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US Moves to Reduce Pollution From Power Plants

by Roy Belden in New York

The US Environmental Protection Agency published two proposed emission standards in the Federal Register in late January that will require spending on costly new pollution control equipment at many power plants.

The first proposal — called the "utility mercury reductions rule" — would regulate mercury and nickel emissions from existing and new coal- and oil-fired electric power plants.

The second proposal — called the "interstate air quality rule" — would require 29 states and the District of Columbia to adopt plans that would dramatically reduce nitrogen oxide, or NO_X, and sulfur dioxide, or SO_2, emitted from power plants and other sources.

The two rules are intended to work in tandem. The government has asked for comments by the end of March, and public hearings have been scheduled for February 25 and 26 in Chicago, Philadelphia and Research Triangle Park, North Carolina. According to EPA Administrator Mike Leavitt, the two rules will trigger "the largest investment in air quality improvement in the history of this nation." Both rules are closely modeled after a "clear skies initiative" that the Bush administration has been pushing unsuccessfully in Congress to reduce NO_X, SO_2 and / continued page 2

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A COAL INDUSTRY CASE in the US courts may have broad implications for other industries.

The coal companies claim the US government has no right under the US constitution to collect reclamation fees on coal mines to the extent the charge falls on coal for export. The US government tried to get the case dismissed, but a federal appeals court said in December that it will hear the arguments.

The export clause of the US constitution says, "No Tax or Duty shall be laid on Articles exported from any state." The US Department of the Interior collects a charge of 35¢ a ton on coal from / continued page 3

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mercury emissions from power plants.

Environmental groups immediately criticized the new proposals as not going far enough. The government proposed two alternative methods for reducing mercury and nickel emissions. It said emissions from power plants would be reduced by 70% by 2018 under one of the alternatives and by 30% by 2007 under the other approach.

Proposed new emission standards will require additional spending on pollution control equipment at many power plants.

Environmental groups are seeking at least a 90% reduction in mercury from coal-fired power plants. The final mercury rule must be adopted by the end of this year under terms of a 1998 settlement of a lawsuit brought against EPA by the Natural Resources Defense Council. Like so many environmental regulations, the details will be settled ultimately in court.

The interstate air quality rule would bring about a 65% reduction in NO_x from current levels by 2015, according to EPA officials. The reductions in SO_2 from current levels would be 58% by 2010 and 70% by 2015. The Bush administration proposed it, in part, in an effort to head off legal action by northeastern and mid-Atlantic states to force more stringent reductions in the pollutants. The states complain that their troubles meeting national ambient air quality standards for fine particulate matter, or PM2.5 and ozone are due to migrating pollutants from coal-fired power plants in the rust-belt states of the midwest. EPA is expected to issue the final interstate air quality rule in early 2005 after incorporating input received during the comment period.

Mercury

As a court-mandated deadline for proposing mercury standards for coal-fired power plants approached, EPA faced a dilemma over possible approaches to regulate mercury without crippling utilities that own coal-fired power plants. EPA has recognized that mercury is highly toxic, persistent, and accumulates in the environment; however, there is no technology "silver bullet" currently available to achieve significant mercury air emission reductions from power plants. Another complication is that there are several different types of coal, including bituminous, sub-bituminous and lignite, and each of these types of coal has different levels of mercury content. There are also significant differences in the types of mercury within these coals. In general, bituminous coal contains higher levels of mercury than sub-bituminous and lignite coals, but the mercury is much harder to remove from sub-bituminous and lignite coals.

The Bush administration favors regulating mercury under a cap-and-trade approach under which emissions limits are established and each existing power plant is given the right to emit a certain amount of mercury. Anyone who wants to build a new facility or emit more mercury than he has been authorized must first purchase credits from others who have them. This is similar to the way sulfur dioxide emissions are limited currently under the federal acid rain program.

EPA proposed two alternative approaches for reducing mercury emissions from coal-fired plants and nickel emissions from oil-fired plants based on different sections of the Clean Air Act. It will choose one of the approaches by the end of this year.

The first approach is a traditional "command and control" approach based on legal authority to order reductions under section 112 of the Clean Air Act. The alternative is a "cap and trade" program based on legal authority under section 111 of the Clean Air Act.

Both alternatives would apply to coal-fired power plants with a capacity of more than 25 megawatts that produce their entire output for sale and to cogeneration facilities that put more than one-third of capacity and more than 25 megawatts on a utility grid for sale. (A cogeneration facility is a power plant that generates two useful forms of energy from a single fuel. An example is a power plant that burns coal to boil water and produce steam, some of which is used as steam and the rest of which is run through a steam turbine to generate electricity.)

The proposed rule that uses a command-and-control approach would apply to both new and existing coal-fired power plants. Section 112 of the Clean Air Act requires EPA to set emission limits for major hazardous air pollutants at a level representing "maximum achievable control technology," or "MACT." For existing plants, the MACT level is set at the average emission limitation achieved by the best performing 12% of plants in a particular category or subcategory of sources. For new plants, the MACT level must be set by law at the level of control achieved by the best controlled similar source.

The government had little choice but to regulate mercury after a December 2000 EPA study identified mercury as the hazardous air pollutant of greatest concern from a public health perspective.

Given the uncertainties surrounding the technologies that will be available to achieve mandated mercury emission reductions, EPA has embraced the regulated community's argument that different mercury emission reduction targets should apply based on the type of coal being burned. Both EPA proposed mercury reduction rules include different emission standards for plants burning bituminous, sub-bituminous, lignite and coal refuse. Anthracite-fired plants would be subject to the same limits as bituminous-fired power plants.

In the command-and-control proposal, EPA proposed the following MACT emission limitations for existing power plants based on five subcategories. These plants would have the option of complying either with an input-based pounds-per-trillion Btus or an output-based pounds-per-megawatt-hour standard. The proposed MACT standards for existing plants include: 2.0 pounds per trillion Btus or 21×10^{-6} pounds per megawatt-hour for bituminous, 5.8 pounds per trillion Btus or 61 pounds per megawatt-hour for sub-bituminous, 9.2 pounds per trillion Btus or 98 pounds per megawatt-hour for lignite, 0.38 pounds per trillion Btus or 4.1 pounds per megawatt-hour for coal refuse, and 19 pounds per trillion Btus or 200 pounds per megawatt-hour for integrated gasification combined-cycle, or IGCC, units.

Under the command-and-control proposal, there would be the following output-based mercury / continued page 4

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surface mines and 15¢ a ton on coal from underground mines to help defray the cost of cleaning up coal mining areas after mines shut down. The charge applies to all coal, whether or not it is exported.

At issue is whether the amount is a "fee" or a "tax." A tax would be unconstitutional. The difference is a fee is usually tied to the cost of services the government provides while a tax varies with the quantity or value of economic activity. In 1993, the US Supreme Court struck down a harbor maintenance tax that imposed a uniform charge on shipments of commercial cargo through the nation's ports on grounds that it was a tax on exports.

The US government collects a variety of excise taxes — for example, on communications services, oil and chemicals, various fuels, heavy truck trailers, gas guzzling vehicles, certain transportation by water or air, alcohol, tobacco, lotteries, firearms, foreign insurance policies, vaccines and coal.

Congress sometimes provides an exception for exports. The tobacco tax contains such an exception. Arguments in the reclamation fee case should be heard later this year.

CONFIDENTIALITY AGREEMENTS no longer need to contain boilerplate language allowing the parties to disclose the "tax treatment" and "tax structure" of the transaction.

The Internal Revenue Service requires US corporations and brokers to report transactions that are possible corporate tax shelters. It has issued a list of six factors that it believes may be a sign that a transaction is a tax shelter. If any of them is present in a deal, then the details of the transaction must be reported to the IRS. One of the factors is that the transaction is "offered to the taxpayer under conditions of confidentiality." In February 2003, the IRS said a general confidentiality clause of the / continued page 5

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MACT standards for new coal-fired power plants: 6.0 x 10^{-6} pounds per megawatt-hour for bituminous, 20 x 10^{-6} pounds per megawatt-hour for sub-bituminous, 62 x 10^{-6} pounds per megawatt-hour for lignite, 1.1 x 10^{-6} pounds per megawatt-hour for coal refuse, and 20 x 10^{-6} pounds per megawatt-hour for IGCC units. EPA projects that mercury emissions would be reduced from 49 tons to 34 tons through implementation of the proposed mercury MACT standards.

Plant owners would be required to reduce mercury emissions to these levels by December 15, 2007.

For existing oil-fired units, the command-and-control proposal calls for a MACT nickel emission limit of not to exceed 210 pounds per trillion Btus or 0.0020 pounds per megawatt-hour. New oil-fired units would be subject to an output-based MACT limit of 0.0008 pounds per megawatt-hour. Compliance with both the mercury and nickel MACT standards would be based on a 12-month rolling average.

The alternative to a command-and-control approach is a cap-and-trade program for mercury. EPA is proposing a 34 ton mercury emission cap for the first phase commencing in 2010 and a 15 ton cap for the second phase starting in 2018. This is the amount of mercury emissions that would be allowed each year from all coal-fired power plants nationwide. During the first phase, EPA estimates that the mercury reductions would be achieved without too much additional effort by power companies as a consequence of other steps the companies must take to reduce NO_x and SO_2 emissions at their facilities under rules that are already in effect or are scheduled to take effect. Put differently, EPA does not believe its rule will be a burden to utilities with coal-fired power plants until after 2010. Mercury allowances would be issued to coal-fired plants based on a unit's share of the total heat input from existing coal units multiplied by an adjustment factor that depends on the type of coal. The adjustment factors are 1.0 for bituminous, 1.25 for sub-bituminous and 3.0 for lignite coals.

A cap-and-trade system will require some legal gymnastics to implement. EPA painted itself into a corner with its December 2000 study because the study concluded that regulation of mercury and other hazardous air pollutants from coal- and oil-fired utilities is "appropriate and necessary" within the meaning of section 112 of the Clean Air Act. Section 112 does not allow much leeway in how the regulation must occur. The agency must usually use a command-and-control approach. EPA prefers to set a limit and let the market decide how best to achieve it — the so-called cap-and-trade approach — but it can only get there if it backtracks from its earlier legal finding. Thus, EPA said when it published its competing proposals for mercury regulation in late January that while it still agrees that the regulation of mercury from coal-fired plants and nickel from oil-fired plants is "appropriate," it no longer believes that such regulation is "necessary." This gives it the latitude to regulate under section 111 of the Clean Air Act. Section 111 is much less prescriptive than section 112, and it allows the agency more flexibility in setting mercury and nickel emission standards for new and existing plants.

Mercury emissions might have to be reduced by as much as 70%.

Under the cap-and-trade approach, EPA would set mercury MACT standards for new plants at the following output-based mercury levels: 0.00075 nanograms per joule (6.0 x 10^{-6} lb/MWh) for bituminous, 0.0025 nanograms per joule (21 x 10^{-6} lb/MWh) for sub-bituminous, 0.0078 nanograms per joule (67 x 10^{-6} lb/MWh) for lignite, 0.00087 nanograms per joule (0.53 x 10^{-6} lb/MWh) for coal refuse, and 0.0025 nanograms per joule (16 x 10^{-6} lb/MWh) for IGCC units. These limits are substantially the same as the mercury MACT emission limits proposed in the command-and-control proposal.

For existing oil-fired units, the cap-and-trade limit for nickel emissions would be 210 pounds per trillion Btus or 0.0020 pounds per megawatt-hour. For new oil-fired units, the limit on nickel emissions would be 0.0008 pounds per megawatt-hour. Compliance with the mercury and nickel standards would be calculated on a 12-month rolling average basis.

The two competing proposals are expected to touch off a raging debate that will play out ultimately in the courts. EPA must issue a final rule by December 15, 2004. The costs to comply with the new rule are expected to be substantial.

Migrating Air Pollution

EPA also published a proposed "interstate air quality rule" in late January that focuses on reducing the interstate transport of NO_X and SO_2 emitted from power plants and other sources that significantly contribute to fine particulate, or PM2.5, and ozone pollution in downwind states. NO_X and SO_2 are precursors of PM2.5 and NO_X is a precursor of ozone. The proposed rule directs 29 states and the District of Columbia to issue new regulations that will require major SO_2 and NO_X reductions in two stages.

The proposed rule encourages use of a cap-and-trade approach. While states will be given the flexibility to choose how best to achieve the NO_X and SO_2 emission caps in the proposed rule, the tenor of the proposed rule strongly suggests that EPA expects the states to adopt a cap-and-trade program.

This rule is much more likely to survive expected legal challenges since it is modeled after another proposal — called the NO_X SIP call regulation — that was upheld by a US appeals court last year after a protracted legal battle. Most environmental regulations end up in the courts.

The interstate air quality rule would require NO_X and SO_2 reductions in two stages. EPA proposes a cap of 3.9 million tons on SO_2 emissions by 2010, or approximately a 58% decrease from current SO_2 emission levels. It proposes a further cut to a cap of 2.7 million tons of SO_2 emissions by 2015 for a total reduction of about 70% from current SO_2 levels. Under the proposed rule, NO_X emissions would be reduced to a cap of 1.6 million tons by 2010, with an additional reduction to a cap of 1.3 million tons by 2015, for a total NO_X reduction of about 65%. Under the new rule, the SO_2 and NO_X emissions would be permanently capped and cannot increase.

Power plants that are subject to the / continued page 6

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kind found in most deals is enough to require registration as a tax shelter unless it is clear that "the taxpayer's disclosure of the tax treatment or the tax structure of the transaction is [not] limited in any manner." Lawyers rushed to put boilerplate language in confidentiality agreements allowing free disclosure of tax structures.

In late December, the IRS conceded that it had cast the net too widely. The agency said it has concluded that disclosure should be required only in situations where advisers are paid a fee of at least $250,000 and the *advisers* insist on confidentiality. It is not a problem for one of the parties to the transaction to insist on confidentiality, the IRS said.

In the future, engagement letters with advisers should make clear that the adviser is not insisting that the "tax treatment" or "tax structure" of the transaction be kept confidential. No further carve out from confidentiality restrictions is required.

A US WIND FARM is being sued for killing birds.

Law students at the University of Denver filed the case in a federal district court in California in mid-January. The students charge the owners of the wind farm — along the Altamont Pass in California — with killing birds that are protected under various federal and state protected species statutes and with making misleading environmental marketing claims by not including a warning about the effect on birds as part of their marketing efforts. The parties are required by local court rules to try mediation first. The mediation session has been set for April 23.

PERU increased its corporate tax rate to 30% on January 1, but it postponed until March 1 the date when it will start collecting a controversial 0.15% tax on banking transactions. The government is / continued page 7

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new rule would be allowed to submit acid rain allowances at particular retirement ratios to meet their SO_2 reduction obligations under the new rule. Regulated utilities would be able to use pre-2010 vintage SO_2 allowances on a one-to-one basis. Vintage 2010 to 2014 SO_2 allowances could be used at a two-to-one ratio, and vintage 2015 SO_2 allowances and beyond could be used at a three-to-one ratio.

One effect of the proposal is it could reduce the value of post-2009 SO_2 allowances. EPA is expected to receive a significant number of comments regarding how the new program should interact with the existing federal acid rain program. Many utilities have built up banks of unused SO_2 allowances and list them as valuable assets on their balance sheets. The new program could affect the value of these assets. EPA is concerned that "leakage" in SO_2 allowances may occur, meaning there would be a net outflow of surplus SO_2 allowances in states covered by the rule to non-affected states.

The interstate air quality rule will require the installation of a new round of costly pollution control measures at certain power plants and other industrial facilities, including flue gas desulfurization units to control SO_2 emissions and selective catalytic reduction systems and other NO_x control measures in order to meet the 2010 first phase NO_x and SO_2 emission reduction targets. ◎

New Rules For Off-Balance-Sheet Financing

In most infrastructure deals, a special-purpose company is formed to own the project. The project company often has more than one owner. The question comes up whether one of the owners — or even another participant in the transaction — must "consolidate" the project company, or include the financial results of the project company in a consolidated financial statement that the participant prepares for its own business. Consolidation can be a good thing if the project company has lots of earnings. However, more often than not, consolidation means having to show the debts of the project company as additional debt of the consolidated parent. Therefore, many project sponsors and investors look for ways to keep project companies off their balance sheets.

The accounting rules for when a project company must be consolidated and who must consolidate it became a lot more complicated last year. In late December, the Financial Accounting Standards Board, or FASB, issued a set of guidelines called FIN 46R in an attempt to pull together in one place the new standards for when consolidation is required.

The following is a conversation with Henry Phillips, an expert on the new rules with accounting giant Deloitte. Phillips heads the subject matter team at Deloitte on leasing, and he is also part of a team at Deloitte that fields questions about entity consolidation. He is in the Deloitte national office in Wilton, Connecticut. The questioner is Keith Martin.

MR. PHILLIPS: The title of FIN 46 is "consolidation of variable interest entities." It is best described as an alternative consolidation model.

MR. MARTIN: Let me come back to what is a "variable interest entity" and why FIN 46 provides an "alternative" consolidation model — alternative to what — but first, is it the case that every special-purpose entity must be consolidated with someone?

MR. PHILLIPS: No. It is common today, and it will be common after the issuance of FIN 46, for certain entities not to be consolidated by anyone. The traditional rule was that an entity had to be consolidated with whomever has control over the entity in the sense of possessing a majority vote. In a traditional voting model, in cases where no one had a majority of the voting stock, no one consolidates. In FIN 46, FASB said that this rule no longer applies to companies it calls "variable interest entities." In the case of such companies, the decision who has to consolidate is more complicated. In such cases, if no one has the majority of the expected losses of the entity or a majority of the residual returns, then no one will consolidate.

MR. MARTIN: So now we still have the traditional model for some entities and a new rule for variable interest entities. How does one tell whether he has a variable interest entity so that the decision who must consolidate is governed by the new rules?

Voting Entities

MR. PHILLIPS: There are several tests for identifying variable interest entities. It might be easier to approach this backwards. It is easier to tell whether one has a "voting entity" that remains governed by the old rules.

In order to qualify as a voting entity, the entity must have equity sufficient to finance its operations without any support from other entities. In addition, the equity holders, as a group, must have the ability to control the venture or the entity. They must also have the obligation to absorb expected losses if they occur, and they must have the right to receive residual returns if they occur.

MR. MARTIN: So equity holders as a group must retain both the downside risks and the upside benefits . . .

MR. PHILLIPS: . . . and the ability to control the entity.

MR. MARTIN: A voting entity must have sufficient equity to finance its operations. What if the owners are required to make ongoing capital contributions — for example, to cover any operating cost deficits? Does it have sufficient equity in that case?

MR. PHILLIPS: Those future funding commitments at the inception of a transaction do not qualify as equity at risk for FIN 46 purposes.

MR. MARTIN: So the entity needs all of the equity it anticipates it will need fully funded at the start? Over what time period? Does it need to be fully funded for 10 years worth of future needs or . . .

MR. PHILLIPS: It needs all its equity fully funded. You first apply the test on the effective date of FIN 46 for existing entities or, for new entities, when an investor or sponsor first has to decide whether to consolidate.

MR. MARTIN: So basically the test is that as of today you don't expect the entity to have to go back into the market to raise more capital.

MR. PHILLIPS: That's right.

MR. MARTIN: So these are tests to identify what is a voting entity. If one has such an entity, what is the test for whether someone must consolidate it?

MR. PHILLIPS: Then you would apply a traditional consolidation model, which is if someone has a majority of the voting stock, he would be required to consolidate.

MR. MARTIN: And everything else is a variable interest entity, or is this just a way of narrowing the potential class?

Business Scope Exception

MR. PHILLIPS: If an entity does not qualify as a voting entity, then it will be within the scope of FIN 46. There are other scope exceptions to FIN 46 — for */ continued page 8*

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expected to propose at least a dozen other tax changes as the country tries to lift tax collections to 16% of gross domestic product. Such collections were 13% of GDP in 2003.

BRAZIL discouraged foreign investors from using offshore holding companies in tax havens to make inbound investments into Brazil.

Foreign investors must pay a capital gains tax of 15% when selling off investments in the country. The tax is withheld by the buyer. However, if neither the seller nor the buyer is a Brazilian resident, then responsibility for collecting the tax is imposed on the person acting in Brazil as attorney-in-fact for the buyer.

The tax rate has now increased to 25%, effective January 1, on gains earned by sellers who are residents of "low-tax jurisdictions."

It is not a good idea to own Brazilian investments directly from a tax haven as exiting from the investment will be more expensive.

HUNGARY reduced its corporate tax rate to 16% on January 1.

It also decided to let companies that pay local or municipal business taxes deduct 125% of the amount paid from income before calculating corporate income taxes. Only the actual amount of municipal tax paid had been deductible in the past. The extra deduction has the effect of reducing the average company's effective tax rate by another 0.5%. However, part of this is taken back by a new levy on municipal business tax bills of 0.2 to 0.3% as a special research and development surcharge.

Hungary also extended a tax holiday for new investments in the country to 10 years. A company must invest at least $13.9 million at current exchange rates to take advantage of the holiday.

SALES "THROWBACK RULES" are becoming a thorn in the side of large companies operating in the United States. */ continued page 9*

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example, for certain employee benefit plans and for certain separate accounts of life insurance companies — that take some entities out of FIN 46 and put them back under the traditional voting model. The most significant of these exceptions is the "business scope exception."

MR. MARTIN: What fits in the business scope exception? It sounds like it should be entities that qualify as standalone businesses. Is that the only test?

MR. PHILLIPS: Basically yes. However, unfortunately, what is a business is not very clearly defined in the accounting literature. A business is a self-sustaining integrated set of activities and assets conducted and managed for the purpose of providing a return to investors. It consists of inputs, processes and outputs to generate revenue.

MR. MARTIN: Suppose several power companies set up a special-purpose company to own a single power plant. Is that special-purpose company a "business" and, therefore, does it fit in the business scope exception, and is the consolidation test for it strictly who has a majority of the vote?

MR. PHILLIPS: It could be a business or it could be a variable interest entity. You need to dig more deeply into the facts and circumstances. I have seen situations in the past where a single power plant does qualify as a business.

MR. MARTIN: Can you give me an example where it would not be a business?

MR. PHILLIPS: We probably need to go back and talk about the fact that the business scope exception cannot be applied with a broad brush. There are other caveats to application of the business scope exception. If the reporting enterprise provided more than half of the total equity, subordinated debt or other forms of financial support to the entity, based on an analysis of fair value of those interests, then the business scope exception is not available to that reporting enterprise.

MR. MARTIN: Stop there. The business scope exception is not as simple as if I have a business, then the test for consolidation is strictly vote? There are exceptions where the fact that the special-purpose entity is a standalone business is not enough?

MR. PHILLIPS: That's right. You need to look further to make sure you are not barred from using the business scope exception. I think the other common exception in the power industry is if the entity is designed so that substantially all the entity's activities either involve or are conducted on behalf of the reporting enterprise. In that case, the business scope exception is not available to that reporting enterprise. An example is where a strategic investor that has an equity stake in a project company is also providing more than half the total financial support to the project company. Suppose the strategic investor is a utility. It has a long-term power sales contract with the project company to buy 100% of the electricity from the project. In that case, I think you would conclude that the project company is conducting its activities on behalf of the utility strategic investor. The business scope exception would not be available.

MR. MARTIN: So there are two situations where the business scope exception is not available, even though the project company is a standalone business. Again, if one fits in the business scope exception, then one would look at vote to determine who must consolidate the project company. The two main exceptions where the business scope exception is not available are, number one, a company that provides more than half the total financial support could not claim the business scope exception and, number two, a company on whose behalf substantially all of the project company's activities are conducted could not claim it either.

MR. PHILLIPS: The financial support can take the form of equity, debt or other forms of guarantees.

MR. MARTIN: Then why wouldn't a lender who lends —

The rules for when a project must be put on balance sheet and by whom have become a lot more complicated.

say — 80% of the cost of the project have to consolidate with the project company, particularly where the loan is made on a nonrecourse basis?

MR. PHILLIPS: A lender could be required to consolidate a project company. That brings up a very good point, and that is historically only equity participants have been required to consolidate entities.

Under the FIN 46 model, the variable interest model, whichever party is exposed to a majority of expected losses of the entity would be required to consolidate it. Thus, for example, if a lender supplied all the subordinated debt, and that debt accounted for 80% of the total financing, it might be required to consolidate the entity.

Variable Interest Entities

MR. MARTIN: I was going down a path of probing when the business scope exception would not bring one back under the traditional rule of consolidating on the basis of who has the majority voting rights. Let me move to the next question. Suppose one can't get under the traditional rule. The project company is not a voting entity. And the business scope exception is not available. Thus, one is thrown under FIN 46. In that case, what is the test for whether consolidation is required and with whom consolidation is required?

MR. PHILLIPS: So we have determined that a project company is a variable interest entity. In that case, the first question to ask is whether any of the reporting enterprises — the owners of the project company and other participants in the transaction who are wondering who must consolidate with the project company — is expected to absorb a majority of the expected losses from the project company. If yes, then that person must consolidate the project company.

If no single party is expected to have to absorb a majority of the expected losses, then the focus shifts to whether someone has a right to a majority of the residual returns of the project company. In other words, the focus is to look first at who bears the downside fluctuations in cash flows, and then it shifts to who would benefit from the upside.

MR. MARTIN: What makes returns "residual"? They are left over after what?

MR. PHILLIPS: FIN 46 talks about expected losses and residual returns. Expected losses are the downside cash flow deviations from the mean.

MR. MARTIN: The "mean" is what was expected?

MR. PHILLIPS: Right. And residual / continued page 10

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Most US states have corporate income taxes, but since large companies typically operate across state lines, the state has to figure out how much of the company's income was earned in the state as opposed to outside before applying its tax. State tax departments are outmanned when it comes to sorting through accounts of large multinational corporations. Therefore, states usually treat a large corporation and its many subsidiaries as a "unitary" business and apportion some share of the entire group's income to the state based on a weighted percentage of the overall sales, property and payroll of the group that are in the state.

Follett Corporation is a book publisher in Illinois that sells textbooks and other educational materials to schools. Many of its sales are by affiliated companies in other states. These affiliates pay sales taxes to the other states on their book sales in those states. However, Illinois has a "throwback rule" that treats the sales as occurring *in Illinois* for purposes of apportioning income if the books were shipped from a warehouse or factory in Illinois by a "person [who] is not taxable in the state of the purchaser."

Follett argued that since its affiliates paid sales taxes to the other states, the sales could not be Illinois sales. However, an Illinois appeals court disagreed in December. The court refused to read the word "person" in the statute to mean the Follett group as a whole.

Companies would be wise to focus on how out-of-state sales are structured to avoid tripping throwback rules. The case is Follett Corporation v. Illinois Department of Revenue.

USE TAXES are a danger when companies offer free or discounted equipment to encourage customers to use their services.

Two cellular telephone companies in Louisiana offered their / continued page 11

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returns are the upside variability from the mean.

MR. MARTIN: So the question is, if there is greater loss than expected or greater profit or return than expected, who gets it.

MR. PHILLIPS: That's exactly right. If expected losses are sufficiently dispersed amongst parties such that no one party holds the majority of the expected losses, then you look at residual returns.

If a project company is an "operating joint venture," then chances are no one has to consolidate it.

MR. MARTIN: Then let's go back to the power industry example. A special-purpose entity owns a power plant, and there are several owners of the special purpose entity. Let's say it is a partnership or LLC with several owners. It has a contract to supply power to a utility. It has also borrowed a lot of money on a nonrecourse basis. The issue is with whom must that special-purpose entity consolidate for reporting purposes. And I guess it turns first on whether it is a voting entity.

MR. PHILLIPS: Correct.

MR. MARTIN: You went through four tests to decide whether it is a voting entity, and the main one seems to be whether it has enough equity to satisfy its needs or whether it will have to rely on the partners to contribute more capital going forward or raise more capital in the market.

MR. PHILLIPS: Correct.

MR. MARTIN: Now, if we conclude that the project company is a voting entity, then it consolidates with whomever holds the majority of the vote. It is that simple?

MR. PHILLIPS: That's right.

MR. MARTIN: If the project company is not a voting entity, then we must ask whether we fit in the business scope exception, which pulls us back under the voting model?

MR. PHILLIPS: Right.

MR. MARTIN: That's when things became complicated. On the one hand, this special-purpose project company looks like a standalone business but, at the same time, you said that that's not enough because if there is someone who provides more than half the total financial support or on whose behalf substantially all of the project company's activities are conducted, then the business scope exception is not available and one must use the tests in FIN 46 to decide who consolidates.

MR. PHILLIPS: Correct.

MR. MARTIN: So let's acknowledge that, in the typical power project, most of the financial support comes from the bank that supplies the money on a nonrecourse basis. Doesn't that necessarily take one out of the business scope exception for the typical power project?

MR. PHILLIPS: It may take the financial institution outside the business scope exception, but it may not deny the business scope exception to an equity participant.

MR. MARTIN: That is a very important point. I thought one looked at the project company itself to determine whether the business scope exception applies. Now you seem to be looking at the participants to see whether each of them can use it. What gives?

MR. PHILLIPS: It is applied at the level of the reporting enterprise.

MR. MARTIN: Then going back to the determination whether the project company is a voting entity, does one look at the reporting enterprise or at the project company?

MR. PHILLIPS: The reporting enterprise must determine whether the business scope exception puts it back under the traditional voting model for that entity.

MR. MARTIN: Take a step back. When one is deciding whether a project company is a voting entity or a variable interest entity, is the focus on the project company or on the reporting enterprise — that is, on the person who is trying to decide whether he must consolidate the project company?

MR. PHILLIPS: In terms of which consolidation model to apply, the focus is on the special-purpose entity.

MR. MARTIN: So only with the business scope exception is the inquiry up at the participant level.

MR. PHILLIPS: That's right.

MR. MARTIN: And what question must the participant ask to determine whether the business scope exception lets him consolidate or not on the basis of voting rights?

MR. PHILLIPS: The question is whether the special-purpose entity can qualify as a business on a standalone basis. However, even if the answer is yes, it can, the business scope exception is unavailable to that reporting enterprise — or participant — if the reporting enterprise provided more than half the total financial support or substantially all the activities of the project company are conducted on behalf of the reporting enterprise. FASB has said it will not allow that reporting enterprise to claim the business scope exception because it is too closely involved with the project company.

MR. MARTIN: Therefore, you may have some participants deciding whether to consolidate the project company based on vote and others doing so based on how expected losses or residual returns are shared.

MR. PHILLIPS: That's right.

MR. MARTIN: How can that be? Then you could have consolidation with more than one entity.

MR. PHILLIPS: I think that potential may exist. However, the hope is that only one reporting enterprise will have to consolidate the entity.

MR. MARTIN: Come back then to the power plant model. There are two main situations where a participant in a deal cannot assert that the business scope exception lets it decide whether to consolidate based on who has the majority vote. One is where the participant provides more than half the total financial support for the project company and the other is where substantially all of the activities of the project company are conducted on behalf of that participant.

MR. PHILLIPS: There is no bright line to determine what is "substantial," but I would say it is more than 90% of the activities.

MR. MARTIN: Are substantially all the activities conducted on behalf of a utility that buys 100% of the electricity output?

MR. PHILLIPS: It is a highly subjective / continued page 12

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customers cell phones for less than the wholesale price as an inducement to sign up for phone service. Most states collect both sales and use taxes. Sales taxes are collected on retail sales of equipment and sometimes also on services. "Use" taxes are collected on equipment that someone buys out of state or at wholesale and then uses himself in the state. In this case, the tax collector charged that the phone companies were *using* the phones as marketing tools and levied use taxes.

However, before the case could be heard in court, the state legislature changed the law — retroactively. The tax collector cried foul and said it was unconstitutional for the legislature to change the law retroactively. In December, the state supreme court declined to rule on the constitutional issue and sent the case back to a trial court for the arguments to be heard there. The case is *Unwired Telecom Corp. v. Parish of Calcasieu*.

The case is a warning to be wary of use taxes when giving away or offering discounted equipment as a marketing tool to sell services.

OIL AND GAS RESERVE CALCULATIONS are receiving scrutiny from the US Securities and Exchange Commission.

A downward revision in reserves by one of the oil majors in mid-January has triggered a flurry of investor demands for tighter rules and greater transparency in connection with petroleum reserve accounting. Shell reclassified 20% of the company's stated proven reserves into a lesser category. El Paso warned that it will make "a material negative revision" to its stated reserves. Forest Oil revised its reserves downward in late January. Other oil companies are expected to follow.

The SEC was already reviewing its reserves definitions, which were established in 1978, and previously sent questionnaires relating to reserve calculations and reporting to a number of oil and gas / continued page 13

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test. The best example of activities conducted on behalf of a participant may be an affordable housing project where the general partner is in the business of developing real estate and the limited partner is investing mainly for the tax benefits. The question is whether substantially all the activities are conducted on behalf of one of the parties. Most accountants have concluded the answer is no because both partners have a purpose for being in the transaction.

MR. MARTIN: Focusing still on the power project where you have a bank supplying 80% of the financing on a nonrecourse basis, the bank may not have to consolidate the project company. Here is the analysis. The project company is not a voting entity. The bank cannot use the business scope exception. Therefore, the question whether to consolidate is decided under the variable interest rules. Under those rules, the bank does not have to consolidate because it does not bear a majority of the expected losses — or does it?

MR. PHILLIPS: It is unlikely that a bank would have to consolidate. When the bank makes a loan, it does so on the basis of a cash flow model that suggests that the loan will be repaid even in a worst case scenario. It also requires that the project company be sufficiently capitalized so that the equity would bear the majority of the expected losses.

MR. MARTIN: There is a margin for error leaving room for unexpected losses to be absorbed by the equity.

MR. PHILLIPS: A bank would not normally lend into a transaction where it is expecting to bear a majority of the losses.

MR. MARTIN: And what about a utility that buys all the output from the power project? It is possible that substantially all the activities of the project company are considered conducted on behalf of the utility. Therefore, the utility cannot use the business scope exception to argue that consolidation should be determined strictly on the basis of who has the majority vote. However, at the same time, the utility does not have to consolidate because, under FIN 46, it's likely that the utility will not bear a majority of the expected losses from the project.

MR. PHILLIPS: Right. But be careful because, in some transactions, the utility offtaker might also be an equity participant in the transaction or be a guarantor of the debt. In such cases, the analysis is more complicated.

Be aware that some participants in a transaction might be labeled "agents" of others.

MR. MARTIN: I can see bad facts arising. What if the power contract has a tracking account where the utility overpays for electricity in the early years with the expectation that it will recover the overpayments in later years?

MR. PHILLIPS: It becomes a tougher case. If the project were to fail and the project go into bankruptcy, the utility might lose the balance in the tracking account. The utility has potentially a significant variable interest in the project company.

Operating Joint Ventures

MR. PHILLIPS: There is one other exception to the business scope exception that we should talk about. If the reporting enterprise participated significantly in the design of the entity, then the business scope exception is not available to that reporting enterprise unless the entity is either an operating joint venture or a franchisee.

MR. MARTIN: What does it mean to participate in the design? What is an example?

MR. PHILLIPS: Suppose a new project company is formed. It has a power company and a financial investor as the partners. They were both actively involved with forming the entity and negotiating the operative documents in the transaction. Both partners would have participated significantly in the design of the entity. That means neither can rely on the business scope exception. They are both thrown under FIN 46 when deciding who has to consolidate the entity. But there is a way out. If the project company is considered a joint venture entity, then they are back under the voting model to decide who consolidates.

MR. MARTIN: What does it mean to be an operating joint venture?

MR. PHILLIPS: Let's just go through the analysis. We conclude that the project company is a standalone business. However, both of the partners participated significantly in designing the entity. Thus, at first glance, it looks like neither can claim the business scope exception that would let the decision whether to consolidate turn solely on who has the majority vote. But the company is an operating joint venture. That throws it back into the voting rights model. It is an operating joint venture because each of two partners has 50% of the vote.

MR. MARTIN: To have an operating joint venture, the partners have to share equally in voting rights? What happens if there are three partners?

MR. PHILLIPS: Joint venture typically means no one party controls. If you have two partners, the vote would have to be 50-50. If you have three, the vote would have to be a third, a third, a third.

MR. MARTIN: And "operating" must mean it runs a real business; it is not just collecting rents or dividends?

MR. PHILLIPS: That's right.

MR. MARTIN: And if you have an operating joint venture, then you are back in the voting rights model.

I am starting to appreciate why accountants like those decision-tree diagrams with lots of arrows and questions. If the answer is "yes," then it leads to another question with arrows splitting off "yes" or "no" from it. The diagrams look like electrical circuitry.

If you have an operating joint venture, by definition, no one controls the vote, so is there consolidation of such entities?

MR. PHILLIPS: If such an entity qualifies as a voting entity, then no one would consolidate it. That's why a number of project companies today are structured as operating joint ventures so that no one party consolidates the entity.

MR. MARTIN: It seems the key, at least keeping power plants as the focus, is one should be / continued page 14

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companies involved in Gulf of Mexico operations last summer. This interest was fueled by increasing concerns that US reserves reporting rules have become outdated due to dramatic changes in the tools for evaluating reserves, as well as in the way in which oil and gas are marketed.

The chairman of the Financial Accounting Standards Board, Dennis Beresford, said, "It's certainly a wakeup call for the SEC and maybe the FASB to think about this." Jim Murphy, an in-house SEC petroleum engineer, has warned in the past that a 10% difference between what a producer initially reports as proven reserves and what is reflected after a revision is likely to trigger an SEC probe.

Current SEC rules allow companies to report only proven reserves, and exclude reporting of lesser categories of reserves, such as "probable" and "possible." Some analysts and investors are now calling for greater disclosure of both proven and probable reserves to supplement the information required under the current rules, as well as much more detail on the breakdown of such reserves. Many companies are also placing greater reliance on independent third-party certification of reserves, at least partly in response to heightened management concerns because of the Sarbanes-Oxley Act.

Canadian reserve reporting rules require third-party reserve certification. There have been calls for the US to adopt the same approach.

NATURAL GAS DRILLING in the shallow water regions of the Gulf of Mexico got a boost from the US government.

The US Department of the Interior announced a new federal royalty relief program on January 23 that will apply to existing federal leases and cover deep-well drilling in water depths of up to 656 feet. Under the program, / continued page 15

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careful not to give anyone a dominant vote. If everyone has an equal say, then — by definition — the project is an operating joint venture, which then means the decision whether to consolidate can turn strictly on vote. And there would never be consolidation.

MR. PHILLIPS: That's right.

Principals and Agents

MR. MARTIN: I heard you say in a speech last week that it is also important who in a transaction is a "principal" and who is an "agent." Why are these labels important?

MR. PHILLIPS: The labels are important in some power plant transactions as well as some of the more common tax structures with affordable housing and synthetic fuel. These terms are only significant if you are under the variable interest model. Thus, we have concluded that we are under FIN 46. We do not have a voting entity. We have a variable interest entity.

The first thing you need to determine with a variable interest entity is whether any of the participants in the transaction is a related party. Related-party relationships are deemed to exist if a party cannot finance its operations without the support of a reporting enterprise. Someone who is an officer, employer or governing member of the board of a reporting enterprise is a related party. One of the more significant situations where a relationship may exist is where a reporting enterprise has agreed that it cannot sell, transfer or convey its interest in the project company without the prior approval of another participant in the transaction. That creates a *de facto* agency relationship.

MR. MARTIN: Again, why do I care whether someone is a principal and someone else is an agent?

MR. PHILLIPS: Let's assume for a moment that there are transfer restrictions on our holdings, either equity or debt holdings in the project company. These transfer restrictions create a principal and agent relationship. FIN 46 requires that we figure out who is the principal and who is the agent. The principal must aggregate the agent's interest as if it was also part of the principal's holding in the project company.

This makes it more likely that the principal will have to consolidate the project company.

Suppose you have two equity participants and a bank that lent money to the project company. There are restrictions on the transferability of the equity instruments as well as on the debt instrument. One of the parties is the principal and the other two are agents. The principal will have to consolidate the project company because it would have to aggregate the other parties' holdings.

In wind farms where there is a guaranteed return, the guarantor might have to put the project on his balance sheet.

MR. MARTIN: So we have established that there are related parties, at least how the accounting literature defines it. How does one then determine who is the principal and who is the agent?

MR. PHILLIPS: You must weigh several factors to determine if you are the principal or the agent. In addition to other criteria, you must assess the significance of the activities of the entity to the various parties in the related party group and the various parties' exposure to the expected losses of the entity.

MR. MARTIN: The concepts are too abstract. Is it possible a utility buying all the electricity from a power plant is an agent or a principal of some other participant in that deal?

MR. PHILLIPS: That is possible. If you are the offtaker under a long-term power sales contract and there are transfer restrictions on the other debt and equity participants, you might conclude that, because the activities of the entity are more closely associated with your company because you are the only power company in the transaction, you may have to aggregate the other interests.

MR. MARTIN: The utility would be the principal in that case?

MR. PHILLIPS: The utility would be the principal and the primary beneficiary, and the primary beneficiary is the company that is required to consolidate the project company.

MR. MARTIN: Surely you would have to find more than just a transfer restriction and the fact that the utility is buying all of the output?

MR. PHILLIPS: True. Other indicators are given weight. Another important indicator is how much exposure each of the parties has to losses in the project company.

MR. MARTIN: In plain English, a principal is what — somebody who has such control over the entity that it really ought to be viewed as his?

MR. PHILLIPS: That's right. This is really an anti-abuse provision that prevents companies from disaggregating their interests among members of a related-party group.

Wind Farms and Synfuel

MR. MARTIN: Just a couple other questions briefly: I believe I heard you say in a speech that the guarantor in an affordable housing project — somebody who guarantees that the equity investors will get a minimum return — must normally consolidate the project. Is that right?

MR. PHILLIPS: Right. I think that would normally be the case.

MR. MARTIN: And if, in a wind farm, there was a guarantor who guaranteed the equity investors a minimum return, the guarantor would end up consolidating the operations of the wind farm, including the debt.

MR. PHILLIPS: I think there is a high likelihood that the guarantor would have to consolidate because when you go through the expected losses, if anybody is expected to lose in that transaction, it is the guarantor.

MR. MARTIN: Does it matter what level the guarantee is? I assume there would be a tranche of losses that would have to be borne by the equity before the guarantor suffers.

MR. PHILLIPS: It turns on the facts and circumstances. If there was a tranche of loss that the equity would have to bear before the guarantee kicks in, then perhaps the equity would have to consolidate the project. Or, perhaps no one would be required to consolidate because the risk has been adequately dispersed.

MR. MARTIN: Who consolidates in / continued page 16

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federal royalties are suspended on the first 15 billion cubic feet of gas produced from well depths from 15,000 to 18,000 feet, increasing to the first 25 billion cubic feet on wells 18,000 feet and deeper. Dry hole credits of up to two per lease are also available to help offset the costs of any unsuccessful drilling. This program is similar to a royalty relief program that has been in effect for new offshore federal leases since March 2001.

The goal is to boost production of natural gas from near-shore shallow waters in Texas, Louisiana, Mississippi and Alabama — areas that gas companies have not been eager to explore because of the expense involved in deep-well drilling and the difficulty in finding gas using seismic surveys. The US government estimates that as much as 55 trillion cubic feet of gas is deep underneath the shallow waters of the Gulf Coast.

The relief program is expected to cost the US government $1.1 billion in lost royalty revenues, but the government believes the cost will be more than offset by the $1.4 billion in additional production royalties that are expected when the royalty relief program ends.

CORPORATE GUARANTORS do not have taxable income as a consequence of being released from their guarantees, the IRS said.

The US Department of Energy found that an oil trading company violated US price controls on its resales of oil and ordered the trading company to repay the overcharges with interest. The government's restitution order also held the parent company jointly liable for the amount. Later, the government released the parent from any liability.

Ordinarily, when a debtor is released from a debt, he must report the amount as taxable income.

However, there was no discharge of debt in this case, the IRS national office said in an internal legal memoran- / continued page 17

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synthetic fuel deals where the sponsor sells the project to an institutional equity for quarterly payments that are tied to the amount of tax credits?

MR. PHILLIPS: Those are interesting structures. In the pay-as-you-go structure, the investor puts in its cash as it takes out tax credits. FIN 46 is applied at inception. At inception, the institutional investor really would not have any money at risk. However, FIN 46 also goes on to talk about trigger points along the way where you have to reassess whether or not you must consolidate the entity. The trigger points in this case probably arise each time the investor puts more money into the deal. However, because the investor only puts in money as he takes out tax benefits, if anyone is going to consolidate, it is probably the sponsor, assuming he retains a small fractional interest as the operating partner.

MR. MARTIN: Last question — have you seen any change since Enron went bankrupt in people's eagerness to keep things off balance sheet? Are they less eager to do so?

MR. PHILLIPS: Enron and the new standards that have been issued by the Financial Accounting Standards Board have not only focused attention on the recognition of certain assets and liabilities on a company's balance sheet, but they have also led to enhanced disclosure of these types of transactions. I think they have been a significant deterrent to off-balance-sheet transactions. People are not pressing accounting distinctions as closely as they might have in the past. ◎

Synfuel projects that are sold under "pay-as-you-go" structures often remain on the balance sheet of the sponsor.

FERC Focuses On Issues Affecting LNG

by Donna Bobbish, in Washington

The Federal Energy Regulatory Commission took two actions that could affect the market in the United States for liquefied natural gas, or "LNG."

The agency ruled in December and repeated in January that changes cannot be made to quality standards for gas carried in interstate pipelines without first getting approval in a tariff filing from FERC. The agency also announced in January that it will hold a public conference on gas interchangeability issues. These actions promise to ignite a vigorous debate among various segments of the energy industry — LNG project developers, interstate natural gas pipelines, local distribution companies and end-users — as to how LNG will be accommodated as an increasingly significant percentage of the nation's gas supply.

LNG: Fuel du Jour

LNG is natural gas that is stored and transported in liquid form at atmospheric pressure at a temperature of -260 degrees Fahrenheit. LNG is transported in double-hulled ships to a receiving terminal and then is sent to a regasifying terminal that turns the liquid back into a gas for transportation via pipelines.

Historically, LNG has played a small role in US energy supplies. The US Energy Information Administration, or "EIA," expects that in 2003, US LNG imports will be more than double the 2002 number and will represent about 2% of US natural gas consumption. EIA further projects that in 2010, US LNG imports will increase to about 8% of US natural gas consumption. These increasing imports are the result of higher natural gas prices, declining LNG liquefaction and shipping costs, rising gas import demand in the US, and the desire of gas-producing companies and gas-producing countries to monetize their gas reserves. Indeed, EIA projects that by 2015, LNG will become the largest source of net US gas imports as US imports of Canadian natural gas decline.

While Algeria and, more recently, Trinidad and Tobago are the largest suppliers of LNG to the US, the US also has purchased LNG from Australia, Brunei Darussalam, Malaysia, Nigeria, Oman and Qatar. Countries that are potential future suppliers of LNG to the US include Angola, Indonesia, Russia, Peru, Saudi Arabia and Venezuela. Indeed, interest in increasing US LNG demand is such that, in December 2003, the US Department of Energy hosted an LNG ministerial summit in Washington that brought together senior officials from both current and potential LNG importing and exporting countries to discuss planned and potential LNG projects and trade.

Currently, the continental US has four LNG import terminals: Cove Point, Maryland, Elba Island, Georgia, Everett, Massachusetts and Lake Charles, Louisiana. However, there are numerous proposals to construct new LNG terminals in North America to serve US markets.

Pipeline Btu Limits

The Federal Energy Regulatory Commission issued two orders in December that make clear that pipeline companies cannot change their gas quality standards without making formal tariff filings. These rulings addressing the issue of "natural gas interchangeability" may have a significant impact on LNG imports because, unlike domestically-produced natural gas or natural gas imported from Canada, most imported LNG has a Btu content higher than the Btu limits that several pipelines want to set. In order to meet these Btu limits, most LNG would have to be treated before being introduced into the pipeline system. The cost of this treatment may well have to be borne by the LNG shipper.

The issue of "natural gas interchangeability" involves the extent to which one type or quality of gas can replace another gas normally used by a customer without harming pipeline or end-use equipment, such as power generating turbines. This issue was raised recently at FERC by gas producers who, as a result of increasing natural gas prices, are not removing from the gas stream that they transport over interstate pipelines liquefiable hydrocarbons, such as propane and butane, for separate sale as natural gas liquids. Allowing these liquefiable hydrocarbons to remain in the gas stream raises the heat content, or Btu / continued page 18

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dum. The agency analogized the case to the situation where a corporation guarantees a debt owed by its subsidiary. The debt remains, but the guarantee is released. The parent guarantor has no income because it has had no increase its net worth. There is no income in the sense of an accession to wealth.

The IRS released a redacted version of its analysis in late January. The memorandum is ILM 200402004.

A WORTHLESS STOCK DEDUCTION can be triggered by filing a form to treat a subsidiary as a "disregarded entity," the IRS said in December.

Corporations with subsidiaries have an investment in the stock of each subsidiary. If the subsidiary becomes insolvent, then the corporation can deduct its investment — or "tax basis" — in what is now considered worthless stock. However, there must be some action to trigger the loss.

The IRS ruled in December the action might be as simple as filing a form with the agency to treat the subsidiary as a "disregarded entity." Such forms can only be filed for certain kinds of subsidiaries. For example, such a form could not be filed for a Delaware corporation. However, it could be filed for a subsidiary that is organized as a limited liability company, or LLC.

The filing of such a form causes the subsidiary to be considered liquidated for tax purposes. Ordinarily a loss cannot be claimed in a liquidation of a subsidiary into a parent corporation that owns 80% or more of the shares if the parent company receives something of value in exchange for canceling its shares. However, the IRS said in this case, since the subsidiary is insolvent, the parent company gets nothing of value by definition.

In testing whether a subsidiary is insolvent, be careful to take / continued page 19

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level, of the gas. Liquefiable hydrocarbons also become liquid at a specific "dewpoint" temperature, and may corrode or obstruct pipelines. Consequently, pipelines have established gas quality standards or Btu limits for the gas that they will accept for transportation over their systems. Recently, FERC has addressed complaints as to how pipelines should establish such standards and limits.

In late 2003, FERC ordered two pipelines, Trunkline Gas Company, LLC and ANR Pipeline Company, to stop using operational flow orders, or "OFOs," and critical notices posted on their websites to establish new, permanent gas quality limitations. OFOs are used by pipelines, typically in emergency situations, to control the flow of gas and maintain correct pressures in the pipeline in order to sustain the reliability of deliveries. A critical notice provides an advance warning that a pipeline may need to issue an OFO.

In its Trunkline order, FERC found that gas quality standards must be included in pipeline tariffs that must be on file with FERC. The agency noted that both ANR and Trunkline currently have gas quality standards in their filed tariffs that allow shippers to deliver gas with a Btu content of 1200 Btu per cubic foot, and neither tariff permits the pipeline to reduce gas Btu content below the level established in the tariff. FERC concluded that from January 2001 through December 2003, both ANR and Trunkline posted notices on their websites reducing from 1200 Btu/cf to 1050 Btu/cf the permissible Btu content for gas delivered to their systems. FERC held that, because section 4(d) of the "Natural Gas Act" requires pipelines to file proposed tariff changes, ANR and Trunkline violated the law by using OFOs and critical notices to change the gas quality standards established in their tariffs.

FERC required both Trunkline and ANR to stop using operational flow orders and critical notices to reduce the gas quality standards on their pipelines. However, it left the door open for both companies to change their current gas quality standards by submitting a formal request to do so with FERC. FERC gave ANR a transition period, through January 31, 2004, to meet with interested parties concerning gas quality standards that will prevail on the ANR system, and required ANR to file a proposal concerning gas quality standards on its system as soon as possible.

Efforts by interstate gas pipelines to set Btu limits on gas could make LNG more expensive.

Building on its ruling in Trunkline, FERC ordered two other pipelines — in a separate action in late January — to file changes to their tariffs restricting the pipelines' discretion to change their gas quality standards. The January order was directed at Columbia Gulf Transmission and Tennessee Gas Pipeline Company.

In its Columbia Gulf order, FERC recognized that gas quality standards included in pipeline tariffs must provide sufficient flexibility for pipelines to act in a timely manner to protect their operational integrity and minimize potential damage to equipment. However, the FERC expressed its concern about tariff provisions that give pipelines too much discretion to vary gas quality standards with inadequate notice and explanation to customers. The agency ruled that if pipelines want flexibility to vary Btu limits, they must include in their tariffs specific mechanisms for doing so that provide protections for shippers. Specifically, pipelines must provide a specified amount of notice to shippers before changing a Btu limit, and further must provide shippers with information concerning how pipelines will calculate Btu and dewpoint at receipt points.

Implications

While the gas interchangeability issue has arisen in the context of natural gas producers allowing liquefiable hydrocarbons to remain in the natural gas stream, FERC's decisions with respect to gas interchangeability have significant implications for developers of projects to import LNG into the US.

Most imported LNG has a Btu content that exceeds maximum Btu gas quality standards in many US pipeline tariffs, including the 1050 Btu/cf limit that Trunkline, ANR and Columbia Gulf attempted to impose on their systems. At present, only Trinidad consistently produces LNG with a Btu content that meets existing US pipeline standards without treatment. In contrast, the Btu content of LNG produced in Brunei, Oman, Abu Dhabi and Libya typically exceeds 1150 Btu/cf, while the Btu content of LNG produced in Indonesia, Australia, Qatar and Nigeria typically exceeds 1100 Btu/cf (with LNG from Qatar and Nigeria typically approaching 1150 Btu/cf).

If pipelines reduce their gas quality standards below the Btu content of LNG, most LNG brought to the US would have to be treated before it could be delivered to interstate pipelines.

The issue is who will bear the costs of such treatment and whether these additional treatment costs could make LNG less competitive. Revaporized LNG does not contain the heavier hydrocarbons — which are removed when the LNG is liquefied — that could lead to some of the condensation and corrosion concerns expressed by pipelines and end-users in connection with untreated, high Btu pipeline gas coming in from the Gulf of Mexico. Another issue is whether the FERC should permit different Btu limits among the interstate pipelines.

The FERC Conference

While it has specifically declined to address the issue of industry-wide gas quality standards in its orders, FERC will convene a public conference on February 18, 2004 to discuss policy issues arising from natural gas interchangeability.

Information presented at this conference could inform FERC policy (as set in individual pipeline orders), or it could form the basis of a future FERC rulemaking proposal. Positions on the issue appear to be splitting along industry segment lines. Producers want the ability to transport higher Btu content gas when it is not profitable to remove liquefiable hydrocarbons from the gas stream for separate sale. Pipelines want to retain the ability to set gas quality standards for their systems and control what gas they accept for transportation. End-users do not want to have to modify their equipment to accept higher Btu content gas.

Additionally, Rae McQuade, executive director of the National Energy Standards Board, has indicated that NAESB will look at the possibility of developing / continued page 20

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into account possible value in intangibles like goodwill and "going concern value." A subsidiary is insolvent if its assets are worth less than its debts.

The parent company can claim a worthless stock deduction even though the subsidiary keeps operating as before after the IRS form is filed. The IRS ruling is Revenue Ruling 2003-125.

MOST DEPRECIATION ADJUSTMENTS that US companies make on their own will require advance approval from the government, the IRS asserted in late December.

Any company that plans a "change in accounting method" in how it computes its taxes must get approval first from the IRS. Such approvals can take more than a year. IRS regulations say it is a change in accounting method to change the *timing* of when income or deductions are reported, but it is *not* such a change to adjust the "useful life" over which an asset is depreciated. This distinction has led some US courts to conclude that reclassifying a project from — say — 15-year property to 5-year property for depreciation is not a change in accounting method because it is the functional equivalent of altering the useful life.

The IRS does not like these decisions. In late December, it modified its regulations to require that most depreciation adjustments be treated as accounting method changes. The two situations where it said it would not require advance approval are where the taxpayer decides that an asset was placed in service on a different date than he thought earlier or where an asset is converted from personal to business use (or vice versa). The new rules appeared in the *Federal Register* on January 2.

FOREIGN DISREGARDED ENTITIES will have to be reported each year to the IRS, under new rules announced in late January.

The first reports are / continued page 21

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industry-wide gas quality standards early this year. In the past, NAESB and its predecessor, the Gas Industry Standards Board, have garnered industry consensus on various standards issues and have filed proposals for approval by the FERC. ◎

SEC Signals Tougher Stance On PUHCA Exemptions

by Robert F. Shapiro, in Washington

Enron lost a fight with the US government in late December over whether it was exempted from burdensome regulatory requirements under the Public Utility Holding Company Act, or "PUHCA."

The US Securities and Exchange Commission rejected Enron's appeal of an administrative law judge's decision that denied Enron's claims that it qualified for various exemptions under PUHCA. The decision could have ramifications for other power companies.

The Public Utility Holding Company Act is a law enacted in the 1930's that makes it difficult for power companies to operate in more than one state. Companies that own power plants in more than one state go to great lengths to qualify for exemptions from the statute. Any company that is not exempted must register with the US Securities and Exchange Commission as a "registered holding company." Most companies want to avoid PUHCA registration because it would subject them to pervasive financial and corporate regulation and could restrict the type and scope of investments that the companies can make.

Single State Exemption

Enron claimed that it was entitled to exemption under the so-called "single state" exemption found in section 3(a)(1) of PUHCA. The "single state" exemption requires a holding company to be incorporated and to operate primarily as a utility holding company in the same state in which the utility is incorporated and operates. It is the exemption that is utilized most frequently by parent companies of utilities in the United States. When Enron acquired Portland General Electric Company in 1997, it reorganized to become an Oregon corporation in order to avail itself of the "single state" exemption and avoid having to become a registered holding company under PUHCA.

The SEC denied Enron's claim that it was entitled to the exemption.

Enron argued that since it reincorporated in Oregon and since the Portland General service territory was limited to the state of Oregon, it should qualify. But the SEC disagreed, finding that Portland General earned an average of 34% of its gross utility operating revenues from interstate sales and owned significant out-of-state generating and transmission assets that represented 13% of its total book value and 14% of its generating capacity.

The SEC also rejected the Oregon Public Utilities Commission's argument that section 3(a)(1) should apply because Portland General is effectively regulated by the Oregon PUC, making SEC regulation unnecessary. The SEC reasoned that substantial out-of-state activity created the potential for the utility to escape effective state regulation.

The SEC was careful to distinguish between a utility's interstate sales, which could be problematic for section 3(a)(1) exemptions, and a utility's interstate purchases, which would not have an impact on the exemption. The SEC also suggested that if Enron had restructured the wholesale trading operations of Portland General into a separate subsidiary, Enron might have avoided the adverse outcome.

There are numerous public utility companies with single state exemptions that make interstate sales and that own out-of-state generating and transmission assets. If they haven't done so already, these companies should review their sales and holdings to determine if they need to restructure in order to avoid a fate similar to Enron's.

Other Exemptions

Enron also made filings for exemption under PUHCA sections 3(a)(3) and 3(a)(5) in order to get around the utility ownership restrictions for "qualifying facilities," or "QFs." A QF is a power plant that produces two useful forms of energy from a single fuel — for example, steam and electricity — or that generates electricity using waste or other renewable fuels . A utility cannot own more than 50% of the total equity in a QF. A utility holding company that is exempted under the single state rule is still considered a utility for purposes of the QF ownership limit. However, the Federal Energy Regulatory Commission has held that a holding company that receives a section 3(a)(3) or section 3(a)(5) exemption under PUHCA would not be deemed to be a utility for purposes of the utility ownership limit. FERC reasoned that these exemptions are based on a finding that the company is only "incidentally" a utility holding company or derives no material part of its income from a public utility company in the United States, and thus there is no reason to consider this interest as owned by a utility. Because Enron wholly owned certain QFs or owned QFs in tandem with utility partners, Enron made section 3(a)(3) and 3(a)(5) filings with the SEC to avoid having to sell off its QF interests.

When Enron made its section 3(a)(3) and 3(a)(5) filings, it claimed that it met the statutory requirements for exemption on grounds that the revenue and income of Portland General paled beside its worldwide revenue and income. Regardless of the validity of the claims when originally made, by the time Enron filed for bankruptcy at the end of December 2001 or within months thereafter, Enron's revenues and profitability plummeted to the point that Enron no longer could argue that it met the section 3(a)(3) or 3(a)(5) standards. The SEC had little difficulty in concluding that Enron was not entitled to an exemption under either section. Since there have been very few applications for section 3(a)(3) or 3(a)(5) exemptions, the SEC's determinations as to these exemptions appear to be less significant for other companies than its ruling with respect to the section 3(a)(1) exemption.

The only lingering issue with respect to its section 3(a)(3) and 3(a)(5) exemptions is whether Enron made a "good faith filing" for these exemptions in 2000, since a good faith filing for an exemption allows the applicant to maintain the exemption until the SEC acts on the filing. If the filings were not made in good faith, the exemptions would be removed retroactively. Neither the SEC nor the administrative law judge whose order was essentially affirmed by the SEC made a finding on the "good faith" issue.

Enron additionally asked the SEC for a temporary exemption from PUHCA registration based on / continued page 22

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due when 2004 income tax returns are filed.

A "disregarded entity" is a company or other legal entity that a US company treats as if it does not exist. The United States has turned tax advisers into magicians. They can snap their fingers and cause whole companies to disappear as far as the US tax authorities are concerned. Their earnings are reported by their owners as if they were received directly. The IRS published a list of one type of legal entity in each country that cannot be treated as "disregarded." All other types of companies in the country are eligible for such treatment. The use of disregarded entities helps in US tax planning. Such entities have been an important factor in the ability of US multinational corporations to reduce their worldwide effective tax rates. That is one reason the IRS wants to know about them.

Forms reporting foreign disregarded entities will have to be filed in the future by US persons who own such an entity directly or own it indirectly through certain other entities like a "controlled foreign partnership" or a "controlled foreign corporation." A "controlled foreign partnership" is a foreign partnership controlled by US persons who own at least 10% interests. A "controlled foreign corporation" is an offshore corporation that is owned more than 50% by vote or value by US shareholders.

The IRS announcement requiring the reporting of disregarded entities is Announcement 2004-4.

"FEES" ON UTILITIES imposed by local governments are struck down by state courts if they are in reality taxes on utility services.

Billings, Montana tried to collect a "fee" from utilities for using public rights of way. However, the fee was 4% of gross receipts from sales of utility services. Thus, the amount had nothing to do with the use a utility made of public rights of way. The Montana supreme court / continued page 23

PUHCA Exemptions

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the fact that it had filed for bankruptcy, filed a reorganization plan, and signed an agreement to sell Portland General. But the SEC determined that the outcomes of the bankruptcy process and the sale were uncertain and that, in any event, Enron had not sought a temporary holding company exemption under section 3(a)(4) of PUHCA. This type of exemption has traditionally been used by banks who foreclose on utility assets and own such assets only long enough to dispose of them to a third party.

A few days after the SEC decision denying all PUHCA exemptions to Enron, Enron made another filing with the SEC seeking exemption from registration under section 3(a)(4) of PUHCA. The commission, on January 14, 2004, ordered that a hearing be conducted on the filing. As with the other PUHCA exemptions, a "good faith" filing for exemption automatically exempts the applicant from PUHCA until the SEC acts. However, in this case, the SEC hearing order expressly noted that the SEC is taking no position as to whether the Enron application met the "good faith" filing requirement. Presumably that will be determined at the hearing, along with the exemption request. ◎

Tax Strategies For Financing Landfill Gas Projects

by Keith Martin, in Washington

Landfill gas operations in the United States throw off tax and other benefits that savvy developers and municipal landfill owners figure out how to tap.

These benefits are potentially a source of cash to help cover the capital or operating costs of a landfill.

The US government pays as much as 220% of the cost of a landfill gas collection system, 27% of the cost of equipment to turn the gas into electricity, and 31% of the cost of equipment to clean it to a point where it can be mixed in a pipeline with natural gas. State tax benefits are worth on average another 3%.

Most of these benefits are in the form of tax subsidies. The problem with tax subsidies is municipalities and smaller developers lack the tax base to use them. There are various ways to "monetize" the benefits by turning them into cash.

But beware: the nature of the tax benefits is changing — and this could lead to a change in how landfill gas projects are structured in the future. Most of the benefits in the past went to gas producers as a reward for producing landfill gas. In the future — assuming an energy bill that is currently stalled in Congress passes — the biggest rewards will go to companies that use landfill gas to generate electricity. Thus, until now, if a landfill owner wanted to share in the government subsidies for landfill gas, it might do so by selling its gas collection system to a large corporation with a tax base in exchange for ongoing payments that are a share of the tax credits that the government allows gas producers to claim on the landfill gas produced. In the future, a landfill owner might do better to keep the collection system and simply increase the price at which it sells the gas.

The Situation Today

Landfill gas projects qualify potentially for three tax benefits today.

One is basic tax depreciation, or the ability to deduct the cost the gas collection system and other equipment over its useful life.

The depreciation on the gas collection system is worth 27.78¢ for each dollar of capital cost. This is the present value of the tax savings from the depreciation deductions over time. The calculation assumes a 35% tax rate and uses a 10% discount rate.

The owner of the collection system can deduct his investment in it over seven years using the 200% declining-balance method. In most cases, this means he can deduct 14.29% of his investment in year 1, 24.49% in year 2, 17.49% in year 3, 12.49% in year 4, 8.93% in each of years 5, 6 and 7, and the remaining 4.46% in year 8. (Even though it is a 7-year depreciation schedule in theory, a small portion of the cost is spread into year 8.)

The cost of equipment to convert the gas into electricity or to clean it to pipeline quality is depreciated more slowly. The generating equipment must be depreciated over 15 years. Depreciation over 15 years is worth 19.92¢ for each dollar in capital cost. Equipment to clean the gas to pipeline quality must be depreciated over seven years. The tax savings from the depreciation on it are worth 27.78¢ per dollar of capital cost.

This is the depreciation that can be claimed in most cases.

In some cases, the deduction the first year may be a different percentage, usually smaller. This might occur because the legal entity that owns the equipment was just starting in business so that it has a "short tax year" or because it was already in business, but made more than 40% of its total new investments for the year in the last quarter of the year, thereby tripping something called a "mid-quarter convention."

If the project benefited from tax-exempt financing or the equipment is considered used by a municipality or other tax-exempt entity, then slower depreciation must be used and the tax savings are not as large. In such cases, the gas collection system would have to be depreciated over 10 years using the straight-line method. (This means that the same amount is deducted each year rather than a relatively large percentage in the early years and a small percentage in later years.) The cost of the generating equipment would have to be depreciated over 20 years, and equipment to clean gas to pipeline quality would be depreciated over 14 years.

Depreciation Bonus

Another tax benefit is a "depreciation bonus." If the project qualifies, this will add another 3.61¢ to 7.54¢ in benefit for each dollar of capital cost.

The US government made a limited-time offer after the terrorist attacks on the World Trade Center and the Pentagon. It is offering anyone who invests in new equipment during a "window period" that runs from September 11, 2001 through December 2004 or 2005 — depending on the equipment — to deduct either 30% or 50% of the cost of the equipment immediately. Collection systems, electric generators and cleaning equipment tied to landfill gas projects must be "placed in service" for tax purposes by December 2004 to qualify. The remaining cost is deducted over the regular depreciation schedule. Thus, for example, anyone who put an expansion well into service at a landfill in December 2003 could deduct 50% of the cost of the well on his 2003 tax return. The remaining 50% would be deducted over seven years, with a fraction of it deducted in 2003 and the rest spread over the remainder of the period.

The tax savings from a 50% deprecia- */ continued page 24*

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held in December that this was an illegal tax rather than a "fee." It cited a similar decision by the supreme court in Florida striking down a 3% tax on utility gross revenue that a Florida county had claimed was an "electric utility privilege fee." Taxes must be authorized by state legislatures. The Montana case is *Montana-Dakota Utilities Co. v. Billings*.

PENNSYLVANIA said independent power companies must pay a gross receipts tax on sales of electricity directly to end users.

Solar Turbines, Inc. — a subsidiary of Caterpillar — owned a gas turbine in York County, Pennsylvania that it used to supply electricity to Caterpillar at cost. Pennsylvania collects a gross receipts tax of 44 mills per dollar on gross revenue from the sale of electricity by any "electric light company." The tax only applies to retail sales — not wholesale. Solar Turbines argued that the tax only applies to utilities and not independent generators. A Pennsylvania court disagreed in late January. The case is *Solar Turbines Inc. v. Commonwealth of Pennsylvania*.

Solar Turbines supplied some of its electricity to Metropolitan Edison, the local electric utility. The court said that taxes did not have to be paid on this electricity because the supply to Met Ed was not a retail sale.

WEST VIRGINIA declined to let a company claim credit for sales taxes it paid neighboring states on gravel and other inputs used for making asphalt against the use taxes that West Virginia collects on the asphalt the company produces. The state supreme court said in December there is nothing inconsistent about collecting taxes twice.

It said the raw materials and the asphalt are two different products. The case is Bluestone Paving Inc. v. Tax Commissioner. */ continued page 25*

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tion bonus on the gas collection system are worth 3.61¢ in present-value terms for each dollar in capital cost. The bonus on electric generating equipment is worth 7.54¢. The bonus on gas cleaning equipment is worth 3.61¢.

The bonus was only 30% for investments to which a company committed before May 6, 2003. Congress increased the amount to 50% starting on May 6 in the hope of giving a bigger boost to the US economy. Whether a company was "committed" to the investment before May 6, 2003 turns on whether it is viewed as building the equipment itself or purchasing it off the shelf from a vendor. In cases where a company is viewed as building the equipment itself, it was not "committed" to the investment until construction started at the site, and then only after at least 10% of the total project cost was incurred. In cases where a company is viewed as purchasing the equipment off the shelf, the company was committed to the purchase when it signed a binding contract to buy it. "Binding" is a term of art. Just because a contract was signed does not mean it was "binding" for tax purposes.

The bonus can be claimed only on new equipment — not purchases of used equipment. However, it applies to improvements to existing facilities. Thus, for example, it could be claimed on the cost of a replacement well at a landfill.

Tax Credits

Tax credits at the average landfill gas project might cover another 190% of the capital cost of the gas collection system.

The average landfill in the United States contains 3.477 million tons of waste, according to US Environmental Protection Agency figures. A landfill that size would generate three to four megawatts of electricity, and the total cost of the collection system and generator would run around $5 million, with the collection system accounting for roughly 20% of the cost.

The US government offers a tax credit as an inducement to companies to produce landfill gas. The credit is in section 29 of the US tax code. The deadline for installing collection systems to take advantage of the tax credit has already passed. Most collection systems put into service between January 1993 and June 1998 qualify for tax credits on the gas produced through 2007. Collection systems put into service before 1993 no longer qualify for credits, although it is possible for gas from some wells at such older sites still to qualify.

> Landfill gas producers in the United States qualify for three tax benefits, but since most such producers lack a tax base, the challenge is how to get value for them.

The credit is currently $1.095 an mmBtu. The amount is adjusted each year for inflation. A landfill of average size produces 571,000 mmBtus a year of gas. The tax credits on that amount of gas output are $605,000 a year. The remaining tax credits on an existing collection system of average size between now and 2007 have a present value of $1.918 million.

The tax credits belong to the company that produces the gas. To qualify as a gas producer — and, thus, be able to claim the tax credits — a company must usually possess two things. First, it must own the gas collection system. Second, it must have the right legally to withdraw the gas from the ground. Thus, in cases where a municipality owns a landfill and cannot use the tax credits, the way to transfer the credits to a private developer is to sell the developer the collection system and enter into a gas lease giving the private developer the right to withdraw the gas from the ground.

The private developer should exercise care in the contracts it signs. It can hire someone else to operate the collection system. However, it must be careful in all its contracts — for example, with the landfill owner for the gas rights, with the company that will operate the collection system, and with whomever will buy the gas — to avoid transferring ownership of the collection system or shifting all the production risks effectively to someone else. For example, it would be a mistake for the gas lease to provide that the collection system will revert automatically to the landfill owner as soon as the tax credits expire. The Internal Revenue Service will assert that the landfill owner remained the owner of the collection system from inception.

A gas producer must sell the gas to an unrelated person in order to claim tax credits. This explains why landfill gas projects that qualify for tax credits are set up with the collection system and the generating or cleaning equipment owned by separate companies. A "gasco" owns the collection system, and a "genco" or "cleanco" owns the other equipment. There can be up to 50% overlapping ownership between the two companies. However, it is important to keep the companies separate in all other respects. Thus, for example, a bank should not lend against the combined revenues of both the gasco and the genco or cleanco as if they are a single large company.

There is an active market in projects that qualify for section 29 tax credits. Such projects have been selling for the equivalent of as much as $1.21 per dollar of tax credit, although most assets trade in a range of 70¢ to 95¢. The reason an institutional investor might pay more than a dollar for a dollar of tax credits is that he is also able to deduct the amount he pays for the project over time. Thus, if he pays the equivalent of $1 for $1 of tax credits, not only does he receive a tax credit of $1 but he also deducts the $1 over time, saving him an additional amount in taxes.

There are two main ways for a municipality or smaller developer that lacks the tax base to use the tax benefits to transfer them. One is to sell the collection system or gasco to someone else who can use them but share indirectly in tax benefits through the purchase price. Many recent sales use a "pay-as-you-go" structure. The institutional investor pays an amount in cash at closing plus installment payments each quarter through 2007. The Internal Revenue Service requires that at least half the total purchase price be fixed in present-value terms. Thus, each quarter, the institutional investor pays for the collection system a fixed amount plus a contingent amount. The contingent amount is a percentage of the tax credits that quarter. After 2007, the seller of the collection system can have

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MINOR MEMOS. Starting in 2004, corporations with at least $10 million in gross assets will have to file a new schedule with their corporate income tax returns — Schedule M-3 — that will help the IRS understand better why the company is reporting less taxable income than book income. The IRS hopes it will help identify potential audit issues more quickly . . . . A survey of corporate tax directors found that the five worst US states in which to locate — because they have the "most unfair and unpredictable tax environments" — are New Jersey, California, Massachusetts, New York and Pennsylvania. The survey was reported in the January issue of *CFO* magazine . . . . Two economists, Rosanne Altschuler with Rutgers and Harry Grubert with the US Treasury Department, wrote in a paper in December that US multinational corporations managed to reduce their global average effective tax rates by 12 percentage points since 1980, with a sizeable drop coming between 1998 and 2000. The reduction in tax rates before 1998 was due mainly to competition among governments as they cut corporate tax rates in an effort to attract business. However, since then, companies have managed to cut their tax rates further by "stripping" income from countries where they have operating subsidiaries — for example, by having the subsidiaries make royalty payments for use of intellectual property. The share of total royalties paid to two prime countries for holding intellectual property rights — Ireland and Singapore — doubled in five years.

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

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an option to buy back the collection system. Ideally, he should do so for the fair market value determined when the option is exercised.

The other way to transfer tax credits is for a smaller developer to enter into a partnership with an institutional investor. (Partnerships work less well for municipalities because of complications in how tax depreciation would have to be shared.) The partnership would own the collection system. The institutional investor would make ongoing payments for his partnership interest. All the economic benefits in the partnership would be shared initially 99-1 in favor of the institutional investor. However, sometime after 2007, the ratio would flip to 20% for the institutional investor and 80% for the smaller developer. The smaller developer could have an option to buy out the institutional investor after the tax credits have expired.

If the energy bill is enacted in its current form, it will change how landfill gas projects are structured.

The problem with landfill gas projects is the transactions are usually too small for the institutional market. There is a need for an aggregator to bundle together groups of projects.

Another problem with landfill gas deals is the existing contracts frequently have impermissible terms. A group of 12 projects might have 12 different sets of contracts, each with very different terms. This makes it expensive for institutional investors to do due diligence. Large institutions that play in this market would be well advised to have a set of standard-form contracts and, rather than try to parse all the contracts that come with a project, make it a condition to closing that the contracts be "amended and restated" — or replaced — with the standard forms. Thus, for example, all the operator contracts would be replaced with standard terms.

The Future?

An energy bill stalled currently in Congress would throw more tax benefits at landfill gas projects and, in the process, will change how such projects are structured in the future.

The energy bill failed to clear Congress in late November by just two votes. It passed the House. It was the target of a filibuster in the Senate. Sixty votes are required in the Senate to cut off debate. The effort to invoke "cloture" — or cut off debate — fell two votes short. (Technically, it was three votes short, but the Senate majority leader, Bill Frist (R-Tennessee), voted against cutting off debate when it was clear the effort would fail so that he could make a motion to reconsider.) The fate of the measure remained up in the air as the *NewsWire* went to press. Republican leaders may make another effort to put all or part of it through Congress this year.

The energy bill would create two new tax benefits for landfill gas projects.

First, it would breathe new life into section 29 credits — but just barely. Section 29 credits can only be claimed currently on landfill gas from wells that were in service by June 1998, and then only on the gas produced and sold through 2007. The credits are currently $1.059 an mmBtu.

The bill would allow tax credits to be claimed on gas from wells put into service after June 1998 through 2006, but only at 51.7¢ an mmBtu. The credit would be only 34.7¢ an mmBtu on gas from landfills that are already required by US Environmental Protection Agency regulations to trap the gas. Both amounts — 51.7¢ and 34.7¢ — would be adjusted for inflation.

However, the total credits that could be claimed would be capped at $37,741 a year per project. And then they could only be claimed on four years of gas output. In the case of existing wells that went into service after June 1998, the four years would start to run on gas produced on January 1, 2004.

This is not enough to interest the institutional market.

It is not clear how the annual cap per project of $37,741 will be applied in cases where credits are being claimed on gas from expansion wells at a collection system that went into service in June 1998 or earlier. (Gas from the rest of the project qualifies for uncapped section 29 credits under existing law.)

The portion of the bill that extends section 29 credits is poorly drafted. There are two separate provisions that extend section 29 credits for landfill gas projects. The other provision would extend such credits on gas from wells put into service after the bill is signed into law by President Bush through the end of 2006. The advantage of relying on this other provision is the annual cap on the amount of credits that can be claimed per project would not apply. This is probably a drafting error. Tax bills in recent years have been followed in time by "technical corrections" bills, like a sweeper cleaning up at the circus behind the elephants. However, unless Congress fixes this bill through a technical correction, both readings of the bill — the extension with or without the cap — are equally valid.

The other new tax benefit is a tax credit for anyone using landfill gas to generate electricity.

This "section 45 tax credit" would be 1.2¢ a kilowatt hour. The amount will be adjusted for inflation. In contrast to section 29 credits, which go to the owner of the collection system, this credit goes to the owner of the generating equipment. It can be claimed for five years on electricity output sold to third parties from new generating equipment put into service during a window period that runs from the day after the bill is signed by President Bush through December 2006.

The average landfill in the United States produces enough gas to generate three megawatts of electricity. The tax credits on a project that size would run $315,360 a year. The present value of the full five years of credits is roughly $1.2 million.

If the energy bill passes, it will have a number of effects on how landfill gas projects are structured in the future.

The bill has language intended to prevent both section 29 tax credits and section 45 tax credits from being claimed on the same project. The language is not well drafted. The IRS will have to move by regulation to prevent companies from circumventing the intention.

However, because of this anti-double-dip language and because the section 29 credits are capped at such a low level ($37,741 a year per project), institutional investors will be more interested in the future in owning the generating equipment than the collection system. This is the reverse of the situation today.

That said, both the collection system and the electric generating equipment can be owned by the same company in the future. If the plan is to claim section 45 credits rather than section 29 credits, then there is no need for the gas to be sold to an unrelated party. However, it would probably still be wise to keep them in separate legal entities. That's because if both the collection system and the generating equipment are owned by the same legal entity, both assets will probably have to be depreciated over 15 years on grounds that the business of the owner is primarily generating electricity for sale. If the assets are in separate legal entities, one of the entities is in the business of collecting landfill gas. Equipment used in that business qualifies for faster depreciation (over 7 years rather than 15 years).

It will make less sense in the future to clean landfill gas to pipeline quality. The better use for the gas is to convert it to electricity since that is what the government will reward through tax credits.

Municipalities and smaller developers will still need institutional investors to take advantage of the tax subsidies. The projects will still be too small. There will still be a need to put together groups of projects.

One problem with tax credits in the past is they cannot be used against "alternative minimum taxes." The United States has essentially two different tax systems for corporations. A company calculates its regular income taxes and then calculates its minimum taxes on a broader definition of taxable income but at a lower rate, and it pays whichever tax is greater. A company that is on the minimum tax cannot use section 29 or 45 tax credits currently. The energy bill would allow section 45 credits — but not section 29 credits — to be used against AMT liability, but only on the electricity output for the first four years after the project is put into service. This is another reason why the institutional market will be more interested in section 45 credits. Large corporations go on and off the minimum tax from year to year.

Anyone signing a gas sales contract in the future would be wise to ensure that the gas purchaser does not claim section 45 credits if the gas producer plans to claim section 29 credits — and vice versa. The energy bill will require a project to choose one or the other tax credit.

RECs

Renewable energy credits — called RECs */ continued page 28*

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— in eight states are a potential source of additional value in landfill gas projects.

They belong to the company that uses the gas to generate electricity. This is another reason why the institutional market is shifting focus from the gas collection side of the project to the generating equipment.

RECs are credits at the state level for using renewable fuels, like wind, biomass or sunlight, to generate electricity. To date, 13 states have adopted some form of "renewable portfolio standard," or law requiring utilities in the state to ensure that a certain percentage of their electricity comes from renewable sources. Five other states have adopted voluntary goals to increase the use of renewable fuels. At least another five states are considering adopting RPS-type legislation.

Landfill gas qualifies as a renewable fuel in eight states: Arizona, California, Connecticut, Massachusetts, New Jersey, New Mexico, Pennsylvania and Texas.

The percentage of electricity that must come from renewable sources varies from state to state and over time. For example, Arizona requires utilities only to generate 1% of electricity from renewable fuels by 2005 and 1.1% by 2007. California ramps up to 20% renewable electricity by 2017.

A utility can meet its obligations by generating the electricity itself or by purchasing the electricity from a renewable supplier or, in some states, by purchasing RECs from an electricity generator who used a renewable fuel.

RECs have been trading this past year for between 0.5¢ to 2¢ a kilowatt hour.

Utilities tried earlier this year to persuade the Federal Energy Regulatory Commission that the RECs convey automatically to the utility that buys the electricity. In October, the commission ruled against the utilities. It said the RECs remain with the electricity supplier unless the power contract provides specifically for their transfer. However, the order left the door open to state public utility commissions to decide otherwise in their states. One state commission — in Maine — has already declared that RECs in that state convey automatically to the utility that buys the electricity, and the issue is pending before the Connecticut Department of Public Utility Control. The Maine decision is being appealed.

Renewable energy credits — called RECs — in eight states are a potential source of additional value.

Possible Refunds

Electricity generators may be entitled to money back from utilities in cases where they had to pay for "network upgrades" — or improvements to the transmission grid — when they connected to the local grid.

Utilities usually make generators pay two kinds of costs as a condition for interconnection. One is the cost of the "direct intertie" — the radial line and related equipment that connects the plant to the grid. The other is the cost of any upgrades that are required to the grid itself to accommodate the additional electricity from the generator's plant.

It is currently Federal Energy Regulatory Commission policy that independent generators should not have to bear the cost of the grid improvements. Rather, these should be borne by all users of the grid through the rates they pay for transmission service on the grid. A model interconnection agreement that FERC adopted in July 2003 allows utilities to require generators to advance the funds for grid improvements, but the money must be returned with interest within five years.

Several generators have asked FERC to order utilities to return money paid for network upgrades under existing interconnection agreements that predated the model agreement. These existing contracts did not require the utilities to give the money back. FERC has shown a willingness in some cases to modify existing contracts.

The energy bill currently stalled in Congress would overturn the FERC policy.

The bill would give utilities the option of asking FERC to let them charge the generator for the cost of network upgrades or to pass through the cost to all grid users in transmission rates. However, FERC could not allow the cost to be passed through to all grid users in situations where the grid improvements are only needed because of the addition of the generator's plant. The bill would also bar FERC from requiring utilities to pay interest when returning amounts collected from generators for network upgrades. Entergy and Southern Company pressed Congress for this language.

The bill would not bar refund claims under most existing contracts.

Landfill Closing Costs

Landfills that are listed as "Superfund" sites got bad news from a federal court in August.

Landfill owners are required by law to prevent gas and leachate from decomposing trash from leaking into the atmosphere or the surrounding soil. They set aside money in a reserve account while the landfill is still earning tipping fees from garbage collection to cover their ongoing obligations after the landfill has closed. Ordinarily, no tax deduction is allowed for merely setting money aside in a reserve account. The amounts cannot be deducted until they are actually spent on cleanup. However, section 468 of the US tax code makes an exception in this case.

A federal district court in Michigan in August denied tax deductions for contributions that were made to a reserve to cover future closing costs in years when a landfill was listed on the "national priorities list" of Superfund sites. The court said section 468 bars deductions for reserve contributions in such years, presumably on grounds that no tax "carrot" is needed at that point for a landfill owner to set aside money once cleanup has been ordered by the environmental authorities.

The court rejected an IRS claim that the landfill owner had to reverse all the deductions he had taken for reserve contributions in years before the landfill was listed by reporting the full amount in the reserve as income. The case is *South Side Landfill v. United States*. ◎

Libya Opens For Investment

by Nabil Khodadad, in London

Western companies are eyeing Libya as a possible market for investment — particularly in the oil and gas sector — but any investments by US companies will have to wait until sanctions are lifted. Some of the sanctions are expected to come off later this year.

The heightened interest follows the announcement by Colonel Moammar Gadhafi in December that Libya is abandoning its programs to produce weapons of mass destruction and allowing immediate UN inspections of key sites.

President Bush welcomed the Libyan announcement, but cautioned that US sanctions would remain in place until the "crisis" over Libya has been fully resolved. Bush signed an order in January that keeps US sanctions in place, but the president made the following promise in a letter to Congress: "As Libya takes tangible steps to address concerns [over WMD], the US will in turn take reciprocal steps to recognize Libya's progress." Although the president did not indicate what would constitute a "tangible step," the betting is that the US will lift some sanctions this spring to demonstrate its goodwill, while leaving others in place to encourage Libya to continue to comply with its pledge.

The US government is considering easing current sanctions to permit US oil companies to bid on new oil contracts, without any immediate payment, and to permit those US companies that acquired interests in Libyan fields prior to the imposition of sanctions in 1986 to start restoring their equipment in Libya and begin test pumping.

Since Gadhafi's dramatic announcement, Libya has quickly taken several concrete steps to dismantle its WMD program. First, Libya ratified the nuclear test ban treaty. In signing the treaty, Libya agreed to host a monitoring station at Misratah, Libya. The US has already begun airlifting nuclear-related equipment and material out of Libya. Then in early February as the NewsWire was going to press, Libya became the 159th country to join the chemical weapons convention and agreed to refrain from producing banned chemical weapons and to destroy any stocks it has. According to press reports, plans are */ continued page 30*

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underway by Libyan scientists to incinerate tons of mustard gas agent manufactured to fill chemical bombs.

Existing Sanctions

There were originally two sets of sanctions against Libya. Sanctions imposed by the United Nations were lifted last year. Extensive US sanctions remain in place and have extra-territorial reach, meaning that they apply not only to US companies, but also to companies from other countries with ties to the US market.

The US imposed a series of escalating sanctions against Libya in 1981, 1982, 1986 and 1996. The 1986 sanctions, which were adopted in response to the bombing of a Berlin disco frequented by US military personnel, imposed a ban on US trade and commercial dealings with Libya. The introduction of these sanctions led to the departure of US oil companies such as Amerada Hess, Marathon, ConocoPhillips, Occidental Petroleum and Grace Petroleum from Libya. Before their departure in 1986, US companies produced close to one million barrels of crude oil a day in Libya.

In response to the air bombing of a PanAm flight over Lockerbie, Scotland in 1988 in which 270 people, mostly Americans, were killed, the United Nations imposed a ban on flights and sales of some oil equipment to Libya and froze some Libyan assets. After Libya extradited two Libyan suspects in the Lockerbie bombing to the Hague in 1999, some UN sanctions were suspended and the US government tacitly agreed to several visits to Libya by US oil and gas companies that had been forced to pull out in 1986. After one of the two Lockerbie defendants was tried and convicted, Libya reached a $2.7 billion settlement with the families of the Lockerbie victims. In response to the settlement, the United Nations lifted all remaining sanctions against Libya on September 12, 2003. Under the terms of the settlement, each family is entitled to $10 million, of which $4 million was paid after the lifting of UN sanctions and the remaining $6 million is to be paid if US sanctions are lifted and Libya is removed from the list of terrorist-supporting states by May 12, 2004. However, Libya is expected to extend the May 12, 2004 deadline if Congress has not lifted US sanctions because Libya had not fully disarmed by that date.

Despite the complete removal of UN sanctions against Libya, US sanctions remain. The US Libyan sanctions regulations have broad reach. First, all Libyan property or interests in property in the control or possession of US persons are blocked. Second, US persons are barred from entering into any transaction involving Libyan property. Third, imports of goods or services of Libyan origin to the US and exports of technology, goods and services to Libya from the US are banned. Fourth, no US person may purchase goods, directly or indirectly, from Libya for export to another country. Fifth, US persons are barred from granting or extending credits or loans to Libya.

The US sanctions were extended to foreign persons when Congress adopted the "Iran and Libya Sanctions Act" in 1996. The 1996 statute had a limited life. Congress extended the sanctions in it for another five years in July 2001. The statute requires the US president to impose at least two out of a menu of six sanctions on foreign companies that make investments of more than $40 million in one year in Libya's petroleum sector or violate UN prohibitions against trade with Libya (which UN prohibitions are no longer relevant since UN sanctions have now been lifted).

The six sanctions from which the president must choose are the following. He can bar foreign companies that invest in the Libyan petroleum sector any loans, credits or credit guarantees from the US Export-Import Bank. He can deny them licenses to export military or militarily-useful technology from the United States. He can order US banks not to lend them more than $10 million in a single year. He can bar any foreign bank that finances petroleum sector investments in Libya from acting as a primary dealer in US government bonds or as a repository for US government funds. He can bar the company from any US government contracts. And he can prevent goods or services from the foreign company from being imported into the United States by invoking powers under the "International Emergency Economic Powers Act."

What constitutes an "investment" in the Libyan petroleum sector is broadly defined. It includes entry into any contract to develop Libyan petroleum resources or any supervision or guarantee of performance of such a contract, any purchase of an ownership interest in Libyan petroleum resources, and any entry into a contract to share profits or royalties with respect to any such development project. However, the purchase of petroleum products or other goods from Libya by foreign persons is not prohibited.

The President has the power to waive sanctions under the Iran and Libya Sanctions Act if such waiver is "important to the national interests of the United States." Although both the Clinton and Bush administrations have conducted informal reviews of several projects in Libya, the US has not imposed sanctions on any foreign company under the 1996 statute for doing business in Libya. This is because most projects in Libya represent continuations of investments made prior to the enactment of the 1996 law.

Crippled Oil Sector

The sanctions have crippled Libya's oil industry by impeding investment and competition even though Libya offers upstream opportunities that are unrivaled anywhere in the Middle East. Over the last two decades, Libya has watched its oil production plummet from about 3.0 million barrels a day to its current production of about 1.4 million barrels per day, or about 2% of world supplies. US sanctions have also blocked about $1 billion in assets that the Libyan government claims are held in US banks.

Compared with Iraq's reserves of 113 billion barrels, Libya's reserves of about 40 billion barrels appear modest. However, many analysts believe that this reflects a lack of exploration. The petroleum consultants Wood McKenzie believe that Libya is "highly under-explored" and would benefit from more advanced drilling techniques that would improve recoveries at existing fields. For example, from 1995 to 2002, Libya had just one fourth the number of oil wells drilled in Egypt and two thirds the number of wells drilled in Algeria. While Libya's petroleum production has plummeted, Libya has watched its neighbors Algeria and Egypt develop their LNG capacity in a market that is forecast to grow dramatically over the next several decades.

Future Opportunities

Libya is seeking more than $30 billion in foreign investment in its upstream, downstream and petrochemical sectors over the next six years. It plans to lift its current production from about 1.4 million barrels per day to more than 2 million barrels per day by the end of this decade. The Libyan government is revising its oil and gas law, and Libya's National Oil Corporation is drafting a new model exploration and production sharing agreement, in each case with the aim of creating a more attractive and stable investment regime for foreign oil companies. Later this year, the National Oil Corporation also plans to launch a licensing round for 10 blocks.

US oil executives have been encouraged by recent developments in Libya. Herman Cohen, a former US assistant secretary of state, said, "US companies are salivating to get back in there." So far, the National Oil Corporation has held on to US oil and gas interests left behind and has not awarded them to other companies. The 50-year leases of the Oasis Group, a consortium of Amerada Hess, Marathon, and ConocoPhillips, on its Libyan fields are due to expire in 2005 and the group is reportedly keen to extend them. Other US oil companies have also expressed an interest in returning to Libya. Not only would the lifting of US sanctions assist Libya in increasing its production of crude oil, but it might also allow Libya to develop its natural gas reserves and resume its efforts to export LNG.

While US companies continue to be barred from investing in Libya, European and Australian petroleum companies such as Total, ENI, Repsol-YPF, OMV, RWE Dea and Woodside have been active. In the second half of 2003, the National Oil Corporation issued such companies licenses to 17 blocks. The return of US petroleum companies to Libya would bring greater competition and much more capital for Libya's oil and gas industry. ◎

Oil And Gas Projects In Kazakhstan

by Kimberly Heimert, in Washington

New tax rules that took effect in January in Kazakhstan help clarify the tax treatment of oil and gas projects in the country. They also impose more downside risk on foreign investors while shifting upside benefits to the state.

One of the main benefits of the new rules is that almost all of the tax legislation that is relevant to "subsoil users" in Kazakhstan can now be found in one piece of legislation. Previously, investors were forced to look not only in the tax code, but also in a plethora of other legislative and executive acts. (Note that although the amended tax code defines "subsoil users" generally as those who perform subsoil operations, including petroleum operations, this article uses the term "subsoil users" to mean only those who perform subsoil petroleum operations.)

The amended tax code makes it clear */ continued page 32*

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that all subsoil users must pay taxes and other mandatory payments under one of two models.

The first model applies to subsoil users that do not operate pursuant to a production sharing agreement. The so-called "Model One" regime requires that subsoil users pay all of the taxes provided under Kazakh law, except for a share of production petroleum. The second model applies to subsoil users that do operate under a production sharing agreement. Unlike in Model One, subsoil users operating under a production sharing agreement are exempted from paying excess profits tax, rent tax on exported crude oil, excise tax on exported crude oil and gas condensate, land tax and property tax. However, such subsoil users also are required to transfer a share of their petroleum production to the state.

The amended tax code suggests that if Kazakhstan's tax legislation is amended, production sharing agreements may be revised to reflect such amendments, but only upon the mutual agreement of the parties to such agreements. However, it also specifically refers to legislative amendments that "improve the conditions of taxation of a subsoil user" and states that revisions to production sharing agreements "shall be made . . . to restore the economic interests of the Republic of Kazakhstan." Although not entirely clear, this language is important because it could mean that if the tax burden of the subsoil user is reduced by changes to legislation, the state could require the subsoil user to amend its production sharing agreement to reestablish the prior tax burden of the subsoil user. It is not clear whether such revisions would be contingent on the agreement of all of the parties to the agreement.

Universal Changes

Some changes to the tax code affect both the Model One and Model Two tax regimes.

For example, changes to the requirements for bonuses payable by the subsoil user to the state apply to both regimes. As in the past, the amended tax code makes it clear that there are two types of bonuses that subsoil users must pay: subscription (signature) bonuses and commercial discovery bonuses.

Previously, the amount of the signature bonus was established in the relevant agreement and was tied to the economic value of the petroleum deposit. Now, the amount of the signature bonus is determined after the tender process by a commission and is based on the value of the petroleum deposit that is established during the tender. However, it is not clear in the amended tax code whether the value of the petroleum deposit is based on proven, probable or possible reserves or at what price the value should be calculated.

The amended tax code also requires that subsoil users pay a commercial discovery bonus to the state in connection with each commercial discovery they make, unless the subsoil user does not intend to extract the discovered petroleum. The amount of the bonus is 0.1% of the value of the petroleum that may be extracted from such discovery. The value is based on the International Petroleum Exchange of London (or London IPE) prices on the date that the payment is made. The amended tax code does not specify how the volume of petroleum is determined, except to say that the volume should be confirmed by an authorized state body. In the past, the commercial discovery bonus was negotiated between the subsoil users and the state, and the only legal mandate was that it be no less than 0.1% of such value.

The amended tax code also changes the structure and procedure for payment of royalties. These changes apply to both the Model One and Model Two tax regimes. Royalties must be paid by subsoil users based on the value of petroleum that they extract, regardless of whether the petroleum is sold or used by the subsoil user. The value is based on the weighted average realized price for the relevant tax period, excluding all individual taxes and transportation expenses. If the petroleum is not sold, then various procedures are used to determine the value, but, generally, the value is based on either the realized price for the preceding or succeeding tax period or the cost of producing the petroleum.

The new royalty rates vary according to production levels during the relevant calendar year. They are as follows:

Crude oil production in calendar year	Royalty rate
up to 2 million tons	2%
2 million tons – 3 million tons	3%
3 million tons – 4 million tons	4%
4 million tons – 5 million tons	5%
5 million tons and more	6%

For purposes of these calculations, associated gas hydrocarbons are converted into their crude oil equivalent at the ratio of 1000 cubic meters of gas to 0.857 tons of crude oil.

Model One Regime

The Model One tax regime applies to subsoil users that are not operating under a production sharing agreement.

The main changes for such subsoil users are in the rent tax on exports of crude oil and the excess profits tax. Both taxes apply only to subsoil users who do not operate under a production sharing agreement.

The rent tax on exports of crude oil is tied to the value of the exports. This value is based on a basket of published market prices that takes into account sales costs and the quality of the crude oil. The tax rate is determined on a sliding scale based on the price of oil per barrel:

Market price *(per barrel)*	Rent tax rate
US$19	1%
US$20	4%
US$21	7%
US$22	10%
US$23	12%
US$24	14%
US$25	16%
US$26	17%
US$27	19%
US$28	21%
US$29	22%
US$30	23%
US$31	25%
US$32-US$33	26%
US$34-US$35	28%
US$36	29%
US$37	30%
US$38-US$39	31%
US$40 and more	33%

There had been some concern during the debate on the amendments to the tax code that this tax would apply to production sharing agreement subsoil users. However, the amended tax code explicitly exempts such subsoil users from this tax.

The amended tax code also requires that subsoil users under the Model One tax regime pay an excess profits tax on the amount of net income that exceeds 20% of certain deductions. Although this tax is not new, the method of calculation has changed completely. The new excess profits tax rates are as follows:

Amount exceeding 20% of net income ratio to deduction	Excess profits tax rate
up to 5%	15%
5% to 15%	30%
15% to 30%	45%
40% and more	60%

Model Two Regime

Some of the changes to the tax law only affect subsoil users who are subject to the Model Two regime and, accordingly, operate pursuant to production sharing agreements with a "competent authority" of Kazakhstan.

Under the Model Two regime, the subsoil user retains a portion of the production petroleum equal to the cost petroleum, plus a portion of the profit petroleum (the production petroleum minus the cost petroleum) that is calculated pursuant to one of three formulas provided in the amended tax code. The state receives the remaining portion of the production petroleum.

The formulas that are used to calculate the subsoil user's share of profit production are based on the R-factor, IRR, or P-factor, depending on which provides the least amount of profit production to the subsoil user and, therefore, the greatest amount to the state.

Under the amended tax code, the R-factor (rate of revenue) is the ratio of the subsoil user's accumulated real income, less its actual aggregate income / continued page 34

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tax, to its accumulated cost-recoverable expenditures, each on an accrued basis. The IRR (internal rate of return) is the annual discount rate at which the net present value of the project is zero. The P-factor (price factor) is the ratio of the value of the subsoil user's cost petroleum and share of profit petroleum to the value of the production petroleum, each during a specific reporting period and each without taking into account certain expenses (such as sales expenses).

The amount of production petroleum that may be allocated as cost petroleum during any reporting period is now further restricted in the amended tax code. In the past, a subsoil user could designate as much as 80% of the production petroleum as cost petroleum. With the amended tax code, that amount is now limited to a maximum of 75% before the subsoil user recoups its capital investment and 50% after such recoupment. Also, the amended tax code makes clear that if there are eligible costs that are not recovered in one reporting period, then such costs may be carried forward to, and paid during, another reporting period.

It also further restricts the expenditures that are recoverable with cost production. For example, taxes and other mandatory payments to the state budget, expenditures that violate local content rules, fines for environmental, technical or safety regulation violations, social programs, and bonuses are not recoverable under the amended tax code.

Finally, the amended tax code requires that the total value of the profit petroleum allocated to the state and the taxes payable to the state during each reporting period may not be, together, less than 20% of the value of the production petroleum before the subsoil user recoups its capital investment in the project, and 60% after this recoupment.

The amended tax code also provides an additional layer of downside protection for the state. It requires that "if the performance of the production sharing agreement conditions becomes worse," then the state's share of production petroleum "may not be decreased below its fixed maximum point prior to the worsening of the conditions," except in certain limited circumstances. It is not clear exactly what this provision means, but it is clear that there is a minimum amount of production petroleum that the state will receive, regardless of the amount of profit petroleum that is produced in any given reporting period. ◎

Update On Luxembourg Holding Companies

by Derk Prinsen, with NautaDutilh in Rotterdam

Most US companies investing in infrastructure projects in other countries set up offshore holding companies through which to own the investments. This is done to prevent the earnings from the projects from being subjected to US income taxes until they are repatriated to the United States.

Such holding companies are sometimes put in Luxembourg. Its favorable tax laws and extensive tax treaty network make Luxembourg a clear choice for US companies looking to do business in Europe.

This article discusses some of the latest investment structures using hybrid instruments and entities in Luxembourg and also covers recent developments in the international arena that improve on Luxembourg's already strong viability in international tax planning.

Why Luxembourg?

One challenge in foreign tax planning is how to move earnings across international borders without triggering a withholding tax. Most countries collect withholding taxes on dividends, interest, rents, royalties and payments to service contractors when such amounts cross the border.

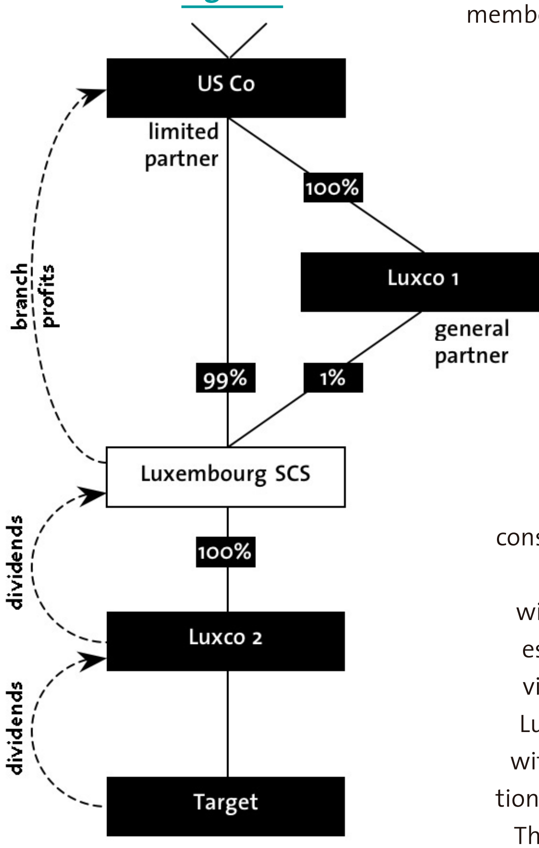
One way to reduce withholding taxes is to take advantage of special reduced rates under tax treaties. However, that only works if the taxpayer establishes a considerable presence in the countries where elements of his ownership structure are situated. One way of repatriating profits to the US, for example, without having those profits suffer foreign withholding tax at the border, is to channel these profits through a foreign branch situated in a country with which the US has concluded a tax treaty. Most tax treaties — and many domestic tax regimes — exempt from withholding tax transfers of earnings across the border from a branch to its foreign head office. But this strategy only works if the branch qualifies as a "permanent establishment" under the relevant tax treaty. In treaty terms, a permanent establishment is a fixed place of business through which the business of an enterprise is wholly or partly carried on. So the taxpayer has to build up a certain measure of activity in the branch before it qualifies as a permanent establishment, which is likely to entail significant expense.

Luxembourg's tax law contains provisions that make it easier to qualify for the treaty relief for earnings deriving from a permanent establishment. For example, a non-resident who is a partner in a Luxembourg partnership can be deemed to have a permanent establishment in Luxembourg, even if the partnership does not carry on the level of activity in Luxembourg normally required to qualify as a permanent establishment. The conditions for the applicability of these provisions are relatively easy to meet. If the partnership is a limited partnership, at least one of the general partners has to be a Luxembourg resident company whose capital is divided into shares.

Another advantage of Luxembourg law is that it is relatively simple to qualify for a tax break known as the "participation exemption" in Luxembourg. If a shareholding falls under the participation exemption, dividends and capital gains arising from it are exempted from Luxembourg corporate income tax. The Luxembourg corporate income tax law stipulates that the permanent establishment of a non-resident taxpayer is entitled to the participation exemption provided that the taxpayer is a company whose capital is divided into shares, that it is resident in a state with which Luxembourg has concluded a tax treaty, and that the shareholding meets certain other requirements such as a one-year holding period and a minimum size or minimum acquisition price. If the subsidiary is not located in an EU member state, there are some additional "comparable tax" requirements: the subsidiary's profits must be subject to tax at a rate amounting to at least 15% and the basis of assessment should be comparable to the Luxembourg corporate income tax basis of assessment. (This requirement is likely to be relaxed; see this article's conclusion.)

The permanent establishment and participation exemption provisions can be used for structuring US outbound investments into Europe as shown in Figure 1. If US Co owned the shares in EU-resident Target directly, dividends paid by Target to US Co would probably be subject to withholding tax in Target's state of residence. But if the ownership of Target were structured as in Figure 1 and if the requirements of the "EC parent-subsidiary directive" are met, then dividends paid by Target would be received by US Co without suffering foreign withholding tax.

Figure 1



The EC parent-subsidiary directive is a rule that the member countries of the European Union have had to incorporate into their domestic tax laws. It requires member countries to exempt from withholding taxes dividends paid by subsidiaries resident in one member country to parent companies resident in another member country. The directive stipulates that the parent company must own a certain proportion of shares or voting rights in the subsidiary and observe a certain holding period. The subsidiary must be subject to tax. The parent as well as the subsidiary must have a specified legal form. A recent amendment of the EC parent-subsidiary directive has relaxed its requirements and broadened its scope considerably.

For Luxembourg tax purposes, US Co will be deemed to have a permanent establishment in Luxembourg — by virtue of its partnership interest in Luxembourg SCS — and thus no withholding taxes will apply on distributions from Luxembourg SCS to US Co.

The Luxembourg SCS in Figure 1 is a "société en commandite / continued page 36

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simple" or limited partnership. The general partner, which is Luxco 1, and Luxco 2 are "sociétés à responsabilité limitée"" (s.à.r.l.s), or limited companies.

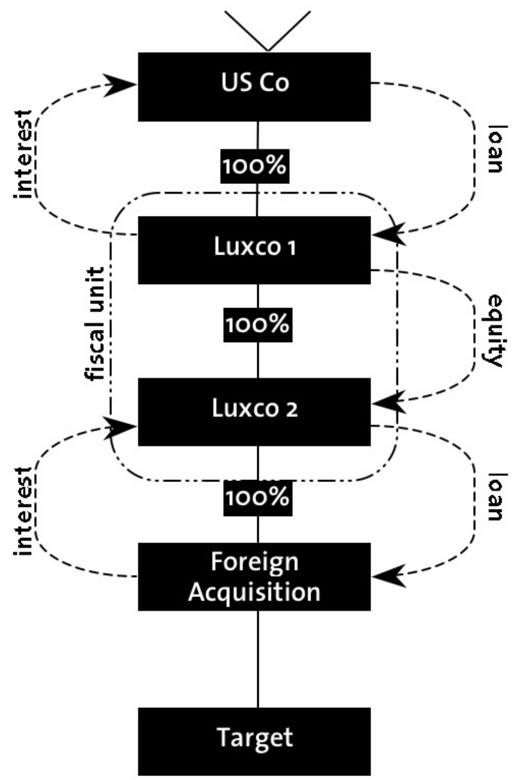
Luxco 1, Luxco 2 and SCS should elect to be treated as transparent entities for US tax purposes. This means that US Co will be treated as owning the shares in Target directly for US tax purposes, which should help US Co qualify for direct foreign tax credits in the US for any taxes Target pays on its earnings in its home country.

Luxco 2 shields gains on the Target shares from Luxembourg's municipal business tax. This tax is imposed on commercial enterprises by the municipality in which the enterprise is situated. If the taxpayer is also subject to corporate income tax, the basis of assessment is the same as for that tax. An SCS is not a taxpayer for corporate income tax purposes in Luxembourg and the basis of assessment for the municipal business tax is determined on the basis of slightly different rules.

Using Hybrid Entities

For Luxembourg tax purposes, limited companies are always treated as corporations, whereas for US tax purposes they can opt for transparency. ("Transparency" means that the entity is treated as a disregarded entity or partnership, depending on the number of owners. It is not considered a taxpayer for US purposes. Any tax is imposed on the owners directly.) A US outbound investment structure that makes excellent use of the hybrid nature of these companies is the structure often referred to as the "Luxco 1/Luxco 2" structure. (The structure used to be known as the BV1/BV2 structure, until the government of the Netherlands put an end to its use on grounds that it was abusive.) Figure 2 shows the Luxco 1/Luxco 2 structure.

Figure 2



US Co makes an interest-bearing loan to Luxco 1. Luxco 1 uses the proceeds of the loan to make an equity investment in Luxco 2, of which it then owns all of the shares. Luxco 2 uses the cash it received as equity to make an interest-bearing loan to another company labeled "foreign acquisition vehicle," which uses the proceeds of the loan to acquire Target or finance a project.

The foreign acquisition vehicle sets off interest payable to Luxco 2 against the revenues from its investment by means of tax consolidation.

Luxco 1 and Luxco 2 form a fiscal unit for corporate income tax purposes, which allows the companies to submit consolidated tax returns. The effect of the fiscal unit is that the interest paid by Luxco 1 to US Co is effectively deductible from the interest Luxco 2 receives from the foreign acquisition vehicle. The Luxembourg tax authority will generally consider the interest paid and the interest received by the members of the fiscal unit as arm's length, provided that the unit annually reports a small taxable margin. This margin typically amounts to 0.25% of the proceeds of the loan from US Co, but it is inversely proportional to the size of these proceeds and can, therefore, be lower than that.

One downside of this structure is that it will not reduce the group's net worth tax. Net worth tax is an annual tax of 0.5% of the net asset value of a company. Luxco 1 and Luxco 2 cannot form a fiscal unit for net worth tax purposes. The equity-financed loan from Luxco 2 to the foreign acquisition vehicle would be subject to net worth tax. The corporate income tax due by the fiscal unit can, however, be set off against the net worth tax due by Luxco 2 (subject to certain conditions).

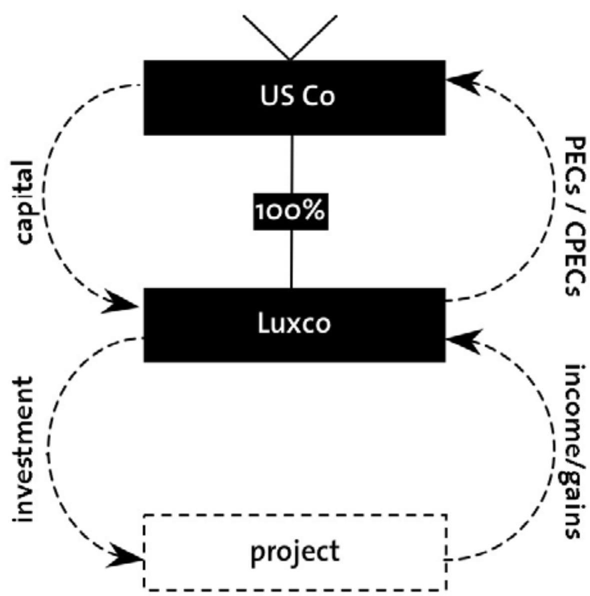
In the US, Luxco 1 elects to be treated as a disregarded entity while Luxco 2 elects to be treated as a corporation. So for US tax purposes, US Co is seen as making an equity investment directly in Luxco 2. From a US perspective, it is probably desirable that the foreign acquisition vehicle also opts to be treated as disregarded so that it is viewed as a branch of Luxco 2. The effect of these elections should be that US tax is deferred on revenues from the foreign investment so long as Luxco 2 does not distribute profits to Luxco 1. Another reason why Luxco 2 should not distribute profits is that it would lead to a recapture of the interest deductions claimed by Luxco 1. Interest paid by Luxco 1 to US Co would not be subject to Luxembourg withholding tax provided that Luxco 1 observes a certain debt-to-equity ratio in how it finances its equity investment in Luxco 2. The exit from the structure consists of Luxco 1 using the proceeds of the liquidation of Luxco 2 to pay interest and repay principal to US Co.

Using Hybrid Instruments

Instruments that are treated as equity for tax purposes in one country and as debt in another — "hybrid" instruments — also offer means of structuring US outbound investments. Preferred equity certificates, or "PECs," issued by a Luxembourg company to its US Co parent company are a well known example by now. Figure 3 shows a structure based on PECs.

PECs can be treated as equity for US tax purposes and, at the same time, as debt for Luxembourg tax purposes. To qualify as equity for US tax purposes, a PEC must have equity characteristics such as a long term (50 years or more), subordination to other debt, a return that accrues to the extent that the issuer has sufficient income, and a return that is payable if and when the issuer's board decides (and only when the issuer is sufficiently solvent). The PEC may be stapled to shares in the capital of the issuer to help with equity classification in the US.

Figure 3



The treatment of PECs as debt for Luxembourg tax purposes means that the arm's-length return is not subject to Luxembourg withholding tax and the return is deductible for corporate income tax purposes. The principal is also not subject to capital duty, a non-recurring 1% duty on contributions of capital. PECs are also treated as debt for net worth tax purposes.

Luxco can, for example, invest the proceeds of the PECs issue in an EU-resident subsidiary. Provided that the shares in this subsidiary qualify under the EC parent-subsidiary directive and meet the requirements for the Luxembourg participation exemption, dividends and gains deriving from the shares in the subsidiary are neither subject to withholding tax in the subsidiary's home country nor to Luxembourg corporate income tax. The deduction of the return on the PECs is not needed in that case. Nevertheless, the fact that this return is not subject to Luxembourg withholding tax means that dividends paid by the subsidiary can be passed on to US Co without suffering withholding tax. If Luxco assumes the form of a limited company (an s.à.r.l.) it should be able to elect transparency for US tax purposes. Alternatively, it could elect treatment as a corporation for US tax purposes and this could result in a deferral of US taxation until the return of the PECs is declared by Luxco's board. */ continued page 38*

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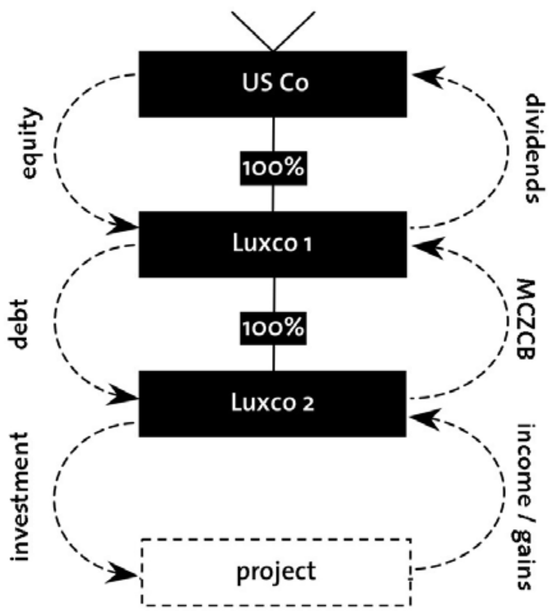
Investing the proceeds of the PECs in a shareholding raises the issue of thin capitalization: the Luxembourg tax authority could treat part of the return on the PECs as a dividend to the extent that Luxco finances the acquisition of the shareholding with less than 15% equity. That part of the return would be subject to Luxembourg withholding tax. The thin capitalization issue could be circumvented by means of convertible PECs, or "CPECs." The precise workings of CPECs are beyond the scope of this article.

Another 'hybrid' instrument that can be used to structure US outbound investments is the mandatorily convertible zero coupon bond, or "MCZCB," as shown in Figure 4. This instrument is hybrid in that the issuer accounts for it differently than the recipient does. An MCZCB is, in the first place, a zero coupon bond. It does not yield interest. Luxco 2 issues it to Luxco 1 at a discount. The discount should reflect the net present value of the interest that would be due on the issue price if it were an interest-bearing loan. Second, the MCZCB is mandatorily convertible into new shares issued by Luxco 2 at the end of its term. The term would normally be linked to the term of the project in which Luxco 2 would invest.

At the level of Luxco 2, the issue of the MCZCB gives rise to a liability. Initially, the size of this liability on the balance sheet of Luxco 2 is equal to the issue price of the MCZCB. Luxco 2 has to revalue the liability under the MCZCB from year to year, until it reaches the nominal value of the MCZCB. The revaluation gives rise to costs that are deductible from the revenues from the project. The margin between the costs and the revenues is subject to Luxembourg corporate income tax. By fine tuning the terms and conditions of the MCZCB, thereby bearing in mind the expected return on the investment in the project, the margin can be kept to a minimum — for example, 0.25% of the issue price of the MCZCB.

Luxco 1 has a receivable under the MCZCB that it can book at the issue price. The receivable does not have to be revalued for commercial purposes from year to year. Hence, the deduction that Luxco 2 can claim from year to year is not mirrored by taxable income in the hands of Luxco 1. The resulting overall deferral of taxation is turned into cancellation of taxation by converting the MCZCB into shares issued by Luxco 2 at the end of its term. Under a provision in Luxembourg's tax law, Luxco 1 is not required to recognize a taxable gain on conversion. This provision does require, though, that the unrealized gain on the MCZCB, if any, is rolled into the shares that Luxco 1 obtains upon conversion. Those shares qualify for the participation exemption, so the gain realized upon disposal of the shares — whether through sale or liquidation of Luxco 2 — is exempted from corporate income tax. One of the requirements for the participation exemption is observation of a certain holding period. The shares received upon conversion of the MCZCB are deemed to have been acquired at the moment when Luxco 1 acquired the MCZCB. Assuming that the term of the MCZCB equals the holding period required for the participation exemption, Luxco 1 should be able to dispose of the newly-acquired shares directly after conversion without paying tax.

Figure 4



Luxco 1 is exposed to net worth tax over the period prior to the conversion of the MCZCB. Given that the MCZCB has been financed with equity, the full value of the MCZCB would be subject to net worth tax at the level of Luxco 1. There are strategies that can prevent the value of the MCZCB from being subject to net worth tax, such as owning the shares in Luxco 1 through a Dutch company that issues a hybrid loan to Luxco 1. Also, because the basis of assessment for the net worth tax is determined on January 1, the net worth tax burden can be saved by implementing the MCZCB structure after January 1 of the relevant year and eventually dismantling the MCZCB structure before January 1 of the relevant year.

Capital duty should not apply to the conversion of the MCZCB into shares of the issuer. The conversion of the MCZCB would be treated as a contribution of capital. Capital duty should not be due, however, because a contribution of all assets and liabilities falls under a capital tax exemption. The only assets and liabilities that Luxco 1 has are the receivable for the MCZCB and the shares in Luxco 2. The shares in Luxco 2 have to be amortized as part of the conversion.

Multinational corporations that run offshore investments through Luxembourg are using at least four different structures.

Looking Forward

The four tax strategies discussed in this article are only a few of the many strategies that can help reduce the foreign tax exposure of US outbound investments. The Luxembourg tax authority is usually prepared to confirm the Luxembourg tax position of the relevant resident and non-resident entities by means of an advance tax ruling. Luxembourg is party to 43 treaties for the avoidance of double taxation. As a member of the European Union, the country has had to implement the numerous directives on direct taxation aimed at improving the internal market in the EU. Finally, in 2001 Luxembourg drastically reformed its tax laws, and this reform is generally considered to have greatly improved Luxembourg's attraction as a stepping stone for cross-border transactions and investment.

The government submitted a number of bills in the second half of last year. One of these introduces an advantageous tax, legal, regulatory and accounting framework for securitizations in which the vehicle issuing the securities or the vehicle acquiring the securitized assets reside in Luxembourg. It also addresses the legal position of investors in securitization vehicles, the transfer of securitized assets in general and receivables in particular to the acquiring vehicle and the management of the securitized assets. Another bill aims to introduce a new form of vehicle for investments in private equity and venture capital, a société d'investissement à capital à risque (known as an "SICAR"). It will be subject to the supervision of the government body that oversees the financial sector, but under a much more liberal regime than regulated investment funds. A third bill implements the EU interest and royalties directive. The aim of this directive is the abolition of withholding taxes on intra-EU interest and royalties payments between related enterprises. The bill has a wider scope in that it abolishes the withholding tax on royalties irrespective of the recipient. Finally, the government has submitted a bill aimed at bringing the regime regarding tax-exempt entities known as "1929 holding companies" in line with the EU code of conduct for business taxation. One can infer from the bill that the comparable tax requirement for the participation exemption will be relaxed to a tax rate of 11% or more from its present level of 15%. ◎

ENVIRONMENTAL UPDATE

Environmental Update

New Source Review

The Bush administration lost a major round in court in its effort to create a "bright-line test" for letting power companies avoid expensive environmental permitting requirements for some work on existing power plants.

The US court of appeals for the District of Columbia put on hold indefinitely the implementation of a final rule the US Environmental Protection Agency issued that would clarify the types of "routine maintenance, repair, and replacement" of equipment that can be done at existing power plants without the need for a "new source review" or "NSR" permit. The rule will now be held in abeyance until the court makes its decision, which could come as late as 2005.

EPA issued the final equipment replacement rule on October 27, 2003. It had been scheduled to take effect on December 26, 2003. The US appeals court said — when it put the rule on hold — that the opponents "demonstrated the irreparable harm and likelihood of success on the merits required for issuance of a stay pending review." The court signaled that it has significant doubts about the rule. There is a reasonable probability that at least portions of the rule will be overturned. The same appeals court stayed implementation of another EPA rule (the "NO_X SIP call rule") in 1999, but ultimately allowed most of the rule to become law.

Power companies can undertake "routine maintenance, repair and replacement" of equipment at existing power plants without the need for expensive permits. The debate about what qualifies has moved to the federal courts.

The new rule was issued to settle conflicting EPA guidance on the scope of the "routine maintenance, repair, and replacement" exemption under the NSR program. Under this exemption, a power plant or other industrial facility does not need to apply for a modification of its existing NSR air permit if it is replacing equipment at the plant in the course of "routine maintenance, repair or replacement." If the replacement does not fit within this definition, then a modified NSR permit typically must be obtained. EPA said it would not insist on NSR permits where three conditions are present. First, the owner must be replacing an existing component of a unit (for example, a boiler or turbine) with identical components or components that serve the same purpose. Second, the fixed capital cost of the replaced component and any other costs associated with the replacement activity must not exceed 20% of the current replacement value of the unit. Third, the equipment replacement must not alter the basic design of the unit or cause it to exceed any emission limitations.

Opponents of the rule charge that the new EPA definition of routine maintenance is a radical departure from 25 years of prior agency and judicial interpretations and the agency lacks authority under the Clean Air Act to implement it. A decision in the case is not expected until late 2004 or early 2005.

In a related development, the EPA administrator, Mike Leavitt, announced that the agency would continue to bring enforcement actions against utilities that have allegedly failed to comply with NSR permitting requirements. In late January, the agency filed a complaint against East Kentucky Power Cooperative seeking both civil penalties and injunctive relief for alleged NSR permitting violations due to three modifications at the company's coal-fired plants during the 1990s. EPA also recently issued a notice of violation to a Westar Energy facility in Kansas alleging that the coal-fired plant undertook activities at the plant between 1992 and 1999 that resulted in increased air emissions without undergoing an NSR permitting review before the modifications took place. The recent enforcement actions signal an intention by the Bush administration to continue to pursue alleged NSR permitting violations, particularly in instances that appear clearly not to qualify for the new "routine maintenance, repair, and replacement" exemption.

Air Permitting

The US Supreme Court issued a decision in mid-January upholding the ability of the federal government potentially to second-guess NSR air permitting decisions by states. The case is *Alaska Dept. of Environmental Conservation v. EPA*. In it, the court affirmed that EPA has authority to halt construction at a plant that is fully permitted at the state level. The decision was 5 to 4.

The case involved a mine owner called Teck Cominco. It had applied for a "prevention of significant deterioration," or "PSD," permit under the NSR program to increase operation of an existing standby diesel generator and to install a new diesel generator at its zinc mine. The PSD program requires that the permitting agency undertake a review to establish permit limitations based on the "best available control technology" for the affected units.

Teck Cominco proposed to install low nitrogen oxide, or "NO_X," combustors — instead of selective catalytic reduction systems — on the standby generator and the new generator, asserting that the low NO_X combustors represented the best available control technology for these units. The Alaska Department of Environmental Conservation agreed with Teck Cominco that selective catalytic reduction systems would be too expensive. The low NO_X combustors were expected to achieve a 30% reduction in NO_X emissions. The selective catalytic reduction systems would cut NO_X emissions by about 90%. EPA took issue with the Alaskan action and issued an order "prohibiting the construction or modification" of a major source which fails to comply with the NSR program.

Alaska argued before the US Supreme Court that the Clean Air Act does not give EPA the authority to second-guess a state PSD permitting decision where the state's PSD program had been fully approved by the agency. The federal government responded that it retains the power to "check" state permitting decisions that are unreasonable.

The Supreme Court said EPA can only overrule a state when a state's permitting decision is "not based on a reasoned analysis." It did not say how long EPA may take before it issues a "stop work" order. The Clean Air Act does not specify any time limits on this authority. As a practical matter, EPA probably could not stop a project that was already built or where construction was well underway; however, there is nothing in the Clean Air Act or the Supreme Court's decision that would prevent EPA from acting several months after a PSD permit is issued to halt construction where construction was not already started or was not otherwise underway. EPA has issued only a small number of "stop work" orders in the past.

Mercury

The New Jersey Department of Environmental Protection proposed a new regulation to cut mercury emissions from power plants, municipal solid waste incinerators, and iron and steel smelters. The draft rule imposes a cap on the 10 coal-fired power plants in New Jersey and calls for up to a 90% reduction of mercury emissions from the affected power plants. The mercury emission reductions from the coal-fired plants must be achieved by the end of 2007; however, the draft rule provides the option of meeting the standards by 2012 if a plant makes major reductions in sulfur dioxide, nitrogen oxide, and fine particulate emissions.

Under the proposed rule, the five municipal solid waste incinerators in the state must not exceed 28 micrograms per dry standard cubic meter of mercury emissions by 2011. Alternatively, */ continued page 42*

municipal solid waste incinerators can reduce mercury emissions by 85% below 1990 levels within one year after the rule becomes effective and achieve a 95% reduction by 2011. The draft rule also limits mercury emissions from New Jersey's six iron and steel smelters to 35 milligrams per ton of steel production by 2009, or a 75% reduction by 2009.

New Jersey criticized a proposal by the Bush administration to reduce mercury emissions at power plants nationwide. (See the related story of page 1.) In touting its command-and-control approach to regulating mercury, New Jersey said "the cap-and-trade form of mercury controls [that the Bush administration proposed] would allow several times more emissions than a Clinton-era plan that called for a technology based standard."

New Jersey is moving on its own to reduce mercury emissions from power plants and certain other facilities in the state.

The draft rule was issued on January 5, 2004, and is currently subject to a 60-day public comment period.

Greenhouse Gas Updates

Work on developing detailed guidance to implement the Kyoto protocol continues, despite continued uncertainty over whether Russia will ratify the protocol and trigger implementation. The protocol requires approximately a 5.2% reduction in greenhouse gas emissions by all signatories to the treaty from 2008 to 2012. Right now, all hopes for implementation hinge on whether Russia ratifies the agreement.

In December, 2003, a subsidiary body of the "UN framework convention on climate change" adopted clarifying guidelines on how to quantify carbon dioxide or CO_2 emission reduction credits from carbon sequestration activities. At recent meetings in Milan, Italy, the group developed model tables for reporting all land use, land-use change and forestry activities undertaken to sequester carbon. Carbon sequestration refers to the idea that carbon is captured and stored in forests and agricultural lands. Trees, plants, and soil absorb carbon dioxide, release the oxygen, and store the carbon.

Under the guidelines, credits toward greenhouse gas emission reduction targets could be available for carbon sequestration activities in connection with "clean development mechanism" projects. Such projects would be sponsored by developed countries.

The Kyoto protocol will enter into effect if it is ratified by 55 or more countries (including both industrialized "Annex I" nations and developing "Annex II" countries) whose combined emissions levels represent at least 55% of the carbon dioxide emissions from Annex I countries in 1990. So far, 120 nations accounting for 44.2% of the 1990 CO_2 emissions have ratified the treaty. At this point, implementation of the Kyoto protocol hinges on Russia, which accounts for 17.4% of the emissions. In December 2003, a senior aide to Russian President Vladimir Putin cast serious doubt on whether Russia will ratify the treaty. Russia is not expected to announce a formal position until after the March 2004 presidential elections.

In related developments, 10 US corporations recently pledged to reduce greenhouse gas emissions under a "climate leaders" program sponsored by the US government. Companies agreeing to implement voluntary greenhouse gas emission reduction targets include: 3M, Advanced Micro Devices, Inc., International Paper, Interface, Inc., American Electric Power, Cinergy Corp., Eastman Kodak, FPL Group, PSEG and United Technologies Corp. The climate leaders program now has 54 companies as participants. Participating companies agree to report greenhouse gas emissions from all major on-site sources and emissions related to the electricity they purchase. A number of climate leader participants have taken the additional step of pledging to meet specific greenhouse gas emission reduction targets. EPA projects that commitments by climate leaders will prevent a total of 7.5 million metric tons of CO_2-equivalent emissions per year.

The World Bank reported in December 2003 that the amount of greenhouse gas emission reduction credits traded worldwide during the first 10 months of 2003 was more than double the amount traded in all of 2002. The report, titled "State and Trends of the Carbon Market 2003," states that approximately 70 million metric tons of CO_2-equivalent emission reduction credits were traded from January to the beginning of November 2003. The figures on trades in past years were approximately 30 million metric tons of CO_2-equivalent emission reductions in 2002 and 13 million metric tons in 2001. Most of the trading in CO_2-equivalent emission reductions occurred in project-based transactions. The motivations for CO_2-equivalent emissions trading reportedly fell into four categories: immediate compliance with national markets, for example, the United Kingdom emissions trading regime, Kyoto pre-compliance, voluntary compliance and retail schemes (that is, companies without significant greenhouse gas emissions that desire to be climate-neutral in their activities). The report notes that buyers of greenhouse gas emission reduction credits include governments, public-private partnerships and, increasingly, private companies, especially from Japan.

Solid Waste

Time is running out for companies to comment on how EPA proposes to define "solid waste" for purposes of the "Resource Recovery and Conservation Act," or "RCRA." The deadline is February 25. The agency is proposing to redefine "solid waste" to exclude from regulation under RCRA certain hazardous secondary materials, by-products and sludges that now qualify as hazardous wastes, but are otherwise reclaimed or recycled in a continuous process within the same industry. Certain types of reclamation and recycling activities would no longer qualify as the "discarding" of these materials, and consequently would no longer be considered "hazardous wastes."

The regulated community is expected to reap savings from reduced disposal costs as more secondary material is reclaimed or recycled. Reduced record-keeping and reporting requirements are also expected to result in substantial savings. The proposed rule has been criticized by environmental groups and some members of Congress as a rollback of the environmental protections under RCRA's cradle-to-grave hazardous waste management program. The idea of revising the RCRA definition of "solid waste" has been debated within EPA for more than 10 years. The agency argues that reclamation and recycling of hazardous wastes should be encouraged.

The government projects that the proposed rule would exclude approximately 1.5 million tons of hazardous waste annually from regulation under RCRA. Under the proposed rule, four criteria must generally be satisfied in order to escape such regulation. The secondary material to be reclaimed or recycled must be a valuable commodity, make a useful contribution and yield a valuable product, and it cannot contain significant amounts of hazardous constituents.

EPA is not expected to issue a final rule until sometime in 2005.

Brief Updates

New Jersey Governor James McGreevey signed two new laws in mid-January that are supposed to encourage the remediation and development of contaminated properties known as brownfields. The first measure provides for the reimbursement by the state of up to 75% of the cost of redeveloping a contaminated property. Tax revenues generated in part by a new sales tax on materials used to clean up or redevelop a brownfield site will be used to fund the measure. The second new law provides for a business tax credit that would allow reimbursement of up to 100% of the cost of remediating a contaminated property, but only if the New Jersey tax department determines that new business activity at the site will generate tax revenue at least equal to the value of the tax credit within three years. A developer may qualify for up to a $4 million tax credit during the period 2004 to 2006, but the credit is limited to 50% of his tax liability.

The US Supreme Court said in / continued page 44

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January that it will review a lower court decision on whether a Superfund lawsuit may be brought by a private party seeking a share of cleanup costs from other private parties absent an initial enforcement action from the US Environmental Protection Agency. The case is *Aviall Services Inc. v. the Cooper Industries Inc*. A US appeals court ruled that private Superfund cost-sharing actions may be brought without having to wait first for the federal government to issue a cleanup or consent order. The US government takes the position that an enforcement order is required first.

The US Environmental Protection Agency issued guidance in December regarding the use of "supplemental environmental projects" in settlement agreements. Examples of such projects are programs to fund local community group activities or to develop community projects like new parks. Companies are often allowed to undertaken such activities to offset a portion of a civil penalty in enforcement actions. The guidance document modifies EPA's previous position that generally prohibited supplemental environmental projects where a company will benefit financially from such projects. Under the new guidance document, the agency will allow such projects as an offset to penalties, provided they do not generate revenue for the alleged violator sooner than three years for small businesses and no sooner than five years for other companies.

The South Coast Air Quality Management District in California is allowing power plants to reenter the regional clean air incentives market, known as "RECLAIM," in 2004. Plants will be limited initially to trading NO_X RECLAIM credits with other power plants until full reentry into the program becomes effective on September 1, 2004. The regulators pulled power plants out of the RECLAIM program in May 2001 when the energy crisis in California led to extremely high prices for NO_X RECLAIM credits.

Finally, EPA issued guidelines in January explaining what "contiguous property owners" must do to be protected from Superfund liability. Under the new guidelines, landowners whose property is contaminated by releases of hazardous materials from neighboring properties must show that they did not cause, contribute to, or consent to the release and that they are not potentially liable for response costs at the neighboring facility. They must also show that they comply with any land use restrictions, and that they will take steps to stop any continuing releases or future releases from the neighboring site and limit exposures to humans and the environment. The new guidelines are of marginal utility to entities purchasing property near known or suspected contaminated sites, because a property is shielded from liability only if it is bought without knowledge or reason to know that a contiguous property is contaminated.

— contributed by Roy Belden in New York

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