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PROJECT FINANCE
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New Opportunities in Poland for Project Developers

by Igor Muszyński, in Warsaw

Poland put new rules for electricity supply into effect in May.

The new rules reinforce opportunities for project developers to pick off industrial customers from the incumbent utilities by building inside-the-fence projects and also make the country a more hospitable place to generate electricity from wind and other forms of renewable energy.

However, their main purpose is to bring Polish electricity laws into line with a European Union directive on operation of the internal electricity market. Poland joined the European Union in May 2004. The new rules address, among other things, the trading of renewable energy, the right to choose an energy supplier, the calculation of energy tariffs and the tender process for constructing new generating capacity.

Inside-the-Fence Projects?

Household gas and electricity customers will have the right to choose their utility suppliers from July 1, 2007. This is the deadline under the EU directive for when all residents of the European Union must have retail choice.

Industrial customers in Poland already have the right to choose / *continued page 2*

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PRIVATE EQUITY FUNDS that want to own utilities or invest in transmission projects should find it easier to do so after a new policy statement by the Federal Energy Regulatory Commission in May.

Utilities pass through the taxes they pay to their customers in rates.

However, the question comes up if the utility is owned by a partnership — which is how a private equity fund might own it — whether any tax expense can be passed through, since partnerships do not pay income taxes. Rather, each partner pays taxes directly on his share of the partnership income.

FERC said on May 4 that it can see “no rational / *continued page 3*

CORRECTIONS

A story on page 1 of the April *NewsWire* reported that large companies have been winning lawsuits against the US government to get back the federal excise taxes they are charged by their telephone companies for long-distance phone service. The refunds can be significant sums of money. The story reported that Honeywell and Fortis won two such cases in February, and it identified Fortis as a large diversified utility holding company that owns utilities primarily in Canada and the Caribbean. This is the wrong Fortis.

In addition, two charts that appeared in a story about new US limits on pollution from power plants said the information in them came from the US Environmental Protection Agency. The charts appear on page 4 of the April *NewsWire*. In fact, the charts were prepared by Sanford C. Bernstein & Co., an independent investment research and brokerage firm.

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their suppliers, opening the door to development of inside-the-fence power projects.

All major power generating projects financed in Poland over the last decade were done on the basis of long-term power purchase agreements with the transmission system operator. Since the European Commission views long-term PPAs entered into in the 1990's as a form of unauthorized state aid and has been pressuring Poland to terminate the existing PPAs, utilities are likely to refrain from executing new long-term contracts.

However, the right to sell directly to the final customers creates a new means of financing independent power projects. The European Union directive requires incumbent utilities in all EU member states to give access to the grid to both power producers and power customers. This right enables sponsors to choose the best location for their projects since they ought to have access to the grid from any location within the European Union.

Project developers who want to pick off industrial customers from the incumbent utilities by building inside-the-fence plants would sign direct long-term power purchase agreements with the industrial customers. The expanding free market means that such customers are unlikely to enter into a "classic" long-term PPA with clauses passing most of the offtake risk to the electricity offtaker. Power contracts will have to be related to the actual electricity prices available in the market and provide certain safeguards to the power producer in the case of market disruptions. Industrials are unlikely to enter into PPAs that do not provide them with visible benefits compared to what they can get by buying electricity directly from power marketers.

Setting up an inside-the-fence project is still not easy for several reasons. First, technical requirements imposed by the transmission and distribution grid operators for metering devices and related data transmission, which must be met by both the generator and the customer, impose high additional costs on independent power projects. Second, a number of additional contracts must be signed to facilitate direct sales from the generator to the final customer, including with special trading operators to secure access to the grid and balancing. These can be time consuming and

expensive to negotiate. Third, the fact that many large industrial customers in Poland are not companies with investment-grade ratings poses an additional risk of payment defaults. Just to give an example, the biggest Polish electricity customer, the Polish railroad, has struggled for years with its lack of financial liquidity, causing permanent problems to its electricity providers.

Existing PPAs

The Polish government submitted a draft law to parliament in the spring that would terminate all existing long-term power purchase agreements.

All major power generating projects to date were financed on the basis of such long-term PPAs. The PPAs were identified during negotiations over Poland's application to join the European Union as an obstacle to full liberalization of the electricity market since they cover around 60% of total generating capacity in Poland. After two years of discussions among the European Commission, the Polish government, the domestic power industry and banks that financed power projects, the Polish government prepared a draft law that offers a voluntary termination of PPAs in exchange for compensation due within 14 days from the date of termination of the PPA. The compensation is subject to later adjustment over the next 10 years based on actual performance of the electricity market after termination, but there is a cap on how much of an adjustment can be made. Compensation will be paid from monies raised through a bond offering made by a special company to be established under the draft law.

The draft law is controversial. There is still an ongoing debate in the power and financial communities, and the measure proposed by the government is by no means certain to be enacted. However, one thing is clear: there will not be any more long-term PPAs with utilities, so new means must be found to finance independent power projects. A turn in the market toward inside-the-fence structures is just one of the possibilities.

Renewable Energy

The new rules Poland implemented in May are expected to stimulate demand for renewable energy.

Poland already has had on its statute books a law requiring utilities and traders selling electricity directly to end users to supply a percentage of their / continued page 4

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reason to limit the income tax allowance to public utility income earned by a corporation." It said it would allow partnerships to pass through taxes paid by their partners in rates for utility service, provided the partners have an "actual or potential income tax liability." Private equity funds often have pension funds and other tax-exempt investors. The agency said that in such cases where partners do not all have the same tax exposure, taxes should be passed through at a blended rate.

The agency did not say what happens in cases where the partners do not pay any taxes in fact because of net operating losses or tax credits. The issue is whether there is at least a "potential" income tax liability in such cases that can be included in rates. It said these issues should be sorted out in individual rate proceedings.

The FERC policy statement is relevant mainly to transmission projects since the rates for interstate transmission are set by the federal government. The ability of electric distribution companies to pass through taxes in rates is still a matter left to individual state commissions.

The issue became a focus of attention recently in Oregon where the Texas Pacific Group made a bid to acquire Portland General from Enron. Newspapers reported that Portland General had included a tax component in rates even though, after Enron purchased it, its tax results were reported on Enron consolidated tax returns on which Enron paid little or no taxes.

SOME LANDFILL GAS projects are in limbo.

Decomposing garbage produces methane gas. Congress voted last October to let anyone who uses landfill gas to generate electricity claim "production tax credits" of 0.9¢ a kWh on the electricity. The generating equipment must be installed between October 23, 2004 and December 31, 2005 to qualify. Credits can be claimed for five years after the equipment is put into service.

Congress was concerned / continued page 5

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total sales from renewable energy sources. In December 2004, the Ministry of Economy set this threshold at 3.1% for 2005, to be increased annually up to 9% in 2010. However, a shortage of renewable energy sources and vague wording in the applicable laws allowed many to circumvent this requirement. For example, many distributors and traders buy renewable energy and then resell it to other suppliers, thereby enabling a number of suppliers to meet the required thresholds with the same renewable energy.

To end this practice, Poland introduced the concept in May of "green certificates," which are certificates of origin for renewable energy. The certificates will be issued by the Energy Regulatory Authority to renewable energy generators. Each certificate will constitute a legal right and evidence the production of a specified quantity of renewable energy. The rights incorporated in the certificates will be traded on the Polish Power Exchange, called the "PolPx," and electricity suppliers will be able to buy certificates on the PolPx in order to meet the renewable energy thresholds.

The "green value" of electricity will therefore be separated from physical energy flows, and the trading of green certificates will provide renewable energy generators with a mechanism for selling electricity on the market at competitive prices.

Electricity suppliers who do not meet the renewable energy threshold will be required to pay a fine equal to PLN 240 (€60) for each mWh of shortfall in renewable energy.

This fee is seen as a major drawback of the new system, as it has the effect of setting a ceiling for the "green value" of electricity in advance since suppliers are unlikely to spend more on green certificates than the fine they would otherwise have to pay. The need for mandatory sales of certificates through the power exchange has also been widely criticized. Critics charge there is no need to require trades to occur through the power exchange, since any fear the government has about skyrocketing prices will be addressed by the effective cap set on prices for the certificates by the market.

Project developers may have an opportunity to pick off industrial customers from the incumbent utilities in Poland by building inside-the-fence plants.

The new rules also remove one of the biggest obstacles for windpower projects by exempting renewable power from the general "balancing rules." These rules impose painful financial consequences on generators who declare a day in advance different production than they actually deliver. Wind projects are exposed to weather risk, and the prospect of extremely high balancing costs has been commonly viewed as a key risk in such projects to date. The exemption is available until the end of 2010 and has been welcomed by project developers.

Another incentive introduced under the new rules in May is a 50% mandatory discount in the interconnection fee for renewable energy suppliers with projects that are smaller than five megawatts.

Cogeneration Projects

The Polish government is expected to propose other changes in Polish law soon to support construction of cogeneration projects.

A cogeneration project is a power plant that produces two useful forms of energy from a single fuel. An example is a power plant that burns coal under a boiler to produce steam, some of which is used to heat an adjacent factory and the rest is run through a steam turbine to generate electricity.

EU Directive 2004/8/EC makes support of high-efficiency cogeneration a priority within the European

Union. Member states are supposed identify all their existing cogenerators. This is the first step, to be followed by new incentives for development of additional projects.

Another directive permits privileges in dispatch of cogeneration units, provided the privileges do not cover more than 15% of total electricity consumption in a given member state. For the past several years, Poland has required utilities in the country to supply at least 40% of their electricity from cogeneration units. The introduction of green certificates has led to discussion about whether to provide an analogous system for cogenerated power. The EU will probably end up authorizing a menu of possible incentives from which member countries will be permitted to choose.

Electricity Tariffs

The new rules allow utilities in Poland to set their electricity tariffs at levels that will earn them a "justified return" on invested capital. This has been viewed in Poland as a victory for the utilities. Tariffs must be approved by the Energy Regulatory Authority.

However, a drawback of the legislation may be its vagueness: the new rules do not specify a minimum capital return ratio. Instead, this ratio is to be set in a future ordinance by the Minister of Economy, making it relatively easy to amend. A draft ordinance has already been circulated that defines "justified return" as a rate calculated by multiplying the sum of a base return plus a premium that reflects risk times the net account value of the assets used in the licensed activity. Such an approach seems correct in general terms, but it may be difficult to apply since reaching agreement on the figures to fill in for the variables in the formula may prove elusive.

Tenders for New Capacity

The new rules introduce a tender procedure for construction of new generating capacity, intended to facilitate government planning. Tenders will be organized by the Energy Regulatory Authority whenever the Minister of Economy foresees a potential long-term shortage of electricity.

Each tender will explain the types of incentives to be offered by the government to potential investors and will be published in the official bulletin of the Energy Regulatory Authority and in the official journal of the European Union at least six months before the closing of the tender procedure. */ continued page 6*

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that it was giving too large a tax subsidy for landfill gas, since many gas producers qualify for a separate "section 29 credit" of $1.13 an mmBtu for trapping and collecting the gas. What Congress apparently did not want was a situation where section 29 credits are claimed by the gas producer and production tax credits are claimed by an electricity generator on the same gas.

However, the language it wrote to prevent this was poorly drafted and does not rule out production tax credits in any case. The US Treasury Department is aware of the problem and has asked Congress to clarify the language. A senior economist with the Joint Tax Committee in Congress said in May that the staff plans to fix the language in a "technical corrections bill" later this year, but it is not sure yet what the new language will say. He said what Congress had in mind was "totally new gas from a totally new facility." Electricity does not qualify for production tax credits, he said, if the generator uses gas on which section 29 credits were claimed. It also does not qualify if the gas is run through a "facility" that was used to collect any gas that qualified for section 29 credits.

Landfills are filled with garbage one section at a time. The collection equipment looks like a large spider. The body of the spider is a "blower" that provides suction to pull gas from the ground. There are also pipes – called horizontal and vertical "wells" – that run down into each section so the blower can draw the gas. When a new section is filled with garbage, the gas collection system is extended by adding wells in the new section.

The hard question is what happens if someone installs a generator today to use gas from a new section, but that gas runs through the same blower used for older sections where gas qualified for section 29 credits. Can production tax credits be claimed on electricity generated with gas from the new section? There is no clear answer. The Joint Tax Committee staff said it plans to leave that question for the Internal Revenue Service. The issue is whether the wells used in the new section are */ continued page 7*

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In selecting the winning bidder, the Energy Regulatory Authority will be obliged to take into account consistency with Polish energy policy, the safety and security of the electricity grid, how much additional work will be required on the grid to accommodate the new project, the potential environmental effects of the project, a preference for local investment, and the types of fuels to be used, among other factors. The winner of the tender will conclude an agreement with the Energy Regulatory Authority establishing the investor's obligations and the financial incentives for constructing the plant.

Depending on the type of incentives offered, which have not yet been announced, the new system could have the effect of pushing developers to build projects that rely on more environmentally-friendly technologies. On the other hand, it may forestall investment in new projects that do not qualify for state aid, as investors may abandon their investment plans until the government organizes a tender and offers special financial incentives. By holding a tender to create new capacity, the government would be admitting that the market is too risky for investment without special incentives. ◎

Temporary Obstacle to US Utility Mergers?

by Adam Wenner, in Washington

A decision by an administrative law judge in May highlighted a potential obstacle to utility mergers in the United States.

A judge with the US Securities and Exchange Commission held that the 2000 merger of two US utilities — American Electric Power based in Ohio and Central Southwest based in Texas — violated a 1935 statute that makes formation of multistate utilities difficult.

The 1935 law, called the "Public Utility Holding Company Act," requires Securities and Exchange Commission approval of most utility mergers.

The SEC approved the merger in June 2000.

However, a US appeals court ruled in January 2002, in a case brought by opponents of the merger, that the SEC had not adequately explained some of the grounds for its approval. After conducting a hearing into the matter, SEC administrative law judge Robert G. Mahony held on May 3 that the merger failed to comply with the PUHCA requirement that the merging utilities must operate in a single area or region.

Legal Issue

PUHCA places limits on utility holding companies. A "holding company" is a company that owns 10% or more of the outstanding voting securities of an electric or gas utility.

Under what is known as the "two-bite rule," if, following a merger or acquisition, a holding company will have two or more utilities as subsidiaries, then SEC approval is required for the transaction to take place.

If the utility subsidiaries are in more than one state, then PUHCA permits SEC to approve the merger or acquisition only if the utility subsidiaries will form a single "integrated public-utility system."

An integrated system may be comprised either of electric or gas utilities, but not both. However, under what is known as the "ABC" clauses of section 11 of PUHCA, a holding company may retain one or more "secondary" utilities — gas or electric — if it shows that spinning off the secondary systems would result in the loss of substantial economies, and that keeping them as part of an expanding holding company will not undermine the benefits of localized management, efficient operation, or the effectiveness of regulation.

To prove that two or more utilities will be an "integrated system," the parties must show four things. First, the assets of the companies must be physically interconnected or capable of physical interconnection. Second, the assets must be capable of economic operation "as a single interconnected and coordinated system." Third, the two companies must be confined to a "single area or region." Finally, the combined companies must not be so large as to impair the advantages of localized management, efficient operation and the effectiveness of regulation.

These standards flow directly from the aim Congress had in 1935 when it enacted PUHCA of protecting consumers and investors from the abuses associated with large interstate utility holding companies, which at the time

were viewed as "pyramidal structures with a few not always responsible shareholders of the top holding company exercising excessive control over the underlying operating companies." Holding companies were perceived as able to evade state commission regulation by "scatteration" — the ownership of widely dispersed utility properties that did not lend themselves to effective state regulation.

Contiguous?

In order to satisfy the interconnection standard, the merging utilities do not need to be physically adjacent to one another. It is enough to be linked by transmission over an intervening utility grid.

American Electric Power and Central Southwest argued that they are interconnected because they have reserved 250 megawatts of capacity on the so-called MISO grid, a regional grid operated by the Midwest Independent System Operator. The SEC had said this was enough when it originally approved the merger. However, the US appeals court questioned whether a unidirectional transmission arrangement satisfies the requirement for interconnection, since the term interconnection implies two-way transfers of power. AEP presented evidence to the administrative law judge, when the case was reheard, that 2% of the transactions on the contract transmission path were west to east, along with 98% east to west. The administrative law judge ruled there is no requirement that any specific percentage of the power from one utility in the system be provided to another and, therefore, even a "miniscule" amount of bi-directional transfers was sufficient to satisfy the interconnection standard.

In contrast, the administrative law judge did not buy the argument that the combined utilities satisfy the requirement that the post-merger utility system must be "confined in its operations to a single area or region."

The US appeals court also had problems with this. It said the SEC had botched the analysis on this issue when it originally approved the merger. The SEC found that because the merged company would be interconnected and capable of economic and coordinated operation, and its size would not impair efficient operation, it should be treated automatically as operating in a single area or region. The court said this approach would allow the merged company to satisfy the single area or region standard, even if, in fact, it does not.

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considered a separate "facility" for producing gas.

The uncertainty may be fatal to many projects. Ordinarily, one would get a private ruling from the Internal Revenue Service settling the issue, but there is almost no time given the December deadline for putting generators in service. A ruling takes three to six months.

A FOREIGN TAX CREDIT strategy passed muster in the US claims court.

Guardian Industries is a US company that makes glass products. Guardian owns three glass manufacturing plants and employs 1,200 people in Luxembourg. Guardian owns several companies in Luxembourg through which it runs this business. The companies are organized with a parent company that Guardian treats as a "disregarded entity" for US tax purposes, meaning that Guardian reports its tax results in the US as if the Luxembourg parent company does not exist. The next-tier subsidiaries of the Luxembourg parent are treated as corporations for US tax purposes. They block any income belonging to them from hitting the US return.

The Luxembourg companies file a group income tax return in Luxembourg.

Guardian takes the position that all the taxes paid on the group return to Luxembourg are taxes solely of the Luxembourg parent company. That's because the subsidiaries do not have any "joint or several" liability for the taxes under Luxembourg law. That means that Guardian can claim the taxes paid as a foreign tax credit without waiting for its Luxembourg earnings, which are parked in the subsidiaries, to be distributed back to the United States. That's because the taxes are treated as if paid by Guardian directly since the Luxembourg parent does not exist for US tax purposes.

The IRS disputed this result. It argued that the taxes should be considered paid by each of the subsidiaries in relation to the income it contributed to the group return. That way, no foreign tax credits could be claimed until the related income is repatriated to the US.

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When the case went back to the SEC administrative law judge for further consideration, AEP argued that the combined companies operate in a single region — the "eastern interconnection of North America," which AEP called a single interdependent "machine." The companies are spread over three regional transmission organizations, or RTOs. AEP argued that since the three RTOs coordinate their operations, the two utilities at either ends of the RTOs are interconnected. It also argued that an analysis of trade flows in several industries shows that the central portion of the United States, which is served by the combined utilities, comprises a single economic region.

The administrative law judge rejected this approach, finding instead that the "single area or region" standard refers to geography, with other factors such as socio-economics and geology also contributing. The judge said that Ohio and Texas are in different regions of the country. Accordingly, he rejected the merger.

Significance

AEP has appealed the decision to the full Securities and Exchange Commission. This has the effect of placing the decision on hold until the full commission can hear the case. Once the SEC issues an order, regardless of whether the SEC approves or rejects the merger, that order will almost certainly be appealed to the court once again. Since the companies have been merged for more than four years, no matter what decision is ultimately reached, it is unlikely that they will be forced to separate. Indeed, the potential loss of economies of scale might enable CSW to qualify as an "additional system" that AEP can retain to avoid loss of economies under the ABC clause of section 11 of PUHCA.

More significant is the potential effect of the latest decision on any pending or future mergers and on the federal energy legislation being debated currently in Congress.

Importantly, neither the court nor the administrative law judge found anything harmful to consumers or investors about the merger. Indeed, 11 state public utility commissions, as well as the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and the US Department of Justice, under the Hart-Scott-Rodino Act, all approved the merger. Moreover, in contrast to the situation in 1935, today the SEC has ample authority to regulate the merged company's securities issuances and corporate activities, and the 11 state commissions that regulate the merged companies' utilities have ample authority and resources to regulate rates. As the US appeals court said, the SEC is clearly correct that "PUHCA's [single] region requirement is outdated in light of recent technological advances. In view of the statute's plain language, however, only Congress can make that decision . . . . In the meantime, the SEC may not interpret the phrase 'single area or region' so flexibly as to read it out of the Act."

> A decision by an administrative law judge in May could make it more difficult for geographically-distant utilities to merge.

The key question raised by the administrative law judge's decision is what is a "single area or region" for purposes of PUHCA, and how can potential merger candidates predict whether a transaction will pass muster under PUHCA?

When the SEC has found that the standard was satisfied in the past, it was because the geographic characteristics of the merging territories were "fairly homogeneous." The SEC has also identified factors such as industrial, marketing and general business activity, transportation facilities and gas

utility requirements, that could be relevant to a finding that different service areas are located in a common economic and geographic region.

In light of the need not to interpret the single area or region requirement so flexibly as to read it out of the statute, the best approach may be common sense. Regarding the limits of what is likely to pass muster, it is significant that the SEC's division of investment management, which participated in the AEP litigation, took the position that, from the perspective of geography, "[t]here is simply no way that [the states in which the combined AEP system operates] are in a single area or region."

The test may ultimately prove to be the same test as for pornography: the SEC knows a single area or region when it sees it. Clearly mergers within a recognized region, such as the New England states or the Pacific northwest, satisfy the standard. Perhaps a sanity check is whether the customers of the merged company speak with the same accent. As the SEC considers the proposed mergers of Exelon and Public Service Gas & Electric Co., Duke Energy and Cinergy, and Mid-American Energy and PacifiCorp., it is clear that the "single area or region" standard, along with the prospects that Congress will repeal PUHCA this year, will be at the forefront of key issues.

Regardless of how the AEP and CSW merger is ultimately decided, absent PUHCA repeal, the latest decisions will make it more difficult for geographically-distant utilities to merge.

In contrast to the integration standard, which can be solved by spending enough money to acquire transmission or construct interconnection lines between utility systems, there is no way to convert two different geographic regions into one. After being slapped once by the court for failing to enforce the laws on the books, the SEC is unlikely to take a lax approach to this issue when it arises in pending and future cases. Moreover, groups that want to fight utility mergers will clearly be emboldened by their success in the AEP case. The result will be that mergers involving utilities in areas that, on their face, are not in the same region will face a much tougher challenge in being approved, and even if approved, will end up fighting appeals in court. Awaiting court review of an SEC order before closing a merger is not a particularly sensible business strategy given the amount of the time the merging companies end up in limbo. */ continued page 10*

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After soliciting input from the Luxembourg tax authorities, the US claims court agreed with Guardian.

It may be too soon for others to adopt the same strategy since the decision will probably be appealed. There is also a risk of being overturned by Congress. In May, the Senate tax-writing committee stuck language in a highway bill that would give the IRS broader authority to attack transactions where foreign tax credits are separated from the related foreign income.

Some Benelux lawyers also warn that the court may have overlooked two other legal principles. In some Benelux countries, when a subsidiary leaves the group return, it may have retrospective liability up to five years for its share of taxes while it was included in the return. In addition, many countries have a civil law principle that when one company pays a liability for another company, the second company may be required to contribute.

TAX OPINIONS have become an area of controversy.

The IRS wants any US tax advice that it considers a "covered opinion" to follow certain rules. Some advice will have to include prominent disclosures. The new rules take effect on June 21.

Some tax lawyers complain that the rules will prevent them from answering questions in the future about just a few tax issues in a transaction. This is probably an overreaction.

In general, any advice starting June 21 this year that rises to the level of a "covered opinion" must be in a "long form" in which the tax lawyer lists all the relevant facts of the transaction, addresses every significant tax issue and expresses an opinion about each issue and about the proper tax treatment of the transaction as a whole. He must explain his reasoning behind each conclusion he reaches.

He can write a more limited opinion, but any such opinion would have to include two prominent disclosures that there may be other issues that could affect the tax */ continued page 11*

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Witness the year and a half that it took for the court to review the SEC decision in the AEP case, and the two and a half years it took for the SEC then to conduct a hearing after the court had heard the case. The consequences, absent PUHCA repeal, will be significant delay in closing transactions that raise questions as to their ability to satisfy the single or region standard.

Ironically, mergers of utilities that are in the same geographic region, while readily satisfying PUHCA, are also likely to have trouble getting approval from the Federal Energy Regulatory Commission. FERC must approve any mergers involving transmission grids or power plants that sell into the wholesale market. In considering mergers, FERC focuses on the market power the merged company will have. If two utilities that own power plants are located near each other, combining their assets generally produces significant increases in the market share that would be held by the merged company. While transfers of control or divestures of generating plants can alleviate the problem, such measures can deprive a merger transaction of significant value.

Until PUHCA is repealed, the concerns that gave rise to this legislation in 1935 will continue to thwart the ability of utilities to combine, whether or not those concerns reflect the same public policy issues today as they did in 1935.

On the PUHCA front, the Senate energy committee voted in May, as part of a broad energy bill, to repeal PUHCA but to give the Federal Energy Regulatory Commission expanded authority to review mergers. The energy bill is expected to be taken up by the full Senate in mid- to late June. It has already passed the House with PUHCA repeal and *no* expanded FERC merger review authority. PUHCA repeal would remove a large obstacle to the Mid-American proposal to acquire PacifiCorp. The expansion of FERC authority to review mergers would not affect the FERC review in the PacifiCorp case, since the existing FERC merger authority already gives the agency jurisdiction in the PacifiCorp transaction. It is already able to review any proposed changes in control of public utilities. The expanded review authority the Senate wants to give FERC would give it a broader say in sales of stand-alone power plants. ◎

Current Issues in Mining Projects

by Nabil L. Khodadad, in London

As metal and coal prices surge, lenders are being asked to finance projects with weaker sponsors and in countries with greater political risk. This has created interesting opportunities and challenges.

Prices for precious, base and ferrous metals and coal have increased 50% or more in the last few years. The price of gold is up by more than 50% since 2001 and is now near a 15-year high. Nickel, copper, lead, zinc and tin prices have doubled in the last two years, and aluminum prices have risen by more than 50%. Coal prices have doubled in just the last year. Major steel producers in Japan, China and elsewhere agreed to a more than 71% increase in the price of iron ore in February. Share prices of most mining companies have also soared.

Many analysts believe that the prices for coal and most metals will remain high in the short to medium term. A construction boom in China has helped to push up the price of many commodities, especially copper and iron ore, and surging oil and natural gas prices have boosted demand for coal. Continued instability in Iraq and elsewhere in the Middle East, concerns about global terrorism and a weak US dollar have restored gold as a safe haven in uncertain times.

Surging prices make mining much more attractive to project lenders at the same time that soaring revenues have made the mining majors less reliant on project finance.

The capital markets have become accessible not only to the mining majors, but also to junior mining companies. For example, Sino Gold Limited, a smaller mining company with limited existing production, recently raised $35 million through the issuance of senior unsecured convertible notes due in 2012 to finance development of phase one of the Jinfeng gold mining project in China.

Project Risks

Lenders considering whether to extend financing to a mining project must analyze many types of risks. The following is a "top 10 list" of key risks that apply in a mine financing.

Reserves. Reserves are key in any mining project. Without

adequate reserves, a mining project cannot generate enough revenue to service debt. Project lenders are only willing to finance proven reserves and not exploration. To give them a buffer against unanticipated costs, project lenders typically require that a mining project have a "reserve tail" of at least 30%, meaning that at least 30% of the project's reserves should remain on the final repayment date. Lenders will require the borrower to submit a reserve report prepared by a reputable source, and they also usually retain an independent mining engineer to validate the reserve report and comment on the feasibility study submitted by the mining company.

The importance of verifying reserves was dramatically illustrated by the Bre-X mining scandal in the late 1990s. Bre-X, a Toronto-listed junior mining company with no production, started as a penny stock. Based on reports that its Busang concession contained as much as 200 million ounces of reserves (which would have made it the world's largest gold deposit), Bre-X's share price soared to a peak of CDN$286.50, giving the company a market capitalization of over CDN$6 billion. However, an independent audit of Bre-X's core samples found that they had been salted with outside gold and that the Busang concession did not contain any commercial reserves. After the audit results became known, Bre-X collapsed, and its shares became worthless. As a result of the Bre-X scandal, stock exchanges and regulators in the US, Canada, the UK, Australia and elsewhere have imposed more stringent standards on the reporting of reserves.

Completion Risk. Lenders in a mine project financing are generally unwilling to take completion risk.

They will require the sponsor(s) of the project to provide completion guarantees. Sponsors of mining projects used to be large mining companies with strong balance sheets and substantial non-project assets to support their completion guarantees. However, loans are being made increasingly today to mining companies with weak balance sheets and fewer non-project assets. This has caused project lenders to look for other ways to mitigate completion risk. For example, project lenders have been forced to conduct more due diligence on the project, focus more carefully on the creditworthiness of the contractor and require more robust construction contracts. They are also requiring larger reserves for cost overruns and contingencies and a larger equity buffer for projects with weaker sponsors. / *continued page 12*

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treatment of the transaction that are not addressed and that the client cannot rely on the opinion to avoid IRS penalties, except on the limited issues covered.

Warnings — or prominent disclosures — are also required in two other circumstances. One is where a third party will use the opinion to market or promote a transaction. Such an opinion must include a warning that the opinion is being written to support such efforts and that the taxpayer should seek advice on the transaction from his own tax adviser. The other situation where a warning is required is where the lawyer fails to express a view at least as strong as "more likely than not" that the taxpayer is taking the right tax position. In that case, the opinion must call attention to that fact and warn that it cannot be used to avoid IRS penalties on positions the taxpayer is taking with such weak support.

One thing that has some tax lawyers up in arms is that "opinion" is so broadly defined in the new IRS rules that it can include something as simple as an email responding to a tax question.

However, to be a "covered opinion," it must fall into one of three categories. One category is written advice about a "listed transaction," meaning a type of transaction that the IRS has put Americans on notice that it does not believe works. Another category is written advice about a transaction with "a principal purpose" of avoiding or evading federal taxes. The last category is written advice about a transaction with "a significant purpose" of avoiding or evading federal taxes, but — in cases where such tax results are only a *significant* purpose — there must be something more. That extra bit might be that the client intends to rely on the opinion to avoid IRS penalties or a third party plans to use the opinion to market a deal, the lawyer giving the opinion insists that the transaction structure or his tax advice be kept confidential, or his fees are tied partly to tax results.

On May 18, the IRS responded to complaints about the new rules by issuing additional guidance. / *continued page 13*

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Mining projects are also being undertaken in countries fraught with political risk. It is precisely in such countries that the mining majors are most likely to seek project finance as a means of reducing political risk. There is a perception that a mining project that has been financed by foreign lenders, particularly international financial institutions such as the International Finance Corporation or the European Bank for Reconstruction and Development, has political clout that can mitigate political risk. Sponsors of such projects may seek to obtain a political risk carve-out from their completion guarantees releasing them from liability where the project has failed for "political" and not commercial reasons.

Surging metal and coal prices have led to a boom in mining projects. Lenders are being asked to finance projects with weak sponsors and in countries with significant political risk.

Mining and Processing Risk. Lenders want a borrower to have qualified and experienced management. This is a greater concern where the sponsor is a junior mining company. Lenders are unwilling to take technological risk and will only lend against tried and tested technology rather than new processes that have not yet been proven on a commercial scale. There are a few examples of lenders extending financing to large projects based on new technology that simply did not work, resulting in substantial write-offs.

If the project takes the form of a joint venture (which is often the case in emerging markets), the lenders will want to check that operating decisions are left to the most qualified party.

Supply Risk. The reliable supply of fuel, power and certain reagents (such as cyanide) may be crucial for the success of a mining project. Supply risk may be of particular relevance for projects located in remote areas without access to good transportation links. Moreover, the cost of key supplies can often make or break a project. For example, power costs alone can represent about 40% of the cost of operating an aluminum smelter. Many mining projects are now located in emerging markets that may have insufficient or unreliable generation and transmission infrastructure. Moreover, such countries may be planning to privatize their utilities, which could have an uncertain effect on the price of electricity. Where possible, project lenders will encourage borrowers to enter into long-term power purchase agreements to ensure that the project has reliable access to power at a predictable price.

Market Risk. If the commodity produced by the mine has a restricted number of buyers or if terminal markets such as the London Metals Exchange are not available, then the borrower may be required to enter into a long-term offtake contract with a creditworthy offtaker. For example, in the $230 million loan financing extended by Export Development Canada and about 20 commercial banks to Aber Diamond Corporation to fund its stake in the Diavik mine in Canada, Tiffany agreed to buy from Aber a minimum of $50 million of diamonds per year for 10 years. This was the largest project loan to a Canadian mining company and the largest non-recourse loan for a diamond mine. Without Tiffany's offtake commitment, the financing would not have been possible.

Price Risk. Lenders must forecast what the price for products will be when the project commences operation in several years time, and not the price at the time they commit to extend financing.

Where feasible, lenders usually insist that the borrower hedge a portion of its production to ensure that the project is protected in case the price of the product declines. However, mining companies are increasingly reluctant to hedge because their shareholders usually want to be

exposed to metal and commodity prices. Moreover, with many hedge funds investing in mining companies, shareholders are putting pressure on companies not to hedge. For example, for established gold producers there appears to be a 3-to-1 rule; each 1% increase in the gold price leads to a 3% increase in the producer's stock price. For this reason, it is probably not surprising that we are currently witnessing the lowest level of hedging since large-scale hedging was introduced in the 1980s.

Both sponsors and lenders have been exploring ways to mitigate price risk in a manner that does not unduly limit the sponsor's upside. For example, producers are more inclined to purchase put options that protect the producer in the event that metal prices decline, but do not penalize it if metal prices rise. Moreover, if the project has a robust base case after including very conservative assumptions about product prices, then lenders may become more comfortable with price risk. For example, with gold prices so depressed during much of the last decade, most gold mining projects are coming on stream based on a price of $275 to 300 an ounce, even though the current price exceeds $400 an ounce.

Legal and Fiscal Risk. A stable legal environment is an important prerequisite to project finance.

Through legal reform of their mining laws, countries such as Chile, Indonesia and Ghana have attracted substantial foreign investment in their mines. For example, Chile has a model mining regime that encourages investment by granting clear proprietary rights to minerals, minimizing bureaucratic discretion in the awarding of licenses and permits and stabilizing much of the fiscal regime through a foreign investment contract.

Many other developing countries have joined the reform movement in the last decade, with the encouragement and support of the World Bank, by introducing mining codes that create a more transparent, predictable and commercially attractive legal and fiscal regime for mining. In the 1990s, many Latin American countries reformed their mining laws and this explains, in part, why Latin America's share of global exploration expenditures doubled from 13% to 26% during the period.

In a mining project, the key legal risks relate to the security of tenure, the enforceability of contract rights and security, and the reliability and neutrality of the forum for resolving any disputes. The mining / continued page 14

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It said that advice that an outside counsel gives in connection with an IRS audit after the taxpayer has already filed his return is not a "covered opinion." Also, most advice given by in-house tax people — at least those not involved in planning transactions — is not a covered opinion.

Finally, it said that transactions where companies are merely claiming tax benefits "in a manner consistent with the statute and Congressional purpose" are not transactions with a *principal* purpose of avoiding or evading federal taxes. However, they still might be considered transactions with a significant purpose.

CANADIAN INCOME FUNDS got an assist from the Canadian government.

Canadian income funds are trusts formed in Canada that raise money in the capital markets and pool it for investment. The trusts are not subject to income taxes in Canada and when they invest across the border in a US business, the investments are structured so that little tax is owed in the United States either. The result is that companies that use this form of business organization return at least 27% more to investors.

A large percentage of the investors in income funds are individuals who invest through their retirement savings plan accounts.

Such accounts are subject to a 30% limit on the amount of foreign content they are allowed. Income funds that invest in US assets often get around this limit by making the investments through a Canadian subsidiary. As long as the subsidiary has a "substantial Canadian presence," the fund can claim it holds Canadian property. A "substantial Canadian presence" usually requires having at least five full-time employees in Canada doing things other than making investments and at least C$250,000 a year in expenses tied to the services provided by the Canadian employees.

The Canadian government proposed dropping the 30% limit on foreign property in the latest budget. The change would make it easier for Canadian income funds / continued page 15

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license or concession is the most valuable asset of a mining project. Lenders will want to ensure that it cannot easily be terminated or revoked by the granting authority, and will want an opportunity to cure any breach of the license or concession before any such termination or revocation. In many countries, it is difficult for a lender to obtain a security interest in mining rights. However, a number of countries permit a lender to do so. For example, mining rights in Chile have all the incidents of real property rights and can be mortgaged. They are also protected by the constitution against taking without adequate compensation.

There is a "top 10 list" of risks that lenders should address in any mine financing.

The importance of security of tenure was illustrated by the *Maba v. Queensland* decision in Australia that recognized indigenous rights in land. This recognition was formalized in the 1993 "Native Title Act." Mining companies in Australia have had, since 1993, to spend considerable time and money negotiating with claimants and potential claimants, since native title still remains an uncertain area of the law with regards to exploration rights, mining and related uses of land.

In many developing countries, mining companies have been granted mining rights over areas where indigenous miners have been illegally mining for decades. While such small-time miners may lack mining rights under law, they may enjoy such rights in practice. In such cases, foreign mining companies often try to reach an accommodation with such indigenous miners.

Many of the legal and fiscal risks mentioned above can be mitigated through an investment agreement with the host government. Such agreements typically establish a stable fiscal regime for the project, contain a commitment from the government to issue permits and approvals when the appropriate documents have been submitted and provide for international arbitration in the event of a dispute.

Tax Risk. The local regime can break a project by making it unprofitable. The rates of import duties, royalties, withholding taxes and corporate income taxes can have a big effect on the profitability of a project and its ability to service debt. Lenders are particularly concerned about the stability of existing taxes and tax rates in those jurisdictions that do not have a long track record of foreign investment in the mining sector. As already mentioned, in some countries it is possible to obtain an investment agreement that grants exemptions or privileges with respect to certain taxes and stabilizes the rest.

Currency Risk. Currency risk includes the risk of inconvertibility, non-transferability and devaluation. Political risk insurance is usually available to cover convertibility and transferability. While it is generally not possible to obtain political risk insurance against devaluation, it may be possible, depending on the currencies involved, to mitigate currency risk through a currency swap. In recent times, the US dollar's dramatic depreciation against many currencies has had an adverse effect on many mining companies whose revenues are principally in US dollars, but whose costs are in appreciated local currency. For example, the depreciation of the US dollar relative to the South African rand has had a particularly adverse effect on South African gold producers who have witnessed a substantial rise in the US dollar equivalent of their costs.

Political Risk. Political risk — the risk of expropriation, interference by national or local authorities, revocation of export or mining licenses and political violence — has grown in importance as mining companies have been drawn to developing countries in Africa, Asia and the CIS

with large ore bodies but less political stability.

There are a variety of public providers of political risk insurance, such as the Multilateral Investment Guarantee Agency and the Overseas Private Investment Corporation, as well as private insurers.

There is a perception that mining projects that have been financed by multilateral lending agencies like the International Finance Corporation and the European Bank for Reconstruction and Development, have political clout that can mitigate political risk. Indeed, the *raison d'etre* of such international financial institutions is the mitigation of political risk.

The mining majors are increasingly likely to view project finance as a tool for reducing political risk and, for that reason, are often keen to carve out political risk from their completion guarantees.

Sustainable Development

Equity investors and lenders in mining projects are also concerned not only with risks, but also with the issue of "sustainable development".

The term sustainable development was first given wide currency in a report entitled "Our Common Future" issued in 1987 by the World Commission on Environment and Development and known as the "Brundtland report" after its chairperson, Gro Brundtland, the then-prime minister of Norway. The Brundtland report urged the nations of the world to commit themselves to a path of sustainable development and defined sustainable development as "development that meets the ability of future generations to meet their own needs."

In the context of mining, sustainability is not found in the resource itself, but in the long-term sustainability of the region. Lenders are focusing increasingly on whether the local population will benefit through employment, transfer of skills and infrastructure and on community investment programs and development initiatives carried out by mining companies. While lenders continue to be concerned about the environmental and economic impacts of investment in mining, they are also starting to look at the social impact of investment as well.

In this area, the multilateral financial institutions lead the way. However, even commercial banks no longer operate in a vacuum where financial return is the sole factor in the decision to lend. They are subject to / continued page 16

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to invest in US assets. The government said the change is needed to allow "broader international diversification opportunities for retirement investments."

HOLLAND is moving to abolish a tax on capital contributions to Dutch companies.

The government proposed the move in a "white paper" in late April. The capital tax is currently 0.55%. It would be abolished in 2006. The government also proposed a cut in the corporate income tax rate in 2007 from the current 31.5% to 26.9%. The proposals must still be approved by parliament.

Holland has been losing ground in recent years to Luxembourg as the European country of choice for offshore holding companies. The latest moves are a bid to restore its luster.

A protocol negotiated last year to the US-Netherlands tax treaty will help. The protocol eliminated withholding taxes at the Dutch border on dividends paid by a Dutch company to any US publicly-traded company that has owned directly for the last 12 months before a dividend is paid at least 80% of the voting stock of the Dutch company paying the dividend. Elimination of the capital tax on top of the protocol will cause many US companies to give Holland another look.

Meanwhile, an issue has arisen under the protocol. One popular holding-company structure in Holland involves setting up a Dutch entity called a CV that, in turn, owns a BV. The US parent company treats the CV as a corporation for US tax purposes; the CV serves as a blocker to prevent overseas earnings from being taxed in the United States. The BV is a "disregarded entity" for US tax purposes, meaning that it is treated as if it does not exist.

The Dutch tax treatment is the opposite: the CV is transparent and the BV is a taxable company.

Under the protocol, dividends are not exempted from Dutch withholding tax unless the US company receiving dividends owns "directly" at least 80% of the Dutch / continued page 17

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scrutiny from non-governmental organizations and the media, and the concept of corporate citizenship has become a central facet of business credibility. Thus, the tendency is for the standards imposed by the multilaterals to be adopted by the commercial banks. This is best illustrated by the adoption in 2003 of the "Equator principles" by commercial banks representing more than 80% of the project loan market, under which they agreed to abide by the environmental standards of the World Bank for projects costing more than $50 million. The export credit agencies, which, as agencies of governments, are subject to great public scrutiny, are also becoming increasingly sensitive to these issues.

Under the World Bank standards, proposed projects are classified into one of three categories depending on the type, location, sensitivity and scale of the project and the nature and magnitude of its potential environmental and social impacts, with category A projects having the greatest environmental and social impacts and category C projects having the least. Many mining projects fall into category A as projects that are likely to have "significant adverse environmental impacts that are sensitive, diverse, or unprecedented." A full environmental assessment, normally in the form of an environmental impact study, must be prepared for each category A project examining the project's potential positive and negative environmental impacts, comparing them with those of feasible alternatives and recommending any measures required to mitigate environmental impacts and improve environmental performance.

For all category A projects and for certain category B projects, an environmental management plan must also be prepared by the borrower or a third-party expert that draws on the conclusions of the environmental assessment and addresses issues such as mitigation, action plans, management of risks and schedules.

In all category A projects, and certain category B projects, the borrower or an independent third-party expert must have consulted "in a structured and culturally-sensitive way" with indigenous peoples and local NGOs. A summary of the environmental assessment must be made available to the public for a reasonable period of time in a culturally appropriate manner and in the local language. The environmental assessment and the environmental management plan must take such consultations into account and, in the case of category A projects, must be subject to review by an independent expert. The borrower must also undertake to comply with the environmental management plan, furnish regular reports on compliance and ultimately decommission the project facilities in accordance with an agreed decommissioning plan.

A mining project should have a "reserve tail" of at least 30%.

The importance of addressing environmental issues in mining project is illustrated by the cyanide spill at the Baia Mare gold mine in Romania. The operator of the Baia Mare mine was Aurul S.A., a Romanian company 50% owned by Esmeralda Exploration Ltd. of Australia, 45% owned by the Romanian government and 5% owned by Romanian enterprises. As a result of poor monitoring of the water table and unusually heavy snowfall, on January 30, 2000, the tailings dam for the mine was breached and more than 100,000 cubic meters of liquid and suspended waste containing about 50 to 100 tons of cyanide, as well as heavy metals, were released into the Lupes, Somes and eventually the Tisza and Danube rivers, causing widespread environmental damage. About 2,000 kilometers of the Danube's water catchment area were adversely affected by the spill. Hungary, the worst affected country,

sought more than $100 million from Aurul in compensation. As a result of this disaster, the shareholders lost all of their equity in Aurul and the commercial banks who financed the project were forced to write off their loans. Within two months of the disaster, Esmeralda Exploration Ltd. went into receivership.

A consensus is also emerging that corruption is jeopardizing sustainable development, particularly in the extractive industries (which are important in more than 50 developing countries). The British prime minister, Tony Blair, launched an "extractive industries transparency initiative" at a world summit on sustainable development in Johannesburg in September 2002. The initiative is aimed at increasing transparency of revenues received by host governments from extractive industries. Both companies and host governments are supposed to implement reporting guidelines so that taxes, royalties, signature bonuses and other payments paid to and received by host governments and government-related entities are aggregated and then publicly disclosed. The initiative has been endorsed by Angola, Azerbaijan, the Republic of Congo, Gabon, Ghana, Indonesia, the Kyrgyz Republic, Nigeria, São Tomé e Principe, Timor Leste, Trinidad and Tobago and other countries, and has been widely supported by international mining companies such Anglo American plc, BHP Billiton, De Beers, Newmont and Rio Tinto, as well as industry associations such as the International Council on Mining and Metals. It has also received enthusiastic support from the World Bank, the IMF, the European Bank for Reconstruction and Development and other multilateral organizations.

Increasingly, investors and lenders view a mining company's ability to address the issue of sustainable development as a proxy for good corporate governance. They are also becoming more cognizant of the reputational risks of being associated with mining companies or projects that have not adequately addressed the issue. For example, one of the banks that financed the infamous Baia Mare gold mining project had to endure headlines from tabloid newspapers in its home country comparing the use of cyanide at the mine to use of cyanide during the Holocaust. As *The Economist* astutely observed several years ago, "The real value of a corporation increasingly comes not from the assets that it owns, or the employees that it supervises, but from the domain of trust it has established." ◎

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company paying dividends. As far as Holland is concerned, the company paying dividends in these structures is the BV.

The Dutch finance minister said, in response to parliamentary questions in early May, that Holland will look through any entity that is treated as transparent for US tax purposes. Thus, if the CV were transparent in the US, the dividend withholding tax would be waived. However, a withholding tax will be collected when the dividend is blocked from the US tax return of the US company because the CV is treated as a blocker corporation for US tax purposes — with one possible exception where a CV-BV structure is used to develop real economic activities. A government decree with more details is expected in June.

Finally, the Dutch Supreme Court is considering when dividend withholding taxes can be avoided by having the Dutch company redeem its shares. As a general rule, share repurchases trigger a withholding tax. The difference between the repurchase price and the average capital contributions on that class of shares is considered a dividend. However, no tax is collected on shares that are repurchased as a "transitory investment" with the intention of reselling them.

The case before the court involves a company that was considering using its own shares to acquire another company. It did not want to issue additional shares since that would dilute the ownership percentages of its existing shareholders, so it moved instead to buy back shares from some of its shareholders as a way of amassing currency that could be used to take over the target company. The government is arguing that there was a dividend because the share repurchase reduced the equity that shareholders had in the acquiring company at a time when there was no legal obligation to use the shares to buy the target. A merger agreement had not been executed.

PROJECT DEVELOPERS who receive partnership interests in exchange for services should be careful. */ continued page 19*

Basics of Construction Contracts

Chadbourne conducts regular training sessions for younger lawyers on issues that come up in project finance transactions. The following is the transcript from a training session in April on construction contracts. The speaker is Paul Weber, a project finance partner in the New York office.

The topic today is construction contracts and the role they play in project finance transactions. One of the fundamental axioms of project finance is to make a catalog of risks and allocate each risk to the party best able to manage that risk. In the case of construction risk — which is a very significant one because projects typically involve complicated feats of engineering — what better person to allocate those risks to than the construction contractor who is well-schooled in managing those risks.

Let me start with the key objectives in negotiating an engineering construction and procurement contract in a project finance transaction.

The key objectives are to get the project built, first, in a manner that meets owner's specifications and second, on time. The first objective is important because an owner should receive what it is paying for. The second objective is important because literally time is money. The longer it takes to build a project, the more interest one must pay during construction and the longer the wait until the project is in commercial operation and making money. For example, you may be building a power plant that will supply power under a power purchase agreement. The power purchase agreement may have a sunset date by which if the project is not in commercial operation, it loses the contract. Or the contract may have penalties for late commencement of operation because the utility has put the project into its integrated plan for supplying electricity to its customers. If the project is not in commercial operation when expected, that may cause problems for the utility.

Another objective is to get the project built at a fixed price. This is the case because another key axiom of project finance is that such financings are done on a non- or limited recourse basis. There is a defined pool of money — equity contributions, senior debt, perhaps also sub-debt, depending on the transaction. There is a budget and, if one exceeds that budget, there is only that defined pool to call on before the project runs out of money and runs into problems. And, of course, the higher the owner's capital costs, the lower its return.

A good construction contract puts as much responsibility for meeting these objectives as possible on the contractor.

A construction contractor will try to avoid taking risks in the construction contract that are outside its control.

Contractor's View

The contractor is in the project to make money just like everyone else. When a contractor bids the job, he prices the many aspects of the work. A lot of the work will be done through subcontractors and vendors. The contractor wants to have back-to-back contracts with those subcontractors so that it can lay off as much risk as possible on the subcontractors. That being said, the typical construction contract in a project finance transaction is a "turn-key" contract. That means that the contractor is the person with the responsibility to get the project built so that, if a subcontractor fails to perform from the owner's perspective, it is the contractor's responsibility. In fact, in every construction contract, the project is implicitly paying for this "turn-key wrap" and the premium paid for this is substantial.

The contractor also wants to avoid taking risks outside of its control or contemplation. Thus, a contractor wants to have as well-defined a scope of work as possible, and it does not

want to be responsible for things that it cannot control or foresee. Contractors report that a typical construction contract does not have a large profit margin. Whether or not you believe this cry of poverty, a contractor will try jealously to protect that profit margin and limit its downside.

Lender' View

The lender's interests are largely aligned with the owner's interests.

A lender wants comfort that the project will work, be done on time at a fixed price and perform as promised. A lender will undertake due diligence of the contract on at least four levels. One is the technical review done by an independent engineer. The independent engineer assesses the contract, looks at the technical specifications, liaises with the contractor, makes a determination as to whether the project will hang together, and puts its conclusions in an independent engineer's report that is delivered to the lender as a condition to closing. The second piece of that review is legal review. A lawyer will review the contract, assess the risks and let the lender know whether it is a market contract — whether there are risks that are outside market norms. The third reviewer will be an insurance adviser, who will look at the insurance package. Infrastructure projects are complicated enterprises. They involve heavy equipment. Things can go wrong, and insurance is important. Finally, the lender does a business review, looking at the economics of the contract. Lenders also protect their interests by engaging the independent engineer to monitor construction progress of the contractor throughout the performance of the contract.

Contractor's Responsibilities

I have outlined the key objectives in a construction contract. The following discussion about the contractor's responsibilities is framed in terms of those key objectives with a few necessary digressions along the way.

One of the ways that the owner makes sure that it will get what it expects is through a very extensive scope of work in the contract. Just to provide a crude sense of how critical a broad scope is, it is not unusual for the "contractor responsibilities" section of the contract to run some 20 pages long. The contractor will be responsible for all the engineering and design work. It will be responsible for construction and construction management. Construction management is managing all the subcontractors and the / continued page 20

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Smaller project developers often form a partnership or limited liability company to own a project and then bring in a money partner to fund the development work. The developer provides labor. He receives an interest in the project for his services. The money partner owns the rest of the project in exchange for putting up the capital.

The danger in such arrangements is the developer must report the value of the partnership interest as income and pay taxes on it just as he would any other compensation.

The IRS said in proposed regulations in late May that it does not matter what kind of partnership interest the developer receives; the developer must still report it as compensation.

However, a mere "profits interest" — as opposed to a capital interest — is less likely to trigger a tax. A "profits interest" gives a partner a share in future profits from the partnership. A "capital interest" would give him an immediate claim on partnership assets if the partnership were to disband the next day. Profits interests must be reported as compensation, but chances are they have little value. The IRS said the developer should report the "liquidation value" of the interest, or the amount of money the developer would be distributed by the partnership if the partnership liquidated.

In the past, some developers may have made elections under section 83(b) of the US tax code to be taxed immediately on the partnership interest — at a time when it is likely to have little value. This was true of anyone whose right to the partnership interest has not fully "vested," meaning his right to it is still conditioned on his providing more services. (The word "vest" is more often heard in connection with pension benefits. An employee's right to a pension "vests" after he has been with the company for several years, meaning he is now entitled to a pension whether or not he continues working for the company.) A person is usually not taxed on compensation received in kind until it vests. The problem with waiting to pay tax until vesting is the partnership interest is more likely to have / continued page 21

Construction Contracts

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like and making sure everyone is doing his or her part in a well-coordinated way. The contractor will be responsible for procurement of all equipment and materials and, to the extent that it is not itself an equipment provider, like General Electric or Siemens Westinghouse, it will subcontract with vendors to provide that equipment. It will provide all construction labor and personnel.

Lenders need to do four levels of due diligence in connection with construction contracts.

The contractor will also be responsible for permitting, although a contractor will only typically be responsible for permits that are customarily obtained in the name of the contractor. There will be many permits that, by their nature, must be obtained by the owner.

The contractor will be responsible for the start up and initial operation of the facility. That is when the project is first turned on and then ramped up to rid the project of kinks. Testing, which is a vital piece of any construction contract, will be a contractor responsibility. Usually, the contractor must also provide training of the owner's or operator's personnel. There will also be reporting requirements — typically a monthly progress report setting forth progress the contractor has made toward meeting milestones, any problems it has encountered, and any expectations of changes in the scope. The other way in which the contract defines the contractor's scope is through what is typically exhibit A or 1 to any construction contract, and that is the technical scope exhibit. This is a key document and is generally the domain of the engineers.

Subcontracts

Virtually every construction contract will have a section on subcontractors and vendors because the typical contractor may do a lot of the design and engineering work in house, but may not have a huge staff of construction labor standing by that can work on a project. The prime contractor must go out and hire that labor. It may not make turbines, so it buys those turbines from a GE. The point is subcontracts are a key piece of the deal. They are somewhat opaque to the lawyer negotiating the prime contract because of the turn-key nature of the agreement. The subcontract section will say that the use of subcontractors by the contractor has no legal effect on the contractor's responsibility for the work. In other words, if a contractor or vendor does not perform, generally that is not an excuse for non-performance by the main contractor. It will also say that the owner has no privity with — or direct legal rights against — the subcontractors.

Nonetheless, the choice of subcontractors can be critical to a deal. For example, in a power project, the owner will be very interested in what sort of turbines are being purchased by the contractor. There are numerous other items of equipment in which the owner will also have a keen interest. The owner may have had a bad experience with a particular vendor and does not want to use that vendor again. The owner needs some control over the choice of subcontractors.

The typical means for addressing this in a construction contract is through use of an approved list — an exhibit that says for this type of equipment, contractor can use these companies and no others. There may also be a provision in the contract that says any subcontract involving more than a specified dollar amount of work must be approved by the owner. Sometimes the contract may use both a list and an approval threshold.

My final remark about subcontracts is that even though the prime contract has the turn-key wrap, the owner is aware that the contractor is looking through to the subcontracts to perform many of its obligations. Thus, for example, even though the contractor provides a warranty for the entire

facility, the owner wants to know that if a turbine the contractor bought does not work, then the contractor can turn to the turbine manufacturer and say, I have a warranty claim under my main contract so I need you to perform under your warranty to me. This means the owner wants the warranties under the major subcontracts to be at least co-extensive with the contractor's warranty. The owner will want to know that the insurance provisions under the subcontracts are comparable to those under the main contract. The owner will want to know that the subcontract can be assigned to the owner under certain circumstances.

Owner's Responsibilities

A much shorter provision of the construction contract (relative to the contractor's scope) is the section on owner's obligations. That should not be surprising.

The owner's principal obligation is to pay money for performance.

The owner will have other obligations that will include providing the site and necessary access rights to the site. The contract may also require provision of something called a construction lay down area, where the contractor puts its materials while it is building the facility. The contract will require the owner to appoint a representative to act as a single point of contact for the contractor to deal with on any issues that come up under the contract. It helps both sides to know that there is one person to turn to if decisions need to be made or approvals obtained. A third obligation is to obtain owner permits. Owner permits will often be critical items for the project. For example, the owner will probably need an air permit before the contractor can even put a shovel in the ground. The owner must provide the personnel needed to start up the facility. The contractor is responsible for training them.

There will be other deal-specific obligations. For example, the owner might be responsible for assuring in a power plant deal that the interconnection to the utility is built on time.

Three Key Concepts

There are three events, among numerous important events, in the process of construction that are critical. These events are defined in most, if not all, construction contracts using various terms. The reason these are important is they are used to capture the notion that the project is being built to owner specifications and working as / continued page 22

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a real liquidation value by then.

The IRS removed any need to make elections. It said the liquidation value on which the developer is taxed becomes fixed when the developer first receives the interest, even if the interest does not vest until later.

The regulations are merely proposed. They will take effect when the IRS reissues them in final form. However, there is no reason to believe the IRS position is any different today than what it is proposing.

TELEPHONE TAXES had to be refunded in two more cases.

The US government collects a 3% excise tax on long-distance telephone calls, but the law is outdated, and the tax only applies to calls for which the fees charged vary by both the distance and elapsed time of the call.

A number of big companies have successfully sued in the US courts recently to get the taxes back. The amounts can be substantial. The latest to do so are America Online, or AOL, a company through which many Americans have email accounts and access to the internet, and American Bankers Insurance Group.

AOL customers can dial a toll-free number to reach customer service representatives. The company sued for a refund of telephone taxes paid not only on these calls, but also on outgoing long-distance calls made by AOL employees. AOL pays a flat rate per minute for the calls, but the rate does not vary by distance, except that a different flat rate applies for calls with Canada than for calls inside the United States. The US claims court held for AOL in a decision released in early April. The case is *American Online, Inc. v. United States.*

The American Bankers Insurance Group sued for a refund of taxes collected by its telephone company, AT&T, on both domestic and international calls. The domestic calls are at a uniform rate. International calls vary only with the country to which the calls are placed. The US government won the case in the district / continued page 23

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promised. They are also used to define timely completion.

The first key event is mechanical completion. Mechanical completion means that the facility is physically complete, except for a few punchlist items. The plant can be turned on safely and is ready for performance testing.

Substantial completion is perhaps the most important of these three concepts. It occurs when mechanical completion has occurred, the facility is ready to be put into commercial operation, the performance tests have been completed and the performance guarantees have been satisfied. I will describe shortly what I mean by satisfied.

The final concept is final completion — that substantial completion has occurred, the punchlist has been completed and all other work has been completed. There might be a requirement that the contractor deliver something called as-built drawings. There might also be other minor items that must be done in order to achieve final completion.

Performance Guarantees

The next topic is performance guarantees and the tests performed to determine whether substantial completion has occurred.

These tests can vary from deal to deal. I will use the example of a power plant, but it is not hard, once you understand the conceptual framework, to see how such tests and guarantees would apply to numerous other types of facilities.

The first test is an output test. In this test, you are testing whether the facility can produce at the promised levels. If the owner has contracted for a 100-megawatt power plant, it wants the contractor to demonstrate that, in fact, when it turns the facility on and runs it at specified conditions, the plant will produce 100 megawatts. Obviously, this is key for several reasons. You may have a power purchase agreement that says you will deliver 100 megawatts. You have a financial model into which you have plugged the number 100 megawatts as the output, and you have multiplied that number by your expected sale price and come up with your expected cash flow.

Early substantial completion should only earn the contractor a bonus if there is a benefit to the owner from having the project in operation sooner than expected.

The purpose of the output test is to meet the guaranteed output level or pay liquidated damages. Liquidated damages are typical in construction contracts and, when it comes to output, the owner will calculate the cost to it if the plant only produces, say, 98 megawatts. The calculation is not hard to do. You plug 98 megawatts of capacity and output into your financial model and you see the impact on cash flow, you do a net present value calculation and you come up with a number. For each megawatt or fraction thereof by which the guaranteed level is not met, the owner will want a liquidated damage payment from the contractor that will make it whole. In reality, do owners achieve this goal to the last dime? No, but that is the goal.

The lender perspective on this is that it lent the owner $100 million to build a 100-megawatt plant, and the lender is expecting the plant to generate certain cash flows that will service its debt and generate debt service coverage ratios at certain levels. If the plant only produces 98 megawatts, those debt service coverage ratios will be negatively affected. The lender's position is that it wants to preserve its deal, so the owner will be required to take the liquidated damages money it receives from the contractor and prepay a portion of the loan, thus reducing the amount of the debt so that the debt service coverage ratios are restored.

On the positive side, the contract might provide for a bonus to be paid for exceeding guaranteed levels. My experience is that if you offer a contractor a bonus for exceeding

guaranteed levels, then the contractor will very often achieve those higher levels. Contractors are generally conservative; they want to know that they can meet the performance guarantees. If a contractor is promising a 100-megawatt plant, it does not design the plant for 100 megawatts; it designs the plant for, say, 106 megawatts. A bonus may be appropriate, but you must look at whether there will be an economic benefit to the owner. If the power purchase agreement commits to supply 100 megawatts to a utility and the owner has no place to sell any excess generation, then it does the owner no good if its plant produces five megawatts more than it bargained for. A bonus in that situation would not be appropriate. If, on the other hand, its contract provides that the utility will take and pay for excess production up to a certain level, then exceeding the guaranteed levels will be worth something to the owner and a bonus would be appropriate. The bonus might be calculated based on some sort of splitting of the benefit with the contractor.

The second test is an efficiency test, known in the context of a power deal as the heat rate test. The efficiency test determines how many inputs it takes to get the anticipated output. There will be a specified number. If the owner has to burn 5% more fuel than it anticipated burning in order to produce each megawatt of power, then that means, for the life of the deal, the owner will have fuel costs that exceed those by 5% in its *pro forma* model. That increased cost may go on forever. You can see how that efficiency shortfall goes straight to the bottom line. Thus, under the efficiency guarantee, the contractor guarantees that the project will produce X amount of output based on Y amount of input. If it fails in a performance test to demonstrate the ability to do so, liquidated damages will be payable. In determining the level of liquidated damages, the same sort of analysis for the output guarantee applies here. The owner will determine the effect on the economics of having to pay for an additional 5% of fuel for the life of the deal and look to get back to a position where it is economically whole. The lenders will do the same analysis I described for an output shortfall, although in this case it is not that there will be less revenue from the plant, but higher expenses. Once again, the debt service coverage ratios will be negatively affected. The lender will want to take the delay liquidated damages, use them to prepay debt and get back to the coverages it bargained for.

A bonus for higher efficiency generally makes sense; if the owner can produce its output for less / continued page 24

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court, but a US appeals court reversed in May.

The judge in the AOL case said that if the US government has a problem with the result, Congress should change the law.

The case "involves a disconnect between a forty-year-old tax scheme and recent innovations in the telecommunications industry. It is plainly Congress's responsibility to decide whether to revise the statute to accommodate such developments," the judge said, quoting from a decision in another refund case earlier this year involving Fortis, Inc.

COAL COMPANIES won a victory in court.

The US government collects reclamation fees on coal. The fees are imposed on coal producers, and the money collected goes into a federal trust fund to be used to repair damage to the land caused by coal mining. The fee is 35¢ a ton on coal from surface mines and 15¢ a ton on coal from underground mines.

Several coal companies sued to have the fee set aside to the extent it is collected on coal produced for export. The case bounced back and forth in the courts as the government succeeded initially in having it dismissed on a technicality. However, in April, the US claims court held that the fees are unconstitutional as applied to coal that is exported.

The export clause of the US constitution says, "No Tax or Duty shall be laid on articles exported from any state." The government argued that the amounts were "fees" rather than a "Tax or Duty" and that they are collected on the act of producing coal rather than exporting it, but the court dismissed both arguments.

If Congress were concerned about the revenue loss, it could reword the statute. The case is Consolidation Coal Company et al. v. United States.

CONSTRUCTION CONTRACTORS cannot be taxed by a state on fees for engineering work that is done physically in another state.

Fluor builds projects in / continued page 25

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money, then clearly there is a benefit in which the contractor may well want to share.

Satisfaction of the performance guarantees means either meeting them or paying liquidated damages and being deemed to have met them. That said, a typical construction contract will stipulate minimum performance levels that must be met before a contractor can satisfy the guarantee by paying liquidated damages. A contract may provide that the contractor must get to 95% at least on output and 105% on efficiency before it even has the right to pay liquidated damages to buy down its obligation on performance. Below this level, the contractor's performance is so out of line from expectations that the performance is not acceptable and the contractor must do whatever it takes to get to the minimum levels.

That sums up performance guarantees and tests — a critical part of any construction contract and one that will attract a lot of attention, not just from the lawyers, but also from the independent engineer, who will make sure that the tests are good tests and that they are designed to measure what they are supposed to measure. The business people will also look at the numbers in the *pro forma* model to determine whether the liquidated damages are set at the proper levels.

Timely Completion

The concept of getting the project built on time is principally captured through something called the guaranteed substantial completion date.

Achieving substantial completion means, among other things, that the facility works and is ready to go into commercial operation. That is when the deal goes from being all outgo to having some money coming in. You turn it on, you start producing whatever you are producing and start making money. The owner's offtake contract may also have a sunset date or penalties for late performance. Therefore, the timeliness of achieving substantial completion is important. This timeliness is enforced by stipulating a guaranteed substantial completion date. The contractor will guarantee that the plant will be built and achieve substantial completion by a certain date. If the contractor does not achieve substantial completion by that date, then it must pay liquidated damages. These liquidated damages are somewhat different than the performance or efficiency damages in that they are addressing what is effectively a temporary problem. It is not something the owner must live with for the life of the deal as is the case with reduced output or lower efficiency. Rather, the owner expected to be in operation and making money by a certain date so that it can pay interest on its loans and start making an equity return. For every day the owner is not in operation, it expects the contractor to pay liquidated damages sized to make the owner whole. Will the owner be made entirely whole in

Liquidated damages are limited to a percentage of the contract price. In a power deal, the cap is often 25% or 30%.

Other Guarantees

Another typical performance guarantee in a construction contract is the emissions guarantee. The emissions guarantee is typically based on permissible emissions levels in the project's air permit. The air permit will contain significant detail about what levels of emissions of things like NO_X,SO_2 and mercury are permissible. The emissions guarantee must be met at the guaranteed levels. No buy down is allowed. You do not want a plant that is 95% in compliance with emissions laws. This is not an economic test. It is an on-off test. If the plant exceeds allowable emissions levels, then it may not be able to operate at all. Passing the emissions test is essential.

terms of getting its full equity return? Probably not, but the owner wants to get close to this result while the lender just wants to know that money will be there to start paying its loan and keep the project going.

Early substantial completion may earn a bonus. There should be a benefit to the owner before a bonus is warranted. If the offtaker doesn't want the owner to be in production until June 1, and has no obligation to take its output until then, then owner should not pay the contractor a bonus for getting it to substantial completion by April 1.

In some contracts, there may be a negotiation about reducing the amount of delay liquidated damages, payable to the extent owner is receiving revenue. Suppose a contractor is toiling away to get the plant done and cannot quite get there, but the plant is operating and owner is actually in operation and making money. The contractor will insist the liquidated damages it is paying should be reduced by the amount of the owner's net revenues.

There are other means of assuring that the project is built in a timely fashion. Obviously, the owner does not want to wait until the guaranteed substantial completion date has come and gone if it is clear at an earlier time that performance is lagging. The owner wants the plant built on time and will closely monitor progress. Payments to the contractor will be tied to the achievement of milestones. The owner may have a right to say to the contractor that it has fallen seriously behind and the contractor must go to double shifts to catch up. That will cost the contractor money and the contractor will be unhappy, but a good owner and its lawyer will seek this right.

Liability Limitations

The contractor's perspective is to lay off the risk and protect its profit margin. Thus, all construction contracts have liability limitations as they relate to liquidated damages.

Liquidated damages will be typically limited to a percentage of the contract price. In a power deal, the cap on liquidated damages will often be somewhere in the neighborhood of 25 to 30% of the contract price. It could be higher when you are dealing with a more risky technology. It will be higher, for example, in windpower projects. This is a money point, and the contractor may say that it can agree to a higher cap, but it has to pay its subcontractors extra for it and the contractor will pass through those costs to the owner. In addition, it is common for there / continued page 26

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Michigan. Michigan collects a "single business tax" on companies doing business in the state. Companies must first figure out what share of their profits from a construction job was earned in Michigan before applying the tax rate. They do it by taking total profits and allocating a share to Michigan based on the fraction their total sales, property and payroll that are in Michigan.

Fluor took the position that its fees for engineering work on Michigan construction jobs should not be considered revenue from Michigan sales since the work was done in a Fluor office in another state.

A Michigan appeals court agreed with Fluor in April. The court said the state tax collector was right when he insisted that Michigan law treats the fees as revenue from Michigan sales, but the statute is unconstitutional. The commerce clause of the US constitution bars a state from overreaching by taxing business outside its borders. "If other states used the same apportionment formula," the court said, "there are situations where more than one state would tax business activity performed in one state for construction activities in another." The case is *Fluor Enterprises, Inc. v. Department of Treasury.*

ARKANSAS has a new law that requires partnerships and limited liability companies doing business in the state to withhold income taxes from distributions to out-of-state partners.

Arkansas is merely the latest state to enact such a law. The governor signed it in May. Withholding is not required if the partnership can get agreements from its out-of-state partners to pay any taxes they owe directly. The agreements must be filed with the Arkansas authorities. Withholding is also not required for certain oil and gas partnerships whose units are publicly traded but that operate under special federal tax rules that allow them to be taxed as partnerships.

THE PHILIPPINES increased the corporate tax rate and scrapped valued added tax exemptions for energy companies. The / continued page 27

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to be sub-caps on liquidated damages. The contract might have a 25% overall liability cap on liquidated damages, but for output and efficiency it will be 15%, and for delay damages it will be 15%.

One analyzes the adequacy of these caps and the liquidated damages through a mathematical exercise based on certain assumptions. For example, the project may involve a turbine that has been used in a hundred other facilities and it always works. The worst that has ever happened is it comes in 2% short. If the contractor is 2% short on its output guarantee, that will use X% of the cap. Through this sort of thinking, you know whether the cap makes sense. Similarly, for a delay, the owner should determine what is a reasonable worst case number of days of delay.

The business team should check the *pro forma* model for a project to make sure liquidated damages are set at an appropriate level.

The owner takes its delay damages for every day specified in the contract, and takes the cap and divides it by the daily amount. This results in a number of days of coverage for delay that the owner can compare against its reasonable worst-case expectations to determine whether the damages cap makes sense.

The contractor will also try to limit its overall liability under the construction contract for performing all of the work. This is not an absolute rule, but typically the overall liability cap will be 100% of the contract price. There are some exceptions to the 100% cap for things like third-party liability. For example, if the contractor's turbine falls off a truck and kills people, then that will attract significant liability and that will be outside the cap and should be covered by insurance. The contractor may negotiate for the overall cap to step down at mechanical completion to a level below 100% of the contract price. At mechanical completion, everything has been delivered and put together so the owner knows that any problems that remain will probably be adequately covered by a reduced cap. If you have a $500 million contract, a step down to a 40% cap still leaves $200 million.

Payment Provisions

Typically, installments are paid based on completion of milestones. There will be a milestone schedule that includes milestones like payment of $10 million at "start of construction" or "issuance of the notice to proceed," payment of another $10 million upon "completion of engineering," and payment of $20 million upon installation of X equipment. In some contracts, payments are made based on the percentage of work completed. From a lender's perspective, the independent engineer will monitor this construction progress closely to verify the progress of the construction. Other payment conditions will include, for example, absence of a material breach and provision of lien waivers by the contractor.

The payment provisions will also provide for something called retainage. Retainage is an amount that the owner holds back from each payment — typically from 5 to 10% of each amount due to the contractor. Retainage is held back as a form of security for contractor's performance. If, for example, the contractor fails to complete some portion of the work on deadline, the owner may be able to use the retainage money to pay someone else to do the work. The Owner may also set off retainage amounts against liquidated damages. This is a way of keeping the contractor interested, because he knows that he must get the owner to substantial completion to get most of the retainage money and then to final completion to get the rest of the retainage money. The contractor's profit margin may not be large, so if the owner is withholding 10% of the contractor's payments, that might be a pretty good chunk of its profit and a good way to keep the contractor focused. Contractors may, for cash

management reasons, want to give the owner a letter of credit instead of actually having owner withhold cash.

Change Orders

Change orders are the means by which the contractor protects itself and can come back to owner and say, these things have happened, I deserve a change in the contract price, maybe in the project schedule, including the guaranteed completion date, and maybe the performance guarantees. Some events that may affect the contractor's performance and permit change orders are things like owner delay. The owner was supposed to have the interconnection done by a certain date so the contractor could hook the plant up to the grid and start performance testing. The owner could not do it. The contractor says it cannot perform because the owner has not performed, and so it should at least get schedule relief and push back the guaranteed substantial completion date.

Owner breach and *force majeure* may also justify a change order. Something happened — the plant is struck by lightning and partially destroyed. Typically what owner's counsel wants to negotiate toward is schedule relief for the contractor. It gets a delay in schedule, but takes the risk on cost. Some of the cost risk can be laid off on subcontractors, and some can be insured. Change in law is another basis for a change order. The law changes, and contractor has to add $10 million in additional pollution control equipment. It is unfair to say that the contractor has to provide all that pollution control equipment without an adjustment to the deal. The contractor will say it wants a change order — a new price, a new schedule and a new guaranteed completion date. The contractor may encounter subsurface conditions that were unexpected. It might excavate the site and encounter valuable, historic artifacts that require it to stop working and call an archaeologist to dust them off and remove them before it can resume. It may run into environmental contamination. These sorts of events may lead to change orders.

The owner protects itself against change orders by having as broad a scope as possible so when the contractor comes back and says something is not in the scope, the owner can point to the scope provisions and disagree. The owner will also ask the contractor to make representations that it has done an assessment of the site conditions and, unless something falls outside of every- / continued page 28

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country acted after budget deficits forced several downgrades of its sovereign credit rating, making borrowing more expensive and sparking rumors that it is in danger of defaulting on its debts.

A new law signed May 24 increases the corporate tax rate from 32% to 35%. President Gloria Arroyo had also asked Congress to increase the rate for value added taxes, but the politics of such a rate increase were too difficult. Value added taxes are like sales taxes that hit home quickly as voters do their shopping. Instead, Congress gave Arroyo standby authority to increase the VAT rate from 10% to 12% in 2006 if more revenues are needed.

Congress scrapped VAT exemptions enjoyed by various industries, including private power companies and oil refiners. At the same time, it eliminated a "no pass-on provision" that would have barred independent power companies from passing through VAT to consumers.

CHINA will end preferential tax rates for foreign companies in 2007.

Foreign companies already operating in China may be able to apply for a grace period as long as five years to ease the transition.

The average domestic company pays taxes today at a 33%, rate while the average foreign company is taxed at only a 15% rate. The unified rate has not been announced yet, but there is speculation it could be around 25%. State-run media announced in late May that the government has decided to end preferential treatment for foreign companies at the beginning of 2007. Other details have not been released.

BOLIVIA is bracing itself for lawsuits after it increased government levies on oil and gas produced in the country from 18% to 50% and directed that exploration contracts signed with the government must be renegotiated.

There is speculation that mining projects will be the next target.

The Bolivian president / continued page 29

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one's expectations about the site, it cannot come back for a change order. The contractor may also be asked to make representations that it understands a broad range of conditions that could affect performance. For example, it might represent that it has done an assessment of weather conditions. If it is building in India, the contractor cannot come back to the owner and say it did not know about the monsoon season. That is how the owner protects itself.

An owner tries to protect itself against change orders that increase the contract price by defining the scope of work as broadly as possible.

Warranties

The owner has protected itself in terms of getting the project built, getting it built to specifications, and performance testing to make sure it works. Now the owner has to put it into operation, and these are typically complicated projects. Things go wrong. Things break. The owner needs warranty protection, and it will come in several forms. I will touch mainly on the simplest form of warranty, and that is a general warranty.

A general warranty will say that everything — machinery, equipment and materials, etc. — is free from defective workmanship and complies with the specifications in the contract and the scope document. It will typically provide for a warranty period of one year to 18 months from substantial completion. That is, the project has to break within that period and the owner has to tell the contractor about it; otherwise, the owner is on his own. The warranty period may vary, depending on the technology. For example, in windpower transactions, the technology is advancing so fast and there have been problems with the technology, so contractors and vendors have been pushed by the market to stand behind a wind turbine for up to five years and sometimes longer. The warranty provisions will also state that if there is warranty work — if something broke in the ninth month and contractor fixed it — that portion of the work will be re-warranted for an additional six-month period, but not beyond, say, 18 or 24 months after substantial completion. The contractor will warrant title; title is what the contractor delivers to the owner in exchange for payment of the contract price. The contractor will insist that the owner waive all other warranties, expressed or implied, including all UCC warranties.

Other Issues

Indemnification provisions in construction contracts include a general indemnity against third party claims. Typically that is a mutual indemnity. Often there will be reciprocal environmental indemnities. The contractor will take the position that pre-existing conditions on the site are the owner's responsibility. The owner will agree, but insist that if spills or any environmental problems are due to materials that the contractor brought to the site and actions the contractor took at the site, the contractor must indemnify the owner.

Finally, the contract will include a patent and copyright indemnity. The owner is often buying equipment that is subject to patent or copyright protection. The owner wants to make sure that it has the right to use the equipment. The contractor will give the owner an indemnity to that effect. If the indemnity is breached, then the contractor's obligation will not generally be to pay the owner money, but instead will be to fix the problem by obtaining for the owner a license to use that patented or copyrighted equipment or work.

A construction contract will typically provide that the owner can terminate the contract or suspend the contract for its convenience. It can suspend performance, typically for a limited period of time. These provisions sometimes are useful if the owner runs into a problem with its lender, and the lender says it will not advance any more money until the

problem is fixed. The owner does not want to be in a position where money is cut off by its lender, leading to loss of the construction contract. In this instance, owner may use its suspension provision. The exercise will cost the owner money, but will save the contract.

Finally, let's talk about remedies for breach of a construction contract. One of the key remedies will be termination of the contract. After a termination, the owner can take over the subcontracts. That is why assignability of subcontracts is important. The owner can take over the existing designs and drawings, get those from the contractor, bring someone else in to complete the facility, and then charge back the difference in cost to the contractor. If the contract price was $100 million and the contractor breached, the owner terminated and hired another contractor at a total cost of $110 million, then the owner has a claim under the contract against the contractor for that $10 million. It is a damages claim. It can be set it off against any security the owner holds, but it will probably end up being settled in court or in an arbitration. The owner will also want to preserve other legal and equitable remedies. A lot of contractors like to say the remedies in the agreement are the only remedies the owner has, but I always try to resist that because I prefer not to limit the universe of remedies that the owner has in the event something goes wrong. ◎

Toll Road Update

by Jacob S. Falk, in Washington

As public and private toll road developers push for increased cooperation on new projects, the importance of a proper legal framework remains noteworthy.

New State Programs

Washington state enacted a new law — called the "Transportation Innovative Partnerships Act" — in early May to encourage development of public-private toll roads in the state. Related legislation appropriates $1.5 million for preliminary studies and suggests that the first opportunities for private investment in Washington toll roads will be for projects in and around Seattle.

The main thrust of the law is to create a mechanism for private companies to participate in the / continued page 30

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let stand in late May a new law, passed overwhelming by the Bolivian Congress, that would impose a 32% tax on oil and gas at the wellhead on top of an 18% royalty that the government already collects. The law also reinstates YPFB as the national petroleum company with ownership over reserves. The company had been reduced to only a regulatory role after Bolivia privatized the oil and gas sector in 1998. Exploration contracts with the government will have to be renegotiated within a 180-day transition period. Oil and gas companies have said they will sue for breach of contract and illegal confiscation. Any political risk insurance policies the companies possess could affect the claims they make in the lawsuits.

Meanwhile, there have been calls in Congress to impose a 10% royalty on mining. The country is expecting a sharp drop in the amount of foreign investment. Huge street demonstrations could lead to renationalization of hydrocarbons.

ECUADOR is moving to collect $282 million in back taxes from 21 foreign oil companies.

The taxes are from the period 1998 through 2001. Among the companies being investigated are Occidental Petroleum, Repsol and EnCana. The move to collect taxes comes on the heels of an announcement that contracts with the state-owned oil company, Petroecuador, must be renegotiated. Petroecuador controls more than 60% of oil output in the country.

VENEZUELA increased taxes on oil projects and is forcing some 22 companies to renegotiate their operating agreements with the government. It is also seeking a total of $2 billion in back taxes from the companies.

The moves are aimed at seizing a greater share of revenues from high oil prices.

In April, President Hugo Chavez increased the corporate tax rate on oil projects from 34% to 50%. In late May, the head of / continued page 31

Toll Roads

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development and financing of transportation projects. Washington has actually had a program for private investment in road projects since 1993, but the old program was severely hampered by community and political resistance and only one project, the Tacoma Narrows bridge, was authorized, despite the submission of proposals for several other projects.

Delaware is moving to privatize one of the main state highways.

The new law requires state agencies to come up with guidelines for public-private projects and complete preliminary studies by 2006. The legislature directed that the studies address the feasibility of "value pricing" on transportation facilities in King, Pierce and Snohomish counties (essentially the western transportation corridor from Everett heading south through Seattle to Tacoma). It also gave orders to address the feasibility of a toll facility on State Road 704 in Pierce County.

The Washington Department of Transportation is expected to issue requests for proposals for private parties to participate in state transportation projects starting in late 2006 or 2007 once the feasibility study has been completed and guidelines have been issued. Unsolicited proposals will be accepted beginning on January 7, 2007. The law explains that the old public-private initiatives act did "not meet the needs and expectations of the public or private sectors" and that the new law "will provide a more desirable and effective approach by applying lessons learned from other states and from this state's ten-year experience" with the old program.

The Pacific northwest is becoming a hot region for private transportation projects. In other news in the region, Oregon issued three requests for proposals in late April for public-private road projects. The three projects — Sunrise, south I-205 and the Newberg-Dundee — are the first three projects put up for bid under an "innovative partnerships program" that Oregon adopted in 2003. All three projects are located near Portland. The deadline for submission of proposals is August 29, 2005. Oregon also had earlier enabling legislation that was enacted in 1995, but no projects were developed under that program.

Georgia recently amended its existing public-private transportation initiatives law. The two-year-old law, which replaced an earlier, ineffective private toll roads law that had been on the books since 1998, has been criticized for creating a process that is too secretive and closed to competition. Georgia has received three unsolicited proposals to date for development of toll roads, but none of the proposals has been challenged by a competing developer. The lack of competition worries Georgia officials who hope that the new amendment will encourage broader participation in the process.

The amendment increases from 90 to 135 days the amount of time that interested developers have to submit competing proposals. It also allows the state transportation department to solicit proposals. Unsolicited proposals are considered less competitive than solicited proposals because they give the developer that submits the unsolicited proposal a significant head start. The amendment also creates an evaluation committee (composed of two appointees of the governor, the state transportation commissioner, the director of the State Road and Tollway Authority and the director of the Georgia Regional Transportation Authority) to comment on state transportation department recommendations before they go to the governor. There is also supposed to be faster disclosure of nonproprietary matters contained in proposals as a further spur to competition.

Public outrage over a $4.70 toll proposed for a $1 billion

public-private expansion of state highway 316 has, at least for now, derailed the first unsolicited proposal reviewed under the Georgia public-private partnership law. While the developer that submitted the bid for the project is proposing to address the public's concern, negotiations have been postponed indefinitely, and it is not clear that the proposal will go forward.

Taking Projects to the Legislature

Delaware recently announced that it intends to privatize a state road — route 1 — by the end of the year. The 51-mile highway runs from the Wilmington-Newark corridor in the north to the state capital, Dover, in the south. Privatization of the road may be packaged with an upgrade of US route 301, a 14-mile road running from the Maryland border to route 1. Like other states considering privatization after the $1.83 billion lease of the Chicago Skyway to private interests (see "Toll Road Update" in the April *NewsWire*), Delaware is hoping that privatization will bring in enough money to offset projected decreases in revenue from gas taxes and other sources. It was encouraged by the $1.83 billion lease of the skyway in Chicago earlier this year to private interests. The Chicago Skyway deal continues to draw accolades; in May, Standard & Poor's upgraded the A-plus general obligation credit rating for Chicago from a stable to a positive outlook.

The Delaware transportation department will have to get approval from the state legislature for the route 1 and US route 301 project once it has a firm proposal in hand. A 2002 law authorizes state officials to look at private road projects, but permits the state only to "enter into agreements regarding a transportation project that has been specifically authorized by the General Assembly, and . . . such authorization [must include] all material terms of the proposed project, including without limitation any terms concerning repayment of debt or capital to or for the benefit of any private entity."

The need to return to the legislature on each project makes the process in Delaware cumbersome. Florida is like Delaware in that it also requires state officials to get separate authority from the legislature for each project. An effort failed in 2003 to strip this requirement from the Florida statute.

The Front Range toll road project in Colorado shows what can happen when the legislature */ continued page 32*

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the national tax agency, SENIAT, told a parliamentary investigating committee that 90% of the 22 oil companies with operating agreements in the country have been reporting no income. A majority had agreed to pay back taxes on SENIAT's terms by the end of May, according to the tax agency.

The government has given the oil companies six months to agree to turn their operations into joint ventures with the government. It would take a 51% stake in each venture.

CHILE imposed a new royalty tax on mining companies.

The Chilean Congress passed the tax by a wide margin on May 18.

It is a tax of as much as 5% on annual income from sales of ore from mines leased from the government. However, some costs of earning the income — like accelerated depreciation of mining equipment — that are deductible for purposes of calculating corporate income taxes would not be deductible against the tax base for the royalty tax.

The tax rate varies depending on annual sales. Companies that produce less than 12 metric tons of ore a year are exempted. The rates move from 0.5% to 4.5% as output increases from 12 to 50 metric tons. The tax rate for companies with more than 50 metric tons in annual output is 5%.

Larger mining companies will see their tax rates increase in Chile from 35% to 38.5% after the new tax is combined with the existing corporate income tax.

PERU will continue to collect new royalties on mining companies after a tribunal held they are constitutional.

The tribunal said in early April that the new law calls for payment of royalties rather than "taxes." The decision could have implications for US companies with mining operations in Peru, since foreign tax credits can be claimed in the United States only for overseas levies that are "taxes." What label a Peruvian tribu- */ continued page 33*

Toll Roads

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becomes too involved with the development of specific projects. The project has suffered significant setbacks in the last couple months. The developer, the Front Range Tolling Co., has been trying to persuade the legislature to adopt a new framework for setting tolls on private roads, but the proposal was defeated in the Senate after heavy lobbying by private landowners whose property is in the way of the new highway.

In May, the plot thickened. The state Senate began considering instead a bill that would strip private toll road companies of the power to exercise eminent domain and require a legislative review of the current framework for private toll roads with the aim of writing new rules for tolls, but not until 2006. The governor has said he is considering vetoing the bill if it passes.

While the Senate debates whether private developers should have eminent domain rights, the Colorado House unanimously passed a bill that would authorize the Front Range project to move forward, but with new restrictions. The developer would have to do the same level of analysis and receive the same approvals that are required for federal interstate highway projects. These requirements include getting approval for the new road from the Colorado Department of Transportation, conducting an environmental impact study and providing funding for environmental mitigations necessitated by the study.

Ironically, Colorado does not require individual road projects to be brought back to the state legislature for approval. The Front Range developer approached the legislature because it wanted the legislature to centralize regulation of toll rates, which under current law are set separately by each county through which a proposed toll road passes. This request gave an opening to opponents of the Front Range project, who wasted no time in mobilizing opposition in the state Senate.

Europe

Fitch Ratings reported in mid-May that "Europe is now poised for an explosion in new toll road projects, both in mature and emerging economies." Western Europe already has experience with private sector involvement in toll roads; budgetary pressures are forcing Western European governments to do more. Probably the area for the greatest potential new growth is central and eastern Europe, which has less experience with private investment in public projects. Roads are inadequate in the 10 countries that joined the European Union in May 2004 to handle the increased volume of truck traffic. For example, truck traffic increased by 50% in the Czech Republic in just the last year.

> The Front Range project in Colorado shows what happens when public controversy about a toll road spills over into the state legislature.

Many Europeans believe that a European Union initiative is needed to clarify the rules for public-private partnerships, or "PPPs." The European Commission is expected to issue a "communication" by the end of 2005 that will recommend how to address the issue. The commission action has the potential to make PPPs a more popular vehicle for highway projects.

Investors are wary of putting money into PPPs in certain European countries due to unfolding controversies. For example, Bulgaria recently embroiled itself in controversy by negotiating a reportedly no-bid concession for the €1.2 billion Hemus motorway with Salini Construttori SpA, an Italian company. Critics charge the concession is unlawful and cost inefficient. These negotiations followed shortly after Bulgaria awarded the Trakia motorway to a Bulgarian-Portuguese

consortium in a similarly no-bid concession. Potential investors are usually wary of investing in an atmosphere charged with controversy.

The European Investment Bank has called for the Bulgarian-Portuguese consortium developing the $1 billion Trakia motorway to withdraw from the concession because of the alleged improprieties surrounding the award. This call, which was made through the Bulgarian press, came several days after the European Investment Bank allegedly withdrew from involvement in the financing of the Trakia motorway. This developing situation highlights the importance of defining uniform tender procedures to avoid controversy.

Private investment in road projects is also mired in controversy in Romania, a candidate for European Union accession in 2007. The former Romanian government awarded a road concession contract for a $3.6 billion PPP motorway without going through a tender process, which is illegal in the European Union. The European Union condemned the road, which will be Europe's most expensive, but Romania, armed with an independent review stating that the price of the road is fair, recently approached US lenders to make up a $128 million budgetary shortfall that put the project in jeopardy. The European Union is backing construction of a competing road running almost parallel to the condemned road. Lenders may be wary of financing the remaining $128 million if Romania is forced to give the competing road priority.

Russia, another country that presents great opportunity, would also benefit from passage of a PPP law. Russian authorities are preparing to tender the construction and management of the 640-km Moscow-to-St. Petersburg highway project and Russia has appointed a group to look into the feasibility of additional project-financed roads, but the country has no law enabling concessions for toll roads.

A concessions law is expected by the end of the year. Russia spends about 1.3% of its gross domestic product on roads. This compares poorly with the 3.5% to 4.5% spent by European Union countries. The Russian transport minister called recently on the government to accelerate work on the concession law due to its huge importance in encouraging PPPs. Private investment in Russian roads is expected to increase gradually to $2 to $3 billion a year. A significant obstacle blocking this investment is investor skittishness about Russian intentions in the wake of the Yukos affair.

Public and private entities in the */ continued page 34*

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nal chooses is not dispositive in the US.

The royalty rate in this case depends on the annual sales of the company. It is 1% for companies with gross sales of up to $60 million. It is 2% for gross sales between $60 million and $120 million, and 3% above that.

The government said it would continue to honor tax stabilization agreements signed with the government before mid-2004 when the new royalties went into effect. A tax stabilization agreement is a contract between a foreign investor and the government in which the government promises not to change the economics of a project by imposing new taxes, fees or other charges during the term of the agreement. Thus, the royalties only apply to companies that had not signed such agreements before last summer.

ARGENTINA is expected to adopt incentives for new oil and gas drilling.

The government sent Congress a proposal in late May that would allow oil and gas companies to claim faster tax depreciation on assets used for new drilling — both at expansions of existing projects and at completely new projects. The measure would also exempt equipment imported for such drilling from import duties. Companies are also supposed to receive faster refunds of value added taxes paid on such equipment. The measure is expected to pass Congress easily.

There is a tradeoff. Companies will have to enter into some unspecified form of association with the state-run oil company, ENARSA.

Meanwhile, the province of Buenos Aires said in early June that it has secured court orders to seize wages of 41 executives of multinational companies who are delinquent in paying real estate and vehicle taxes. It has also commenced court proceedings against another 83 executives at such companies.

A NEW BANKRUPTCY law in the United States will require more extensive tax ***/ continued page 35***

Toll Roads

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United States and internationally are eager to cooperate in the development of toll road projects, but without proper enabling legislation projects often end up creating controversy, falling behind schedule and exceeding their budgets.

Central and eastern Europe are poised for an explosion in new public-private highway projects.

Good enabling legislation, using past experience as its guide, defines the roles of developers, investors, government entities and even the interested public and spells out the rules of the game that must be followed. Good enabling legislation will not create opportunity where opportunity does not exist, but without proper enabling legislation, even the regions most likely to benefit from innovative financing and public-private partnerships will not realize their full investment potential. ◎

Libya Launches Second Exploration Tender

by Nabil L. Khodadad, in London

The state-owned National Oil Company of Libya launched a new licensing round in early May for companies interested in exploring for oil and gas in 26 contract areas, divided into a total of 44 blocks.

The contract areas being auctioned include three in the Cyrenaica basin, four in the Ghadames basin, six in the Sirt basin (Libya's most prolific basin), six in the Murzuq basin, two in the Kufra basin and five offshore in the Mediterranean. The blocks and contract areas being offered are described in more detail in Table 1.

This is the second competitive tender organized by the National Oil Company, or NOC, under its new model exploration and production sharing agreement called "EPSA-4." In launching this new licensing round, the NOC is keen to capitalize on the success of its first EPSA-4 licensing round that was concluded on January 29, 2005.

First Round Results

There was keen interest in the first round, with 63 international companies from six continents submitting bids. The round attracted the most interest from US oil companies who had been barred by US sanctions from investing in Libya for more than 18 years. US oil companies won, or were in consortia that won, 13 of the 15 exploration areas.

The first round has been widely praised for its transparency. The bids from each bidder were opened in front of representatives from all bidders and were broadcast live on Libyan television. After all the bids for an exploration area were announced, the winning bidder was immediately declared.

The winning bids for the first licensing round are shown in Table 2. The company that bid the lowest production allocation, or "X factor", was declared the winner. The X factor is the percentage of oil production allocated for the recovery of the international oil company's costs and for the profit split. The international oil company will receive a percentage of production equal to the X factor until its costs are recovered. Thereafter, the oil company's share of excess production or "profit oil" is determined in accordance with the following formula: the amount of profit oil multiplied by the "base factor" multiplied by the "A factor". The base factor is expressed as a percentage and can vary with the average daily production of oil. In the first round, the base factor for oil produced from onshore blocks declines as the average

daily production exceeds certain levels, but the base factor for oil produced from offshore blocks, and gas produced from all blocks, is set at a constant 100%. The A factor is also expressed as a percentage and varies with the ratio (commonly known in the oil industry as the "R factor") of cumulative revenues received by the international oil company to its cumulative capital and operating costs. As the R factor increases, the A factor decreases in a manner predetermined for each contract area.

The total in signature bonuses for all 15 contract areas was approximately $133 million, with an average of about $8.8 million per contract area. The amount bid for the signature bonus was a secondary bidding parameter used to break a tie for lowest X factor, but in the first round there were no ties. It was possible to win a tender for an exploration despite having a low signature bonus bid. For example, the consortium of India Oil and Oil India was able to win the tender for Area 86 even though it bid zero for the signature bonus.

Most winning bids for the X factor were between 15% and 20%, with one winning bid as low 12.4%. The average winning X factor was about 19.5%. As the X factor just determines the amount of oil available for purposes of cost recovery and the profit split, it understates the take of the NOC and the Libyan government. Since the NOC is entitled to share in profit oil, it has been estimated that the actual share of production of the NOC and the Libyan government in the first licensing round is closer to 88% and, in the case of Area 54, may be as high as 92.8%. These are considered very good results for Libya. However, these aggressive terms could make it difficult to make a commercial discovery of less than 500,000 barrels of oil equivalent for some of the first round EPSA-4 licenses.

The total work commitment for the 15 contract areas included in the first licensing round was about $298.7 million, or about $20 million per contract area. However, most analysts believe that the winners are likely to spend much more on exploration.

Tender Rules for Next Round

The tender rules for the second licensing round are similar to those of the first round. Under the tender rules for the second round, potential bidders must pre-qualify by submitting an application letter, audited financial statements for the last three years, activity reports for / continued page 36

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disclosures by companies that are in bankruptcy.

The new law, enacted on April 20, is supposed to make it harder for individuals to file for bankruptcy protection from their creditors, but it also makes extensive changes in the bankruptcy rules affecting companies. Among other things, it would require any company trying to reorganize in bankruptcy to file a thorough disclosure statement discussing the effects of any reorganization plan on creditors before creditors can be asked to vote on the plan. The statement must include a discussion about the potential tax effects of the plan on both the company and a composite creditor.

"Although it might seem a given that adequate disclosure of tax risks must be provided, my experience is that the tax disclosures are often generic and not tailored in a meaningful way to the particular case, often because of concerns about creating an audit trail," said Richard M. Leder, a Chadbourne tax partner in the New York office. He said the new standards may lead to interesting disclosure questions about grey issues.

LUXEMBOURG altered the rules for "1929 holding companies" effective July 1.

US companies that own projects in other countries usually hold them through offshore holding companies. The holding companies act as "blockers"; they prevent overseas earnings from being taxed in the United States until the earnings are repatriated.

Luxembourg is one of several popular countries for holding companies. Luxembourg has a wide network of tax treaties with other countries that can help in pushing down withholding taxes at project country borders when earnings are pulled out of a project country. In theory, income received by a Luxembourg holding company is subject to corporate income tax in Luxembourg at a 30.38% rate, but in practice, income that the holding company receives as dividends is usually exempted from tax under a "participation exemption."

One form of holding / continued page 37

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the last three years and copies of their constituent documents. These documents must be submitted to the NOC by June 4, 2005. Applicants who pre-qualified in the first round or who are currently operating in Libya are exempted from the qualification requirement. The NOC has committed to inform applicants whether they have qualified by June 18, 2005.

Upon payment of the relevant data room fee, each qualified applicant is invited to visit the data room in Tripoli between June 25 and July 8, 2005. The data room fees range between $10,000 and $26,000, depending on the contract area. In the data room, each applicant will receive instructions and bidding procedures, technical data prepared by the NOC with respect to the relevant blocks, a model EPSA-4, a form of commitment letter, and a form of bid guaranty.

Applicants will have an opportunity to seek clarification of any terms in the proposed tender at meetings they can schedule with the NOC between July 15 and August 5, 2005. If the NOC accepts any clarification comments, then it will include them in a revised bid package and circulate the same to all bidders by August 18, 2005.

All bids are due in Tripoli on the morning of October 2, 2005, together with a bid guaranty issued in the form of an irrevocable letter of credit issued by the Libyan Arab Bank. The stated amount of the letter of credit must be equal to 10% of the minimum exploration program set out in the tender rules for the contract area. It is permissible for companies to bid as a consor-

Table 1: EPSA-4 Round 2 Exploration Tender

Basin	Area No.	Block Nos.	Total Acreage, Sq. Km.	Contract Area Acreage	Contract No.
Offshore	2	1	2,220		
		2	2,430	4,650	2 - 1 & 2
	17	3	2,010	2,010	17 - 3
		4	2,535	2,535	17 - 4
	40	3	2,590		
		4	1,950	4,540	40 - 3 & 4
	44	1	2,560		
		2	2,550		
		3	2,590		
		4	2,590	10,290	44 - 1, 2, 3 & 4
Cyrenaica	42	1	2,540		
		3	2,024	4,564	42 - 1 & 3
		2	2,288		
		4	1,064	3,352	42 - 2 & 4
	94	1	2,750		
		2	2,594		
		3	2,750		
		4	1,907	10,001	94 - 1, 2, 3 & 4
Ghadames	81	1	1,900	1,900	81-1
		2	2,650	2,650	81-2
	82	3	2,500	2,500	82-3
		4	2,306	2,306	82-4
Sirt	102	3	2,750	2,750	102-3
		4	2,750	2,750	102-4
	121	2	1,830	1,830	121-2
	123	1	2,750	2,750	123-1
		2	2,000	2,000	123-2
		3	2,030	2,030	123-3
Murzuq	146	1	2,444	2,444	146-1
	147	3	810		
		4	1,460	2,270	147 - 3 & 4
	161	1	2,750	2,750	161-1
		2	2,750		
		4	1,150	3,900	161 - 2 & 4
	176	3	2,750	2,750	176-3
		4	2,750	2,750	176-4
Kufra	171	1	2,750		
		2	2,750		
		3	2,750		
		4	2,750	11,000	171-1, 2, 3 & 4
	186	1	2,750		
		2	2,750		
		3	1,450		
		4	1,450	8,400	186 - 1, 2, 3 & 4
TOTAL ACREAGE		44	101,672	101,672	26

tium as long as they give the NOC notice at least three weeks prior to the date that the bids are due. In order to ensure the transparency of the bidding process, all bids will be publicly opened on October 2, with the winners announced on the same day. Each winning bidder is expected to sign an exploration and production sharing agreement with the NOC by the end of November 2005. The EPSA will become effective on the date that it is approved by the Libyan General People's Committee.

Proposed Business Deal

The commercial terms for the second EPSA-4 licensing round are similar to those of the first round.

A minimum exploration program is specified for each of the 26 contract areas. The exploration period is five years. During the exploration phase, a management committee consisting of two members appointed by the NOC and two members appointed by the international oil company will be established. In order for a discovery to be declared commercial, all members of the management committee must declare the discovery commercial. If the management committee members appointed by the international oil company do not approve the subsequent development of the discovery, but the management committee members appointed by the NOC do, then the NOC has the right to pursue the development of the field at its sole cost and risk. However, the international oil company has the right to rejoin in the development of the discovery within one year of the NOC's implementation of the development of the field if it pays the NOC an amount equal to the international oil company's share of development expenditures, plus accrued interest.

During the development phase, a joint operating company will be established by the NOC and the international oil company to act as the operator of the field. The joint operating company will be managed by a board of directors consisting of four members, with two members appointed by the NOC and two members appointed by the international oil company. The board of directors of the joint operating company will delegate certain of its authority to a separate committee, with two members of the committee appointed by the NOC and only one member appointed by the international oil company. A separate shareholders' agreement will govern the relationship between the shareholders in the joint operating company. */ continued page 38*

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company used in Luxembourg is called a "1929 holding company." Such companies are exempted from corporate income taxes altogether in Luxembourg. However, the tradeoff is they do not qualify for benefits under Luxembourg tax treaties. Therefore, when they are used, it is usually in tandem with at least one other Luxembourg holding company. One reason to use one might be to provide a means to "strip" earnings from a project in another country by having the project company pay its earnings to Luxembourg as interest. Interest does not qualify for the "participation exemption." Therefore, other ways must be found to shield the interest income from tax in Luxembourg.

Luxembourg narrowed the tax exemption for 1929 holding companies in April. The new rules take effect on July 1.

Under the new rules, a 1929 holding company will lose its tax exemption in any year in which at least 5% of the dividends it receives are from subsidiaries that were not subject to tax in another country at a comparable tax rate to the base tax rate in Luxembourg. The base rate in Luxembourg is currently 22%. Therefore, the tax in the other country must be at least 11%.

Any 1929 holding company that loses its tax exemption will be able to claim benefits under Luxembourg tax treaties. Existing holding companies are "grandfathered" from the change in law through 2010.

A TAX BENEFIT PAYMENT made in a corporate acquisition had to be reported as income.

Company A sold two subsidiaries to company B. The acquisition agreement had standard language making the seller responsible for any taxes that relate to the period before closing. The buyer took the subsidiaries with net operating loss carryforwards that the seller group had been unable to use. At the time, such losses could be carried back two years and forward for 20.

Soon after the transaction, Congress changed the law to allow companies with losses to carry them back up to *five* years. */ continued page 39*

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Following the exploration period, the term for the development phase shall be 25 years for crude oil. If commercial production continues during the last three years before the end of the term, the international oil company may request an extension of the term "for a reasonable time" and the NOC is authorized to approve the request subject to terms and conditions to be agreed with the international oil company. The international operating company is not permitted to assign its interest in the EPSA until all seismic work has been completed and the drilling of at least 50% of the new field wildcat wells set out in the exploration program. The NOC has a pre-emption right with respect to any assignment by the international oil company.

During the exploration phase, the international oil company will be responsible for all exploration and appraisal costs, as well as training expenses for Libyan nationals. In the first licensing round, the annual budget allocated for training Libyan nationals had to be sufficient to cover 24 man-months per calendar year during the exploration period and to account for not less than 10% of the direct and indirect manpower cost during each year of the development phase. While the training commitments for the second licensing round have not yet been disclosed, they are likely to be the same or similar to those of the first round. During the exploitation phase, all development costs (including those relating to pipelines, abandonment and site restoration) will be shared equally between the NOC and the international oil company. All operating costs shall be shared according to the primary production allocation, with the international oil company's share of such costs equal to the X factor and the NOC's share equal to the remaining balance.

As with the first licensing round, the X factor is the primary bidding parameter. In the first EPSA-4 licensing

Table 2: EPSA-4 Round 1 Results

Area	Winner	Production Allocation to International Oil Company (X Factor)	Signature Bonus in USD
Area 54 (Offshore)	Amerada Hess (100%)	12.40%	6,177,888
Area 53 (Offshore)	Woodside Petroleum (55%) Occidental Petroleum (35%) LIWA (10%)	19.80%	8,120,000
Area 52 (Offshore)	Woodside Petroleum (55%) Occidental Petroleum (35%) LIWA (10%)	17.90%	10,510,000
Area 36 (Offshore)	Woodside Petroleum (55%) Occidental Petroleum (35%) LIWA (10%)	17.40%	16,130,000
Area 35 (Offshore)	Woodside Petroleum (55%) Occidental Petroleum (35%) LIWA (10%)	20.40%	5,210,000
Area 18 (Offshore)	Petrobas (70%) Oil Search (30%)	31.80%	1,000,001
Area 106 (Sirt)	Occidental Petroleum (90%) LIWA (10%)	14.60%	25,600,000
Area 86 (Sirt)	Oil India (50%) India Oil (50%)	18.40%	0
Area 124 (Sirt)	Occidental Petroleum (90%) LIWA (10%)	10.80%	15,300,000
Area 131 (Murzuq)	Occidental Petroleum (90%) LIWA (10%)	13.30%	25,600,000
Area 163 (Murzuq)	Occidental Petroleum (90%) LIWA (10%)	15.90%	15,300,000
Area 177 (Murzuq)	ChevronTexaco (100%)	22.80%	600,000
Area 47 (Ghadames)	Verenex (50%) Medco (50%)	13.70%	250,000
Area 65 (Ghadames)	Sonatrach (100%)	25.00%	2,000,000
Area 59 (Cyrenaica)	Occidental Petroleum (90%) LIWA (10%)	38.90%	1,100,000

round, the X factor could not exceed either 35% or 40%, depending on the contract area. The maximum permissible percentage for the X factor has not yet been disclosed for the second licensing round. The X factor will prevail as the international oil company's share of production until its costs are recovered. Thereafter, the oil company's share of profit oil will be equal to the amount of profit oil multiplied by the base factor multiplied by the A factor (as discussed above). Pricing of crude oil for cost recovery purposes will be determined by reference to the weighted monthly average of the market price for crude oil realized by the NOC.

The international oil company is required to pay a signing bonus that is a secondary bidding parameter. Unlike the first EPSA-4 licensing round where bidders could bid zero for the signature bonus, a minimum signature bonus will be established for each contract area.

Production bonuses are also payable by the international oil company at pre-set production levels: $1 million is payable for each commercial discovery within 60 days of the commercial production start date of such discovery; an additional $5 million is payable upon achieving a cumulative production of 100 million barrels of oil equivalent from each commercial discovery; and thereafter, $3 million is payable upon achieving each additional 30 million barrels of oil equivalent. Neither the signing bonus nor the production bonuses are recoverable from cost oil. The international oil company is also subject to tax on its net income and to royalties. However, the NOC is responsible for discharging these taxes and royalties and for procuring a receipt from the government confirming payment of the amounts.

As in the first licensing round, the X factor will be the primary selection parameter. The bidder with the lowest X factor will win the tender. In the event that the X factor for the two lowest bidders are the same, then the bidder with the highest signature bonus will be declared the winner.

Conclusion

Over the last few years Libya has gone from international pariah to one of the most sought after destinations for upstream oil and gas investment. With the successful conclusion of the first EPSA-4 licensing round and the recent launch of a second round, Libya is well on its way to regaining its former position as one of the world's key petroleum producers. ◎

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The idea was to inject cash into struggling companies; it was part of a package of measures that were supposed to jump-start the US economy after the terrorist attacks on the World Trade Center and Pentagon in September 2001.

The buyer contacted the seller and asked whether it could use the net operating losses if they were carried back five years. It could. The parties entered into an agreement in which the seller agreed to pay the buyer two-thirds of its tax savings from using the losses.

The IRS said in a private letter ruling the government released in May that the buyer had to report the payment from the seller for the losses as ordinary income. At the same time, the seller could deduct the payment. The ruling is Private Letter Ruling 200518014.

MINOR MEMO. The IRS told a utility that it could claim production tax credits of 1.9¢ a kilowatt hour on electricity it generates from a wind farm the utility owns. The utility mixes the electricity with power from other power plants before selling it, so there is no way to know which customers buy electricity from the wind farm. The IRS said that does not matter. Electricity from a wind farm must be sold to a third party to qualify for tax credits. It is obvious the electricity ends up with third parties, even if it is intermingled with other power. The IRS made in the statement in a private letter ruling that it made public in May. The ruling is Private Letter Ruling 200518060.

— contributed by Keith Martin

Environmental Update

Renewables

The US Senate is expected to debate in June whether to adopt a national "renewable portfolio standard," or law that would require electric utilities in the United States to supply a certain percentage of their electricity from renewable sources. Nineteen states and the District of Columbia have such laws currently. A federal standard would apply in all states.

The issue is expected to come up during debate on the national energy bill. The bill passed the House in April without a renewable portfolio standard. The Senate energy committee passed its own version of the bill in May, also without such a standard. Democrats are expected to raise the issue when the bill is taken up by the full Senate in mid- to late June.

The energy bill still faces a long road before it can become law. Assuming it passes the Senate, then a "conference committee" of senior members from the House and Senate will have to iron out differences between House and Senate versions of the bill. There are many contentious issues. President Bush has asked Congress to send him a final bill by early August.

Senator Lamar Alexander (R-Tennessee) is considering trying to add language to the bill in the Senate that would set up additional barriers to development of onshore and offshore wind farms. Alexander wants wind farm developers to get a siting approval from local authorities as a prerequisite to the required Federal Energy Regulatory Commission approval before they can build a project. If the local authorities deny the siting approval, then FERC would be unable to grant the project status as an "exempt wholesale generator" or issue market-based rate authority or help the project enforce its rights to avoided-cost prices for its electricity in cases where the project is a "qualifying facility," or QF. Second, Alexander's language would prevent production tax credits from being claimed on the output from projects located within 20 miles of a coast line, military base, national park or other highly scenic area, and such projects would require the preparation of a detailed environmental impact statement. Third, wind farms proposed for construction within 20 miles of a neighboring state's boundary could be vetoed by the neighboring state.

Pressure is building in the United States to take steps to reduce greenhouse gas emissions from power plants, but Bush is not yet sold on the idea. The Senate will debate the issue in June.

In related news, Montana became the nineteenth state to adopt a renewable portfolio standard. Under the Montana program, electric utilities must purchase or generate 5% of their power from renewable energy sources by 2008. The percentage ramps up to 10% over the period 2010 to 2014 and to 15% by 2015. The new law defines eligible technologies to include geothermal, solar, wind, landfill gas or other methane gas projects, biomass, small hydroelectric plants and fuel cells where hydrogen is produced with renewable fuels. The Montana Public Service Commission has been directed to issue regulations implementing the program by June 1, 2006.

Global Warming

Canada unveiled a plan in April for achieving the commitment the country made in the Kyoto treaty to reduce greenhouse gas emissions by 6% below 1990 levels during the first commitment period of 2008 to 2012. The plan calls for spending as much as C$10 billion over the next seven years to achieve reductions of

approximately 270 megatons of CO_2-equivalent per year during 2008 to 2012.

Canada plans to achieve a 75- to 115-megaton reduction through a new climate fund that will reward domestic greenhouse gas reductions by farmers, businesses and local communities as well as pay to buy certified international greenhouse gas emission reductions. It expects another 55- to 85-megaton reduction from agreements with the Canadian provinces and territories to help fund infrastructure projects on a cost-sharing basis, including clean coal projects and carbon storage projects and shutdowns of existing coal-fired power plants. The Canadian plan also calls for a 45-megaton reduction from large industrial greenhouse gas emitters, including oil and gas companies, power plants, mines and other segments of the manufacturing sector. Energy efficiency initiatives are expected to contribute reductions of up to 40 megatons, and carbon sequestration in forests and soil is supposed to contribute CO_2-equivalent reductions of up to another 30 megatons a year. Renewable energy incentives are expected to provide approximately 15 megatons of reductions, and other programs, including consumer initiatives, reductions from government sources, and motor vehicle efficiency improvements are anticipated to contribute about 11 megatons of reductions per year.

Meanwhile, the pressure continues to build slowly in the United States to act on greenhouse gases. Two senior Senators — John McCain (R-Arizona) and Joseph Lieberman (D-Connecticut) — reintroduced a modified version of a bill they have been pushing for several years that calls for reductions in greenhouse gases from four major sectors of the US economy — electricity generation, transportation and the industrial and commercial sectors. These sectors account for approximately 85% of greenhouse gas emissions in the US. The bill would require the affected sectors to reduce greenhouse gas emissions to 2000 levels by 2010. The Senate rejected an earlier version of the bill in the last Congress by a vote of 55 to 43. The new version of the McCain-Lieberman bill includes a new title that is supposed to promote development and use of new low or zero greenhouse gas emitting technologies. The bill would also create a greenhouse gas emission allowance trading system that would be tied to the 2010 mandatory reduction target.

There do not appear to be any more votes for the new version of the bill than there were in the last Congress. Nevertheless, the Senators plan to try to add the text as a rider to the energy bill in the Senate in late June.

Meanwhile, the Regional Greenhouse Gas Initiative, or RGGI, organized by nine northeastern and mid-Atlantic states is moving forward with a state-led regional approach to reducing CO_2 emissions from power plants. The nine states — Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont — agreed in 2003 to work together on a regional cap-and-trade program to reduce CO_2 emissions. Representatives from Maryland and Pennsylvania also attend RGGI meetings as observers.

The RGGI states are expected to announce a memorandum of understanding and a final emissions trading model this summer. The focus is reducing CO_2 emissions from power plants. The program may ultimately expand to cover other industries and additional greenhouse gases. The states have not decided yet what level of CO_2 emissions reductions will be targeted under RGGI. In 2001, the New England governors and the premiers of the eastern Canadian provinces signed a climate action plan calling for a 10% reduction below 1990 CO_2 emissions by 2020. A large coalition of environmental groups is pressing the RGGI states for a 25% reduction.

The California governor, Arnold Schwarzenegger, issued an executive order in early June that establishes aggressive greenhouse gas emission reduction targets for the state. The order calls for emission reductions to 2000 levels by 2010, and a reduction to 1990 levels by 2020, and an 80% reduction below 1990 levels by 2050. The state legislature is also working on legislation that would achieve similar greenhouse gas emission reductions. The legislation was passed by the State Assembly at the end of May, and is now pending before the state Senate.

Chemical Security

The level of talk in Congress is increasing about the need for tighter security at power plants and other industrial facilities that use or manufacture potentially dangerous chemicals.

Two bills have been introduced in / continued page 42

the House. The Senate homeland security and governmental affairs committee held a hearing on the subject in late April, and committee staff are drafting a bill to present to the full committee.

Legislation on chemical security got through the committee in the last Congress, but was never taken up by the full Senate.

Under the House bills, the Department of Homeland Security would draw up a list of "high priority" facilities. In identifying high priority plants, a number of security-related factors would be considered, including the severity of harm that would be caused by an unauthorized release of dangerous chemicals, the proximity to population centers, the threats to national security, the quantity of substances of concern at the site and the threats to critical infrastructure. The "high priority" plants would have to prepare vulnerability and hazard assessments and develop a prevention and response plan. Companies will then have to get their implementation of the plans certified by the Department of Homeland Security.

Under the House bills, covered "chemical sources" are plants required by section 112(r) of the Clean Air Act to complete a risk management plan. Power plants that store anhydrous ammonia in large amounts for use in selective catalytic reduction systems are typically subject to the 112(r) requirements.

One issue that derailed the chemical facility security legislation in the last Congress was whether plants should be required to use "inherently safer technologies." Industry groups have opposed this provision arguing that it would be too costly and burdensome to implement.

The chemical security bills are expected to gather momentum in the coming months. If enacted, they could require big new capital investments in covered facilities.

State Emissions Reductions

Environmental officials in the northeastern and mid-Atlantic states are considering whether to adopt a regional plan that would require further reductions in nitrogen oxide, or NO_x, and sulfur dioxide, or SO_2, emissions that go beyond anything the federal government has ordered. The states are members of an Ozone Transport Commission, or OTC, that was created in 1990 to address elevated levels of smog or ozone pollution in the eastern US. The smog moves across borders, and a regional approach is more effective in achieving emission reductions. The states met in April to discuss potential strategies for implementing additional emission reductions.

The northeastern and mid-Atlantic states are moving to require reductions in other power plant emissions beyond what the federal government has ordered.

The OTC states have had a history of acting before the federal government to force reductions in NO_x and volatile organic compound or VOC emissions in the region.

The OTC states also want a nationwide cap on SO_2 and NO_x emissions from power plants that goes well beyond the levels proposed so far by the Bush administration. They want a nationwide cap of three million tons on SO_2 emissions and 1.87 million tons of NO_x emissions by 2008 — with further reductions to an SO_2 cap of two million tons and a NO_x cap of 1.7 million tons by 2012. The states also want a more stringent crackdown on mercury emissions.

Discussions are underway between the OTC states and environmental officials in several midwestern and southern states about possibly bringing other states into a regional partnership to limit NO_x and SO_2 emissions from power plants. The OTC states have in mind a

regional NO_X and SO_2 emissions trading scheme that would take effect as early as late 2006.

Mercury

Eleven states are suing the US government challenging the "clean air mercury rule" that requires reductions in mercury emissions from existing coal-fired power plants in a two-phased "cap-and-trade" approach. The 11 states are predominantly New England and mid-Atlantic states, but also include California, New Mexico and Wisconsin. Illinois has also announced that it plans to appeal the final rule.

Twelve environmental and conservation groups also filed lawsuits challenging the final mercury rule on the same day it was published in the *Federal Register*. The lawsuits were filed with the US court of appeals in Washington, DC.

The clean air mercury rule has been controversial from the start, and several states and environmental groups have criticized the Environmental Protection Agency for deviating from the more traditional framework of regulating air toxics under section 112 of the Clean Air Act. Under section 112, EPA must set emission limits for major sources of hazardous air pollutants at a level representing maximum achievable control technology or "MACT." For existing facilities, the MACT level is based on the average emission limitation achieved by the best performing 12% of plants in a particular category or subcategory of sources. For new facilities, the MACT level is set at the level of control achieved by the best-controlled similar source.

Instead of using its section 112 legal authority to set such standards, the Environmental Protection Agency looked to its "new source performance standards" program in section 111 of the Clean Air Act as a model for what to do about mercury. Section 111 is much less prescriptive and provides more flexibility in establishing emission standards. The petitioning states and environmental groups want tighter controls. They argue that the Clean Air Act does not authorize EPA to regulate mercury under section 111.

Strict MACT limits would probably require reductions in mercury emissions by as much as 90% from most coal-fired plants, resulting in a reduction in mercury emissions from the current nationwide figure of about 48 tons a year to approximately five tons. Under a MACT standard, coal-fired power plants would have to implement mercury reductions within a three-year time frame. The states and environmental groups argue that the "cap-and-trade" approach the Bush administration adopted will potentially leave toxic "hot spots" of mercury because companies will have a choice of reducing mercury emissions or buying "allowances," or rights to pollute. They argue that coal-fired plants clustered in certain parts of the country may find it cheaper to purchase allowances rather than invest in new pollution control systems.

Under the clean air mercury rule, the first phase of the mercury reductions commences in 2010 with the imposition of a 38-ton cap followed by a reduction to a 15-ton cap in the second phase starting in 2018. New coal-fired power plants that commence construction on or after January 30, 2004 will also have to meet stringent "new source performance standards" for mercury emissions. EPA anticipates that most coal-fired power plants will not have to take additional steps to reduce their mercury emissions until the phase two mercury cap takes effect. That's because actions that the plant are expected to take to rein in NO_X and SO_2 emissions as a result of a separate government crackdown will also reduce mercury by a large enough amount to meet the mercury cap of 38 tons during phase one.

Coal-fired power plants capable of generating 25 megawatts of electricity and that sell more than 25 megawatts to the grid are subject to the clean air mercury rule. Cogeneration units capable of producing more than 25 megawatts of output and that put more than a third of their capacity and more than 25 megawatts into the utility grid for sale are also covered by the rule. Under the clean air mercury rule, states have the option of participating in the model EPA cap-and-trade program or electing to adopt their own state programs to achieve the mercury reduction targets.

A decision in the lawsuits over the mercury rules is not expected until late 2006 or early 2007.

Brief Updates

EPA said in April that it will delay issuing "best available retrofit technology," or BART, guidelines for power plants and certain other industrial facilities / *continued page 44*

Environmental Update

continued from page 43

built between 1962 and 1977 that potentially affect visibility in a so-called class I areas, such as national parks or federal wilderness areas. The final rule implementing the regional haze guidelines is now scheduled to be issued by June 15 under an agreement with a citizens group. The rule is expected to require states to identify older power plants and industrial facilities that will be subject to BART requirements by January 2008. The required emission reductions are expected to take effect in 2014, with full implementation anticipated before 2018.

The Massachusetts Energy Facilities Siting Board approved construction of two undersea cables in May to connect the 420-megawatt Cape Wind project in Nantucket Sound to the regional electricity grid. The project still must obtain numerous other federal and state regulatory approvals before it can start construction. Portions of a draft environmental impact statement for the project prepared by the US Army Corps of Engineers have been criticized as inadequate by the US Environmental Protection Agency and several conservation groups. EPA commented that the study should have done a better job of evaluating the potential impact of the project on aquatic habitat, threatened and endangered species, eelgrass and migratory birds.

In April, a US appeals court in Washington heard oral arguments in a case filed by 12 states and 14 environmental groups challenging an EPA decision that it lacks legal authority to set motor vehicle emission standards for CO_2 and other greenhouse gases. The states and environmental groups argue that CO_2 and other greenhouse gases, including methane, nitrous oxide and hydrofluorocarbons, emitted by motor vehicles qualify as "air pollutants" that might adversely affect "public heath or welfare" under the Clean Air Act. EPA concluded that it is not authorized to regulate these substances as "air pollutants." A decision is expected later this year.

Massachusetts is considering restrictions on offshore ocean projects, including wind farms. Massachusetts Governor Mitt Romney (R) has asked the state legislature to prohibit certain ocean projects unless they conform to an "ocean use management plan" to be developed by the state. In developing the plan, the secretary of environmental affairs is supposed take into account the "existing natural, social, and economic" characteristics of the ocean planning area. The state legislature is expected to hold hearings on the proposal this summer.

— contributed by Roy Belden in New York

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