail, air traffic services, and telecoms.

Fifth, the regime does not extend to the appointment of an administrative receiver of a "project company" if the project company incurs or is expected to incur debt of at least £50m for the purposes of carrying out the project, and the project creditor providing the debt has qualifying step-in rights as defined earlier.

Sixth, security from certain companies operating in the financial markets and certain social landlords under social housing schemes are exempted from the prohibition.

Crown Preference and Ringfencing

In Great Britain, as in most jurisdictions, certain creditors are mandatorily preferred by law on the winding up of a company.

Among the debts so preferred under British rules are debts owed to the government, or "Crown," on account of income tax, capital gains tax, value added tax, and debts owed on account of UK social security contributions.

Following trends in other jurisdictions, notably Australia and Germany, the Enterprise Act provides that all such tax and social security debts will lose their preferred creditor status (although some other categories of preferred creditor will remain). The result will be that more assets should be available for other creditors on a winding up.

A benefit that is afforded currently to preferred creditors under section 40 of the Insolvency Act should be noted. That section provides that if a receiver is appointed under a charge that, when created, was a floating charge, preferential debts will have priority to the security held by the floating charge holder from the floating charge assets coming into the receiver's hands. Section 40 will remain. However, the removal of preferred creditor status to tax and social security debts should see proceeds from assets comprising "changing pools" — such as trade receivables, some moneys in bank accounts and trading stock — more readily available to secured creditors.

However, there is a qualification. Floating charge holders will not benefit entirely from this increased pool of assets liberated from the Crown. A new ringfencing provision has been inserted in the Insolvency Act under which a portion of recoveries from a floating charge may be paid to unsecured creditors. The liquidator, administrator or receiver has some discretion to decide how much the unsecured creditors will receive. It remains to be seen how this ringfencing will operate as the "statutory instruments" that are supposed to designate the portion of such assets that will go to the unsecured creditors are still being drafted.

Foreign Borrowers

The treatment of foreign obligors and borrowers under the administration provisions of the new insolvency regime remains a point of confusion.

Section 254 of the Enterprise Act enables the Secretary of State, by way of statutory instrument, to make provision for the Insolvency Act to apply to foreign companies. It remains to be seen if the new rules will be extended beyond the current position under the Insolvency Act, but if past trends are a guide, this is possible. This is because over time, mainly through the influence of EU insolvency laws, administration has increasingly expanded so as to apply potentially to more foreign companies.

At present the administration provisions of the Insolvency Act, by virtue of the implementation of Article 3 of the "EC Regulation on Insolvency Proceedings," apply in the following circumstances. They apply to companies incorporated under the British "Companies Act" or in an EU member state (other than Denmark) whose "center of main interests" is in the UK. Following a recent court decision in a case called *Re: Brac Rent-A-Car International Inc.* in February, they apply to companies incorporated outside the EU whose "center of main interests" is in the UK. They also apply to secondary proceedings involving foreign companies with an establishment in the UK but their "center of main interests" in another EU member country. Finally, they apply to administration orders issued after a request from another country under section 426 of the Insolvency Act. That section promotes cooperation with bankruptcy courts mainly in former British Commonwealth countries.

Traditionally, British insolvency procedures were not intended to be used for foreign companies because of the general proposition that establishment and dissolution of a foreign company should be dealt with mainly by the laws of the foreign country in which the relevant company is incorporated. However, if the present rules are further extended, then English law transactions involving foreign companies granting securities permitting appointments of administrative receivers or even receivers of specific assets could find the relevant lenders' rights eroded or, at least muddied, by the intrusion of court-ordered administration in the UK. In discussions with drafters of the new rules, Chadbourne has been advised that it is not intended, at this stage, to extend the reach of administration any further and that any proposal to do so would be preceded by consultation. Nevertheless, the applicable detailed statutory instruments covering this topic should be monitored by international lenders.

Appointing an Administrator

The Enterprise Act has also recast the provisions in the Insolvency Act relating to administration.

In the future, an administrator of an insolvent company may still be appointed by order of the court, but he may also be appointed directly by the holder of a floating charge or by the borrower or its directors. However he is appointed, an administrator will be an officer of the court and an agent of the company.

The goals of administration have also been revised. In the future, an administrator will have to perform his functions with the objectives of rescuing the company as a going concern or, if this is not possible, achieving a better result for creditors as a whole than if the company were wound up or, if neither purpose is achievable, realizing property in order to make a distribution to one or more secured or preferential creditors. The administrator must also exercise his functions in the interests of creditors "as a whole" and must perform his functions as quickly and efficiently as possible.

An inherent tension will exist given these new goals. The main stated objective of the new insolvency rules is to pursue a corporate rescue. However, it is the disposal of the business of the company as a going concern that is usually in the best interests of the company's secured and unsecured creditors and employees. This tension reflects a concern in the market that the new legislation does not distinguish between a rescue of the business of a distressed company and a rescue of the company itself and that both should be treated with equal weight as policy objectives.

Floating charge holders who hold a qualifying floating charge can appoint an administrator directly. Security will qualify for this right of appointment if it expressly refers to the relevant provision of the Insolvency Act permitting such an appointment, or if it authorizes a floating charge holder to appoint an administrator.

Two days' written notice of appointment must be given to the holder of any prior floating charge.

Following the administrator's appointment, his appointer must file a notice of appointment at court together with a statutory declaration as to the security held by the appointer and right to make an appointment. If a false statutory declaration is sworn, a lender commits an offense (in the absence of it believing reasonably that the relevant statement is true). If there are doubts as to the ability to make an appointment the appointer risks swearing a false declaration and, in such a case, it may be safer to pursue a court appointed administration. In addition, the filings must be accompanied by a statement from the administrator that he consents to his appointment and that, in his opinion, the purpose of the administration is reasonably likely to be achieved (as to which he may rely on information provided by the borrower's directors). The costly accountants' reports currently required to support the appointment of an administrator will be discarded.

The borrower or its directors may also appoint an administrator out of court, but not within 12 months after the cessation of a previous administration appointment by the company or its directors. Moreover, / continued page 32

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neither the company not its directors may appoint an administrator if a winding-up petition has been presented, another administration order application is outstanding or an administrative receiver is in office. Five business days' prior written notice must be given to floating charge holders of the company's or directors' intention to appoint an administrator.

Once an administrator is appointed by the company or its directors, similar documents to those required to be filed by a floating charge holder must be lodged with the court (for example, a statutory declaration from the appointer, administrator's consent and statement as to likelihood whether purposes of the administration may be achieved).

Moratorium

Administration results in a winding-up petition being either dismissed or suspended generally and winding-up resolutions and orders being prohibited. Moreover, an administrative or other receiver will be required to vacate office on the appointment of an administrator. No secured creditor may enforce security without the administrator's or the court's consent. No legal process may be instituted or continued against the company to which an administrator has been appointed.

Interim variants of the administration moratorium apply where an administration application has been made to the court but not yet granted. All these moratoria are designed to provide breathing space to the company to develop a rescue package. One problem, though, with the reforms is that, in the past, a senior lender often provided funds to the business of the insolvent company to assist it in continuing to trade and on the basis that the funding was secured by his security package and given to his appointed administrative receiver. The changes in the rules will probably make lenders less willing to continue such practices.

Timetables

Within eight weeks after being appointed, the administrator must publish his proposals for achieving the purposes of his administration and notify the registrar of companies and the borrower's creditors and shareholders of the same.

As soon as reasonably practicable, but within 10 weeks after his appointment, an initial creditors' meeting must be held, except where the administrator determines that creditors will be paid in full, or that insufficient property is available to creditors for a distribution or he has already decided that the key purposes for which he was appointed will not be achieved. Procedures exist for creditors to insist on a creditors' meeting to be held nevertheless.

Another policy goal of the new legislation is to shorten the duration of administrations. Consequently, administration appointments now will be required to cease within a year of their taking effect in the absence of a court order or creditor consent to the extension. Where creditor consent is obtained, the extension cannot exceed a further six months but, in the case of an extension by the court, the period is unlimited. Secured creditors are effectively given a veto to any creditor extension. Other procedures also exist to bring an administration to an end.

Observations

So what do all these proposals mean for secured creditors in practice?

A number of points emerge depending on whether a transaction is governed by English law and involves a corporate borrower incorporated in Great Britain.

First, all lenders — both foreign and domestic — should review standard forms or prospective new transaction documents to see if events of default and other provisions should be amended to reflect the new rules and if floating charge security should permit, for example, the appointment of an administrator. Certainly with the concept of qualifying floating charges having been introduced, floating charges will continue to be taken as holders of such security are still granted "favored creditor status" of sorts. After all, they enjoy similar rights to appoint an administrator directly as they enjoyed in appointing an administrative or other receiver previously.

Also, secured creditors should treat floating charge security granted prior to the new regime with reverence since they will enjoy "grandfather" rights to appoint an administrative receiver and veto an administrator's appointment in such cases. This should have an impact on refinancings and, where possible, may encourage assignment of security from an outgoing secured creditor to a refinancier rather than creation of new security.

For the great number of transactions involving foreign incorporated borrowers that are largely unconnected with Great Britain but for the presence of, say, project accounts in London over which security is created, the new regime should not have a material impact unless the British government proposes, by statutory instrument, to extend administration beyond companies having their main centers of interest in the EU. If English law security is taken in such cases with provisions for appointment of receivers, then security arrangements should be unaffected, if the rules stay as they are at present, and secured creditors should be able to continue to appoint receivers without the specter of court administration affecting their rights by virtue of the new regime. However, the situation should be monitored.

For British domestic transactions or transactions with obligors incorporated in Great Britain, the rules should have a huge impact and could well influence the basic structuring of future transactions. The possibility that domestic deals will be structured so as to continue to allow administrative receivers to be appointed under floating charge security so as to block the appointment of a court administrator is a very real one. This is, in effect, what happened after 1986 when the Insolvency Act opened the door to this course of action; for some, the door remains ajar.

For example, large transactions that would not otherwise be project deals could be structured by lenders to fall within, say, the project finance exclusion to qualifying floating charges. Conversely, smaller deals involving, say, a mezzanine lender and senior lenders could be restructured as a multi-tranche loan facility sharing a common security structure so as to equal, in aggregate, the £50m debt requirement. The new rules may also result in an increasing use of special-purpose vehicles in financing transactions in excess of £50 million. Disappointingly, however, the £50m debt threshold excludes many small and medium-sized projects for no coherent reason, and projects in sectors such as renewables may be particularly affected. Moreover, the complex exceptions to the general prohibition against qualifying floating charge holders from appointing an administrative receiver may result in project finance deals carrying less than £50 million in debt being structured with more recourse to a sponsor than would be the case for a larger deal.

Another issue (although perhaps not a frequent concern in practice) is the introduction of "purpose" tests and the exclusion of non-project activities in the context of the definition of "project company". These requirements may exclude entities operating multiple projects or undertaking other activities. (An example is companies operating different projects through branches in different countries, which sometimes arises in the oil and gas sector.) Project lenders may look differently on such cases than those where they can appoint an administrative receiver. ◎

Merchant Transmission Projects: Opportunity or Fantasy?

There is little incentive at the moment to build new power plants in the United States because of the amount of spare generating capacity. Wholesale electricity prices have fallen to levels that make it impossible in many cases to finance additional projects. At the same time, in some parts of the country, transmission bottlenecks prevent sellers of low-cost power from delivering their product to areas where power prices are higher. This has led many companies to look at the possibility of buying sections of the existing grid or of constructing new transmission lines. Chadbourne hosted a workshop in Houston in March about the regulatory thicket through which anyone wanting to get into the merchant transmission business must navigate, the ownership structures that independent transmission companies are using, and the issues they face in doing business. The following are excerpts from that discussion. The speakers are Bob Shapiro and Adam Wenner, two regulatory lawyers from the Chadbourne Washington office, Philip Hanser from the Brattle Group, and William Hieronymous from Charles River Associates Inc.

Regulatory Thicket

MR. SHAPIRO: Let me start with an abridged history of utility regulation.

You may recall that, at one time, dinosaurs roamed the earth and it was very warm, and electricity was really not needed. And then it got cold, Thomas Edison invented the light bulb, and monopolists set up electric utilities. Franklin Roosevelt persuaded Congress in 1935 to pass two important pieces of legislation — the Public Utility Holding Company Act and the Federal Power Act — in an effort to rein in those monopolists. Jimmy Carter / continued page 34

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a few years later persuaded Congress to pass still more energy legislation, including the Public Utility Regulatory Policies Act, or "PURPA," in order to encourage competition. George Bush I put another important bill through Congress called the "Energy Policy Act" in 1992. It created something called "EWGs."

Then everyone forgot about regulation altogether and Enron roamed the earth and, like the Pied Piper, the power industry followed it into the sea.

And then everyone started out handing business cards at job fairs.

To the question, "What does this have to do with transmission," the answer is very little. The reason is that transmission, unlike generation, has never been perceived, at least until now, as a competitive business. It has always been heavily regulated. It is a bottleneck monopoly.

While the Federal Energy Regulatory Commission has undertaken a number of regulatory initiatives, very little has moved forward in the transmission area. Many proposals are pending. There remains a serious question whether FERC can do very much in this area without significant federal legislation, and there remains a question whether the FERC initiatives are even relevant any longer given the current state of affairs in the power industry where major power companies are simply fighting for their lives.

I will talk about four statutes that come into play when someone wants to acquire transmission assets. The main one is the Federal Power Act. Most of my talk will be about the Federal Power Act and the initiatives under it, but three other pieces of the regulatory puzzle that are relevant for this discussion are PUHCA, PURPA and the Energy Policy Act of 1992.

Federal Power Act

Starting with the Federal Power Act, be aware that it covers all of the United States, except Alaska, Hawaii and a small part of Texas called the Electric Reliability Council of Texas, or "ERCOT."

The Federal Power Act labels as a "public utility" any person who owns or operates facilities that are subject to the commission's jurisdiction. Jurisdictional facilities include transmission facilities used in interstate commerce and transmission contracts. It excludes facilities that are owned by municipalities, federal power marketing agencies, and federal coops. Those are coops that have federal financing from an agency in the US Department of Agriculture called the Rural Utilities Service, or what used to be called the Rural Electrification Administration.

FERC has authority under the Federal Power Act to set rates and remedy anticompetitive and unduly discriminatory practices. It is this part of the Federal Power Act that has been used to try to open the transmission system and get the integrated intrastate network moving to a fair, competitive playing field.

FERC has authority to order electric utilities to let independent power plants interconnect with their transmission grids. FERC has authority to order utilities to provide transmission service and enlarge transmission capacity needed to provide transmission service. The Energy Policy Act in 1992 added a procedure for would-be transmission customers to ask for a transmission service from a utility that controls the grid and, if it does not receive a timely response to its request, to complain to FERC.

What has FERC done with all these powers under the Federal Power Act?

It has issued since 1996 a series of orders and proposed rulemakings. I will mention them fairly rapidly. They are Orders 888, 889 and 2000, a proposed policy statement on new transmission pricing, a proposed rulemaking on "standard market design," another proposal to adopt a standard interconnection agreement for electricity generators connecting to the grid, and some case-by-case adjudications of transmission issues.

Starting in 1996 in Order 888, FERC ordered all utilities under its jurisdiction to file open access transmission tariffs, or a schedule of rates that anyone wanting service could pay for transmission. An interesting feature of Order 888 is that nonjurisdictional utilities — utilities that are not subject to regulation by FERC under the Federal Power Act, which include municipal utilities, Rural Utility Service-financed electric utility cooperatives, and federal power marketing agencies, as well as utilities in Canada and Mexico — are required also to file open access tariffs, even though they are not subject to regulation by FERC, if they want to use the open access tariffs of jurisdictional utilities. In other words, they do not have to do it, but if they do not, they will not have access to neighboring utility grids.

FERC in later orders read Order 888 also to require utilities to allow anyone wanting transmission service to be able to connect to their grids.

A companion order was Order 889. This created the so-called OASIS system. "OASIS" stands for "open access same-time information system." It is a real-time information system that lets users see what capacity each jurisdictional utility has for additional transmission. It also has real-time information on transmission pricing. It requires that all requests for transmission and all responses be posted on the Web. The goal is to create a level playing field for all generators and other electricity sellers who are using the transmission systems of vertically-integrated utilities.

The next significant order was Order 2000 issued in 2000. It came about primarily because the Energy Policy Act of 1992 failed to include authority for FERC to order regional transmission organizations, or RTOs, that would control regional sections of the grid. There was language in the draft legislation that lost at the eleventh hour, and FERC lost the authority that it wanted, so, in other words, it ended up the authority the authority to order utility to transfer control over their grids to RTOs. What FERC has been trying to do ever since is to do administratively what it was never given authority to do by Congress. And that has led a number of people to wonder what the real scope of authority is that FERC has over this whole area, and also may help to inform why FERC has not gone farther than it has today.

The goal of the Order 2000 was to put in place RTOs nationwide by December 2001, but in fact as of March 2003, only two RTOs have been more or less completely approved — the Midwest ISO and PJM. Others have had some aspects approved, but obviously things have gone fairly slowly compared to what FERC set as its goal in 2000.

The goal was to have utilities transfer operational control over their transmission facilities to RTOs. A key principle for RTOs was a separation between market participants and the people who are controlling the RTO. Each RTO was supposed to have sufficient regional scope to bring economies of scale. FERC remains concerned that entities like the New York ISO and New York power pool are too small to function effectively as RTOs.

FERC determined that what it has done so far is not enough. RTOs have not come into being as quickly as it hoped. Consequently, it initiated more rulemakings with the goals of giving the vertically-integrated utilities an incentive to give up ownership or control of their transmission grids, of making it easier for independent generators to obtain interconnection and transmission service, and of the construction of new transmission capacity.

These new initiatives were principally the introduction of incentive pricing for independent transmission and new transmission, an attempt to impose a standard market design, and a model interconnection agreement that all utilities and independent generators would be expected to use in the future, and the adoption of a fairly simple regulated transmission policy — the so-called "or" policy — for pricing regulated transmission interconnection.

FERC has issued a number of orders on transmission policy. The agency tried to bundle them all together in a single proposed policy statement on transmission pricing on January 13 this year. Basically what FERC is trying to do is to create incentive rates to induce utilities to transfer ownership and control over their grids to RTOs and to build new capacity on the grid. The main carrot for new construction is the ability to earn up to 300 basis points in additional return above what a utility would ordinarily be allowed.

This is regulated transmission. Merchant transmission is another story. FERC has been willing for purely merchant transmission to allow essentially unregulated rates — whatever can be negotiated with customers. However, to date, merchant systems have been fairly limited mostly to undersea cables.

Under the proposed policy, action must be taken by December 31, 2004 to receive the incentives. The incentive rates would be guaranteed through December 31, 2012. FERC has sought comment on whether additional incentives are needed and also how to encourage certain new technologies.

The big rulemaking that has been debated for the last nine months is the proposal for "standard market design." The goal is to remedy undue discrimination in the use of the transmission grid. One very controversial issue is that FERC proposes to exercise jurisdiction over the transmission components of bundled retail transactions — that is, transactions in which the customer receives electricity and transmission as a single product. This is something that many oppose. The goal of standard market design is to have each RTO serve as a completely independent transmission provider. It would make all the important transmission decisions, including decisions about availability, the need for and implementation of transmission expansion, congestion management. Each RTO would create a */ continued page 36*

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single, very wide regionally-based tariff and avoid "pancaking" of rates. Each RTO would make all of the resource decisions for its region.

At the same time, FERC has been reiterating that it is sticking to what is called its "or" policy for existing transmission and for interconnection to the grid. The "or" policy allows the transmission provider to charge an independent generator connecting to the grid the higher of rolled-in pricing or incremental costs for any upgrades that must be made to the grid to accommodate another power plant, but it cannot charge both. Rolled-in pricing would include the cost of the upgrade, but that cost must be allocated to all of the transmission provider's customers. There can be no "direct assignment" of that costs of the upgrade to the generator. If the generator advances the funds for the upgrade to the utility, then the utility must credit the amount — with interest — against future transmission service payments. However, the generator is required to pay the cost of the direct intertie to connect its plant to the grid — for example, the radial line running from the plant to the grid, as well as the cost of step-up transformers.

PUHCA and Other Statutes

Let me now touch briefly on three other statutes that also affect transmission. The Public Utility Holding Company Act, or "PUHCA," regulates utility holding companies and their subsidiaries. An entity is considered a holding company if it owns or controls 10% or more of the voting stock of a public utility company. A "public utility" company is a company that owns or operates facilities used for the generation, transmission or distribution of electricity for sale, so owners of transmission companies could be subject to potentially onerous regulation as utility holding companies under PUHCA, unless they own less than 10% of the voting stock or they have taken care to structure things so that they qualify for an exemption.

Regulation as a registered holding company is apparently a less daunting proposition than it used to be because owners of some planned independent transmission companies seem willing to bite the bullet and become registered holding companies. In the past, people were scared of PUHCA because almost every major business decision by a registered holding company must be approved in advance by the US Securities and Exchange Commission.

Moving to PURPA and its link to transmission, "qualifying" cogeneration and small power production facilities are exempted from regulation under the Federal Power Act, PUHCA and state utility law. A QF can include the intertie needed to deliver the QF power to the grid. Thus, the transmission line that is associated with a QF would not be regulated under any of these statutes unless that line is also used to transmit power for a third party.

But a note of caution: the Energy Policy Act gave FERC authority to order transmission over anybody's transmission lines — whether or not the lines are subject to FERC jurisdiction so that a QF could be a target of a transmission request by a third party.

The Energy Policy Act also created a category of power plants called "exempt wholesale generators" or "EWG's." There is a common misconception that EWGs are exempted from utility regulation. They are exempted from regulation by the SEC under the Public Utility Holding Company Act, but they are not exempted from such regulation by FERC under the Federal Power Act.

I should say something about state regulation of transmission. It really is the Achilles heel of transmission because siting restrictions can be devastating to the construction of new transmission capacity. The states today control all siting decisions. Also, states have condemnation authority that they can assign to franchised utilities.

The Federal Power Act gives FERC authority to license hydroelectric projects, and it has eminent domain authority over the entire property of the hydro licensee, including associated transmission lines. That's it. FERC has no other federal eminent domain authority. So it can't really do much to help with the shortage in transmission capacity, which is somewhat in distinction to the Natural Gas Policy Act and pipelines and gas transportation where it does have some eminent domain authority.

Congress has been debating whether to give FERC eminent domain authority for electric transmission either directly or after a period of time if the states fail to implement transmission expansion, but this proposal is vigorously opposed by the states. It is unlikely that we will see any federal eminent domain rights in the near term. Without federal legislation, intrastate transmission expansion is going to be very difficult unless there is a regional crisis.

In conclusion, let me leave you with a series of questions because at this point, it appears that no one has any good answers.

Who will be the next giants to roam the earth?

Who will take the dilapidated current market and exploit it for greater profits? Will it be the individuals like Warren Buffet and Bill Gates? Will it be the oil majors? Will it be the investor-owned vertically-integrated utilities again? Will it be deep-pocket private equity funds? Will it be foreign utilities? Or will it be the law of jungle?

On the screen is a cartoon of a lion talking to its cub saying, "Fortunately, the law of the jungle doesn't require lawyers of the jungle." I would say, though — to paraphrase the Master Card commercial — for everything else you need lawyers.

Opportunity or Fantasy?

MR. HANSER: I want to talk a little bit about the relationship between transmission and generation. It is hard to talk about one in the absence of the other. That would be like talking about the design of a new automobile without talking about whether there are going to be highways on which the automobiles can drive.

I want also to talk about some problems that arise in terms of efficient investment behavior that FERC does not seem to have addressed in its standard market design proposal.

Finally, I want to talk about some roles that might arise for RTOs and I'm going to talk at the end about the general market that will arise out of this. These are my opinions and not necessarily those of the Brattle Group.

The first point is that the existing transmission systems are "legacy systems." They are very old systems. They have been developed with some specific purposes in mind. For example, ISO New England has a transmission grid with very thin wires. The transfer capability of ISO New England is relatively limited compared to the transfer capabilities of the transmission systems for the New York ISO.

Why is that? Historically, generation in New England was built close to load centers. The result was there wasn't a need for building a transmission system in which large amounts of power were moving around. In New York, in contrast, you had the great Niagara Falls and other hydroelectric facilities that sat in the north and the eastern part of the state, or sometimes in the western part of the state, but large amounts of power had to be moved toward New York City in the south.

The net result — I'll give you a stupid one — is that if you look on a transmission map of ISO New England and the New York ISO, you will see that there are lines in both systems rated at 220 kilovolts, but the power carrying capability of the two lines is vastly different. The reason is the New York ISO transmission lines are four times the diameter of the lines that are used in ISO New England. Thus, New York has roughly four times as large a power-carrying capability as New England.

The net result is that you have two 220 kv lines running in parallel through Connecticut and southern New York and you say, "Why can't you connect the two?" The answer is: You can't connect the two easily because, if you did, you would blow one system off the map. This is a legacy of history.

In the western United States, on the other hand, you have transmission lines that are of enormous length. For example, the line that connects Bonneville to northern California is 1,100 miles long at its longest point, which is a distance longer than the distance between New York City and Chicago. There are stability problems that arise in moving power back and forth over such a long distance. Therefore, that transmission system operates differently from an electrical standpoint than any of the other systems in the eastern US.

The net result is it is almost impossible to have a "one-size-fits-all" standard market design. That's why I think we are moving from SMD to IMD where "I" stands for idiosyncratic.

Pricing Issues

Let's talk about location-based marginal pricing, or "LMP," for electricity transmission. I have just a few points to make.

LMP is an appropriate short-term method for charging people to move electricity, but it has peculiarities that are important to understand and that are a function of the transmission system. With LMP, users of the grid are charged a different price depending on whether or not there is congestion. If there is no congestion, then there is a single uniform price that steers the entire transmission system and the entire market.

One of the problems is that LMPs tell you that there is congestion on the system and to make changes, but they don't necessarily tell you exactly where. One of the problems also is that the price differences may not be sufficient to reduce demand so that the congestion is relieved. And in fact, depending on the assumptions you make about how generator costs are bid in, you can show */ continued page 38*

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they are insufficient to pay for the cost of the investments associated with transmission lines.

If I think about the nature of the transmission investments that I want to make, one of the problems is that there are siting restrictions that to a large degree determine where I build generation and transmission. Given this legacy grid, a lot of generation is built in places where companies *could* build generation as opposed to where they *wanted* to build generation, and the same thing goes for transmission lines.

Therefore, if you are going to talk about having an optimal investment strategy for the country as a whole in terms of social policy, you must deal with the fact there is a lot of poorly located transmission and generation already that could not have been built anywhere else.

When people say, "We're just going to redo this and have this wonderful wholesale market based on this wonderful transmission system to move electricity," the question that comes to mind is, "What's the reality of it? If you could not build it when you had state-regulated monopoly utilities, what makes you think you are going to be able to build that system when you don't have state authority."

I don't mean to sound pessimistic. I just want people to understand that there is a grand conception that that we will have this wonderful deregulated wholesale generation market and a transmission system to support it. I love the grand conception, but the reality is there is a lot of history to overcome and we must be realistic about what really will happen

There is certainly the appropriate economic motivation to say, "We should have transmission investments paid for by the parties that benefit," but the problem is the benefits are sometimes so diffuse that it can be hard to identify precisely the degree to which different parties benefit. The Federal Energy Regulatory Commission could have a completely different policy, but if it operates in parallel to the policy it adopted for gas pipelines, this suggests the majority of transmission is going to end up being paid for through rolled-in rates.

Trends in Regulation

I think that in the long run what will develop on the generator side is either quasi- or crypto-regulation. It is possible for a generator to earn enough of a return by having prices spiky enough to make it worthwhile to own a power plant. The problem is there is no political appetite for it. No one wants to wake up one morning and read in the newspaper that the price of power spiked to $3,000 per megawatt hour for one hour on August 11, 2005, even though 98% of the hours of the rest of the year were floating at $25 to $30 a megawatt hour. The reality is we have price caps. The problem is there is no money to be made to cover fixed costs in the long run in a market like that. Therefore, someone will eventually say to the regulators, "Here is the cost for capacity," and ask them to set a price for capacity that will implicitly set a rate of return that an investor can make. I don't know whether the forum for this argument will be the RTO or FERC, but it will mark the return to good old rate of return regulation.

In the end, what will happen is we will have a system in which there is regulation for generators at the RTO level and for transmission at FERC. The only way the twain will meet is when generators and transmission owners are put on committees together to decide what new transmission will be built and where new power plants can be located in relation to the grid.

Here is my bottom line. Basically we are back to the bad old days. A competitive strategy on the part of a company, whether it is a generator or a transmission company, is essentially a regulatory strategy at this point. Where you will make your money is by being inside the regulatory process. Fundamentally, you have to be as big a technocrat as the technocrats who are running the RTOs and ISOs. You have to know their models. You have to understand their information. You have to understand the rules by which they operate. This is true whether you own an existing power plant or you are trying to figure out where to build a new power plant or you are planning to build a new transmission line.

I don't mean to be cynical about this, but I don't see any other possibility at this point unless somebody comes up with a brilliant new theory for how to make all of this work.

Merchant transmission in the long run will be a no go. There are a few isolated places where you can put merchant transmission lines and collect revenues for relieving congestion, but each new line built reduces the amount of congestion revenue and the potential profit. You will never get to the "necessarily optimal level."

In the end, you will need to understand the regulatory process and the technical details. There is a stupid paper that

I love that says it turns out there are these things called algorithms that choose which power plants will run. They all have approximations in them. The computer model can come to two solutions that are nearly identical, but the problem is it chooses different generators when it gets done with the program. So here is a situation in which this model is making choices about which generators will run. From the standpoint of the technocrat, the two solutions are equivalent. From the commercial interest of the generator, they are very different because in one situation one generator runs, and in another situation another generator runs. That is the kind of thing that it will be important to understand because that is where the money is to be made.

Policy Challenges

MR. HIERONYMUS: I think FERC has a lot more to do. I plan to touch on three subjects. The first is transmission investment. We have created the right incentives. Phil Hanser and Bob Shapiro talked about the problem of siting. We are not going to fix that, at least not through this process.

The second thing I want to talk about is the allocation of congestion revenue rights, or "CRRs," and the third thing is what FERC refers to as "resource adequacy," which is to say the mechanism by which we assure that a reliable system gets built.

I'm not going to mention everything about these subjects. Rather, I have tried to focus on things that are of particular interest to merchant generators. In particular, I want to talk about the allocation of transmission costs as between merchant generators and the other users of the transmission grid, about the process of determining who gets CRRs, and how we handle the problem of assuring sufficient capacity for reliability purposes.

The standard market design proposal that FERC issued assumes that transmission will enter the merchant business and that people will build transmission lines for profit. I agree with Phil Hanser that this is not going to happen. The US electricity grid is an interconnected system. The system cannot tolerate merchant transmission facilities except for direct current, or DC, facilities. It cannot tolerate alternating current, or AC, facilities that perform on a merchant basis where capacity is sold to the highest bidder.

FERC has said the costs of new transmission should be allocated on a user-pay basis. That's fine, except that it turns out that it is really difficult to determine who the beneficiaries are. FERC has recognized this to the extent it said, "If somehow or another there are transmission assets needed that participants won't voluntarily pony up to have built, then we will allow the cost to be rolled into rates or allocated among the participants within the rate-making process."

This leaves the question, "Can you really have a system that at its core relies on voluntary investments from participants?" Is it a viable system if people know that investments that are needed but don't get made voluntarily will be paid for in rolled-in rates?

To give you a notion of the scale of the problem — and this is admittedly one of the worst examples — Entergy estimates that accommodating the 21,000 megawatts of planned and reasonably committed generation on its system will cost more than $1 billion. The generation itself will cost more than $10 billion. The dollars involved matter to the public utility commissions in Arkansas, Louisiana and Mississippi and, because of rate freezes, they matter a whole lot to Entergy. There is a huge fight by Entergy and these commissions to avoid having to roll into rates the costs that are needed to accommodate all of this generation, most of which, they contend, is of no benefit to the Entergy system.

Utilities historically have used high participant funding allocations as a way of putting costs onto merchant generators. I worked on one case where a merchant plant was being built in Boston that would actually eliminate all the congestion into Boston, and the home utility — to whom the ISO had handed off the job of determining what the generator owed — said, "If you will solve $50 million worth of transmission problems within the city of Boston and also pay us $30 million for the excess power costs when we're doing the transmission upgrades, then you can build your plant."

The extraordinary thing is the generator is going to save that utility and its ratepayers a great deal of money by making available 1,600 megawatts of brand-new combined-cycle capacity in a city that has nothing but ancient units. But that is the way the game is played. It wasn't done in this case to preserve a market for the utility's own electricity generation. The utility had already sold all its power plants. It was done because the utility is subject to a rate freeze, and if the utility had to add to its grid while still subject to a rate freeze, it would lose money.

On the other hand, we have a situation where many generators have built their plants without any regard whatsoever to the relationship to the / *continued page 40*

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transmission system. There is currently no way to get all that electricity to market. We have this problem in New England, in Rhode Island, in southeastern Massachusetts and in Maine. That happens to be the system I know the best. Around the Palo Verde belt in Arizona, there was all this generation built to serve California load and there is no way to get the electricity to market.

Billions of dollars have been put into the ground without the slightest conception about who is going to build the highway to get it to market and how that highway will be paid for. What we see in many cases is a game of chicken. The utility says, "When you come up with the money, we will build the transmission." The generator says, "But you are the transmission utility. You build it." In this situation, the utility holds the winning hand.

That having been said, if we systemically ratify these bad siting decisions by generators, then generators will continue to build new power near gas lines, near cheap water sources and so on without any regard to what it costs to get the electricity to market.

Who Should Pay?

A useful framework to think about is you have the costs of direct interconnection — the leads, the switchyards. That incontrovertibly is something that the generator pays for. Then you have what FERC has in mind when it talks about a base load, which is the kind of generation that customarily would have to be built in order reliably to serve the load in the control area.

In Entergy's case, I think it says about 6,000 megawatts of generation is needed and so, at least in some sense, Entergy ought to pay for the cost of grid improvements to accommodate the 6,000 megawatts. Of course, that begs the question: "Which 6,000 megawatts?"

Then there is economic reinforcement. Entergy has mostly old gas steam units. They are not very efficient. The new power plants are efficient combined-cycle units. They can indeed economically displace a lot of the older Entergy units. Thus, there is a benefit to Entergy's ratepayers to gain access to an additional tranche of this generation. Of course, there is also a benefit to the generator to be able to sell its output. This suggests something about how to allocate the costs. The other piece of it is for the next six, eight or 10 years, there is no use for the additional capacity on the Entergy system. So the excess load is resold in the meantime to another region. Intuitively, the beneficiaries are the generator and load in the importing region, but there is no way under the current rules to force the importing region to pay any of the costs.

Another question about interconnection is, "Who decides what is the incremental amount of grid improvements that is needed to support merchant generation?" This is partly a boundary issue. In the Duke Energy Hinds decision, FERC said the substation upgrades that Entergy demanded of Duke — and that Duke in the first instance agreed to pay for — are part of the network. Duke could not be required to bear their cost as an interconnection asset. Duke may advance the funds, but it receives a refund through transmission credits with interest. It is partly a question of deciding what is being done for the benefit of the independent generator and what is being done for the benefit of other users of the grid. FERC would leave this decision to the RTO or ISO, but it often lacks the capacity to answer the question. It is also like putting the fox in charge of the chickens. It is not necessarily an honest broker. We see frequent capture of ISOs by subsets of their participants. RTOs currently have an incentive to shift the costs to merchant generators because of rate caps.

This may change if the government starts giving meaningful incentives for building new transmission lines. However, at least for now, FERC is saying if you have hot-shot transmission project to build and you will receive CRRs from it, that should be enough incentive by itself to build. As Phil Hanser alluded to, as a general, that is not going to work. Transmission investments are lumpy. If you have a lot of transmission and congestion before you build it, you will have a lot less congestion after you build it, with the result that you have solved a big problem and will never receive the congestion revenue on which you were counting. Meanwhile, generators get the benefit of being able to sell at higher prices into what were previously constrained markets. Loads, in turn, get access to lower cost generation and face lower locational marginal pricing at the load buses. The bottom line is there is a large benefit that is extracted by someone other than the owner of the CRRs.

Another problem with any transmission investment in this new world is that if I am building transmission to reduce congestion — let's say into New York City — and someone else comes along and builds a thousand megawatts of new generation in New York City, the value of my transmission investment just went south. So in the absence of central planning, there is the hazard of competing investments.

The last topic is resource adequacy. In its SMD proposal, FERC came up with something truly bizarre. The essence of it is the idea that everyone will contract forward for capacity, but no one will have to pay for it unless the system turns out to be short in real time. If you want your basic free-rider problem, you have created it here in spades.

FERC has recognized that this will not work. The plan is basically off the table. I don't know what we will see in April when it issues a white paper, but we will see a different approach.

So where do we want to go? We have forward markets for power in substantial part due to new generation. New development can compete. That's what FERC has been trying to achieve. We need to make sure that the electricity is really deliverable, that the additional generating capacity is real. We must come up with a way to accommodate retail access. That may involve the ISO buying capacity and then a forced resale to people who lack it. We need to move to where we accept reliability levels that are by the market.

We have the short-run stuff right. FERC still has a long way to go on the long-term stuff. And since FERC chairman Pat Woods wants us all in RTOs operating under a standard market design by the end of his term, we are going to have to move fast.

Two Different Project Models

MR. WENNER: Let me try to inject some optimism in this discussion. I will try to describe some of the actual projects that real world investors have invested in notwithstanding the risks that have been identified by some of our speakers.

FERC has divided the transmission that it is trying to encourage into two categories: merchant transmission and the independent transmission company model.

Merchant transmission projects are discrete new projects that involve DC interties that permit load flow to be controlled and that connect regions with significantly different energy costs so that the owner of the transmission system can capture the benefits of those differences and make a profit. FERC has permitted deregulated rates for merchant transmission. Thus, if the cost of generation is $40 a mWh on Long Island and $20 a mWh in Connecticut, the merchant transmitter can capture all the benefits by charging up a toll of to $19 for use of its transmission lines to move the power.

FERC has required that an "open-season" process be used to award entitlements for merchant transmission projects, much like the process that is used for gas pipelines. Although FERC has the usual affiliate concerns, it does allow a project to be developed by a company that has both a power marketing affiliate and a generation affiliate. In essence, FERC does not view merchant transmission projects as having monopoly power. It views them as taking generation and moving it — in the example I described — from Connecticut to Long Island. There is no reason to regulate the transaction.

Merchant transmission involves DC transmission lines that allow the load flows to be controlled. Because of this, one doesn't have to worry about the congestion rights that occur on an AC system. In an AC system — the traditional utility grid — electricity moves in the direction of least resistance. DC lines are used more typically to move power in a particular direction. In other words, if you buy 50 megawatts of firm capacity on the cross cable that connects Long Island to Connecticut, no one is going to interfere with your 50 megawatts. Those flows are controlled, since the transmission line operates like a gas pipeline.

The other side of the coin of being allowed to charge unregulated rates is that the merchant transmission owner must bear all market risk. There are no captive customers on whom to impose the costs of a failed or uneconomic merchant transmission project. The developer is at risk if he builds a project that fails to attract enough use to pay for itself. This problem is addressed by having firm contracts in place before the project is financed.

One disadvantage for merchant-transmission projects is that since they are not "franchised" utilities, they do not have the authority to exercise eminent domain to acquire rights-of-way. Moreover, were they to receive such authority, FERC has indicated that it would be concerned, since eminent domain authority usually gives a company an advantage over competitors.

There are concerns — since rates are left to the market — that a franchised utility whose affiliate is developing a merchant transmission project could either cross subsidize the project by having the work done by its regulated side and direct the costs through the / continued page 42

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merchant project, or use its own transmission system to limit access to the merchant project so as to favor its own affiliated generation. Northeast Utilities, which has proposed a merchant project, withdrew its initial request that for its merchant affiliates to participate after FERC made it clear that it was concerned with this issue.

As of today, FERC has approved five merchant transmission projects. They are the cross-Sound cable project connecting NEPOOL to the New York ISO in Long Island. High energy cost differentials justify that project.

The harbor cable project would connect New York City and the New York ISO with the PJM system in New Jersey, another underwater project. Again, you can see that these projects are used to cross geographic barriers. Indeed, that is why there are such big rate differentials. Otherwise, there would be a free flow of energy, and these differentials would not exist in the first place.

The Northeast Utilities project would go from NEPOOL to Long Island to New York ISO.

Hydro One is a project that would connect Ontario, by going under the Great Lakes, to either the PJM or the Midwest system. The point of connection has not been determined yet.

Finally, at least on paper, there is the Neptune project, which would be hundreds of miles of cable under the ocean. It would connect the power-rich areas in Maine, New Brunswick and Nova Scotia with New England loads.

The second type of merchant transmission is the "independent transmission company" model. Projects in this category do not involve new construction. The independent transmission company owns an existing utility grid and is no longer affiliated with any generation or merchant function. It is a "pure" transmission company. FERC's goal in the independent transmission company model is to eliminate the favoritism that transmission owners might accord to their affiliated merchant functions and eliminate the discrimination that they have the temptation to exercise against competitors.

By focusing only on transmission, a company has an incentive to disfavor generation. Independent transmission companies will own AC systems for which load flows are not subject to control, and so congestion rights are necessary to ensure that the holder of legal rights gets the financial benefit of its investment.

FERC has proposed incentives for companies to become independent transmission companies. Rate regulation for such transmission companies will be done under traditional costs of service as opposed to the deregulated rates that merchant companies will be allowed to charge. So you have a cost-of-service model, and then FERC is proposing benefits on top of that to provide incentives for becoming independent and for investment in innovative technologies.

One benefit to independent transmission company status is that if a company becomes a transmission-only company, it becomes subject only to regulation by FERC and ceases to be subject to regulation by state commissions. FERC generally is viewed as a more stable regulator than a state commission. It more removed from the pressures of consumer intervention. This is the big unspoken benefit from spinning off transmission assets into a transmission only company: the owner is insulated from state commission regulation.

FERC has acted on several independent transmission company applications already. These involve real-world sales of utility transmission systems by an integrated utility to a transmission-only company. They include the sale by Consumers Energy of its transmission grid to Trans-Elect, the proposed sale by Illinois Power Company of all of its transmission system to another subsidiary of Trans-Elect, and a sale by Detroit Edison Company of its system to International Transmission Company. FERC has also approved formation of the Translink Transmission Company, which would own, lease or exercise operating control over participating utility systems.

Ownership Structures

Now let's see how the regulatory issues that Bob Shapiro described are affecting how these transmission-only companies are structured. First, as Bob pointed out, an entity that owns transmission assets is a "public utility" under the Federal Power Act and, as such, is subject to regulation by FERC. That's not really a problem, and it does not affect the structure because FERC regulation does not go upstream. It applies only to the transmission company.

However, as Bob also pointed out, the owners of that company are owners of voting securities of an "electric utility company" under PUHCA and, therefore, unless they can find a way to get out of it, they would become subject to SEC regulation as a registered holding company under PUHCA. That's not something they want to be because, unless an exemption applies, the holding company can only own utility businesses or utility-related businesses, and all its utility subsidiaries must be in a single region of the country.

In practical terms, this means that a company like Microsoft, Marriott and McDonnell Douglas cannot acquire the common stock of a transmission company, because it would have to divest its core business. That is not going to happen.

It also means that the owners of independent transmission companies are going to be a small class of companies. They will not be the traditional utilities. Those are the companies that divested themselves of their grids. The criteria for an independent transmission company would not be satisfied if American Electric Power, for example, owned it. In general, the owners will be new companies that are not very highly capitalized so that they can tolerate PUHCA regulation. They will significant outside investment.

There is an alternative ownership structure that those of you who lived through the independent power project movement before 1992 and the creation of EWG's will recognize. "PUHCA pretzels" are back. That is a structure in which individuals own the voting securities of the transmission company with outside investors participating through a limited partnership.

Three of the independent companies that have already been created have dealt with the structuring problems as follows. Michigan Independent Transmission, which owns the Consumers Power system, was sold to Trans-Elect. Trans-Elect is a Canadian company. It will be a registered holding company, but it can tolerate PUHCA regulation. The outside investor is General Electric Capital Corporation. GECC is putting in a lot of money through a limited partnership that enables GECC to avoid PUHCA regulation.

The Illinois Power transmission grid is being sold to the same company, Trans-Elect. AIG will be the outside investor in this case, and it will invest through a limited partnership to preserve its non-PUHCA status. The transmission system of Consumers Power Company is being sold to a new company, International Transmission Company, that will have Kohlberg Kravis Roberts, or "KKR," and Trimaran as the passive investors and an individual, Lewis Eisenberg, as the owner of the voting securities.

The same structuring challenge exists merchant transmission projects. The same PUHCA issue must be solved. In the cases of the cross-Sound cable project and Hydro One, the owner is TransEnergie, which is a subsidiary of Hydro-Quebec and which is entitled to an exemption from PUHCA as a foreign utility holding company. Northeast Utilities, another owner of a merchant transmission project, is already a registered holding company. PUHCA regulation is not an additional burden to it.

Turning to rate-related issues, when a new company buys a transmission company, it is convenient to hire the employees who operated the grid to continue servicing it. They are familiar with the system. They are trained. For example, one might hire Detroit Edison to operate a grid that it sold to an independent transmission company. FERC has expressed concern that such an arrangement results in a grid that is not really independent of the utility that originally owned it. Thus, it has given the new grid owner only a year to keep the former utility owner under contract as the operator. After that, the independent transmission company needs to have hired its own employees. This has created stress because it is not easy to do this within a year. Expect to see the industry to ask FERC to revisit the issue

Now for the good news: FERC allowed the International Transmission Company, which is acquiring the Detroit Edison grid, a 13.88% return on equity in a capitalization structure that included 60% equity. This is significantly higher than what is normally allowed in the utility industry. FERC hopes this will serve as an incentive for the creation of more independent transmission companies.

FERC permits the recovery through rates of accumulated deferred income taxes that become due on the sale. This is the accumulated difference between the book and tax depreciation to the date of sale on the grid.

Conclusions

The regulatory climate is not ideal, but investors are going ahead with independent transmission companies.

PUHCA repeal would make it unnecessary to have the convoluted ownership structures I mentioned, but based on recent events, PUHCA repeal is not likely to happen soon.

Finally, as Bob Shapiro mentioned, many people feel that the deadline of 2004 to vest operating control of the national grid in regional transmission organizations, or RTOs, is too short. They are asking FERC to allow more time. Similarly, the short deadlines for reworking the O&M arrangements for the system are creating problems. ◎

Environmental Update

Clean Air Act

Competing proposals to impose stricter limits on air emissions from power plants are starting to take form in Congress.

Three key members of Congress introduced bills in late February to implement the president's plan — what he calls his "clear skies initiative." The three include the chairmen of the House and Senate committees with jurisdiction over environmental issues. Since Republicans control both houses of Congress, and the president called for action this year on the proposal in his "state of the union" address to Congress in late January, one would think the bills these three introduced will eventually become law. However, Congress has so much on its agenda with the war in Iraq and the weak economy that it may not. Also, the Republicans lack support for their approach from some key moderates in their own party in the Senate.

The Republican bill would require substantial reductions in nitrogen oxides, or "NO_x," sulfur dioxide, or "SO_2," and mercury emissions from power plants by setting nationwide emission caps in a two-phase process. The emission reduction targets are as follows: caps of 4.5 million tons of SO_2 in 2010, 2.1 million tons of NO_x in 2008, and 26 tons of mercury in 2010.

These caps would decline in 2018 to 3.0 million tons of SO_2, 1.7 million tons of NO_x, and 15 tons of mercury.

Three years ago in 2000, approximately 11.2 million tons of SO_2, 5.1 million tons of NO_x, and 48 tons of mercury were emitted. Overall, the Republican bill calls for a 74% reduction in SO_2, a 67% cut in NO_x, and a 69% reduction in mercury emissions by 2018 from a 2000 baseline. The bill does not call for any cuts in carbon dioxide, or "CO_2," emissions from power plants.

The emission reductions would be required of all fossil fuel-fired power plants with a capacity of more than 25 megawatts that generate power for sale. Cogenerators selling less than a third of their potential electrical output would be exempted. New "affected units" under the bill would also be subject to specific minimum emission limits for SO_2, NO_x, mercury, and particulate matter.

The bill proposes a mandatory "cap and trade" emission allocation program similar to the federal acid rain program for the three pollutants. The legislation would create a "backstop" ceiling price for allowances of $4,000 for each ton of SO_2 or NO_x and $2,187.50 for each ounce of mercury. These prices would be adjusted annually for inflation. The "backstop" allowances would be available directly from the US Environmental Protection Agency, and could be used in the year of purchase or for prior-year commitments.

As a *quid pro quo* for having to meet new stringent emission reductions targets, the bill would exempt affected power plants from having to comply with the so-called "NO_x SIP call" rule requirements starting on January 1, 2008. Affected plants that meet stringent carbon monoxide and particulate matter limits might also be exempted from the major source "new source review" permitting program requirements and the "best available retrofit technology," or "BART," standards that apply to older power plants located near national parks and wilderness areas. The bill would also exempt utility power plants that produce steam from regulation under the "maximum achievable control technology, or "MACT," standards program.

If enacted, the Republican bill would completely overhaul the current Clean Air Act provisions that apply to power plants. Many older power plants would have to be retrofitted with costly pollution control technology or spend significant amounts to purchase "allowances" to cover their emissions.

The competing plan that has the support of many Democrats was introduced in the Senate by Senator James Jeffords (I.-Vermont). The Democrats charge the Bush administration with trying to weaken the existing "Clean Air Act" and with failing to take meaningful steps to combat global warming.

The Jeffords bill would require greater reductions in SO_2, NO_x, and mercury emissions as well as reductions in CO_2 emissions and on a much tighter time frame.

Under the Jeffords bill, all power plants larger than 15 megawatts would have to meet emission reduction targets by 2009. The bill would set nationwide emission caps of 2.25 million tons of SO_2, 1.51 million tons of NO_X, 2.05 million tons of CO_2, and five tons of mercury. These levels amount to an 81% cut in SO_2, a 71% reduction in NO_X, a 21% cut in CO_2, and a 90% reduction in mercury from 2000 levels. If EPA fails to write regulations in time to implement these caps, then even more stringent emission limits would take effect automatically. The automatic limits would require each such power plant to reduce its emissions by the following percentages compared to output at an "uncontrolled" plant: a 95% reduction in SO_2, an 85% reduction in NO_X, a 25% reduction in CO_2, and a 90% reduction in mercury.

Under the Jeffords bill, emission allowances would be created and traded, except for mercury. The measure also includes a controversial departure from previous federal emission trading programs in that the bill directs EPA to distribute the majority of allowances — approximately 62.5% — to households and consumers. Up to 20% of the allowances would be allocated to owners of power plants that use renewable energy, such as wind, biomass, landfill gas, solar and geothermal. Only 10% of the allowances would be allocated to existing power plants.

The Jeffords bill is more draconian than the Republican bill. Republicans complain that the bill imposes unrealistic targets and deadlines and predict dire economic consequences.

Meanwhile, two moderate Senators — Patrick Leahy (D.-Vermont) and Olympia Snowe (R.-Maine) — introduced a separate bill calling on EPA to set a 90% reduction in mercury emissions from 1999 levels in the soon to be issued utility MACT standard for coal- and oil-fired power plants. EPA is required by a settlement reached in litigation with environmental groups to come up with a utility MACT standard by December 2003. The MACT standard would be finalized by December 2004 and implemented by December 2007. EPA has not yet determined at what level to set the utility MACT standard, and is considering reductions of between 60% and 90%. The Leahy-Snowe bill would also establish mercury MACT standards for coal- and oil-fired commercial and industrial boilers at a 90% reduction rate from 1999 levels.

Multi-pollutant legislation is a hot-button issue in the current Congress. There is basic agreement that tighter limits are needed on NO_X, SO_2 and mercury. The most contentious issues are how much tighter and should there also be limits on CO_2 emissions.

Many Democrats will not support a multi-pollutant measure without a CO_2 reduction component. Republicans acknowledge that a multi-pollutant bill probably cannot get through the Senate without a CO_2 component. At this point, with more pressing budgetary concerns facing Congress, the prospects of passing a multi-pollutant measure this Congress are uncertain. The current Congress runs through the presidential election at the end of next year.

NSR Reforms

Changes to the federal "new source review," or "NSR," air permitting program took effect on March 3 and apply immediately in 11 states and the District of Columbia.

These states directly implement federal NSR rules through authority "delegated" to them by EPA. The states are Hawaii, Illinois, Massachusetts, Michigan, Minnesota, Nevada, New Hampshire, New Jersey, New York, South Dakota and Washington. The District of Columbia NSR program is partially delegated. The remaining 39 states implement the NSR program through EPA-approved state implementation plan or "SIP" rules. These states will have up to three years — until January 2, 2006 —to adopt conforming revisions to existing state NSR program rules.

There are five key components to the NSR program that have been modified. First, factories and other industrial facilities will be able to calculate their emission increases under the program the same way power plants calculate them — that is, by comparing past actual emissions to projected future emissions. Second, baseline actual emissions for industrial facilities will be calculated based on a "baseline" period of any consecutive 24-month period in the past 10 years. Power plants will still use a baseline period of a consecutive 24-month period in the past five years. Third, sources that keep their emissions below a plant-wide applicability limit or "PAL" will be able to make operational changes and equipment modifications without having to get prior approval through the major source NSR permitting process. Fourth, plants that have recently installed state-of-the-art pollution control technology on new or modified emission units as part of */ continued page 46*

an NSR or similar state permitting process would be allowed to make certain future changes without trigging additional NSR permitting for a 10-year period. Fifth, the rule codifies EPA's policy of excluding pollution control and prevention projects from NSR permitting review where the projects have a net beneficial effect on the environment. The final rule contains a presumptive list of technologies that will automatically qualify for the exclusion.

A group of Democratic state attorneys general — mostly from northeastern and mid-Atlantic states — have banded together to file lawsuits challenging the changes to the NSR rule. Those cases have been consolidated into one lead case (*New York v. EPA* (D.C. Cir. No. 02-1387)). A decision by the court is not expected until sometime in late 2003 or early 2004. Several environmental and health-related organizations have also joined the litigation, and several Senators have notified the court that they intend to file an *amicus* brief against the new NSR rule.

The Bush administration has lined up supporters for its changes to the NSR rule. They include several industry groups and the Republican attorneys general in eight states. The coalition of Republican attorneys general filed a motion to intervene in the lawsuit. Several industry groups have also filed petitions for review of the NSR rule, in part to ensure a "seat at the table" for any potential settlement discussions.

The group of Democratic attorneys general filed a motion on February 6 seeking an emergency stay against implementation of the new NSR rule on March 3. The court rejected the motion on March 6 concluding that the grounds for granting an emergency stay had not been met, but it agreed to grant an expedited review of the rule. Based on the courts' traditional deference to agency rulemakings on complex issues within its areas of expertise, it is questionable whether the court in this case will ultimately overturn the changes that EPA is proposing to the program. In order to do so, it would have to find that the changes were arbitrary and capricious, an abuse of the agency's discretion or otherwise not in accordance with the law.

The Environmental Protection Agency also proposed a separate rule at the end of last year that defines what qualifies as exempt "routine maintenance, repair and replacement." There would be two types of qualifying categories of "routine maintenance, repair, and replacement."

Since it is only a proposed rule, the "routine maintenance, repair, and replacement" proposal is still subject to public notice and comment. The public comment period was recently extended to May 2, 2003. EPA has scheduled five public hearings on March 31 in Albany, New York, Romulus, Michigan, Research Triangle Park, North Carolina, Dallas, Texas, and Salt Lake City, Utah. It expects to publish a final rule by the end of the year. However, the proposal is controversial and the timetable is liable to be pushed back. If the rule is finalized as proposed, it will undoubtedly be challenged by many of the same entities that are challenging the new NSR rule changes.

On the NSR enforcement front, the US Department of Justice and EPA continue to pursue enforcement actions filed in 1999 and 2000 alleging that several coal-fired power plants failed to undergo NSR permitting for major modifications. Several of the higher profile enforcement cases in this area are scheduled to go to trial later this year, and two cases have already been argued and are awaiting decisions.

In February 2003, a federal district court in Ohio heard oral arguments in *United States v. Ohio Edison Co.*, a case involving Ohio Edison's alleged failure to undergo NSR permitting for plant upgrades at its Sammis power plant. Last year, a US appeals court heard oral arguments in a similar case involving the Tennessee Valley Authority, and a decision is expected any day. Another similar case — *United States v. Southern Indiana Gas and Electric Co.* — is scheduled for trial starting March 31, 2003 in a federal district court in Indiana. EPA has won several early motions in the case.

The outcome of these NSR enforcement cases may affect EPA's proposed rulemaking on the "routine maintenance, repair, and replacement" exemption. If EPA is successful in court, it may face significant pressure from environmental groups to drop its proposal to define more clearly the scope of activities that qualify for the "routine maintenance, repair and replacement" exemption.

State Air Permits

The US Supreme Court has agreed to review a decision by a US appeals court that EPA was within its rights to bar a state from issuing a prevention of significant determination or "PSD" permit. Under the new source review or NSR program, companies proposing major modifications to existing air emission sources or developing new major emission sources in areas meeting the federal ambient air quality standards must obtain PSD permits before construction may start on the project.

The case is of particular interest because EPA has been thought to have only limited control over what the states choose to permit. EPA could provide comments on a draft PSD permit, but it was generally accepted that EPA could not override a state decision to issue a PSD permit except where EPA was willing to go to the extreme of withdrawing the state's PSD program authority altogether. The case involves states that have adopted their own PSD permit rules. It does not involve 11 states and the District of Columbia that issue permits under so-called "delegated" authority from the federal government. These 11 states use the EPA rule rather than rules they adopted on their own, and EPA clearly retains the ability to review their actions.

The case is *Alaska Department of Environmental Conservation v EPA*, 298 F. 3d 814 (9th Cir. 2002). The appeals court held that EPA could not only block the Alaska Department of Environmental Conservation — called "ADEC" — from issuing a PSD permit, but also issue a separate order to the project directing it not to start construction.

In the case, ADEC planned to allow a major modification to the PSD permit for a mine mouth power plant in Alaska. The owner of the power plant planned changes that would lead to a significant increase in air emissions from one of its diesel-fired units, and ADEC agreed that low NO_x burners constituted the "best available control technology" or "BACT" for the unit. EPA disagreed and concluded that a much more expensive selective catalytic reduction or "SCR" system would constitute BACT. Over EPA's objection, ADEC proceeded to issue the PSD permit.

The issue of EPA "second guessing" state and local air permitting agencies with fully approved air programs has long been a contentious issue. If the Supreme Court sides with EPA in the Alaska case, then EPA will be able to veto certain state-issued PSD permits. A favorable decision would also embolden EPA to take a much more active role in reviewing state-issued PSD permits than it has taken in the past.

Global Warming

Seven Democratic state attorneys general from the northeast (Connecticut, Maine, Massachusetts, New Jersey, New York and Rhode Island) and Washington state notified EPA that they will file suit against the agency for its alleged failure to regulate carbon dioxide emissions from US power plants. Under the Clean Air Act, notice of a citizen suit must be filed with EPA at least 60 days before the lawsuit is filed.

The notice letter alleges that EPA has a duty to update its federal new source performance standards or "NSPS" for power plants that produce steam at least once every eight years. The petitioners claim the last such review was 20 years ago and that a review of the NSPS would lead to the conclusion that CO_2 emissions from such power plants should be regulated.

The February 20, 2003 notice letter closely follows a similar notice letter filed by Connecticut, Maine, and Massachusetts on January 30, 2003. In the earlier letter, the state attorneys general assert that EPA should use its authority under the Clean Air Act to establish CO_2 as a criteria pollutant subject to a national ambient air quality standard.

Both lawsuits are long shots to force EPA to take action on reducing CO_2 emissions from power plants and other combustion sources. Nevertheless, the state efforts keep the issue alive and keep the pressure on EPA to act.

In related global warming news, in February, the Bush administration unveiled a number of agreements with industry trade associations whose member companies have agreed to reduce greenhouse gas emissions voluntarily. Participating trade associations include the American Petroleum Institute, Edison Electric Institute, National Rural Electric Cooperative Association, American Public Power Association, Electric Power Supply Association, the National Mining Association, the American Chemistry Council, and the American Forest & Paper Association.

The Bush administration also announced in February that US greenhouse gas emissions declined 1.6% from 2000 to 2001. This decline was the first recorded reduction in US greenhouse gas emissions / continued page 48

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since 1990. Total US greenhouse gas emissions are currently about 13% higher than 1990 baseline emissions. The US Department of Energy also recorded a 5.2% increase in 2001 in the volume of voluntary reductions in greenhouse gas emissions reported to the US government. The Department of Energy maintains a registry of voluntary reductions in greenhouse gases and carbon sequestration projects.

Brief Updates

The New York Department of Environmental Conservation issued final regulations in March 2003 implementing a state program that is supposed to produce significant reductions in NO_x and SO_2 emissions from New York power plants. The final rules will require SO_2 emissions to be reduced by 50% below current federal standards starting on January 1, 2005 with full implementation completed by January 1, 2008. Under the new rules, the current ozone season NO_x reduction requirements will also be imposed year round with the implementation starting in October 1, 2004.

The Ozone Transport Commission and EPA released a study in early March that reports NO_x emissions from power plants and other major combustion sources in 12 northeastern and mid-Atlantic states and the District of Columbia dropped by 60% since 1990. The OTC region states implemented a NO_x cap and trade program in 1999, and emissions have been reduced from 473,000 tons of NO_x in 1990 to about 200,000 tons in 2002. Starting in 2004, the OTC NO_x budget program will be integrated with EPA's NO_x SIP Call program, and the cap will be further reduced to 141,000 tons of NO_x for major sources in the OTC region.

A vote in the US Senate on March 19, 2003 dealt a serious blow to the Bush administration's plans to allow oil drilling in the Arctic National Wildlife Refuge. The Senate voted 52 to 48 not to assume that such drilling would produce $2.15 billion in royalties for the government. The vote came during debate on the budget for the coming year. After the vote, the chairman of the Senate Energy Committee said he would not try to include Arctic National Wildlife Refuge language in the comprehensive energy bill expected to be debated later this year. The House is still expected to include such language in its energy bill. The two houses will have to come to a common position before they can send a final bill to the president.

The Bush administration asked Congress in its budget this year to make the "brownfields" tax incentive permanent. The brownfields tax incentive allows companies to deduct certain costs associated with the remediation and redevelopment of qualified contaminated sites immediately as the money is spent. The authority for such deductions is currently set to expire on December 31, 2003. The Bush administration wants to extend it. ◎

— contributed by Roy Belden in New York

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