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New Tax Subsidies For Energy Projects

by Keith Martin, in Washington

Energy projects in the United States qualify potentially for an array of new tax subsidies under a massive new energy bill that runs 1,724 pages.

President Bush signed the bill into law on August 8. Congress estimated that the tax subsidies will be worth $14.6 billion over the next 10 years.

The biggest beneficiaries are developers of renewable energy projects like wind farms and power plants that run on biomass, landfill gas or geothermal energy. Approximately 19% of the tax benefits under the bill will go to renewables. Electric cooperatives, municipal utilities and Indian tribes that are not normally in a position to use tax subsidies will also benefit. They will be allowed to finance new equipment they install to generate electricity from renewables using interest-free bonds that pay the holders of the bonds tax credits in place of interest.

There are also new tax benefits for projects that make use of coal — for example, that turn coal into a liquid fuel for motor vehicles or gasify coal or use advanced processes to generate electricity. An example of an advanced process is an integrated gasification combined-cycle power plant. Companies that mine coal from reserves on Indian reservations will be given tax credits of $1.50 to $2 a ton.

The bill provides tax subsidies for power lines and pipes and */ continued page 2*

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UNCERTAIN TAX POSITIONS may force American companies to restate earnings later this year.

The US Financial Accounting Standards Board is collecting comments on proposed new rules that experts say will require companies to reserve against — and in some cases reverse — tax benefits they claimed in the past unless they are roughly 75% certain the benefits will be sustained if challenged by the Internal Revenue Service on audit. This applies only to tax benefits in tax years that are still open to IRS audit. Comments are due by September 12.

FASB wants the new rules to apply to fiscal years */ continued page 3*

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related equipment needed to transmit electricity equipment or distribute natural gas. Electric transmission assets and gas distribution lines can be depreciated more rapidly in the future. The tax savings from the faster depreciation will pay roughly 3¢ per dollar of capital cost of such equipment.

Power companies that lost money in 2003, 2004 or 2005 — at least for tax purposes — will be allowed to use the losses in one of the years to get back any federal income taxes the companies paid up to five years in the past. There is a condition. The refunded taxes must be used to pay either for new transmission equipment or air or water pollution control devices. The transmission equipment might include an "intertie" or a substation upgrade to connect a new power plant to the grid.

Utilities will have to recalculate amounts they collect in the future as "tax grossups" on electric and gas interties. When an independent power company connects a new power plant to the grid, the utility that owns the grid usually requires it to reimburse the utility for the cost of the "intertie" — the radial line, circuit breakers and other substation improvements needed to connect the plant to the grid — as well as for any improvements to the grid itself to accommodate the additional electricity. Utilities sometimes insist that the independent power supplier pay not only these costs but also a "tax grossup" to compensate the utility if it has to report the value of the intertie and grid improvements as income. Because utilities will be able to depreciate transmission assets more rapidly in the future, the amount of any tax grossup should decrease to reflect the benefit the utility will receive from this faster depreciation.

The bill gives operating subsidies — in the form of "production tax credits" — to owners of new nuclear power plants.

It allows faster writeoffs of air pollution control equipment installed at power plants that burn coal.

It gives a windfall to owners of some existing coke batteries at steel mills. Anyone producing coke or coke gas in existing coke ovens built between 1980 and 1992 or after June 1998 will be allowed to claim up to $4.38 million a year in tax credits per coke battery. The credits can be claimed for four years. They can also be claimed on the output from new coke ovens installed through 2009.

Tax subsidies can be a mixed blessing. Foreign companies trying to develop projects in the United States and smaller US developers are usually not in a position to use them since both lack a US tax base. They must find ways to "monetize" the tax benefits in order to compete effectively against larger companies that can use them. Private equity funds looking to invest in the energy sector are often inefficient users of tax benefits and, as a consequence, they may have a have a harder time bidding against traditional institutional equity investors on projects that receive heavy tax subsidies.

Roughly 19% of the $14.6 billion in new tax subsidies in the energy bill will go to renewable energy projects.

Renewables

The bill extends a deadline for completing wind farms and other renewable energy projects to qualify for "production tax credits." The tax credits are currently as much as 1.9¢ a kilowatt hour on the output. The deadline for completing projects to qualify had been December this year. Developers now have another two years through December 2007.

This is expected to give a significant boost to the US wind market. Production tax credits on wind farms are worth roughly 35% of the capital cost of a typical project. That is the present value of the tax savings from claiming such credits.

Production tax credits are given to the owners of certain kinds of power plants as a reward for generating electricity from renewable fuels.

Seven types of projects qualify potentially for such credits after the new energy bill. They are: wind farms, power plants that are fueled by biomass, geothermal energy, landfill gas or municipal solid waste, small turbines of less than five megawatts in size that produce electricity in irrigation canals or ditches, and new turbines installed at existing dams. "Biomass" is organic material like wood, rice hulls or manure.

Solar projects had qualified, but the deadline for them was not extended. They continue to qualify if put into service by year end in 2005.

How long the tax credits run and the amount depends on the type of project and when it is first put into service.

The tax credits are 1.9¢ a kilowatt hour on output from wind farms and power plants that run on "closed-loop" biomass, geothermal energy and sunlight. They are half that amount on other projects. These are the amounts for electricity produced during calendar year 2005. The credits are adjusted each year for inflation. "Closed-loop" biomass is matter from plants that are grown exclusively for use as fuel in power plants. Congress had in mind crops grown at so-called electricity farms.

The credits run for 10 years on wind farms and power plants that burn closed-loop biomass. The 10 years start when the plant is first put into service. Other projects qualified previously for only five years of credits. The energy bill extends the period to 10 years for all projects. However, the extra time applies only to new projects put into service after August 8 when President Bush signed the bill.

Developers of ocean energy projects had hoped to persuade Congress to let them claim production tax credits, but they were unsuccessful.

However, Congress did allow tax credits to be claimed for the first time on electricity from hydroelectric projects. Tax credits can be claimed on the "incremental output" from such projects, meaning the increase in output due to "efficiency improvements or additions to capacity" after August 8, 2005. Congress said that "efficiency improvements" are not "operational changes,"

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ending after December 15, 2005.

The board has had rules for some time on accounting for income taxes, but the rules were imprecise about when companies must reserve part of the tax benefits they expect from a transaction, and how much, due to uncertainty about the US tax rules.

The new "interpretation" the board proposes requires companies to assume that each tax position will be examined by the IRS, and it allows a company to recognize the position only when it is clear the position is probable of being sustained on audit. FASB suggests a number of factors that could lead a company to this conclusion. An example is where it has a "should" opinion from an outside tax counsel. Benefits that are not yet at least "probable" cannot be reported.

Once a position is probable of being upheld, then the company must decide how much of the benefit to reserve. This calls for a best estimate of risk. Legal developments, like an IRS announcement or news that the tax agency is challenging others on audit, might require revisiting the amount reserved. Such developments could also require reversing altogether a benefit that was claimed earlier.

Any such reversal would show up as a liability on the company's financial statement for the year the reversal occurs. Restatement of prior year financial statements will not be permitted.

The FASB proposal could make for a busy year end as US companies are forced to review open tax positions. The proposals are in an "exposure draft" called "Accounting for Uncertain Tax Position, an interpretation of FASB Statement No. 109."

SYNFUEL plant owners won a round in the IRS national office in June.

Another round is expected.

IRS agents in the field are moving on audit to disallow section 29 tax credits claimed on synfuel plants. Credits do

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suggesting that the owner of an existing hydroelectric facility probably must install new equipment to be able to claim credits, even if he or she can increase output without any new equipment. However, the bill is unclear. Anyone installing new turbines at a dam that was not used previously to produce electricity must show that there will not be "any enlargement of the diversion structure, or construction or enlargement of a bypass channel, or the impoundment or any withholding of any additional water from the natural stream channel" as a consequence of using the dam to generate electricity.

Although Congress failed to extend the deadline for solar projects, it gave the solar industry a 30% "investment tax credit" instead. That's a tax credit for 30% of the cost of equipment used at solar installations, but only for solar equipment put into service during calendar years 2006 and 2007. The entire tax credit is claimed in the year the project is put into service. (Solar projects completed after 2007 will qualify for a 10% investment tax credit.)

Congress cleared up some confusion that it created last October when it voted to let owners of existing power plants that burn biomass claim five years worth of production tax credits on the electricity they produce. The tax credits started to run in January this year. The confusion was that it looked like the five years might be counted from October 23, 2004, so that no one would actually get a full five years of tax credits. The energy bill makes clear that the five years are measured from January 1, 2005.

Congress also tried to address an issue that affects landfill gas projects, but did so poorly.

Decomposing garbage at landfills produces methane gas. The gas is trapped in collection systems. There are two tax credits that encourage the use of landfill gas. One is a "section 29 credit" of $1.13 an mmBtu that rewards anyone who traps and sells landfill gas to a third party. The other tax credit is the production tax credit given to anyone who uses landfill gas to generate electricity. Congress did not want projects to double up on these credits. However, a provision it wrote last October to do this was poorly drafted.

Electric cooperatives and municipal utilities will be able to finance renewable energy projects using interest-free bonds that pay the bondholders tax credits in place of interest.

Congress tried in the energy bill to clear up the confusion, but still left one big question unanswered. The US tax code now bars anyone using landfill gas to generate electricity from claiming production tax credits if the gas comes from a "facility" on whose output section 29 credits were allowed at any time in the past. Landfills are filled with garbage one section at a time. At many landfills, the gas might come from a newer section from which section 29 credits were never claimed on gas because the wells used to draw the gas from the ground were not put into service in time to qualify for section 29 credits. (Wells had to be in operation by June 1998 to qualify.) However, the gas passes through a central blower that is also used for older wells that draw gas that qualified for section 29 tax credits. An electricity generator who uses gas from the newer section should probably qualify for production tax credits, but this may require a private letter ruling from the Internal Revenue Service to confirm.

Production tax credits are subject to a "haircut" if the project benefited from government grants, tax-exempt financing, "subsidized energy financing" or other credits. However, only government subsidies or credits that help pay the capital cost of a project are a problem. Thus, for example, state tax credits that are calculated on output — so that they are essentially operating subsidies — are not a problem. Also, the Internal Revenue Service has taken a liberal view in private rulings about what is considered a grant. Money might not be considered a grant if there is a possibility that it might have to be repaid. The maximum haircut is 50%.

Production tax credits are hard for individuals, S corporations and "closely-held" C corporations to use. A "closely-held" corporation is one in which five or fewer individuals own more than half the stock.

Tax-Credit Bonds

Congress tried to give something equivalent to production tax credits to electric cooperatives, municipal utilities, state and local governments, US territories and possessions and Indian tribes planning wind farms and other renewable energy projects. (Examples of US territories and possessions are Guam, Puerto Rico and the US Virgin Islands.)

However, early calculations suggest such entities would do better to let an institutional investor own such a project and merely buy the electricity with an option to acquire the project after 10 years. An institutional investor could claim accelerated depreciation and production tax credits in the meantime and share the benefits indirectly by charging a reduced price for electricity.

The energy bill would let electric cooperatives, municipal utilities, state and local governments, US possessions and Indian tribes issue "clean renewable energy bonds" to finance any project that would qualify, in private hands, for production tax credits.

These are bonds on which no interest has to be paid. The bondholders receive tax credits instead.

Congress directed the IRS to calculate the minimum tax credit that would have to be offered to the bondholders to get them to forego interest. The IRS is also supposed to set the maximum term on the bonds. The term is supposed to be the number of years that would set the present value of the principal repayments on the bonds equal to one half the principal amount originally borrowed. The US Treasury Department already does these calculations for "qualified zone academy zone bonds" and updates the figures on a daily basis on its website. Qualified zone academy bonds are bonds issued to finance improvements at public schools in low-income areas or that draw at least 35% of their students from low-income groups. The credit rate and term in early August were 5.3% and 16 years.

The bonds must require level princi- / continued page 6

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not appear to have been disallowed in audits handled by the West Virginia district office, but credits have been disallowed elsewhere.

The plants produce synthetic fuel by putting crushed coal in a mixer and adding a chemical regent. The plant owners claim tax credits of $1.13 an mmBtu on the output. The credits are intended as a reward for anyone making synthetic fuel from coal.

The IRS field agents are arguing in some of the audits that the plants were not put into service in time to qualify for tax credits. They had to be in service by June 1998. Many plants were hurriedly built close to the deadline and then produced little output for months afterward. It was the middle of 1999 before most plants had appreciable sales.

In order to be in service for tax purposes, a plant must be in a "condition or state of readiness for its intended purpose." The IRS is arguing on audit that the fact the plants made few sales is an indication that they were not yet in a position to make a usable product and it was only after tinkering with equipment, the chemical reagent or the feedstock fed into the plants late in 1998 or in 1999 that the plants were able to make marketable synfuel.

The IRS national office rejected this argument in the first case to be heard in June. The plants at issue in that case had measurable output and better operating histories than most such plants had in 1998, but they were shut down by the fall and remained shuttered until mid-1999. The owner had a fulltime sales staff that tried throughout 1998 and 1999 to make sales. All of the output produced during 1998 was eventually sold. The taxpayer argued that it took time to overcome initial market resistance to the product and this — rather than any problems with the equipment — explained the period when the plants were idle.

The IRS national office agreed and said so in a "technical advice memorandum," or a ruling to settle a dispute stemming from an audit. It was helpful that there was / continued page 7

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pal repayments over the term.

Each bondholder must report the tax credits it receives in place of interest as income.

Only $800 million in total in clean renewable energy bonds can be issued for all projects. All bonds must be issued in 2006 and 2007. The IRS will allocate the bond authority among interested projects if there is more interest in the bonds than there is capacity. It must reserve at least $300 million of the bond authority for electric cooperatives.

> New tax credits reward the use of coal, including turning coal into a liquid fuel, gasifying it or using it in an advanced process to generate electricity.

Coal

There are three separate tax subsidies in the bill to encourage the use of coal.

First, the bill allows an investment tax credit to be claimed on new IGCC (integrated gasification combined-cycle) power plants, but the credit can be claimed only on part of the plant — the equipment that is "necessary for the gasification of coal, including any coal handling and gas separation equipment." The credit is 20% of the cost of such equipment.

There is a 15% investment tax credit for other power projects that use "advanced" technologies to generate electricity from coal. In such projects, the credit can be claimed on the *entire* project. The project can be a new power plant or a retrofit or repowering of an existing plant. To be considered an "advanced" technology, the project must have a design net heat rate of 8,350 Btus/kWh with 40% efficiency of energy conversion. (A majority of the energy in fuel is lost as the fuel is converted into electricity.) The plant must also be designed to meet certain pollution standards, including 99% removal of sulfur dioxide and 90% removal of mercury. The energy bill describes a series of assumptions that should be made in calculating the heat rate.

The tax credit can be claimed on progress payments to the construction contractor each year while a project is under construction, or the owner can wait to claim the full credit in the year the project is put into service.

The IRS will have to certify that a project qualifies. The fuel must be at least 75% coal. The plant must have a nameplate capacity of at least 400 megawatts. No more than $1.3 billion in total tax credits can be taken under the program; the IRS will have to allocate the credits among competing applicants. Congress envisioned that there would be two rounds of awards. There would be a first round within the next three years and then a second round in 2011 if the IRS receives too few applications to use up the full credits in the first round or credits have gone unused because projects for which awards were made go unbuilt. The IRS is supposed to set aside $800 million for IGCC projects and $500 million for other types of advanced clean coal projects.

Second, the energy bill allows a separate investment tax credit for gasification projects, but only in the following industries: chemicals, fertilizers, glass, steel, petroleum residues, forest products and agriculture.

The material being gasified can be any "solid or liquid product from coal, petroleum residue, biomass, or other materials which are recovered for their energy or feedstock value." The equipment must turn the material into a "synthesis gas" composed primarily of carbon monoxide and hydrogen. The gas must be used as gas or for "subsequent chemical or physical conversion." Thus, it appears the credit can be claimed on equipment used in the Fischer-Tropsch process to make fuel for motor vehicles from coal.

The credit cannot be claimed on gas collection equipment at a landfill. "Biomass" is defined more narrowly than in the past. It includes only agricultural or plant waste, byproducts from wood or paper mill operations, and forest trimmings.

Anyone hoping to claim a tax credit for a gasification project must have his or her project certified by the IRS. Total credits for all projects are limited to $350 million. No more than $130 million in credits can be allocated to a single project. Certificates will be issued during a 10-year period that runs from October 1, 2005 through September 30, 2015.

Projects that benefit from these new investment credits will get less tax depreciation. The "tax basis" is reduced by half the amount of "energy credits," but Congress did not use that label for these new credits. Therefore, it appears in this case that the basis is reduced by 100% of the credit.

Projects that benefit from tax-exempt bonds or "subsidized energy financing" will suffer a reduction in the tax credits they can claim.

Third, the energy bill lets anyone who produces coal from reserves on Indian lands claim tax credits on the coal sold to third parties. The credits can be claimed on seven years of output.

The credits can be claimed on coal from existing mines as well as from new mines opened through 2008. The credits are $1.50 a ton on coal sold in 2006 through 2009 and $2 a ton thereafter. Both the $1.50 and $2 figures will be adjusted for inflation. The first adjustment will apply to 2007 coal and reflect inflation during 2006. The coal reserves had to be owned by an Indian tribe or held in trust by the US government for the benefit of a tribe on June 14, 2005.

Electric Transmission

The bill gives electric utilities more time to shed all or part of their transmission grids. One obstacle to doing this has been that the utilities face potentially large tax bills if they have little unrecovered "tax basis" in the grids. In such situations, virtually all the compensation they receive is taxable.

Congress voted last October to let any utility that sells transmission lines or related equipment spread the income taxes on its gain over eight years. The utility must reinvest the sales proceeds in other electric or / continued page 8

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a pattern of steadily increasingly output during the four to five months the plants operated in 1998 before they were shut down.

The national office has at least one other case in front of it. A decision in expected in September or October.

The field appears to be refusing to let any other cases be heard in Washington.

Meanwhile, plant owners are keeping a wary eye on rising oil prices. The tax credits phase out if oil prices return to levels reached during the Arab oil embargo in the 1970's. Credits would have phased out during 2004 if the average wellhead price for domestic crude oil in the United States had moved across a range of $51.35 to $64.46 a barrel. The average price that year was $36.75. The range is adjusted each year for inflation.

NYMEX futures prices reached $65 a barrel in early August. NYMEX prices have generally been more than $3 a barrel higher than the reference oil price used by the IRS for its phase-out calculation, but the gap is increasing according to Meridian Investments, which studied the historic price link. The reference price was about 85% of the NYMEX futures price at the start of this year. Meridian calculated in late March that NYMEX futures prices would have to average $64.02 for the rest of 2005 in order for the reference price to reach the bottom of the phaseout range.

Separately, House and Senate negotiators working on the energy bill wrote the following in the "conference report" on the final bill: "The conferees understand that the Internal Revenue Service has stopped issuing private letter rulings and other taxpayer-specific guidance regarding the section 29 credit. The conferees believe that the Internal Revenue Service should consider issuing such rulings and guidance on an expedited basis to those taxpayers who had pending ruling requests at the time the moratorium was implemented."

IRS officials in Washington say they are not aware of any morato- / continued page 9

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gas utility property or another power or gas company.

The legislation last October set a deadline of December 2006 for utilities to shed their grids to take advantage of the spread.

The energy bill would allow another year through 2007.

The grid must be sold to an "independent transmission company." An independent transmission company can be an ISO (independent system operator), RTO (regional transmission organization) or other independent transmission provider approved by the Federal Energy Regulatory Commission, or any company that is not a "market participant" as FERC defines that term and whose own transmission facilities are put under operational control of an ISO or RTO before 2007.

The bill also lets power companies depreciate their transmission lines and related equipment over 15 years using the 150% declining-balance method. Such equipment is depreciated over 20 years currently. The change applies to new equipment put into service after April 11, 2005. The utility cannot have been under binding contract to acquire the equipment on or before April 11 or have started construction of the equipment before that date in cases where the utility is building the transmission line itself. The tax savings from the faster depreciation are worth about 3¢ per dollar of capital cost.

Most independent power plants involve a transmission line to connect to the utility grid. The part the independent power company owns would benefit from the faster depreciation. Transmission can be an especially significant cost for wind farms.

Utilities will have to recalculate amounts that they collect in the future as "tax grossups" on electric and gas interties.

Loss Carrybacks

Some power companies will be given cash by the US government to pay for new transmission equipment and air and water pollution control devices.

Any power company that had tax losses in 2003, 2004 or 2005 can elect to use the losses in one of the years to get a refund of any federal income taxes the company paid within the five years before the loss year.

The election must be made between 2006 and 2008.

The company must spend the money on electric transmission assets or pollution control. It can only elect to carry back losses equal to 20% of the amount it spent on such property *the year before* the election is made.

The money can be used on interconnecting a new power plant to the grid, but only on the part of the intertie that the independent power company will own. Congress said it will consider the tax refund as properly spent only if the refund is invested in property that the taxpayer will own.

Pollution Control

The United States allows the cost of pollution control devices installed at older power plants that were in operation before 1976 to be "amortized" — or deducted — on a straight-line basis over five years.

The energy bill eliminates the requirement that a plant must have been in operation before 1976, but only for equipment installed to control air pollution at coal-fired power plants. The bill allows the cost of such equipment installed at post-1975 power plants to be amortized over seven years.

It will be interesting to see how many power companies take advantage of the provision. Some power companies already depreciate such equipment over seven years using the 200% declining-balance method. Congress estimated that the provision will be worth $1.147 billion to US power companies over the next 10 years. It applies to air pollution equipment acquired after April 11, 2005 (or built by the power company itself and completed after April 11, 2005).

The state where the power plant is located must certify that the equipment is required to comply with state law.

The power company must also get a certificate from US environmental authorities that the equipment complies with federal environmental regulations. The tax code bars the US from certifying any equipment "to the extent" the costs will be recovered through sale of ash or other byproducts.

Section 29 Credits

Congress renumbered section 29 of the US tax code. It is now section 45K. Documents in future section 29 tax credit deals should reflect this.

The energy bill gives a windfall to owners of some existing coke batteries at steel mills.

Steel production requires a fuel that, when burned, produces very high temperatures. Coke comes close to pure carbon and is produced by heating pulverized coal in a coke oven. The process also produces coke gas.

Companies that produce "synthetic fuel" from coal are allowed currently to claim section 29 tax credits of $1.13 an mmBtu on their output. The synthetic fuel must be sold to a third party. The equipment used to produce the fuel must have been put in service between 1993 and June 1998. The tax credits can be claimed on the synthetic fuel produced through 2007.

Coke and coke gas qualify as synthetic fuels.

The bill allows four years of additional tax credits to be claimed on coke and coke gas produced at facilities that were put into service during two "window periods." The first runs from 1980 through 1992. (Coke batteries put into service during the first window period used to qualify for section 29 credits, but the credits have expired.) The second window period runs from July 1998 through 2009. The additional tax credits will be at a reduced rate: 51.7¢ an mmBtu. The credit amount will be adjusted for inflation, starting with inflation during 2005. The bill limits the total credits that can be claimed on output from a single "facility" to $4.38 million a year (before inflation adjustments). A "facility" is a coke battery with multiple ovens. Credits on output from existing coke batteries can / continued page 10

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rium. They speculate that the conferees may be referring to a policy that the IRS has had in effect for at least the last year and a half of not ruling on plants that use processes for making synthetic fuel that the IRS has not already blessed in prior rulings.

THE OREGON legislature voted in July to require utilities to reduce rates if they end up not paying the full taxes that were included in rates.

Utilities would have to submit annual reports to the state showing the actual taxes they paid. A utility would be treated as having paid one of the following two amounts in taxes: the taxes the utility would have paid on a standalone basis if it did not join in filing a consolidated tax return with other, affiliated companies or, if less, the total taxes paid by the consolidated group. This calculation could force utilities to share tax benefits with ratepayers that their affiliates receive — for example, from investing in wind farms.

The governor is expected to sign the bill in September.

The move comes on the heels of disclosures that the taxes for which Portland General received reimbursement in rates during the period Enron owned the utility were not actually paid. The utility's taxable income was offset by losses elsewhere in the Enron consolidated return.

HOLLAND granted partial relief in July to US companies that have made offshore investments through Dutch holding companies using a so-called CV-BV structure.

A new protocol to the US-Netherlands tax treaty took effect last January 1. Among other things, the treaty waives withholding taxes on dividends where a US parent company owns directly at least 80% of the voting rights in a Dutch subsidiary.

In a CV-BV structure, a US parent company owns a Dutch CV that, in / continued page 11

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be claimed for four years starting in January 2006.

Companies that own other synfuel plants or landfill gas facilities were not given an extension on their tax credits — the credits run out after 2007 — but Congress made it easier to use section 29 credits to which such companies become entitled in the future.

The energy bill makes section 29 credits into a type of "general business credit." This will let companies that have extra section 29 credits they cannot use carry them back one year or forward for 20 years until the companies are in a position to use the credits. Until now, credits were lost if they could not be used immediately (except where the reason a company cannot use them is because it is on the "alternative minimum tax").

Section 29 credits were originally supposed to encourage Americans to look in unusual places for fuel. They were enacted in 1980 soon after the Arab oil embargo. The hope was that if US companies would produce more alternative fuels, then the United States would be less dependent on the Middle East for oil. The credits were given originally to anyone producing gas from biomass, tight sands, Devonian shale, geopressured brine and coal seams or synthetic fuel from coal.

Some producers of these alternative fuels were hoping for an extension in the tax credits. There was none. However, Congress may have given them another outlet.

The energy bill allows half the cost of any new "refinery" put into service during the period August 9, 2005 through 2011 — defined as equipment for turning oil or landfill gas, synfuel or other fuels that qualified previously for section 29 tax credits into a liquid fuel — to be deducted immediately. Any such equipment put into service after 2007 must be under binding contract by December 2007 to be built.

The government will make tax refunds to power companies that reported losses in 2003, 2004 or 2005, provided they invest the refunds in new transmission lines or air and water pollution control.

Gas

The bill lets gas utilities depreciate their distribution lines over 15 years using the 150% declining-balance method rather than the current 20 years. The change only applies to distribution lines put into service during the period April 12, 2005 through 2010.

Congress also clarified that "gathering lines" that bring gas from the field to a larger pipeline or processing plant can be depreciated over seven years. Gas pipeline companies had been fighting with the IRS over seven-year depreciation in court. Congress stepped in to settle things in favor of the pipeline companies.

Prepaid Contracts

More than 20 prepaid gas deals have been done where a gas supplier enters into a long-term contract to supply gas to a municipal utility. The utility pays in advance for the gas that it will receive over the contract term in exchange for a discount off the gas price. It borrows the funds to cover the prepayment in the tax-exempt bond market. The gas supplier gets access indirectly to money at tax-exempt borrowing rates.

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

Many independent power companies are looking at doing similar deals with electricity not only with municipal utilities, but also with electric cooperatives.

The IRS wrote exceptions from the arbitrage restrictions into its regulations for prepaid gas contracts in 2002 and for prepaid *electricity* contracts the next year.

The energy bill adopted a slightly different version of the exception for prepaid gas deals than is in the IRS regulations. It wrote it directly into the US tax code. The bill is silent about electricity, raising the question what to make of Congressional silence on electricity. A judge might read into the silence a suggestion that Congress intended a special rule for gas but not for electricity. On the other hand, the exception from the arbitrage rules for electricity remains in the IRS regulations. A Treasury official told Chadbourne that he believes there was no intention to rule out prepaid electricity deals.

Nuclear

The bill gives operating subsidies — in the form of "production tax credits" — to owners of new nuclear power plants.

The credits can only be claimed on the output from "advanced" nuclear power plants. These are plants that use a reactor design approved by the Nuclear Regulatory Commission for the first time after 1993. A "substantially similar design of comparable capacity" cannot have been approved earlier.

The credit is 1.8¢ a kilowatt hour. It runs for eight years after the nuclear plant is first put into service. Credits may be claimed only at new nuclear power plants built by 2020. There is a limit on the total number of projects that can qualify for credits of 6,000 megawatts. The IRS will allocate the megawatt capacity among projects that apply for credits. No more than $125 million in credits can be claimed on a single project for each 1,000 megawatts in capacity the project is allocated by the IRS. Thus, for example, if a project is allocated 1,500 megawatts in capacity, then it will be allowed to claim up to $200 million a year in tax credits.

Projects that benefit from government grants, tax-exempt financing, "subsidized energy financing" or other tax credits that are a function of project cost will suffer a "haircut" in production tax credits. The haircut will not be more than 50%.

Credits that a company cannot use because of insufficient tax capacity can be carried back one year and carried forward for 20 years. They can be used only against regular taxes and not alternative minimum taxes. The revenue estimators in Congress are guessing that / continued page 12

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turn, owns a Dutch BV that, in turn, owns a project company in another country. Holland taxes the BV like a corporation, but it views the CV as transparent so that dividends paid by the BV to the CV are considered received by the US parent directly. Meanwhile, the United States taxes in the opposite manner. The US parent company makes a "check-the-box election" to treat the CV like a corporation for US tax purposes, and the BV is treated as transparent.

Thus, when a dividend is paid by the BV to the CV, it does not reach the US tax net but remains blocked in the CV.

Dividends paid by a Dutch company to someone without the benefit of treaty protection attract a 25% withholding tax. The new protocol to the US treaty has a clause that bars treaty benefits in cases where "hybrid" entities are used, like in this case. Even though the Dutch view a dividend paid by the BV as received in the US directly, the protocol rules out treaty benefits. The protocol language is intended to prevent governments from being whipsawed by clever tax planning.

The Dutch finance minister announced on July 6 that the Dutch government will not enforce the hybrid entity clause in cases where the hybrid entity is engaged in "real" activities in Holland. Dutch counsel are advising US companies to seek rulings from the Dutch tax authorities to confirm their status. To be considered "real," among other things the hybrid company must have resident directors who make real decisions in Holland, and its main bank account must be in Holland. Having employees in the country will also help.

There is still uncertainty about whether the US company will face capital gains taxes in Holland upon any future sales of the BV shares. The treaty bars Holland from taxing US tax residents on capital gains from the sale of shares in Dutch companies. The July decree only applies to dividends paid by the BV. It does not address whether the Dutch government will waive the hybrid entity / continued page 13

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it will be another eight years before the first new nuclear power plant will come on line. The final "conference report" on the energy bill shows no revenue loss from the tax credits before 2013. ◎

US Remakes Playing Field For Gas and Electricity

by Robert Shapiro and Adam Wenner, in Washington, and Dan Rogers, in Houston

The US Congress changed some basic ground rules that have an effect on how gas and electricity are supplied in the United States.

The changes are part of a massive energy bill that President Bush signed into law on August 8. The bill repeals a 1935 law that was a barrier to utility mergers, strips away major parts of a 1978 law that was the original foundation for the independent power industry in the United States, and gives help to companies that want to build new transmission lines or LNG terminals.

The energy bill repeals a 1935 law that was a barrier to utility mergers across state lines.

Bye Bye PUHCA

One of the most significant parts of the bill is repeal of the Public Utility Holding Company Act, a 1935 statute that was originally supposed to make it difficult for utilities for form large multistate combines. The repeal takes effect in February 2006.

PUHCA threatens any company that owns or controls at least 10% of the voting stock of an gas or electric utility with extensive regulation as a "holding company." Among other things, the company must get advance approval from the US Securities and Exchange Commission of its securities issuances and inter-corporate transactions. PUHCA also requires all utility subsidiaries of such a holding company to be in the "same area or region" of the country. Although this limitation had been applied liberally by the SEC, with the SEC stretching the statute in recent years to grant exemptions and to approve various utility mergers, PUHCA nonetheless prevented the formation of national utility companies.

PUHCA also presented an additional barrier for companies that are not already in the utility business to become active owners of utilities in more than one state. While companies like Enron and Dynegy managed to sidestep this restriction by reincorporating utilities they acquired in the state in which their utility subsidiary operated to take advantage of a "single state exemption" from PUHCA, this was not a viable strategy for many companies. The single state exemption is a rule that allows a company to own one or more utilities in a single state without being subjected to regulation as a utility holding company. Perhaps more importantly, PUHCA barred companies that own utilities from engaging in other lines of business beyond owning utilities and related energy companies. This restricted the universe of potential utility purchasers to companies that are already in the utility business — and to those who are willing to divest their other lines of business. As a result, companies like Berkshire Hathaway were limited to acquiring non-voting shares of utilities, or acquiring voting shares not exceeding 9.9% of the total. Similarly, private equity funds had to structure their investments in franchised utilities and independent transmission companies so that another entity exercised management control -— an unappealing prospect for companies investing hundreds of millions of dollars in a business enterprise. Finally, while foreign companies were permitted to acquire US utilities, they had to submit to SEC regulation and limits on unrelated business activities.

PUHCA repeal does not mean an end to regulation. Utilities will be able to expand their operations without geographic restrictions, and private equity funds as well as other enterprises will have the opportunity to acquire utilities with fewer restrictions. However, this does not mean that companies are exempted from other regulatory constraints on utility ownership.

Virtually every US state regulatory commission has approval authority over acquisition of regulated utilities in their states.

The Federal Energy Regulatory Commission also has jurisdiction over acquisitions of utilities and utility assets of investor-owned utilities (except for utilities in the ERCOT region in Texas). The Department of Justice and the Federal Trade Commission retain jurisdiction over mergers, and the Atomic Energy Act, administered by the Nuclear Regulatory Commission, requires approval for acquisitions of utilities that own or operate nuclear power plants. The principal focus of the Department of Justice and FTC review, and one of the public interest factors in the FERC review, are the competitive effects of a proposed merger. Thus, proposed mergers of utilities with large portfolios of power plants in the same geographic market will continue be examined by multiple federal agencies to determine if they will adversely affect the relevant markets.

The likely effects of PUHCA repeal will be consolidation in the industry and entrance of new players as owners, although the pace of any change will be tempered by the need for multiple regulatory approvals of merger transactions. Financially-strong and well-managed utilities will be in the hunt for other gas and electric utilities that can provide strategic value or economies of scale. Among the open issues are whether many utility subsidiaries can be effectively managed by one centralized company, whether significant cost reductions can be obtained and passed on to ratepayers by eliminating duplicative back office, administrative, management and billing operations, and whether the local public utility commission can assure that reliable service can be maintained when control over the local utility resides with an out-of-state and / continued page 14

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clause for purposes of capital gains taxes.

Separately, in mid-July, the European Court of Justice barred Holland from collecting a capital tax in a situation where a UK parent company made a capital contribution directly to a second-tier German subsidiary, bypassing its first-tier subsidiary in Holland.

The UK parent company owns a Dutch holding company that, in turn, owns a German subsidiary. The UK parent contributed approximately €5.1 million to the German subsidiary directly. Holland collects a 1% capital tax on funds passing through Dutch holding companies, and it insisted the tax had to be paid in this case because the money must have passed through the first-tier subsidiary in Holland to get to Germany. The court disagreed. The parent received no additional shares in the Dutch company, which the court said one should normally receive in exchange for a capital contribution.

The case has the potential to create an enormous hole in the Dutch capital tax. It is Senior Engineering Investments BV v. Staatssecretaris van Financien.

INDIA and Singapore have a new protocol to their tax treaty.

Singapore is hoping the protocol will cause investors to make future investments into India through Singapore holding companies. Most investments into India today are made through either Mauritius or Holland.

Under the protocol, a foreign investor will be able to avoid capital gains taxes in India on the sale of shares in an Indian company — when the investor exits a project — provided the holding company the investor forms in Singapore to invest is considered a tax resident of Singapore. "Shell" holding companies will not be considered Singapore tax residents. However, a holding company is automatically not a "shell" if it has spent at least S$200,000 on operations in Singapore in the preceding 24 / continued page 15

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more remote owner.

While companies owning only power plants — as opposed to transmission and distribution lines — have been exempted from PUHCA since 1992, PUHCA repeal should cause an increase in the number of power plants that are on the market, as "wires and pipes" utility companies expand their reach into geographic areas previously off-limits, and shed the generating assets of companies that they acquire. Also, PUHCA repeal greatly boosts the ability of transmission-only companies to acquire transmission systems anywhere in the United States and to construct new transmission lines without having to limit investments to passive ownership or small-percentage ownership arrangements.

Finally, at the same time that it repealed PUHCA (effective six months after enactment), Congress added the Public Utility Holding Company Act of 2005, a title bound to create confusion in documents that refer to PUHCA.

The new PUHCA responds to concerns that regulators would no longer have access to the books and records of companies that own or may now acquire public utilities. New PUHCA retains the same nomenclature of old PUHCA, defining a "holding company" as a company that owns 10% or more of the voting securities of a public utility. It requires parents and other affiliates of public utilities to make available to FERC and to state regulatory commissions the books, accounts, memoranda and other records of the parent holding company and other any member of the holding company's corporate family that are determined to be relevant to the costs incurred by a public utility company in a rate proceeding.

The authority to obtain and review books and records is also extended to affiliates of interstate natural gas pipeline companies, which previously were not subject to PUHCA at all. New PUHCA does require FERC to issue rules exempting from this new regulation companies that were exempted from regulation under old PUHCA — for example, foreign utility companies or owners of so-called qualifying facility projects.

The bill also strips away major parts of a 1978 law that was the original foundation for the independent power industry in the United States.

PURPA Haze

The independent power industry in the United States got its start with help from a 1978 statute called the Public Utility Regulatory Policies Act, or PURPA. PURPA created a market for the output from two kinds of independent power plants — cogeneration facilities that produce two useful forms of energy from a single fuel, and small power production facilities that burn renewable of waste fuels. Utilities were required to buy electricity from such projects at their "avoided cost," the cost the utility would have had to spend the generate the electricity itself. The projects are called "qualifying facilities" or "QFs."

After many years of repeated assaults by the franchised utilities on PURPA, the utilities finally succeeded in gutting essential components of the original legislation.

The utility industry never liked the idea of being forced to buy power from competitors who use more efficient technology (cogeneration) or renewable fuels or waste (small power production) to generate electricity. Utilities also claimed that the states were setting rates above the cost of alternatives available to the utilities. On a prospective basis, the utilities will, for all intents and purposes, be freed from the federal requirement to buy power from new cogeneration facilities, and, in some sections of the country, from small power production facilities as well.

PURPA was a very significant milepost on the road to introducing competition to the generation markets in the

United States. The statutory structure required FERC to issue rules to encourage more efficient and alternatively-fueled projects, and the states were to implement the federal rules. Once the states with high cost power and a shortage of generating capacity started to implement the federal rules in earnest, hundreds of projects and tens of thousands of megawatts were brought on-line. The utility industry, surprised by the surge of competition and fearful of building rate-based capacity before regulators that could disallow cost overruns and restrict returns, moved to build so-called independent power plants in competition with qualifying facilities, mostly in other utilities' service territories, while fighting encroachment by cogenerators in their own. In addition, with the fledgling efforts to deregulate the industry in several states, state commissions encouraged vertically-integrated utilities to sell off their power plants in order to avoid the "stranded costs" that would result if they tried to sell power from expensive older plants in a newly competitive world. QF projects were forced to compete in this new environment.

With the industry moving rapidly toward a generation market functionally and legally separated from transmission and distribution, and with the movement toward the creation of retail choice in numerous states, utilities became reluctant to sign long-term contracts with qualifying facilities, even with the mandatory purchase obligation built into the law. State commissions were sympathetic to the claims of utilities that forcing them to sign such contracts would merely create more unrecoverable "stranded costs" because the utilities faced a loss of a retail market when retail choice kicked in. As a result, state commissions have generally failed to enforce PURPA with respect to new contracts for the past several years, and most independent generators have not had the financial strength or the time to devote to filing a court challenge to the state. This may help to explain the apparent acquiescence of the QF industry to the PURPA revisions in the energy bill, although the fact that the statute was amended rather than repealed made the changes easier to swallow.

Under the energy bill, existing QF contracts will be "grandfathered." In other words, the commitments in the contract between a QF and a utility will not be affected by the legislation.

Moreover, the bill added a require- */ continued page 16*

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months before the shares are sold.

The protocol took effect on August 1.

Companies doing new projects in India would probably do well to compare the tax results from investing through Mauritius versus Singapore.

NEW MARKETS TAX CREDIT applications for calendar year 2006 must be posted by August 22.

New markets tax credits are an incentive for institutional investors to invest equity in entities that, in turn, lend the money to finance projects in low-income communities. The companies that do the lending are called "CDEs," or community development entities. Congress created the program in 2000. It had in mind storefront operations that lend small amounts of money to help get small businesses get off the ground in low-income areas. CDEs apply to the US Treasury for permission to offer equity investors in them tax credits as an inducement to invest. This helps the CDEs raise money. Each equity investor gets a tax credit for 39% of the equity he or she invests. The tax credits must be taken over seven years.

Each August and September, the Treasury opens the window to new applications from CDEs for allocations of tax credits for the coming year. Last year the Treasury allocated $2 billion in tax credits among 41 CDEs. It has $3.5 billion to allocate for 2006.

US banks and tax credit syndicators have been looking at the program as a way to offer more product to their customers.

Applications for tax credit allocations must be postmarked by September 21 and received by September 30. However, entities that are not yet certified as CDEs must apply separately for CDE status in late August. Such applications must be postmarked by August 22.

There will be one more round of tax credits allocated in the fall next year for 2007. At that time, the Treasury will have another $3.5 billion in tax credits to allocate.

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ment for FERC to issue and enforce regulations to ensure that a utility purchaser will be able to pass through the costs associated with its QF purchases under a contract to its ratepayers, whether the contract is existing or new. This provision is supposed to discourage state commissions from allowing only a partial recovery of utility payments to QFs in retail rates. Not only will this protect utilities from potential losses, but it will also protect QFs that have so-called "regulatory-out clauses" in their contracts with utilities. A regulatory-out clause allows the utility to reduce payments to the QF if the utility cannot pass through all of the QF payments to its retail customers. Although the existing FERC regulations have been consistently interpreted to require passthrough of payments by the courts, the regulations themselves are not so specific on the point.

The bill makes "regulatory-out clauses" in power sales contracts less likely to be invoked.

The bill is silent about the impact of amending an existing QF contract. However, if a QF and a utility agree to amend the contract, there should not be an adverse impact on the QF, whether or not the amendment substantially modifies the existing contract. The QF would remain exempted from federal and state rate regulation. Depending on the language of FERC's new regulations that will require state commissions to let utilities pass through QF payments to ratepayers, it may be prudent to get the state commission's blessing for the amendment before it becomes effective to ensure that the state will not be able to challenge the amendment in the future.

Unlike the language of the PUHCA section of the bill, the Congress does not simply repeal PURPA. Rather, it directs FERC to examine regional power markets and determine if the particular market is workably competitive. If it is workably competitive, then FERC can end any obligation by utilities in that market to purchase power from QFs or to sell backup power services to QFs. If the regional market is not workably competitive, then the utilities' obligation remains in effect. A workably competitive market is independently run and has one of two features. Either the QF must have nondiscriminatory access to real time, day-ahead, and long-term capacity markets, or a QF in a regional transmission organization must have a meaningful opportunity to sell capacity and energy on a competitive basis to customers other than the QF's interconnecting utility.

In regions where regional transmission organizations are in place, like PJM and the New England ISO, FERC is expected to remove the purchase and sale obligations from utilities. This would apply only to new QF contracts. In many other regions, however, conditions do not yet exist for FERC to be able to make that finding.

In addition, entities that want to become qualifying *cogeneration* facilities and that did not file for QF status before August 8, 2005 will be subject to far more stringent requirements before they will be certified as QFs.

A utility does not have to purchase power from an entity that was not already a qualifying cogeneration facility before August 8, 2005 unless the new cogeneration facility satisfies the more stringent requirements. FERC has 180 days to enact rules that explain the new requirements. The most significant new requirement is that the electrical, thermal and chemical output must be used fundamentally for industrial, commercial or institutional purposes and not be intended for sale to an electric utility. This will drastically limit the available electricity for sale to a utility and will require that the economic viability of the facility be determined by the purchases by the industrial host, not the utility. Consequently, it is unlikely that a significant number of new cogeneration QFs will be certified.

On the other hand, no new regulations are required for small power production facilities, so the utility purchase obligation will remain for existing and new small power production facilities, unless the FERC finds that the region is workably competitive. The same result applies for existing cogeneration facilities.

Finally, utilities will be allowed to own 100% interests in qualifying facilities. FERC's current rules limit a utility's ownership to 50%. Lifting this restriction will probably encourage utilities to acquire additional interests in QF projects, and there will be fewer partnerships of the kind that utilities entered into in the past with non-utility interests in order to acquire QF projects without running afoul of utility ownership limits.

Clearly, the financial prospects are better for small power producers — like developers of windpower and biomass projects — than for cogenerators. Even if FERC removes the federal mandatory purchase obligation in a particular region of the country, small power producers can still benefit from the renewable portfolio standard that may be in place at the state level and that imposes on the utilities a minimum percentage of renewable generation to be included in their overall generation mix.

Wheeling and Dealing in Transmission

FERC has exercised siting authority for interstate gas pipelines for years. Such pipelines are regulated only by FERC. By receiving a certificate from FERC under the Natural Gas Act, a pipeline company is authorized to construct and operate the pipeline and related facilities along the entire right-of-way. In addition, a certificated pipeline is granted the power of eminent domain to acquire any property rights needed to develop the line that cannot be obtained through negotiations with the property owners.

In contrast, electric transmission line permitting has been exclusively a state function to date, and construction of transmission lines ordinarily requires a utility or private transmission developer to obtain a "certificate of public convenience and necessity" from each state or states in which the lines would be located. The state power of eminent domain, which is especially important for developing continuous transmission corridors, is usually available only to the local franchised utility, so that transmission-only companies and non-utility genera- / continued page 18

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TELEPHONE EXCISE TAXES remain in play.

A former top official in the US Department of Justice said in June that the government will probably try to argue a telephone excise tax before another appeals court before giving up on the tax. The United States collects a 3% excise tax on long-distance telephone calls, but the statute is badly out of date. It only applies to calls that are billed based on time and distance. Most telephone companies no longer bill on that basis.

Large companies have been suing the government to get back taxes that their telephone companies collected. The government has lost several such cases recently, including a key decision in May in a US appeals court for the 11th circuit.

The former Justice Department official said the government will probably try to persuade another appeals court to uphold the tax before conceding. Kent Jones was the tax assistant to the US solicitor general from 1990 to 2004.

SUCCESSOR LIABILITY was not a problem when a lender foreclosed on a business.

In some states, when someone buys the assets of a business, he or she is exposed potentially to any back taxes that the company selling the assets failed to pay. Buyers usually ask for a certificate from the state tax department confirming that no back taxes are owed.

Kentucky tried to collect back sales taxes from a company that bought the assets of a Papa John's pizza franchise. The original franchisee defaulted on a loan. The lender foreclosed on the assets and sold them to someone else, who resumed operating the business under the name Papa John's. The original franchisee owed the state $45,000 in delinquent sales taxes, plus penalties and interest.

Kentucky law requires anyone buying a business to "withhold sufficient of the purchase price to cover / continued page 19

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tors that want to develop their own lines face significant obstacles if private landowners are unwilling to grant needed rights-of-way. An additional problem has been the reluctance of state commissions to authorize the construction of a transmission line when the line will be used solely to move power through the state to load centers in the state next door.

To address these problems and permit the development of transmission that benefits users of the multi-state US power grid, the energy bill directs the US Department of Energy, within one year, to designate areas where transmission is needed.

If an application is submitted to FERC to construct transmission lines in a designated transmission corridor, then the FERC must determine if the state or states in which the lines would be constructed lacks the authority to authorize transmission construction, or if its approval process fails to take into account the benefits that would accrue to other states, or if the fact that the applicant is not a utility that serves end users in the state prevents it from receiving state siting approval. If FERC finds that one or more of these obstacles is present, or if it finds that the state has failed to approve a transmission project for more than one year or has conditioned its approval so as to make the proposal economically infeasible, then FERC can authorize construction of a transmission project in a designated corridor (except in the ERCOT region of Texas).

In addition, if FERC grants a transmission permit, then it can authorize the permit holder to acquire the rights-of-way needed to construct the project upon the payment of "just compensation" as determined by a federal district court, under procedures similar to those currently available to pipeline companies that obtain a FERC certification to develop interstate pipeline projects.

The new siting authority also puts pressure on federal agencies that have permit or environmental review authority over the development of transmission projects by granting the Department of Energy authority to ensure that all such federal agencies complete their reviews within one year of the submission of a completed permit application, or as soon afterward as is practical. In addition, if a federal agency denies a needed authorization to construct a transmission project or fails to act within the deadline, then the applicant may appeal to the president of the United States, who may issue the authorization.

The US government now has the power to push through needed new electric transmission projects that are facing obstacles at the state or local level.

Will this new siting authority be enough to add the needed wires?

The jury is out, because the law does not exempt transmission developers from extensive environmental review, including compliance with National Environmental Policy Act, the Endangered Species Act, and the Federal Land Policy and Management Act. Moreover, to authorize transmission line construction, FERC must make numerous findings about the public benefits of the line, including its consistency with national energy policy. In many instances the development of new transmission lines has been hindered by permit-related delays, by the exclusive focus on local, rather than regional or national benefits by permitting authorities, and by the unavailability of eminent domain rights for non-utility developers. However, many transmission projects, especially those involving the development of mine-mouth coal and wind energy projects located hundreds of miles from load centers, have been hindered more by the cost of transmission construction or upgrades necessary to deliver their power to load than by siting considerations. As demonstrated by FERC's recent decision to assign the costs of the proposed Tehachapi "trunkline" transmission line in California exclusively to wind projects that would tie into the line, rather than treating these costs as part of the system costs to be borne by all users of the grid, transmission pricing policies will continue to play a key role in the development of transmission projects.

Nevertheless, for the first time, the federal government will have the authority to override parochial state transmission permitting policies. It gives utilities, transmission companies and power plant developers the ability, under an admittedly cumbersome and time-consuming process, to overcome obstacles to construction. The threat to resort to federal authority may make states and private property owners more willing to approve new wires and reach voluntary accommodations with transmission project developers.

Closing the Generation Gap

Congress made two significant changes to the part of the Federal Power Act that gives FERC jurisdiction over sales of, and changes of control over, utility assets and the utilities that own them.

The first is an increase in the minimum dollar value of such "jurisdictional facilities" before FERC approval is required for a sale. The minimum value was increased from $50,000 to $10 million. Thus, smaller transactions involving small facilities can avoid the requirement to obtain FERC approval.

The second change is to give FERC, for the first time, authority over the sale or change of control over generation-only transfers. Under existing law, FERC lacked jurisdiction over a sale or disposition of a generating asset, unless jurisdictional facilities were involved. Often, this limitation did not limit FERC's authority over the transfer, because interconnection lines and transformers were often part of a sale of a generating plant, and FERC would assert jurisdiction over the entire transaction on the basis that a component of the transaction contained jurisdictional transmission facilities. However, in recent years, utilities have sold thousands of megawatts of generation — Southern California Edison Company and Pacific Gas & Electric Company sold about 10,000 MW this way in the late 1990s — without seeking FERC approval by making sure that the sale of generating assets did not include any equipment that could be characterized as transmission equipment. */ continued page 20*

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[any delinquent taxes] until the former owner produces a receipt from the [state] showing that it has been paid or certificate stating that no amount is due."

There was no withholding in this case, perhaps because the buyer bought the assets from a lender and had no direct contact with the original franchisee.

A Kentucky appeals court held that because of that, there was no successor liability. The court said there was no opportunity to withhold since the lender — who had contact with the original franchisee — paid nothing for the business assets when it foreclosed on them.

The case is LKS Pizza v. Commonwealth of Kentucky. *The court released its decision on July 15.*

SALES TAX PLANNING around sale of one plant failed.

Sales taxes are normally collected on asset sales, but not on sales of interests in a project company that owns the assets. This is one of several reasons why most sales are structured as sales of a company rather than the assets directly.

International Paper Co. signed a letter of intent to sell a corrugated box manufacturing plant in Colorado to Weyerhauser Corp. for $16.5 million. However, the parties thought better of the structure. International Paper contributed the plant to a new limited liability company and sold the LLC interests instead. The Colorado tax authorities collapsed the transaction and assessed a sales tax as if the assets had been sold to Weyerhauser directly. A Colorado appeals court upheld the tax in June.

The case is International Paper Co. v. Cohen. *It is a warning to figure out the tax structure before the negotiations get very far along.*

DOMESTIC MANUFACTURING INCOME is taxed more lightly by the US */ continued page 21*

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FERC Chairman Joseph Kelliher had expressed concern about this "loophole" and lobbied hard to get this merger provision into the final version of the bill. The merger authority amendment takes effect in early February next year (six months after enactment).

I Can See Clearly Now

In response to allegations of market manipulation, false reporting of prices used for energy price indexing, and other activities that came to light following the California energy crisis, Congress extended FERC's authority to prohibit these practices (through market transparency rules) and increased the civil and criminal penalties to which those engaged in these practices are subject.

The energy bill prohibits the submission of false information relating to the price of wholesale power or interstate transmission to a federal agency, if the person providing the information knows it to be false and intends fraudulently to affect data being compiled by the federal agency.

The bill helps developers of LNG projects by giving the federal government the power to decide where new LNG terminals will be built.

The bill also codifies actions taken by FERC in the wake of the California energy crisis by prohibiting the use of "any manipulative or deceptive device or contrivance" — terms used in the 1934 Securities Exchange Act –- by any entity in connection with the purchase or sale of power or transmission subject to FERC jurisdiction. The bill gives federal courts the authority to prohibit a person who has engaged in such practices permanently from serving as an officer or director of an electric utility or engaging in power sales or transmission activities subject to FERC jurisdiction.

The energy bill also significantly expands FERC's authority by allowing the agency to impose stiff civil and criminal penalties on persons and companies that violate the Federal Power Act or FERC orders.

Natural Gas

The energy bill resolved a dispute between the federal and state governments in the United States by declaring that FERC has exclusive authority over the siting, construction, expansion and operation of liquefied natural gas facilities located both onshore or in state waters.

FERC will still have to consult with state and local governments, as the states retain certain rights under the Coastal Zone Management Act of 1972, the Clean Air Act and the Federal Water Pollution Control Act.

However, the most immediate effect of the decision in the energy bill to give FERC the final say over where LNG terminals get built should be the dismissal of a case — currently in a US appeals court — in which the California Public Utilities Commission is challenging a FERC decision that it has exclusive authority to allow construction of an LNG terminal by Mitsubishi and ConocoPhillips in Long Beach harbor.

The energy bill also names FERC the lead federal agency for purposes of the National Environmental Policy Act environmental review process. FERC will set a regulatory review schedule and prepare a single environmental review document, which will then be used as a basis for all decisions under federal law on applications for authorizations under the Natural Gas Act. The bill also sets firm deadlines for disposing of appeals under the Coastal Zone Management Act of 1972. The deadlines were needed because states have been able, in some cases, to delay approvals for new LNG terminals indefinitely by manipulating the CZMA appeals procedure.

The energy bill also codifies a FERC order in 2002 called the "Hackberry" decision. Hackberry set a precedent for private, non-open access LNG terminals to charge market-based rates. It also eliminated the requirement for tariffs or other terms and conditions of service to be filed with FERC or otherwise made available to the public.

Congress also recognized the potential for inconsistencies at LNG terminals that provide both open access service and private unregulated service. The bill bars owners of LNG facilities that offer open access service from passing through the costs of any new private, non-open access expansion capacity in the open access rates. Open access ratepayers are also protected from any degradation of service or discrimination in terms and conditions of service resulting from such private expansion capacity.

Finally, the bill authorizes market-based rates at natural gas storage facilities for new storage capacity placed in service after August 8, 2005. Until now, a gas storage company had to show that it lacks "market power" to get authority to charge market rates. Such a showing will no longer be required if FERC determines that market-based rates are in the public interest and necessary to encourage the construction of storage capacity in areas needing storage services and customers are adequately protected.

Given the plans of many LNG import terminal developers to use nearby underground gas storage facilities for additional storage capacity, this part of the bill provides a mechanism to better link the terms of service of the LNG import terminal with the associated underground storage service. ◎

Will PUHCA Repeal Hasten Utility Consolidations?

The energy bill that President Bush signed on August 8 repeals a 1935 statute — called the "Public Utility Holding Company Act" — that makes it hard to form multistate electric and gas utilities in the United States. The repeal takes effect in early February next year.

Chadbourne hosts an annual conference for leaders in the energy industry. One topic at the conference this year was whether repeal of this statute will lead to a wave of utility consolidations. There are 3,000 electric utilities and 1,500 gas utilities in the United States. / continued page 22

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government than other income.

This is to encourage American companies to keep manufacturing jobs at home. Electricity generation is considered "manufacturing," but transmission or distribution is not. Rather than a lower tax rate, companies are allowed to deduct a portion of their domestic manufacturing income. This has the same effect as reducing the tax rate.

As the *NewsWire* went to press, 27 states were considered likely to allow the same deduction as at the federal level, and 19 states either already have rejected it or are expected to do so. Among the states expected to follow the US lead are Arizona, Florida, Illinois, Iowa, Kansas, Louisiana, New Mexico, New York, Oregon, Pennsylvania and Virginia. States expected not to allow the deduction include California, Hawaii, Maryland, Minnesota, New Jersey, Texas and West Virginia.

THE CALIFORNIA Franchise Tax Board hired an outside tax counsel in June to train the state audit staff on what to look for in audits of companies that may be diverting income to offshore holding companies in tax havens.

A PENNSYLVANIA appeals court held in late May that municipalities in the state have the right to collect property taxes from companies that merely hold rights to subsurface minerals.

The case involved a company that mines limestone at a quarry in Fayette County. The court said subsurface minerals are considered "land," citing a state supreme court decision that "coal and minerals in place are land." The case is *Coolspring Stone Supply, Inc. v. Fayette County.*

INSURANCE is not always easy to recognize.

The issue is important for wind farms and low-income housing deals in which investors are offered a minimum guaranteed return through arrangements that sometimes look like insurance. It is also / continued page 23

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When a similar statute was repealed in 1994 that inhibited interstate banking, the number of US banks dropped from 14,000 to 7,000 in just a few years. The discussion took place in late June.

The speakers are Stephen P. Reynolds, chief executive officer of Puget Sound Energy, the largest private utility in the state of Washington, Michael Hogan, senior vice president of Centrica North America, the North American arm of a large energy company based in Britain that was created after the demerger of British Gas, Peter Rigby, director for utilities, energy and project finance for Standard & Poor's, David Haug, formerly with Enron and now a managing director of Arctas Capital Group, and Christopher Seiple, director of global power for Cambridge Energy Research Associates. Keith Martin and Adam Wenner, two Chadbourne lawyers, participated in the discussion. Neil Golden, a Chadbourne partner in Washington, was the moderator.

MR. GOLDEN: The agenda for this panel discussion talks about 3,000 electric utilities and 1,500 gas utilities. A lot of those are probably not what we are thinking about when we talk about mergers of utilities, since many of them are electric cooperatives or municipal utilities that are not potential acquisition targets. The real volume of potential merger activity is much smaller than that.

As to the banking analogy, my own view is that banks are a good bit different than utilities in the M&A context because, while banks are regulated, they are regulated not so much in terms of pricing of the product to the consumer, and they do not provide a monopoly last-mile service to the end user. It is easier from a regulatory and economic perspective to form new banks, to combine banks, and to consolidate the banking industry than would seem the case in the electric and gas utility businesses.

Mayo Shattuck, who is CEO of Constellation Energy, said recently at a Constellation shareholders meeting that he believes we will be down from a hundred major electric utilities in this country to 50 within a few years. He pointed out that Japan has only seven utilities for 120 or 130 million people.

A few days ago, an investment banker named George Bilicic at Lazard was quoted in the *Wall Street Journal* as saying, "I think this sector will be white-hot for the next two years. This industry is more fragmented than any other."

Many people believe we are about to see a wave of utility consolidation in the United States, but there are also doubters who take issue with the conventional wisdom. With that background, let me ask Steve Reynolds: where do you see this going? Will we see a large number of utility mergers?

The utility merger mania that many foresee in the wake of PUHCA repeal may not happen because utility acquisitions still require approval from state regulators.

State PUCs as an Obstacle

MR. REYNOLDS: I can't help but reflect when I hear Mayo Shattuck talking about consolidation that there was a sell side analyst 20 years ago who predicted that that there would only be 12 utilities left in the country by 1990. He has taken a lot of grief in the last 15 years because it did not happen.

The truth is there has already been a wave of consolidation, but it slowed after Enron collapsed. I think you will hear from Peter Rigby that one of the key issues is the financial health of potential merger candidates.

My utility is a product of a merger. In 1997, the electric company bought the gas company, and in the seven-plus years since then, the financial strength necessary to move forward from both a credit rating standpoint and balance sheet standpoint has been slow to be achieved. That is an issue that I think those who predict a large number of mergers need to take into account in their calculations. Some of those trying to fan the flame of merger mania today are the advisers who would work on any deals. It is important to keep such predictions in context. If you look at some of the mergers that are being talked about today, they have fairly unique circumstances that may not — I would underscore — may not be transferable.

It has been fascinating in our neck of the woods in the Pacific Northwest to watch the MidAmerican acquisition of PacifiCorp. It is not clear whether it is really an indication of a new wave of merger activity as much as a very strong signal from ScottishPower that it believes it made a mistake coming to the United States. The consequent acknowledgement of that in the dollar writedown the company took upon announcement of the sale indicates that it is having a very difficult time dealing with state regulatory economics.

If I were to offer any observation today, it is that regardless of whether the Public Utility Holding Company Act is repealed, deals will still need state approval. We have just seen a state reject the proposed acquisition of Portland General by a private equity group. We saw the same thing in Arizona with the KKR-UniSource deal. There are difficult state issues that are a barrier to the type of merger mania that some forecasters foresee. That does not mean mergers have no value. There are good arguments for the advantage of scale in the interest of ratepayers that often are not very well understood by more parochial state commissions, cities and others.

Effect on Credit Ratings

MR. GOLDEN: Let me move next to Peter Rigby. Standard & Poor's has just issued a report that suggests that the rating consequences may make many utility combinations challenging.

MR. RIGBY: Our experience is that when utilities have merged, the cost savings that were touted as one of the reasons for merging never really materialized. They were harder to achieve than the companies expected. Bringing the companies together was much more difficult and took longer than expected. Merger proposals also face regulatory risk. Most regulators will want to grab some portion of the anticipated cost savings — if they ever materialize — for ratepayers because ratepayers, rather than the providers of capital, tend to be their primary inter- / *continued page 24*

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important to deals where third parties protect a synfuel plant or landfill gas project owner against risk of loss of section 29 tax credits due to high oil prices.

How a relationship between two parties is characterized for tax purposes has economic consequences. What looks like an insurance contract may be a partnership, loan, capital contribution or indemnity contract in substance — rather than insurance — the IRS warned in late June in a revenue ruling. Payments to an insurer are deductible as premiums. Payments under other arrangements may not be.

The IRS analyzed four fact patterns in the ruling in June. It said insurance requires both a shifting of risk to the insurer and a distribution of the risk by the insurer among a pool of insured parties. Thus, in one of the fact patterns, a company like United Parcel Service entered into an arrangement with a third party where, for payment of a "premium," the third party insured UPS against business losses. The IRS said this was not insurance because there was no risk distribution.

Risk distribution requires "the statistical phenomenon known as the law of large numbers," the IRS said, where premiums are pooled from a number of companies seeking risk protection so that, if a claim has to be paid, the burden is shared among them and is not borne entirely in a two-party bet by the "insurer." The ruling is Revenue Ruling 2005-40.

KANSAS cannot assess interstate and intrastate gas pipelines differently for property tax purposes, the state supreme court said in June. The state's method of assessing gas pipelines violates the "commerce clause" of the US constitution because it discriminates against interstate commerce. The case is *In re CIG Field Services Co.*

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est. Right there is the reason why it is tough for mergers and acquisitions to lead to any sort of positive rating.

That said, if a very large entity acquires a very small entity, particularly if the smaller entity has a lower rating, it will probably not have much effect, if any, on the larger company's rating, and it will pull up the rating of a lower-rated entity.

The types of mergers we are seeing today tend to involve companies that are roughly comparable in size. Exelon has about $40 billion dollars in assets; PSE&G has about $29 billion dollars in assets. In that case, we put Exelon, which was the higher rated entity, on "credit watch negative." We put PSE&G on "watch developing" because we are unsure how the pieces will fall out in that merger.

Utilities that merge tend to end up with worse credit ratings.

With the Duke-Cinergy merger, we put both companies on "credit watch negative." Duke is the bigger company, and it had the lower rating. We are not sure what will happen. We have not figured out yet exactly why this merger is happening and how things will unfold. Cinergy's rating will probably end up closer to Duke's.

With MidAmerican Energy and PacifiCorp, the PacifiCorp rating was largely a function of the consolidated rating of its ScottishPower parent entity, which was higher rated. We put MidAmerican Energy Holdings on "credit watch positive" mostly because we have a better understanding of how MidAmerican has handled acquisitions in the past, and that is a better way to describe what the company has done with acquisitions as opposed to merging. We don't see PacifiCorp being merged into MidAmerican Energy Holdings.

To get back to our report or article, there are three or four main points.

First, utility mergers tend to jeopardize a company's credit profile more often than not, partly because the industry is highly regulated and it is very fragmented. The way it is regulated tends to make what you might achieve in other industries more difficult to achieve in the utility industry. Second, as with many other mergers, the cost synergies may never materialize. Third, there is regulatory risk. The regulators may take some or all of the savings. They may also force divestiture of certain assets that the merged entities might not have counted on, which would then change the economics. Finally, it is unclear whether repeal of PUHCA will have a meaningful effect on utility credit profiles, because it already looks as though the states are stepping in to fill whatever void will be created. For example, Steve Reynolds just mentioned about what happened with Arizona.

MR. GOLDEN: Let me move to another issue that is tied to PUHCA repeal, and that is the possibility of other players coming into the industry. PUHCA requires that anyone who owns 10% or more of the voting stock of a public utility company must register with the Securities and Exchange Commission and submit to strict regulation on its ability to raise financing and do a host of other things. PUHCA has been an obstacle in particular to non-utility players coming into the industry because they must divest themselves of nonutility lines of business. Will PUHCA repeal bring a lot of fresh capital into the utility sector? Michael Hogan?

Influx of New Capital?

MR. HOGAN: Not many people realize this, but we have five million customers in North America. We are actually the largest retail energy provider in North America, and we have not had to think much about PUHCA.

Maybe that has more to do with who were are. We are a marketer. We also are an E&P company in gas, and we generate electricity in Texas. We are operating very effectively, very successfully, very profitably as a marketer in Ontario, Alberta, Texas, and increasingly in parts of the upper Midwest and the Northeast. We are in nine states; we are in the process of entering three more in either the gas or the electricity market or both, and we just don't see PUHCA as an impediment.

There are some good reasons to repeal PUHCA. It chokes off investment in the transmission sector by trapping transmission assets inside outmoded and outdated local vertically-integrated utilities that either cannot or will not invest in transmission. PUHCA also inhibits competition by driving greater regional concentration in the generation sector. Finally, PUHCA also leads to regulatory duplication of effort. The SEC performs functions that the Federal Energy Regulatory Commission and the US Department of Justice are better placed to fulfill.

We do not think PUHCA repeal will have much of an impact in terms of utility consolidations, except perhaps at the margins.

The most interesting question is whether utility mergers are a good idea. How many of these deals are going to take two plus two and create three-and-a-half?

MR. RIGBY: People have argued to us that PUHCA repeal will bring lots of new capital to the industry. Perhaps that's true that it will bring new capital, but this is an industry that has not had much difficulty attracting capital. Almost every week, some utility is issuing a bond, and none of these bonds issues has had a problem attracting investors. Look at how much money the merchant power sector was able to attract a few years ago, not that was not money well spent. There seems to be plenty of money, and the industry has had no trouble attracting it.

Deal Drivers

MR. HAUG: If two big utilities merge, CEOs and CFOs get a lot more money, the regulatory guys have a lot more staff, the accountings have a lot more staff, and all the people in the acquiring company are going to have an incentive to do the deal just from personal and career perspectives. The investment bankers will make huge fees. The process of going through the regulatory approvals will generate lots of fees for people.

I don't want to sound cynical. The / continued page 26

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own land and groundwater must be offset against revenue from sales of his products.

The IRS explained in a ruling in June how to offset the cleanup costs against sales revenue. In each of the cases, the manufacturer was allowed to deduct the full cleanup costs against revenue from sales of product during the year the cleanup occurred. The IRS said it does not matter whether there is still manufacturing at the contaminated site that year if the taxpayer is manufacturing at another site. It also does not matter whether the manufacturer was legally obligated to clean up while the pollution was occurring or that the pollution built up over time. The ruling is Revenue Ruling 2005-42.

Anyone generating electricity is a manufacturer.

It was important that the cleanup merely restored the site rather than improved it. Otherwise, the cleanup costs might have to be added to the "tax basis" in the land and would not be deductible.

A PARTNERSHIP had no cancellation of debt income, but it took the IRS a year and a half to come to that conclusion.

Normally when a borrower is excused from having to repay a debt, he or she must report the principal amount excused as income. Tax lawyers refer to this as "COD," meaning cancellation of debt, income.

A partnership was formed to develop a project. Two partners withdrew before the project was built. Under the terms of the partnership agreement, the partnership had to repay the partners their capital, but not until it could do so comfortably out of operating earnings. Interest accrued on the obligation to repay the capital in the meantime.

The project was never built.

A company that owned 50% of the partnership eventually bought the "debts" for a nominal amount from the two former partners (so that if / continued page 27

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paper that Standard & Poor's did is really good. It points out that you can have a lot of consolidation activity without any underlying substance. It is always hard to argue that having your local utility owned a long way away by people who aren't your neighbors is a good thing, and I don't think it will get any easier. However, there will be huge drivers to get such deals done because the M&A industry and the amount of private capital looking for a home. Merely moving money back and forth may not create synergy, but it creates lots of fees and lots of economic wealth.

MR. REYNOLDS: I don't disagree. I think I tried to say the same thing a little bit more gently. There are differences among the deals that have been announced to date. Over time, there will be companies that will decide to sell certain assets that no longer fit into their revised business plans and who are driven to a merger after concluding that it will improve the balance sheet and credit position.

The fundamental problem with a merger for what I would call the classic regulated entity is regulatory accounting does not reward anyone from a financial standpoint, absent a lot of synergies, and such synergies are very difficult to find.

AUDIENCE MEMBER: We have heard this morning that there are three drivers for utility consolidation. Actually, one was in the newspaper about the Duke-Cinergy deal. It appears that Cinergy has so many coal-fired units that it needs access to the Duke nuclear units in order to meet its pollution control requirements. We heard David Haug's suggestion that the market just throws up deals to do things. And then the suggestion was made t that some CEOs just want to sit atop a larger company. Are there any other drivers for consolidation besides those three?

MR. REYNOLDS: Another possible driver is there are going to be huge capital requirements in certain areas of the country. I would use the Pacific Northwest as an example. One of the reasons that ScottishPower withdrew may be that several billion dollars of capital will have to be invested in additional generating capacity. ScottishPower must not have believed that it could get the return it requires as a public company. Meanwhile, Warren Buffet comes along, and he says, "I have $45 billion parked. I am happy to invest, I am going to be a long-time holder, and I believe that's the type of return I can get." When Buffet can buy at the price he has been offered, he probably has secured himself a reasonably good investment.

Acquisitions of transmission-only utilities may be easier after PUHCA repeal because they are subject solely to federal regulation.

MR. MARTIN: What does Warren Buffett know that ScottishPower did not? How can PacifiCorp be a good investment for him when it was not for ScottishPower?

MR. REYNOLDS: When you buy a regulated entity more cheaply than the original buyer did, you do not have to worry as much about synergies and cost savings in order to get your return. If you can run a pretty good utility, then you can get a regulated return, which is what PacifiCorp is — strictly a regulated entity. Buffet will still have the challenge of regulation in six states and the risk that each state may require a pound of flesh, which is what has tended to happen to PacifiCorp over the years.

MR. RIGBY: One might argue that MidAmerican Energy Holdings and David Sokol are in a better position to deal with the quirks of US regulation than ScottishPower is, since ScottishPower is 6,000 miles away.

MR. REYNOLDS: I think you are pushing it, Peter. I don't know that David Sokol in Omaha is any better able to deal with the Utah, Oregon and other state commissions. However, MidAmerican does not have the same "foreign ownership" taint, which in the West was an issue for ScottishPower.

MR. HOGAN: Just to add to that, as a North American subsidiary of another British utility company, British Gas, I think ScottishPower had some other issues. It is a small player in a rapidly consolidating European market, and the PacifiCorp thing just increasingly looked like it made no sense whatsoever. It was a drag on earnings; it was a drag on future capital commitments, and ScottishPower got huge kudos for dumping it in the European share market.

There are many instances of Europeans acquiring North American subsidiaries and finding — surprise, surprise — that they had to deal with unpredictable state commissions. Centrica has had good success here. Someone made the comment earlier that perhaps one driver for some deals is people want to merge their way out from under state commissions. Perhaps there is something to that.

Because we are rolling up customers, not wires and pipes, we can do so with relative ease. We have other issues about opening markets to real customer choice in, but rolling up customer bases is an easier proposition than what ScottishPower tried to do.

The idea of merging companies for the sake of size invites a backlash from state regulators who fight such mergers for fear that the merged entity will be beyond their control. Maybe the end game is the law of unintended consequences. It is that these entities will become either deliberately or as an unintended consequence unbundled to the point where the piece of the business that does lend itself to economies of scale and to the ability to grow and roll up customers and diversify and multiply services and products is the piece that will eventually be taken out from under state commission control.

MR. MARTIN: Let me suggest another possible driver for deals. The United States is a market in which certain types of projects or assets are rewarded with tax subsidies. Europeans coming into the US cannot compete effectively in this market without a tax base. ScottishPower needed a tax base to get a jump on the wind market.

MR. WENNER: Another type of acquisition or consolidation which may be made a lot easier by PUHCA repeal is for the transmission-only companies — the Trans-Elects of the world — that are constrained today by PUHCA in that they can only control a transmission system in one part of the country. With PUHCA repeal, they will be / continued page 28

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anything was ever paid on them, it would receive the payments). Nothing was expected to be paid.

When a borrower or a related party buys back his own note from a lender at a deep discount, this has the same effect as canceling most of the debt.

However, the IRS said there was no real "debt" in this case. The partnership merely had a contingent obligation to the withdrawing partners to give them a share of any operating cash flow. The ruling is Private Letter Ruling 200523007. The IRS made it public in late June. The IRS agonized about the conclusion: it was a year and a half before the partnership got its ruling.

CIRCULAR 230 has spurred debate about what warnings must be included in tax discussions in offering circulars.

Circular 230 is a set of rules that applies to lawyers and accountants who practice before the IRS. The IRS threatens in the circular — in its most severe sanctions — to disbar entire tax departments in law firms if any lawyers in the firms fail to comply. South Carolina has adopted the same rules as part of its own standards for law practice, and it is moving to disbar 14 tax advisers who violated the terms.

The circular requires that anyone giving a "covered opinion" about a deal must either give a "long form" opinion that recites all the facts, discusses each material tax issue and expresses an opinion not only about each issue but also about the tax treatment of the transaction as a whole. Lawyers complain that clients frequently want quick answers to isolated questions rather than a treatise on the entire deal. The circular requires that any more limited advice given in writing must be accompanied by a warning that there may be other issues that could affect the tax treatment of the transaction that are not addressed and, thus, the client cannot rely on the advice to avoid IRS penalties except / continued page 29

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able to own transmission systems throughout the United States and, unlike utilities in the retail business, they would be subject to exclusive federal regulation by FERC for all of their properties. For that type of company, PUHCA repeal could be a very significant opportunity.

In commodity markets, the greater the degree of concentration, the higher the returns are for market participants.

Lessons from Past Deals

MR. SEIPLE: Over the course of the past year, we conducted detailed interviews with executives at 12 companies that had previously gone through large-scale mergers and acquisitions in the power business. We interviewed them about what they thought they were going to achieve through the merger and then what actually happened after the merger. We were interested in finding out what lessons can be learned from previous rounds of M&A. I could talk for three hours about all the things we learned.

One interesting comment we heard over and over again from all the utilities interviewed was: "We thought our core competency was regulatory management skills. We did not realize that it was incredibly local and only related to our state PUC."

The second thing that was interesting — and I think this applies to the Exelon merger in part — is that a number of utilities have cited a kind of diversification of regulatory risk as justification for mergers. Most people we interviewed said that post merger, they actually found that regulatory risk increased rather than decreased. All of a sudden, the state PUCs in one state were watching what PUCs were doing in every other state and always asking for better deals than what somebody else got in a different state. The merged company no longer had a home state in the sense it did earlier.

There were other interesting findings. In most transactions, costs actually increased rather than decreased after the merger. This was due in part to two factors — lack of experience in integration and underestimation of costs involved. If you look at the mergers three or four years after the transaction closed when the companies actually have their acts together, there are now substantial cost savings coming out of many of these companies. Statistical analyses we did indicated that there are economies of scale in the power business; they are not substantial, but on the order of 10% depending on the size of the companies that merged.

I sense that the industry as a whole has a much more intense focus on the issues of cost reductions, cost efficiency and things of that sort. Another thing we found in the analysis is there is a large unexplained difference in cost performance among individual utilities.

Contrary to some of what has been said today, our study suggested that if one can develop a competency in integration and move one's own company to a point that it is far superior to others in terms of operational performance and then find someone who is willing to sell at the right price, then a merger or acquisition can create value. Few companies are in a position to do this, but it is possible.

There is a direct correlation in commodity businesses between the ownership concentration of the top four companies and return on capital employed. The greater the degree of concentration, the higher the return. This suggests to us that on the unregulated side of the business, consolidation could be healthy. One doesn't have to look to do things on a national scale; increasing concentration in a regional market will do. The biggest challenge is regulatory oversight and whether the types of transactions that would actually create consolidation that was meaningful from a value perspective would be allowed by the regulators.

MR. HOGAN: If I could reinforce one thing Chris Seiple just said, one thing we have noticed, and it is a very mundane aspect of this, is the immobility for many regulated utilities of their regulatory expertise. Consider something as mundane as billing, collection and credit. They are one of the strongest competitive advantages one can have in building a customer base in multiple jurisdictions.

PSE&G left ERCOT and left a lot of blood on the table simply because — and PSE&G is a darned good New Jersey utility — but they left a lot of blood on the table because they could never get billing, collection and credit right under the Texas regulations. These are not easily transportable skills, and there are very few companies — and I would humbly maintain that we are probably one of them because of our experience with deregulation in Britain over the past 15 years — that have developed or will develop a platform that allows them to administer those very mundane aspects of operating in multiple regulatory environments.

MR. GOLDEN: Steve, do you have any thoughts on that, the issue of the economics of the day-to-day operational part of the business that Mike Hogan mentioned?

MR. REYNOLDS: Mike is absolutely right. Often, to get the synergy you need to overcome any premium that had to be paid for the business, you must integrate systems. Most of the systems in what I characterize as the vulcanized integrated utility systems that exist today are not scaleable. You cannot just merge two companies. You have to develop brand new systems rather than continue to use what one or the other incumbents has. That comes at a cost. Ultimately it may lead to efficiency because something new will be done that will probably improve things, but it may take five years to see any benefit.

We operate a fairly inefficient utility system in the United States. We have some giant utilities and then some really small companies, many of which are anachronisms that would have disappeared long ago but for local politics and local boards.

There should be a lot more consolidation. It can be expected. Virtually every large company today has a family tree of about 50 to 100 companies that at one time were consolidated into the parent entity that */ continued page 30*

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on the limited issues the lawyer addressed.

This is why emails from many law firms now have boilerplate warnings at the bottom.

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 the fact and warn that it cannot be used to avoid IRS penalties on positions the taxpayer is taking with such weak support.

Large corporate transactions often involve preparation of an information memorandum or offering circular that includes a discussion about the potential tax consequences to companies that invest or lend money.

In July, two lawyers with prominent New York firms discussed what tax warnings are required in such tax discussions with Cono Namorato, the head of the IRS office that administers Circular 230, and shared a letter they sent Namorato summarizing their conclusions with other large law firms.

The letter says that warnings are required in the tax disclosure sections of prospectuses that will not be filed with the US Securities and Exchange Commission, but the warnings are not required in the following other circumstances. They are not required in prospectuses that *are* filed with the SEC. They are not required in opinion letters that counsel to the issuer or underwriter gives expressing agreement with the discussion in the information memorandum or offering circular, including an opinion that the tax disclosure in the offering circular is a "fair and accurate summary." (This assumes the warning */ continued page 31*

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exists today. It is a natural thing for consolidation to occur. We have not had the economies of scale in the last 10 to 15 years to encourage it. I do not know if they will be there in the future, but I think as fuel costs in particular continue to skyrocket, everyone will be looking for ways to gain a cost advantage.

MR. MARTIN: I have a question for Peter Rigby. You listed at the start the utility mergers that are in the market at the moment, and it sounded like in every one of those cases, other than the MidAmerican-PacifiCorp transaction, the utilities that were merging are being downgraded or threatened with downgrades. Is there any circumstance where people will do better from a credit rating standpoint by merging?

MR. RIGBY: There are different ways to measure that. If you look at the marginal effect on the rated debt, certainly where a large utility buys a very much smaller one with a lower rating would be a case where the combined entity gains by merging. More than likely, what will happen is that the smaller one will see its debt get wrapped up into the larger entity because the difference in sizes is so big that the rating of the larger entity is unaffected. Such a merger helps the target utility.

There are large unexplained differences in cost performance among individual utilities.

Perhaps also if you have two utilities that are geographically contiguous, and they are about the same size, there are inefficiencies that can be squeezed out. That said, our experience is it is hard to realize such cost savings at least in the near term.

A friend of mine at McKinsey was sharing his thoughts about utility mergers. He thinks there are great inefficiencies to be wrung out of operations and maintenance, which is a big part of the cost to operate a utility. But the question to be asked is, "Why can't a utility do that without going through a merger?" We have seen some of those kinds of efficiencies realized in generation when utilities sold off their power plants to the unregulated sector. The point is a merger may not be the best route to efficiency gains. ◎

New Grants and Loan Guarantees in the Energy Bill

by Luis Torres, in Washington

The new energy bill that President Bush signed on August 8 offers project developers a number of interesting financing and funding opportunities such as loan guarantees, production incentives, grants and other forms of financial support.

There are subsidies for clean coal and coal gasification projects, new hydroelectric facilities added to existing dams, ethanol projects that use cellulosic biomass or sugar — rather than corn — as the feedstock, biofuels projects and integrated-gasification combined-cycle power plants. Some of the subsidies will help pay the capital cost of the projects. Others are operating cost subsidies.

The energy bill merely "authorizes" the US Department of Energy to help private developers pay the cost of these types of projects. There is a two-step process in Congress before a government agency can actually spend money. First, the spending must be "authorized" as has been done in the energy bill. Second, the money must then be formally "appropriated" in a later appropriations bill. The energy bill is only the first step of the process.

This does not necessarily apply to the loan guarantees. Although the government might end up having to spend money on account of a guarantee, the Department of Energy can start making the loan guarantees described in the energy bill without waiting for an appropriation if the borrower whose loan is guaranteed pays the government for the estimated losses the government may incur as a consequence of a loan default.

Ethanol

The energy bill authorizes the US Department of Energy to guarantee repayment of loans to build new plants for making ethanol and other byproducts with commercial potential from municipal solid waste or cellulosic biomass. Ethanol is a fuel that can be used directly in vehicles or blended with gasoline. The "municipal solid waste" whose use the loan guarantees are supposed to encourage is refuse from waste treatment and waste supply plants and other solid, liquid or gaseous material resulting from industrial, commercial, mining and agricultural activities. It does not include domestic sewage refuse. "Cellulosic biomass" is any organic matter available on a renewable basis, including, in addition to municipal solid waste, trees, wood and wood residues, plants, grasses, agricultural residues, other fibers and animal waste.

The federal government will guarantee up to 80% of the cost of each project but, there is no limit on the amount of debt the government is authorized to guarantee per project or under the entire program..

Each applicant will have to show that his or her project cannot be financed on reasonable terms without the guarantee, that there is reasonable assurance of repayment — collateral valued for at least 20% of the amount of the loan is required — and that the loan bears a reasonable rate of interest. The loan cannot have a term longer than 20 years.

In addition to the construction financing program just described, the energy bill also directs the Energy Department specifically to guarantee up to four demonstration projects to show the commercial viability of producing ethanol from cellulosic biomass or sucrose. One of the four projects must use cereal straw and another one must use municipal solid waste as / continued page 32

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either is already in the offering circular or is not required.)

They are also not required in so-called 10b-5 letters where the law firm acting for the issuer or investment bank distributing the securities says that it is not aware of any false or misleading statements or omissions in the offering materials.

MINOR MEMOS: The owners of the Trans-Alaska Pipeline System largely won a dispute with three Alaska municipalities over what value should be assigned to the pipeline for property tax purposes. The owners claimed the value is only $1.5 billion based on a discounted cash flow analysis. They looked at the value of the oil flowing through the pipeline. The municipalities claimed the value is $8.9 to $13.9 billion. The Alaska state assessment review board assigned a value of $3 billion based on the depreciated replacement cost to rebuild the pipeline. The municipalities are expected to appeal . . . . Twenty-two power companies lost a challenge in court in June to supplemental taxes that Pennsylvania ordered them to pay on their real estate. Utilities are exempted from local property taxes in Pennsylvania. Rather, the *state* collects an equivalent amount and distributes it to the counties. There is a mismatch between what the state collects and what it distributes to localities. Taxes are collected on the net book value of real property, but the proceeds are distributed based on local assessed value. The state has been distributing more since 1997 than it collects. The gap was $77 million in 1997. It levies a supplemental tax to plug the gap. Twenty-two power companies challenged the supplemental assessment for 1997, but lost in a decision released in late June. The case is *Safe Harbor Water Power Corp. v. Fajt.*

— contributed by Keith Martin and Jana Dimitrova in Washington.

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feedstock. Each project should be able to produce at least 30 million gallons of ethanol each year. Each such guarantee cannot exceed $250 million per project and can cover up to 80% of the estimated cost of the project. The remaining 20% of project cost must be covered by equity commitments.

The energy bill gives the Department of Energy separate authority to provide operating subsidies — called "production incentives" — to companies that produce cellulosic biofuels. "Cellulosic biofuels" are fuels that are produced from cellulosic feedstock such as residue from trees and plants, grass or industrial waste. A cellulosic biofuels producer qualifies for the incentives as long as he or she is located in the United States, meets all permitting requirements and satisfies certain financial criteria to be established by the Department of Energy.

The energy bill is a cornucopia of new grants, loan guarantees and other forms of financial assistance for different kinds of projects.

The production incentives are expected initially to be an amount per gallon of cellulosic biofuels, with the amount still to be determined. They will then shift to a reverse auction system. The first reverse auction will be held one year after the first 100 million gallons of cellulosic biofuels have been produced in the United States, but no later August 8, 2008. A reverse auction works as follows. Bids are solicited from producers for the amount of production incentive they require on a per gallon basis in order to produce an estimated annual output in gallons. The bid for the lowest level of production incentives on a per-gallon basis will be the first to receive an award; the second lowest bid will receive another award and so on. Each recipient will receive the performance incentive requested in the auction for each gallon produced and sold by a project during the first six years of operation.

The awards will be limited as follows: not more than 25% of the funds committed within each reverse auction can go to a single project, not more than $100 million may be spent on production incentives in any one year and not more than $1 billion may be spent over the lifetime of the program (which has not yet been determined).

Finally, the bill also authorizes loan guarantees of up to $50 million per project for financing up to 80% of the estimated cost of projects to produce ethanol from sugar cane, bagasse and other sugar cane byproducts.

Other Renewables

Biofuel and hydroelectric projects also qualify potentially for federal funds.

The federal government will provide grants for integrated biorefinery demonstration projects to be selected by the Department of Energy. Total grants under the program are limited to the following amounts: $100 million in 2007, $125 million in 2008 and $150 million in 2009.

The department is supposed to look for projects that use a wide variety of feedstocks and apply biomass technologies for a variety of uses, like making liquid transportation fuels, high-value biobased chemicals and substitutes for petroleum-based feedstocks. Projects selected should be able to operate without direct financial assistance after construction and be of a type that can be easily replicated. These are demonstration grants and not operating subsidies.

Hydroelectric projects that are put into service in the next 10 years might qualify also for production incentive payments from the Department of Energy.

To qualify, the new plant must generate electricity for sale and be an addition to an existing dam or conduit. The dam or conduit must not require any enlargement of impoundment or diversion structures to install the new turbines. The amount of the payment is 1.8¢ per kilowatt hour (adjusted for inflation beginning in 2006). The payments run 10 years after a project is put into service, but cannot exceed $750,000 per project per calendar year.

Fossil Fuels

The energy bill authorizes a series of grants, loan guarantees and other assistance for projects that use fossil fuel.

The United States has more than 500 billion tons of coal reserves out of which 275 billion tons are considered economically recoverable. These reserves are sufficient to satisfy US coal demand for the next 200 years at current levels of consumption.

The bill gives the Department of Energy authority to make grants to coal gasification projects. Total grants cannot exceed $200 million a year over the period 2006 through 2014. The bill gives examples of the types of coal gasification projects that Congress has in mind. They are combined cycle, fuel cells and turbine combined cycle, co-production, hybrid gasification and combustion projects. The Energy Department will set minimum emissions and thermal efficiency levels that projects will have to meet in order to qualify for funding.

There is no set minimum or maximum dollar amount for each grant, but the federal government will fund only up to 50% of the cost of a project. The rest must come from non-federal sources unless the Energy Department determines that the project will only get built, given the technological risks, with a larger share of federal funding. In general, the department will be looking for projects that reduce gasification costs, improve the competitiveness of coal vis-à-vis other fuels, and demonstrate methods and equipment that could be applied to at least 25% of US power plants. The bill also authorizes loan guarantees for at least five petroleum coke gasification projects. No other details are given for this program.

Assuming money is appropriated, the bill directs the Department of Energy to make a grant for a coal integrated gasification demonstration project in a western state that is 4,000 feet above sea level. The project must show that it is able to use a variety of coals mined in the western United States and with different energy contents (from 9,000 to 13,000 Btus). A separate "rifle shot" provision in the bill directs the department to provide loan guarantees for an integrated-gasification combined-cycle, or IGCC, power project with a capacity of at least 400 megawatts that will produce power at competitive rates in a deregulated market.

The bill also includes "rifle shot" loan guarantees for a coal-fired power plant to be built in the upper Great Plains with a heat rate of less than 7,000 Btus/lb and that uses advanced integrated-gasification combined-cycle technology. The project that Congress had in mind will combine production with wind and other renewables, minimize or sequester emissions of carbon dioxide and provide hydrogen for nearby fuel cell demonstrations. It is expected to produce at least 200 megawatts of electricity at competitive rates and meet the same technical criteria as for clean coal power projects.

Finally, the bill authorizes the Department of Energy to pay up to 50% of the cost of clean coal projects. The department is authorized to make grants or loans or enter into cooperative agreements. It will come up with criteria to qualify. Priority will be given to projects that use equipment and processes that have been developed and applied but are not yet cost competitive.

Technological Innovation

The bill creates another new loan guarantee program to help finance energy projects that avoid, reduce or sequester pollutants and gases emitted by power plants and other sources by using innovative technology. "Sequestration" is the process of capturing and permanently isolating gases and other emissions that otherwise would be released into the atmosphere. Sequestration projects that use currently-available technology are expensive. The goal of the program is to encourage development of new or significantly improved technology that will bring down the cost.

Congress identified 10 categories of projects across a wide ambit of energy sources and carriers that are eligible for the loan guarantees: renewables, fossil fuels, nuclear energy, hydrogen fuel cell technologies, carbon capture and sequestration, efficient electrical and end-use energy technologies, facilities for fuel efficient vehicles, pollution control and oil refinery projects. Gasification projects are also mentioned as potential beneficiaries. Four types of gasification projects qualify: integrated combined-cycle projects, industrial gasification projects that gasify coal, biomass or petroleum coke to produce */ continued page 34*

Energy Bill

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synthesis gas for use as fuel or feedstock, petroleum coke gasification projects and coal-to-oil liquefaction projects.

The federal government will guarantee up to 80% of the project cost. There is no limit on the individual or total amounts that will be guaranteed under this program; however, the term of each loan being guaranteed cannot exceed the lesser of 30 years or 90% of the projected useful life of the physical assets being financed.

How Will Guarantees Work?

The new federal loan guarantee programs will have the same structure as private sector guarantees: the federal government, acting through the Department of Energy, will guarantee payment of certain debt obligations owed by a borrower to a lender. The guarantee will be backed by the full faith and credit of the US government. This ought to let the project borrow at a government borrowing rate.

Many guarantees are issued by parent companies for the debt of their subsidiaries (the so-called downstream guarantees) or by affiliates of a borrower (cross-stream guarantees). When the guarantee is issued by a party unrelated to the borrower, such as in the case of a federal loan guarantee, the guarantor usually requests assurance of repayment of the underlying loan. Many times reasonable assurance of repayment can be obtained from a borrower's income stream as well as from the collateral pledged as security for the loan. As with all guarantees, if the borrower fails to pay the debt when due, the lender can demand payment from the guarantor, in this case the federal government. After paying on the debt, the federal government "steps into the shoes" of the lender and has the right, among other things, to recover from the borrower.

It is common in federal loan guarantees to request the borrower to pay a fee in consideration for the government's guarantee commitment and also to cover its administrative expenses. Also, in many cases the terms and conditions of the underlying loan agreements cannot be changed without the consent of the federal government. All these rights and duties will be negotiated in the guarantee agreement. ◎

IRS Addresses Interconnection Payments

by Keith Martin, in Washington

The Internal Revenue released new guidelines in July that should let some independent power companies get back "tax grossups" that utilities required them to pay in connection with "network upgrades."

The guidelines also require that certain language be included in interconnection agreements if independent power companies want to avoid paying a tax grossup on the cost of future network upgrades.

"Network upgrades" are improvements that a utility makes to its grid when an independent power company wants to connect a new power plant to the grid. The improvements are needed to accommodate the electricity from the new plant.

Background

Connecting a new power plant to the grid involves construction of a radial line and substation improvements, and it might also require upgrades to the grid itself. Utilities usually do this work and charge the independent power company for the cost. It is current Federal Energy Regulatory Commission policy that the utility can charge the independent power producer for the cost of the "direct" intertie to link his or her power plant to the grid, but the cost of any network upgrades must be collected from all users of the grid through the tariffs the utility charges its customers for wheeling electricity.

This puts utilities in a bind. The grid upgrades must be made immediately, and it takes time to collect the cost from all grid users in rates. Therefore, FERC lets utilities require independent power producers to *advance* the funds for the grid upgrades. The advances must be repaid over time with interest. FERC released a model interconnection agreement in 2003 and revised it in 2004. Under the model agreement, such advances must be repaid within 20 years. The advances may be repaid in cash or in the form of "transmission credits," meaning credits that the independent power company can use to offset any future charges it incurs with the utility for wheeling electricity from its plant.

Ordinarily whenever a utility or other corporation receives money from someone else, it must report the amount as income. This normally would apply to the value of any intertie paid for by an independent power producer.

However, the IRS issued two notices in 1988 and 2001 in which it said utilities ordinarily do not have to report interconnection payments from independent generators as income. This is true only in cases where the independent generator is not a customer of the utility. Therefore, independent power companies are careful to sell their electricity to someone else before it reaches the utility grid. That someone else will be a customer of the utility for wheeling the electricity across the grid.

In cases where the independent generator is a customer, then the utility usually insists that a "tax grossup" be paid — on top of the interconnection costs — to compensate the utility for the taxes it must pay. Tax grossups can make interconnection 25% to 40% more expensive.

A handful of utilities have taken the position that amounts independent power companies advance for network upgrades must be reported as income — at least until the IRS says otherwise.

Independent generators insist that the advances are loans. No corporation reports borrowed money as income. They are also startled by the position these utilities take that direct intertie payments the utilities get to keep do not have to be reported as income, but while amounts the utility must give back for network upgrades must be reported.

The IRS balked at addressing the tax treatment of the advances in private letter rulings after receiving eight requests for such rulings quickly from utilities. It was afraid it would be overwhelmed with requests. It promised the industry instead in 2003 that it would issue general guidance on which all utilities can rely. That guidance is what the agency issued in July.

New Rules

The guidelines are in Revenue Procedure 2005-13.

The revenue procedure creates two "safe harbors" under which utilities will not have to report payments from independent generators to cover the cost of network upgrades as income.

A "safe harbor" is a set of facts the IRS has analyzed carefully.

One safe harbor covers interconnection agreements signed on or after December 20, 2004.

Payments from an independent power producer for network upgrades under such an agreement do not have to be reported by a utility as income if the utility is required by the interconnection agreement to return the network upgrade payments to the generator within 20 years with interest.

The interconnection agreement must require that the refunds be made in cash.

It must require that the interest be calculated at the FERC interest rate in Order No. 2003-B. That order refers to Federal Energy Regulatory Commission regulations that explain interest should be paid at the average prime rate for each quarter, calculated to the nearest one hundredth of one percent, as reported in the *Federal Reserve Bulletin* or the "Selected Interest Rates" (Statistical Release G. 13) published by the Federal Reserve Board. The 20-year period within which the utility must be required to reimburse the generator for the full amount of the network upgrade payments runs from the "commercial operation date," defined as the date the power plant "commences commercial operation . . . after trial operation . . . has been completed and confirmed in writing as / continued page 36

New IRS guidelines should let some independent power companies get back "tax grossups" they paid in connection with upgrades to the utility grid.

Interconnection Payments

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prescribed by FERC." The model interconnection agreement that FERC adopted in March 2004 has a form of letter that independent generators are supposed to send utilities announcing when their power plants have been put into commercial operation.

The other safe harbor covers older interconnection agreements.

Payments from a generator for network upgrades under such older agreements do not have to be reported by a utility as income as long as the agreement requires the utility to return the full amount of the payments "either in cash, assignable transmission credits, or a combination of both." The utility must also reasonably expect on July 11, 2005 that full reimbursement will be made within 20 years. There is no need for the utility to return the money with interest. The safe harbor for older agreements appears to have been modeled on the standard interconnection agreement that Entergy was using at the time.

The guidelines will require a change in how future interconnection agreements are drafted.

The IRS said that it is a "change in accounting method" for a utility to alter the way it has been reporting network upgrade payments from independent generators, even if the utility is merely following the new guidelines for how to treat such payments. A taxpayer must have approval from the IRS before it can change its accounting method. However, the IRS said approval will be given automatically to any utility that files a form with its tax return. A utility seeking permission for such a change for a tax year ending on or after July 11, 2005 must attach an IRS Form 3115. Utilities will also be given permission automatically to change their treatment of network upgrade payments for all past tax years that remain open to audit. In such cases, the Form 3115 would have to be attached to an amended return.

Amended returns for open tax years must be filed no later than December 31 this year.

Comments

Independent generators may not have seen the last of the controversy in this area.

The new guidelines fail to address all the possible fact patterns.

The model interconnection agreement that many utilities are using talks about returning advances for network upgrades in cash or in transmission credits, at the option of the independent generator. The only fact pattern the IRS addressed in the guidelines — at least for newer agreements meaning interconnection agreements signed since December 20, 2004 — is the case where the agreement talks about a refund solely in cash.

Also, when FERC released its model agreement, it said that regional transmission organizations and independent system operators — like the PJM region in the mid-Atlantic states — are free to adopt their own pricing policies for network upgrades. The guidelines do not address these other cases.

It is not clear whether the IRS will reopen the window for private letter ruling requests to address the other cases.

A "safe harbor" is usually a set of facts that he IRS has taken time to analyze carefully a reach a conclusion. It necessarily does not suggest the IRS has problems with other fact patterns.

Two trade associations — the Electric Power Supply Association and the Edison Electric Institute — have asked senior IRS and Treasury officials for a meeting to discuss the situation. The meeting is expected in late August or September.

In the meantime, the IRS has changed its policy for private letter rulings on electric interties. It will no longer rule in cases where the utility had to take a position on a filed tax return about how to report interconnection payments under an agreement by the time the private letter ruling request relating to that agreement is filed. This new rulings policy is also on the agenda for the meeting with senior IRS and Treasury officials.

Independent generators are exploring other options in the meantime. They include having a utility that reported payments as income test whether the payments had to be reported by filing a refund claim. The other is having the utility apply for a "pre-filing agreement." The IRS has a program where large companies that are planning to file tax returns in the future can ask the IRS whether it agrees with a position the company plans to take on the return. Interconnection payments are often made over several years. Even if a tax return has already been filed for the year the payments started, there are still additional payments to report — or not to report — on future tax returns. ◎

FERC Rebuffs Wind Developers

by Adam Wenner, in Washington

The tensions between federal and state energy regulation were dramatically highlighted by a Federal Energy Regulatory Commission order in July that its transmission pricing policies require wind developers to pay the cost of two new transmission lines to bring electricity from the Tehachapi area to the Southern California Edison grid.

Southern California Edison had asked FERC to let it "roll in" the costs of the lines so that they would be borne by all users of the grid as part of the rates the utility charges transmission customers. FERC regulates rates for transmission on the interstate grid. The two transmission lines in question are a new 26.1-mile 500-kilovolt line and a separate 9.4-mile 220-kilovolt line. They are part of the Antelope Transmission Project, which is intended to tap 4,000 megawatts of potential wind generation in Tehachapi, California,

The Tehachapi area is near Edwards Air Force base and is California's largest wind resource area. Developers have already applied to connect 1,100 megawatts of new wind farms in the Tehachapi area to the grid. That is good news for California, which in 2002 enacted legislation requiring California utilities to supply 20% of their power from renewable fuels by 2017; Governor Schwarzenegger and the California Public Utilities Commission later moved up the date to 2010.

While there is plenty of viable wind in Tehachapi, the existing transmission lines lack the capacity to move the power to nearby Los Angeles or other parts of the state.

The California Public Utilities Commission granted "certificates of convenience and necessity" for transmission line construction after concluding that new lines are needed in the Tehachapi area. Edison, the utility that serves the Tehachapi region, then asked the CPUC for permission to build the Tehachapi lines, as well as two other 500-kv lines that the utility calls the "Antelope project." Unlike the Tehachapi lines, the two other Antelope lines are not "radial" lines used solely to deliver power from a generator to the grid. Instead, they are part of a "looped" transmission system where energy flows in both directions. They will be used to serve load and increase transfer capacity from existing generators, as well as facilitate imports into the grid from Tehachapi.

Competing Policies

FERC policy on "network upgrades" — or improvements that must be made to the grid to accommodate additional electricity — has been favorable to generators. A generator must pay the costs of the "direct intertie" that connects his or her plant to the grid, but utilities are supposed to collect the costs of network upgrades in the transmission rates charged all grid users, even if the upgrades are needed only to accommodate power from the generator.

This cost allocation approach, called "rolled-in pricing," has historically been used by FERC because it views the transmission grid as an integrated system, rather than a collection of discrete wires, that functions as a network to permit multi-directional power flows to occur and thereby to facilitate transactions throughout the grid to occur. A corollary of FERC's policy is that it fights against utilities' attempts to include the costs of facilities that are used for other functions, such as generation, out of the transmission rate base, so as not to force trans- */ continued page 38*

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mission customers to subsidize individual generators (including the utility's own generation) through transmission charges.

The costs of radial lines, that do not function as part of an integrated system, but instead serve only one or an identifiable universe of persons, are not rolled in along with the rest of the costs of the transmission system. Instead, these costs are "directly assigned" to the generator connecting a plant to the grid. FERC's pricing policies follow this dichotomy, dividing the universe transmission facilities into "interconnection facilities," which are "sole use" facilities "necessary to . . . interconnect the Generating Facility to the . . . Transmission System," and network upgrades, which are improvements to the transmission grid necessary to accommodate the import of power from a generator.

The California legislature apparently recognized a problem with the FERC approach. The costs of a transmission line used solely to transmit power from new wind projects to the grid could be allocated to the wind developers, thereby threatening the viability of projects needed to satisfy the state's renewable portfolio standard requirements. Therefore, the legislature directed the CPUC to require utilities to which renewable power projects will be connected to try to recover the interconnection costs through general transmission rates, at least in cases where the CPUC concludes a transmission line provides broad benefits to the entire grid and is needed to reach the goals the state has set for itself in the renewable portfolio standard. The CPUC was also directed to defend these positions before FERC, and to allow recovery in a utility's retail rates of any costs for new transmission facilities that FERC does not allow to be folded into the rates for transmission.

The plan to fold the cost of the Tehachapi lines into general transmission rates ran into opposition from several California wholesale power users. The Transmission Agency of Northern California, the California Department of Water Resources and several California cities with municipal utilities opposed Edison's proposal. They argued that the plan would result in "distorted generation siting policies," since generators using the trunkline will be able to locate anywhere "regardless of the costs of needed transmission, because such costs will be borne by users of the entire grid, rather than load that is served by the generation."

The Arguments

Edison asked FERC to create an exception to its policy of assigning the costs of "sole use" interconnection facilities to generators. The exception would apply to high-voltage trunklines that will be used to connect large concentrations of renewable power plants in a limited geographic area in a state with a renewable portfolio standard. The state commission or "independent system operator" or "regional transmission organization" that operates the grid must have determined that the new transmission lines or upgrades are necessary to meet the state's policy objectives. Both the CPUC and the California Energy Commission supported the Edison position.

Edison argued that renewable energy developers have no choice except to locate their projects where the resource is found and do not have the same flexibility as other generators about location.

Edison also asked FERC to let it fold the costs of the Antelope project into its transmission rates, whether or not the full increment of forecasted wind generation used to justify the other upgrades actually develops. It is possible

FERC said project developers must pay the cost of trunklines that carry electricity from areas served by high concentrations of wind farms.

that the anticipated demand will not materialize, and then Edison would have installed transmission facilities with more capacity than is needed. In that scenario, under FERC's traditional utility ratemaking policies, utilities may recover only 50% of the costs of equipment that is abandoned or cancelled. Edison argued this policy is an obstacle to investing in the Tehachapi trunkline because it does not have signed interconnection agreements yet with developers that would subscribe to all of the available capacity.

FERC rejected the Edison proposal on July 1. It declined Edison's invitation to create a third category of transmission facilities — new high voltage trunk transmission lines necessary to interconnect large concentrations of potential renewable resources located at a reasonable distance from the existing grid. Instead, FERC stuck to its "fish or fowl" world view, holding that since the Tehachapi line would be a "sole use" facility that will not operate in parallel with existing transmission facilities, it is not a network upgrade and, therefore, is not eligible for rolled in rate treatment.

California has found a way around the FERC decision, but wind developers in other states may not be as fortunate.

Analysis

It appears that FERC was swayed by the argument that since the Tehachapi line would function as a line for connecting power plants to the grid, shifting its costs to all users of the transmission grid would be inconsistent with the principle of functional separation of transmission from generation, which is at the core of FERC's open-access, pro-competition paradigm for the utility industry. If generator A who is trying to compete in, for example, the Oregon market, must bear the costs of wind generation in Tehachapi, while generator B, a competitor located in Oregon, does not, improper price signals can occur. Moreover, if FERC were to tailor its transmission pricing policies to favor development of whatever generation that state favors, then there would no longer be a national policy on transmission pricing. The interstate transmission system could become weighed down with the equivalent of toll booths at every state line.

However, FERC could have established a policy that applied to California utilities but not to those in other states. FERC distinguishes in Order No. 2003, which establishes uniform requirements for utilities to interconnect with generators, between utilities where an independent grid operator — for example, an RTO or ISO — has operational control of the grid, and utilities that operate their own grids. Independent grid operators are allowed to deviate from the standard interconnection pricing policies "to meet their regional needs."

On the same day that FERC turned down the Edison proposal, it determined in another case that the governing board of the California ISO now satisfies the independence requirement. As a consequence, FERC could have evaluated Edison's request under that more flexible standard. Had it done so, instead of mechanically applying its sole-use-facilities-are-not-rolled-in approach, FERC could have acknowledged that California has unique opportunities to satisfy the laudable policy goals it has established, and that since the development of renewable resources is a statewide goal, it is reasonable for the costs of expanding the grid to permit resource development to be shared by all users of the California grid. Further, FERC could have recognized the fact that in many instances, the transmission "network" includes transmission lines used primarily, if not exclusively, to supply power from generating plants that were previously owned by California utilities, as well as transmission lines from the nuclear and hydroelectric plants that California utilities continue to own and operate.

Somewhat inconsistently, FERC granted Edison's request that it be allowed to recover 100% of the costs of the non-sole use portions of the Antelope

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project, even if these facilities are abandoned or cancelled. FERC said that Edison is carrying out an order from the CPUC rather than following a course of action developed by company management and that Edison faces greater-than-normal risks because its ability to use the transmission lines depends on decisions by wind developers. FERC could have used this same rationale to roll in the costs of the Tehachapi transmission line.

The outgoing FERC chairman, Pat Wood, dissented from the commission decision on the Tehachapi lines. He argued that trunkline facilities are distinguishable from sole-use lines because they serve multiple generation developers and their multiple customers, and they provide access to significant and diverse supplies of energy that provide benefits to all users of the grid.

The wind developers in this case will do okay. California enacted a backup plan to let Edison fold costs of the Tehachapi lines into retail rates if FERC refused to let them be included in transmission rates. Developers in other states may not be as fortunate.

How Pollution Control Will Reshape the US Market

The US government is moving to reduce pollution from power plants. New rules announced by the US Environmental Protection Agency in the past year will require power companies to spend billions of dollars on new pollution control equipment within the next five to 10 years. Power companies are being urged by pension funds and other shareholders holding large blocks of stock to take into account the possible costs to comply in their financial reports.

A panel at the Chadbourne project finance conference in late June discussed what participants in the domestic power sector should know about the looming costs and what bets they are making by investing. The speakers are Dr. Terry Surles, who holds a Ph.D. in chemistry and is vice president for the environmental sector at the Electric Power Research Institute, Leonard Hochschild, a commodity trader who is director of the San Francisco office of Evolution Markets LLC, a brokerage house that trades in renewable energy credits and in the national and regional air emissions markets, Michael King, an economist who is senior vice president of NERA Economic Consulting, and Roy Belden, an environmental lawyer in the New York office of Chadbourne. The moderator is Keith Martin.

MR. MARTIN: There are four main pollutants that come out of power plants: sulfur dioxide, nitrogen oxide, mercury and carbon dioxide. The Bush administration has been clamping down on three of the four and, Roy Belden, perhaps you can explain briefly what has happened in the last year to crack down on three of the four, and on which three?

MR. BELDEN: The US Environmental Protection Agency issued a "clean air mercury rule" in May that sets a two-phase target for the reduction of mercury from coal-fired power plants. The first phase starts in 2010, and the second phase begins in 2015. By 2015, you will have had about a 70% reduction in mercury from current levels. Current levels of mercury emissions are around 48 tons a year from US power plants, and the reductions will get down to a 15-ton level.

The second recent action is the "clean air interstate rule" that places limits on nitrogen oxide and sulfur dioxide from power plants and other industrial plants in the 28 eastern states. The rule builds on an existing nitrogen oxide reduction program that affects about 21 states. The first phase of NO_X reductions under the clean air interstate rule will start in 2009, and the second phase will start in 2015. The first phase of sulfur dioxide reductions starts in 2010, and the second phase begins in 2015. Ultimately, you will end up with about a 60% reduction in NO_X emissions and about a 75% reduction in SO_2 emissions from 2003 baseline levels in the 28 states.

Significant Reductions?

MR. MARTIN: George Bush is viewed by many people as not being terribly interested in dealing with pollution, yet these seem like significant reductions. I wrote down a 70% reduction in mercury, 60% in NO_X, and 75% for sulfur dioxide. Terry Surles, will these new rules will require significant reductions in power plant emissions?

DR. SURLES: A lot of what has been proposed has been in motion, in one form or another, for a number of years and, while these are significant reductions — make no mistake of that — there will not be a real push by the Bush administration to do much more. So, I would not really characterize this as a crack-down.

MR. MARTIN: So you don't view Bush as really cracking down significantly on pollution?

DR. SURLES: There will be continued pressure to reduce the amounts of some of these emissions further. I think we have seen everything taken care of for the time being, but over the coming years one should expect a further racheting down.

MR. MARTIN: Mike King, will what has been done so far cause significant pain for US power companies?

MR. KING: I think there is an opportunity to make money, now that we at least know what the ground rules are with the release of the clean air interstate rule and the mercury rule. I think the Bush administration has been both business friendly and environmentally astute. By that, I mean the administration realizes that the biggest impediment to installing pollution controls is uncertainty. Now that it has established the rules of the game, it is getting out of the way and letting industry decide how best to comply. I think it is really a fantastic move by the Bush administration. Now if the administration can get rid of the litigation hammer that it has been holding over utilities in "new source review" cases, which only introduces additional uncertainty, I think you would see environmental improvements start to be made by US companies.

MR. MARTIN: Back up one step. You said that this is a good move by the Bush administration because it introduces more certainty. Do power companies have the certainty they need now to know what pollution controls to install?

MR. KING: Perhaps. The big uncertainty that remains is what will happen with carbon dioxide in the United States. Resolution of some of the rules of the game is causing people to start thinking about investing substantial sums in pollution control, but I go back to the settlements in the new source review cases.

MR. MARTIN: Could you explain what that is?

MR. KING: The new source review program was instituted in 1974 and then amended in 1977 through an act of Congress, but the Clinton administration in 1997 brought a series of lawsuits against power companies, primarily in the Midwest. Some of the defendants are independent power producers who bought generating assets from utilities, and the government alleges that, back as far as 30 years ago, the maintenance activities that they had undertaken at their power plants were really not maintenance but rather were major modifications of the plants as defined in the Clean Air Act.

The United States has ordered roughly a 70% reduction in three pollutants from power plants within approximately the next 10 years.

MR. MARTIN: So people were rebuilding their power plants, and they should have gone into the federal government for a permit before undertaking such improvements?

MR. KING: That is what is at the core of many of these cases. They are huge cases in which power companies are facing billions of dollars of exposure if the government prevails, because they will have to expend huge amounts of capital and possibly pay civil fines that are on the order of millions of dollars, depending on how you think the statute of limitations applies.

American Electric Power is facing the largest suit; it goes to trial in about two-and-a-half weeks, and who knows what the full liability is that AEP is facing, but it is something on the order of $7 to $10 billion.

My point is the clean air interstate rule has provided some needed certainty. Thus, for example, Illinois Power, which was awaiting a ruling from a / continued page 42

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federal district court in its own new source review case, saw that the economics are now well enough established in the market place, and that the regulatory framework, at least as it relates to NO_X, SO_2, and mercury is now well enough established, that Illinois Power could choose to settle with the government. It settled for about a billion dollars, but the billion dollars will be spent on installing scrubbers that the utility can see it will have to install anyway as a result of the new regulations.

Giving more regulatory certainty allows the government to get out of the way and let utilities figure out what to do. No one wants to strand an investment that he or she might make in pollution control because there is still a regulatory process underway that could alter the equation.

Enough Certainty?

MR. MARTIN: Terry Surles, let me come back to you. Is there enough certainty now for utilities to know what to do?

DR. SURLES: There is more certainty in the current regulations, but one of the issues to consider is a potentially carbon-constrained world because more power plants will have to be built in the next decade to replace an existing fleet that, in many cases, is 40 or 50 years old. The industry would also like to see some level of certainty related to carbon constraints.

For NO_X, SO_2 and mercury, the industry is comfortable with these standards.

The one fly in the ointment is the ongoing litigation about the mercury rule.

MR. MARTIN: There is litigation over whether the government can do what it proposed?

DR. SURLES: Right. There are a number of states, primarily northeastern states and California, that would like to see more stringent mercury rules, and they are suing the US government over that. I might point out, in the case of mercury, because we have done the analysis, about 80% of the mercury deposition in this country comes from foreign sources. Most of it comes across the Pacific from eastern Asia.

US power companies have been reluctant to spend money on pollution control until they know the full list of reductions that will be required.

MR. MARTIN: Any idea how much the programs proposed by the Bush administration so far will cost the industry in terms of new investment in pollution control? Roy Belden, we will start with you.

MR. BELDEN: The number I have heard is around $23 billion dollars.

MR. MARTIN: I believe that is just spending through 2010. I read somewhere that 13% of total capital spending by utilities between now and 2010 will be on pollution control.

On a call to prepare for this panel, we talked about whether utilities like being ordered to install pollution control because it gives them an excuse to add to rate base. I suggested that, but our panelists disagreed. Terry Surles, what is your view?

MR. SURLES: My view is mixed. I think most of the industry would just as soon keep costs down, but I come back to the issue of certainty. One of the problems with lack of certainty is that you get into battles with public utility commissions over what rates you can charge. There was a recent case before the Public Service Commission in Wisconsin where We Energies wanted to build an integrated gasification combined-cycle facility using coal. Its request was denied because the rates would have had to be substantially increased to do that compared to the cost of a pulverized coal unit.

The reason We Energies wanted to go with integrated gasification combined-cycle is that if there are even more stringent limits on NO_X, SO_2, and particulates in the future, integrated gasification combined-cycle will let it reduce emissions a lot more effectively, and there are also opportunities for removing CO_2 from the atmosphere as well.

However, the PSC rejected the request because it is only speculation that there might be more stringent regulations in the future, it is not prepared to accept the additional burden on ratepayers in the meantime. Clarity allows a utility to have a much more powerful set of arguments in front of the public utility commissions.

MR. MARTIN: We have been talking about this as if there are potentially tougher regulations in the offing on those three pollutants — nitrogen oxide, sulfur dioxide and mercury. Does anyone really see that potential?

DR. SURLES: Certainly in the case of mercury, at least one of our clients is already looking to cut a deal with its coal-fired power plants to meet maximum achievable control technology, because it believes that the US government is going to lose the mercury litigation. There is also the driver, particularly more in the particulate matter standards, that as the analytical instrumentation gets more and more refined and you start looking at the speciation of particulate matter and also the further issues with NO_X as an ozone precursor, it is conceivable the government might adopt tougher limits. That said, I think you will not see any changes for maybe up to a decade.

Cost to Comply?

MR. MARTIN: Lenny Hochschild, you wanted to add to that?

MR. HOCHSCHILD: Just getting back to the question of the overall costs, I think it is public knowledge that American Electric Power announced that it will spend just over $4 billion over the next five years.

MR. MARTIN: Just one utility? Does that call into question the $23 billion estimate for all power companies?

MR. HOCHSCHILD: AEP consumes about 75 million tons of coal per year, which is roughly 8% of the market. So if you multiply 3.7 by 12, that should get you a rough back-of-the-envelope number. The number is around $40 billion.

MR. MARTIN: Let me ask, what power plants are affected most directly by the clean air interstate rule and the mercury rule? Is it just older power plants, or is it also some newer independent power plants? Is it mainly coal, or is it also gas and other types of fuels? Roy Belden?

MR. BELDEN: For mercury, it really depends on the type of coal that the plant is burning. The mercury rule could affect new plants as well as older plants. Newer plants may already have scrubbers and selective catalytic reduction systems and would likely be able to meet the first phase reductions for mercury. For the second phase, it is a question of the type of coal being burned and whether plants may need to install additional controls.

For NO_X and SO_2, the newer plants have typically been built with state-of-the-art technology. So your NO_X and SO_2 emissions will already be at fairly low levels. It is mainly older plants that are facing big costs for NO_X and SO_2 reductions.

Just one other comment, Keith. You asked whether there are more stringent regulations on the horizon. In the northeastern and mid-Atlantic states, they are talking about implementing a new rule that would go beyond what the federal government is requiring under the clean air interstate rule.

MR. MARTIN: Mike King, if you were a banker lending money to a project and trying to get into the *pro forma* all the foreseeable costs, what would you look for as a guide to whether billions of investment might be required in pollution control?

MR. KING: The first question is, what fuel is it? If it is a gas-fired power plant, then you have a lot fewer environmental risks. But certainly you want to be thinking about what the future carbon schemes are going to be that may apply in the United States. I think most people have the sense that it is not a question of whether there will be carbon regulation, but a question of when and how long it is going to take us to get there. So, if I was a banker, I would think long and hard about the implications of the various types of possible carbon schemes.

Another Shoe Left to Drop?

MR. MARTIN: We have an odd dynamic in this country. We have a national administration that is dragging its feet on controlling greenhouse gas emissions, and yet there is a lot of pressure to take action coming from shareholders and from utilities that want certainty. I saw a report that Prime Minister Blair met with President Bush last week about greenhouse gas emissions, among other things. The *Financial Times* had a headline the next day that President Bush conceded that he needs to "learn / *continued page 44*

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more about" global warming. So maybe we are heading in that direction. Lenny Hochschild, do you see a crackdown on carbon looming?

MR. HOCHSCHILD: Yes. There is no question. My job on a daily basis is to broker renewable energy credits and renewable energy. And in the United States you now have 20 states that have renewable portfolio standards. That's up from roughly 12 just last year. Taking it to a lower level, the trade association for mayors recently met in Chicago and it unanimously passed a resolution that calls for meeting or exceeding the Kyoto protocol target reductions for greenhouse gas emissions.

Then if you take it to an even lower level and just look at the American population, here in California, 89% of the public supports actions to promote renewable energy and combat global warming. It is probably not 89% in the United States as a whole, but it is also probably above 50%.

You have regional carbon initiatives. For example, Governor Schwarzenegger just announced a new California initiative last week at the conference of mayors in San Francisco.

And you have the regional greenhouse gas initiative in the northeast. RGGI is a consortium of I believe nine states in the northeast that are working together to come up with a cap-and-trade system for greenhouse gases. It is not really a question of whether carbon constraints are coming; it is a question of what constraints and when.

You asked what assumptions a banker should build into the *pro forma* for a project? I think the thing that everyone here needs to realize is that, even today, you are taking a position regarding carbon risk, whether you like it or not.

MR. MARTIN: Terry Surles, when do you see a crackdown on carbon emissions coming?

DR. SURLES: I don't think you are going to see any significant rulemaking for a while.

MR. MARTIN: What if the Democrats regain the White House in 2008?

DR. SURLES: I have rattled back and forth between Washington for a long time. The US government is like a huge oil tanker; it takes it a long time to turn. The earliest you might see any real regulations on this is in the 2011 time frame, which would then imply that somewhere between 2015 and 2020 you would have implementation of some type of national standards — perhaps a carbon tax of some type.

Everyone lending to or investing in US utilities is making a bet about future controls on carbon emissions.

When you think about it in terms of the construction that is going on now — it gets back to the certainty issue — you will have some kind of standards with which the project will have to comply. For example, if you have a plant that will go on line around 2010 that you would like to run for 50 years, that means that early in its lifetime, you will face carbon restrictions.

MR. MARTIN: Let me ask the other panelists quickly — does each of you agree that 2015 to 2020 is the first period when we would see some significant action required on greenhouse gas emissions? Lenny Hochschild?

MR. HOCHSCHILD: I think that's a pretty political question, so I don't really have a view on it, but I would not be surprised if it happened earlier.

MR. MARTIN: Mike King, is that the right time period, if the Democrats regain control?

MR. KING: I don't think it matters whether the Democrats are in control or not. It is really a matter of economics. It is a question of whether, with the huge base of installed coal-fired power plants in the United States, we can really afford a carbon tax. It will take time to work through that. It is out there somewhere; 2015 to 2020 is as good as any guess.

MR. MARTIN: Let me throw out one statistic. US utilities account for 39% of greenhouse gas emissions in the US and 10% of global emissions. Paul Anderson of Duke Energy has said that government policies will inevitably lead to a carbon constrained world, so Duke is already taking action in anticipation. It is not waiting for the government. What do carbon and other pollution controls mean for the power industry? Lenny Hochschild?

MR. HOCHSCHILD: A good starting place is the forward curve for NO_x and SO_2. SO_2 was recently at an all-time high, and SO_2 allowances are trading today at around $800 per ton. If you look at the forward curve for SO_2 allowances, 2010 to 2015, they are trading at about $400 per ton, but the figure is deceptive because under the new clean air interstate rule, there is a two-to-one ratio that is required, which basically means that when you look at $400 per ton on the forward curve, that is really the equivalent to $800 dollars per ton today.

MR. MARTIN: Let's back up and dissect that for people who don't follow the air emission markets as closely as you do. Power plants require a certain number of allowances to cover their emissions of sulfur dioxide and nitrogen oxide?

MR. HOCHSCHILD: Right, but we are talking just about the acid rain program. Under the acid rain program, SO_2 allowances are traded. There is a separate NO_x component, but that is based on emission limits.

MR. MARTIN: So the prices you were citing were for acid rain program SO_2 allowances.

MR. HOCHSCHILD: Right. If you convert that $800 per ton number into dollars per megawatt hour, then the cost translates into $7 a megawatt hour.

The cost of existing NO_x controls right now is roughly the same, or $7 per megawatt hour. The total of $14 per megawatt hour is obviously not insignificant, but if you look at a coal-fired plant — the type of plant that has the most exposure to these NO_x and SO_2 prices — and then you compare it to a 6,500 heat-rate natural-gas unit, the volatility of natural gas prices will make a significantly larger difference than the price of SO_2 allowances, or the price of NO_x allowances, even at these high levels for those allowances.

MR. MARTIN: That's very interesting. Back up one step. A coal-fired plant, based on current allowance prices, is paying roughly $14 dollars per megawatt hour just for pollution allowances. What does the forward price curve suggest about the cost in the future?

MR. HOCHSCHILD: For SO_2, the forward curve is fairly flat-lined. Companies will evaluate the incremental cost of adding scrubbers and other pollution control equipment to reduce sulfur dioxide as opposed to buying allowances. At some price level, companies choose to clean up rather than buy allowances.

MR. MARTIN: Suppose you then layer on top of the $14 a megawatt hour the need to buy allowances for greenhouse gas emissions or carbon emissions. How much more do you have to pay per megawatt hour?

MR. HOCHSCHILD: I think that's the unknown, and that's the certainty that the industry needs. If you look at what is going on in Europe today, CO_2 allowances there are trading about €18 per ton. My understanding from my colleagues in Europe is that adds around $10 per megawatt hour.

MR. MARTIN: That is $24 a megawatt hour just to deal with pollution costs.

MR. HOCHSCHILD: That is correct. But, I'll go back to a natural gas example. If you look at a 6,500 heat rate unit and you see the amount of natural gas needed dropped from 650 thermal BTUs down to 350 BTUs, that is $20 right there.

MR. KING: The big bet that people are taking in this business is a bet on future carbon controls. That is going to dictate which way these technologies go.

One of the reasons that CO2 allowances are trading so high in Europe — at €18 per ton — is that the allocation scheme for the post-2007 time frame is not yet set. Some believe that if you trade your emission allowances in the current cycle, you may affect your entitlements in the next cycle. That means the current price may be artificially inflated because people are holding back allowances in an effort to get their gains from the distribution for the next cycle.

MR. KING: Pollution control has an effect on the shape of the US fleet. If we have a carbon policy going forward, I think we will see people thinking about new gas-fired power plants, but what that will do is drive up the price of natural gas. Gas prices are already under pressure because of declining gas reserves. I don't believe the United States has any alternative; coal will be the fuel for new power stations going forward. Whether that drives companies toward integrated gasification / continued page 46

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combined-cycle plants in the long run, who knows? It is not yet economic to build an integrated gasification combined-cycle unit in today's market.

Making Lemonade

MR. MARTIN: The previous panel on gas talked about gas prices coming down because of the LNG entering the US market. Here is a factor that will tend to push them back up because there will be more demand for gas-fired power plants if there is a looming crackdown on carbon emissions from coal.

Pollution controls are expected to add $24 to $26 a megawatt hour to the cost of generating electricity from coal.

Let me switch to the final topic for this panel and that is, what opportunities are created by this looming crackdown on pollution? Jeffrey Immeldt from GE has announced an Ecomagination program. Immeldt says that GE will be earning $20 billion a year from sales revenue from products that deal with pollution by 2010, and that's quite a significant addition to GE's revenues.

What opportunities are created by pollution control?

MR. HOCHSCHILD: Renewables are clearly one big opportunity. Investors and investment banks are starting to take renewables to the next level. Goldman Sachs just acquired US wind developer Zilkha. We are starting to see companies like Shell increase their wind holdings dramatically. That's one opportunity.

Whether nuclear is an opportunity remains to be decided. Some argue that the only way to comply with future carbon constraints is to invest more heavily in nuclear, but there are a lot of issues with nuclear.

The "clean tech" players, backed by venture capital, are coming into this market, and that's another opportunity. "Clean tech players" are guys who come up with new clean types of technologies.

Finally, forward-thinking companies that are big buyers of electricity — Dupont is an example — have retooled their manufacturing processes to reduce emissions and, in the process, freed up allowances for sale. I believe the initial reason why they acted was concern about public perceptions. The decision to be good public citizens ended up turning into a source of additional revenue. Excess allowances are sold into both voluntary and compliance markets.

MR. MARTIN: What other opportunities do people see from pollution control? Certainly trading in pollution credits, which is what you do for a living, Lenny Hochschild. What about financing? We talked about how $23 to $40 billion will be needed for new investment between now and 2010, and God knows what after that.

MR. BELDEN: There will be the opportunity to finance pollution controls in larger plants, particularly coal-fired plants. There will be new opportunities in emissions trading. Trading volumes should increase dramatically, particularly with the renewable energy credit market. Carbon trading in some form will also pick up.

MR. MARTIN: Mike King, anything to add to the list?

MR. KING: Whatever bet you place in the power generation sector is a bet on the environmental regulations that will come into place in the future. Therefore, if you think that carbon controls are not going to happen any time soon, you might think about investing in entities like Exxon, which has disavowed any issues associated with global warming or, for that matter, coal-fired power stations. On the other hand, if you want some exposure to the upside of carbon, you might be thinking about investing in gas-fired vehicles.

I would just point out, though, that I don't think that under any scheme of carbon in the next 20 years can we expect environmental regulation to save the gas-fired power plants that have been overbuilt in some US markets. Pollution control has some impacts around the margin, but it is probably not enough to cause some of these underwater power plants to become more economic.

MR. MARTIN: Terry Surles, you have the last word.

DR. SURLES: Let me add one thing we didn't talk about earlier. Electricity prices are expected to go up under almost every scenario. We really have to be thinking about new technologies associated with end-use energy efficiency and demand-side management and demand response, because that will also enter into the mix in the long run.

Real Estate Issues in US Wind Deals

by Cindy Wenig, in New York

Wind developers learn quickly that expertise in wind technologies, electricity transmission and tax credits is not enough — they must also be savvy real estate developers.

They need to understand the basics of leases, easements, mortgages, option agreements, title insurance and surveys, as well as quirks in local laws relating to wind farms, in order to make projects financeable and avoid mistakes that waste time and money. Securing the site for a project can be straightforward if the site is one tract of land with a willing landowner, but most sites consist of many landowners and many, sometimes even hundreds, of parcels.

The Site

The size of the site needed for a wind farm varies based on the speed, strength and consistency of the wind flow over the site and the type of terrain. According to the American Wind Energy Association, about 50 acres are needed to produce one megawatt of installed capacity on a flat terrain, although only 5% (2.5 acres) or less of this area may actually be occupied by turbines and equipment. A wind farm in a hilly area may only need about two acres for each megawatt of capacity.

The developer will also need a right to cross over adjacent land to get access to the turbines and for a transmission line to connect the project to the local utility grid. The developer can get access to the land for meteorological testing and gathering of wind data through a letter agreement, option agreement or through a wind farm lease or easement.

The developer should have an understanding of the boundaries of the property, either through initial discussions with the landowner or preliminary survey work. A title insurance company or local attorney should be hired to perform a title search of the land to verify that the person answering the farmhouse door *is* the sole owner of the land and to check for liens and title irregularities.

In some states, title search costs can be reduced by entering into a contractual arrangement with a title insurance company whereby the title insurance company performs searches for a fixed fee with the expectation that it will issue title insurance for the entire wind farm for a set premium at a later date. The availability of this arrangement varies from state to state, but it is worthwhile to develop a relationship with a title insurance company early on in the development stage of a project.

If there is a mortgage on the land, which is often the case, then negotiations over use of the land will also have to involve the lender holding the mortgage. The developer will probably need not only a formal consent to the lease or easement from the lender, but also a "subordination and non-disturbance agreement" in which the lender agrees not to disturb the developer's use of the land for the wind farm and that any lender who finances the wind farm will have first claim over the land. Such an agreement is a prerequisite for the project to be financeable. If a landowner has not been current on his mortgage payments, then the developer will probably have to cure the defaults, or even pay off the landowner's mortgage, before a lender will finance the wind project.

A title report prepared by a title insurance company or an attorney will also tell the developer whether the land has already been leased to a third party, or if others have rights to use the surface or the subsurface of the land. It is not uncommon to find that lands are encumbered by long-term oil and gas leases or mineral leases. If such leases exist, then the developer must obtain a waiver from the holder of the lease that its right to use the property (or at a minimum, its right to mine the surface */ continued page 48*

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of the property) is limited or waived.

Multiply these situations by 100 tracts of land and the wind developer quickly becomes more knowledgeable about real estate and its pitfalls than Donald Trump.

Main Business Issues

The developer will need both a site lease and easements over surrounding property. These documents usually range from 10 to 30 pages in length and should address, at a minimum, a dozen issues.

There are a dozen key issues that must be addressed in the site lease for a wind farm.

Term: The typical lease has a term of 25 to 30 years. Perpetual easements are not favored; they may not be enforceable and, in some states, may create tax consequences for the landowner as they may be characterized as a sale.

Renewal terms: Most leases have one or two renewal terms, at the developer's option. Renewal terms usually last five or 10 years, at an increased rental rate (based on the consumer price index or percentage increases).

Use: The lease will describe how the developer can use the land. The use clause should allow collection of meteorological data and environmental testing, construction of wind turbines, roads, transmission lines, communications facilities and other equipment, wind conversion, the gathering, collection and transmission of electricity and ancillary uses.

Rent: Typical methods of compensation to the landowner include an upfront lump-sum payment, annual fixed payments per wind turbine, variable payments based on a percentage (usually 1% to 4%) of the gross revenue generated by the turbines, or a combination of these approaches. Sometimes "tax credits" are included in the definition of gross revenues. Some states require that payments to the landowner be made at least annually.

Additional payments: Developers occasionally offer additional fees to landowners for the right to build improvements other than turbines on the property, such as meteorological towers, substations, transmission lines or roads. Optically, these varying payment categories give the impression that the landowner will be receiving a lot of money, but this may be misleading, for payments only get made if the improvements are built, which is in the developer's discretion.

Other uses of the land: The landowner is frequently permitted to use the balance of the land for farming or grazing, subject to the developer's security and safety requirements. Sometimes this is a material business point for landowners.

Existing liens: The landowner represents that there are no liens, encumbrances or leases affecting the land, other than as specified in the document. The landowner is required to obtain subordination and non-disturbance agreements from any existing or future lenders.

Environmental issues: The landowner represents that it is not aware of any contamination of the land by hazardous materials and may indemnify the developer for existing environmental conditions (although some challenge this practice of expanding the landowner's liabilities as unfair because it might make a landowner responsible for a larger share of any later cleanup of the land than is required by law). If hazardous materials are present on the property, remediation costs must be addressed. The wind developer indemnifies the landowner for any hazardous conditions it creates.

Transfers and liens: The developer has broad rights to sublease, assign and mortgage the property. Some complicated wind instruments have provisions permitting multiple simultaneous subleases and subeasements to various parties, permitting phased construction of the wind project and limiting the liability of the various subtenants and easement holders. The developer's lender must be given notice of any default under the lease or easement and be given the right to cure the landowner's defaults.

Removal: The developer owns the turbines and improvements it constructs and either has the right to or must remove them at the end of the lease term. Sometimes, the landowner has the right to retain one or more turbines at the end of the lease or easement for personal use.

Early termination: The developer often has the right to terminate a lease or easement at its option. Certain farmers' rights groups criticize these provisions as being unfair, as the landowner's land is tied up for a period of time and he may ultimately receive little or no compensation. One fair compromise is that the landowner receives a termination payment if the developer terminates early. The landowner should not have the right to terminate the lease or easement, as that would make the project unfinanceable.

Purchase option: Some wind leases give the developer an option to buy the land on a specified date based on the fair market value of the land or other agreed-upon compensation.

If the project is in the infant stage, some developers begin the process by presenting an option agreement to the landowner. An option agreement provides the developer with the option to purchase, lease or obtain an easement over the land for wind energy use, at the developer's option. The landowner is paid for keeping his property off the market. The option terminates automatically if not exercised by the developer by a certain date. There is no single "market" price for such an option, as it is based on local real estate conditions and potential sales or other uses of the land that the landowner must forego during the option period. Sometimes option payments made by a wind developer are credited against lease or easement payments due once the option is exercised.

Developers occasionally obtain "noise easements" over neighboring properties to avoid conflicts or litigation. In return for payments, the abutting landowner agrees not to object to noise generated by the turbines.

State-Specific Requirements

Not just any form of lease or easement will do; the requirements for the lease and easement vary from state to state. Therefore, before signing any agreements, a developer should consult with an attorney about local zoning laws, as well as about state-specific legal requirements for wind farm instruments.

Any lease, easement or option agreement must be executed by both parties and should contain a legible legal description of the property. In some states, a "memorandum" of the document should also be executed by both parties. A memorandum is a short form of the document that contains a few material provisions, such as the term of the lease or easement and describes the property. In some states, a memorandum of the agreement can be recorded in the public records instead of recording the entire document. "Recording" means that the document is listed in the county records. By recording a document (or, where permitted, a memorandum), the wind developer is protected against someone else claiming conflicting rights over the land later. Lenders financing the wind project will want the property rights the developer has to be recorded. Recorded documents lay the foundation for a mortgage or deed of trust to be granted to a lender.

In the last few years, certain landowner advocacy groups have advised landowners to insist that the entire wind farm lease or easement be recorded in the public records, with only the financial terms redacted.

Several states have passed laws concerning the form and content of wind farm conveyances that may become traps for an uninformed developer. In South Dakota, for example, a wind lease or easement cannot exceed a term of 50 years. Furthermore, under South Dakota law, a wind lease or easement will automatically terminate if no development of the potential to produce energy from wind power has occurred on the land within five years after the lease or easement began.

A lease or easement should also describe the real estate with specificity. For example, in Kansas, a vague property description stating that the lease or easement burdens all of a developer's land in the county (known as a "Mother Hubbard clause") may be subject to challenge. Sometimes horizontal and vertical information about the turbines must be included in the wind instrument. Kansas, Minnesota, Montana, Nebraska, Oregon / continued page 50

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and South Dakota have laws requiring that wind instruments include a description of the vertical and horizontal space on the land (expressed in degrees or distances from the turbines) that must remain unobstructed to accommodate wind flow.

Surveys and Title Insurance

Most lenders will insist that a survey of the property be completed as a condition to closing on the financing. The survey must conform to established rules called the "Minimum Standard Detail Requirements for ALTA/ACSM Land Title Surveys."

The lender will also require that a title insurance policy be issued at closing. This insures, among other things, that the mortgage held by the lender will have priority over other liens and that there are no title defects that might lead to a loss of the property or restrict use of the property as a wind farm.

Developers would be wise to establish a relationship with a title insurance company as soon as a potential site is identified. There are several steps in the title insurance process, beginning with a land record search of the property — called a "title report" — issuance of a policy insuring an option agreement, if any, in favor of the developer, issuance of an owner's policy or a leasehold owner's policy in favor of the developer when land is purchased or a lease is executed, and then later issuance at financial closing of policies in favor of the lenders. In certain states, it is possible to combine the search costs and title premiums into an overall package rate, so that the developer is not charged for each step in the process. In other states, the form of the title insurance and the premiums are not negotiable.

Title insurance is one of the least understood components of real estate development, but it is a necessity for secured lenders. In a title insurance policy, the title insurance company insures the owner of the land and the lender against title defects and adverse claims up to a specified amount of coverage. The cost of the title insurance policy (known as the "premium") is set by statute in some states and is negotiable in other states.

The title policy contains a list of risks or "exceptions to title" that are not insured against, and the developer and lender review this list with particular care.

Not just any lease will do. The requirements for the lease vary from state to state.

In certain states, title insurers can provide additional coverage through "affirmative insurance" or "title endorsements" that provide protection against specifically-identified risks. Common title insurance policy endorsements include such things as the property has access to a specified public road, there are no restrictions on use of the land that will extinguish the lender's lien, the land is the same land as shown on the survey, the property has been validly subdivided, and the zoning for the property will permit its use as a wind project.

Title insurance is insurance to cover a loss in the value of real property — including the wind turbines — as a result of any title defect. The question arises: are wind turbines "real property" or "personal property" (which would typically not be covered by title insurance)? In some states, it is possible to purchase an endorsement to the title policy that covers this legal uncertainty. The endorsement states that the policy will cover the value of the wind turbines, transmission lines and other wind facilities (even if such facilities have not yet been located on the land). Without this endorsement, the value of the turbines, transmission lines and wind facilities may not be covered.

In sum, the real estate aspects of a wind project can be a complicated process and will likely involve many parties

–- the landowner, the landowner's lender, its neighbors, leaseholders, a title insurer, surveyor, governmental officials, the project's lender, attorneys on all sides and parties who enter the story as a result of any title defects or unforeseen issues. The last piece of real estate in a multi-site project is often the most difficult to secure, leading one developer to comment after an especially trying lease negotiation that acquiring the dirt was the "dirty little secret" of clean energy project development. ◎

Biodiesel: The Next Growth Opportunity?

by Todd Alexander and Jonathan Phillips, in Houston

Both Rudolf Diesel and Henry Ford incorporated biofuels in their early designs. When Rudolf Diesel first displayed his diesel engine at the World Exhibition in 1900, it was designed to run on peanut oil. Later, Henry Ford followed suit and designed the Model T to run on ethanol and gasoline.

For most of the remainder of the twentieth century, neither ethanol nor biodiesel received much attention in the United States.

This began to change for the ethanol industry in the early 1980s after governments recognized that support for non-petroleum-based motor fuels could lessen US dependence on imported oil and produce environmental benefits. In the 1990s, the banning of MTBE, a petroleum additive that, like ethanol, is used by refiners to comply with federal clean air regulations, provided a further impetus for growth of the ethanol industry.

Biodiesel appears to be on the verge of benefiting from similar trends. In particular, new environmental regulations that require the use of ultra-low sulfur diesel fuel in the United States beginning in June 2006 should spur more biodiesel production.

Biodiesel also enjoys bipartisan political support. President Bush used a biodiesel plant in Virginia in the spring as a prop for a speech encouraging Congress to pass an energy bill. A "biofuels caucus" has also been formed in the Senate with Norm Coleman (R-Minnesota), Tom Harkin (D-Iowa), Blanche Lincoln (D-Arkansas) and Jim Talent (R-Missouri) as the "co-chairs."

Notwithstanding this political support, biodiesel production in the United States is still in its infancy. Total biodiesel sales in 2004 were only 30 million gallons. Although this was a 60-fold increase over output five years ago, the US Department of Energy has forecast that the market could reach as much as 1.2 billion gallons a year in the next decade. This forecasted growth is likely to depend to a great extent on the continuation of government subsidies and advances in the use of different feedstocks.

What is Biodiesel?

Biodiesel is a cleaner-burning diesel replacement fuel that is made from natural, renewable sources such as animal fats, oilseeds, used cooking oil, sugar and grain. The most common feedstock used in the US is soybean oil, while the most common feedstock used in Europe is rapeseed oil.

Biodiesel fuel alone, or in combination with petroleum diesel fuel, can be used in most diesel engines with little or no engine modification. Americans currently use biodiesel blended with standard diesel in percentages of 2% to 20%. Such blends are referred to as B2 to B20. In certain circumstances unmixed biodiesel, or B100, is being used by consumers. The majority of European consumption is B5, or a 5% blend of biodiesel.

How is it Made?

As shown in the diagram on the next page, biodiesel fuel can be made from new or used vegetable oils and animal fats. Vegetable oils, when made to react chemically with methanol or another alcohol, produce chemical compounds known as esters. This process is known as transesterification. During transesterification, the vegetable oil or animal fat is filtered, preprocessed with alkali to remove free fatty acids, and then mixed with an alcohol and a catalyst (usually sodium or potassium hydroxide). The oil's triglycerides and the alcohol react to form esters and glycerol, which are then separated from each other and purified.

Biodiesel is the name given to the esters formed by transesterification when they are intended for use as fuel. Glycerol, produced as a co-product, is used primarily in pharmaceuticals and cosmetics.

Although the primary feedstock in the U.S. is soybeans, waste animal fats and used frying oil, known as yellow grease, are also potential feedstocks. / continued page 52

Biodiesel

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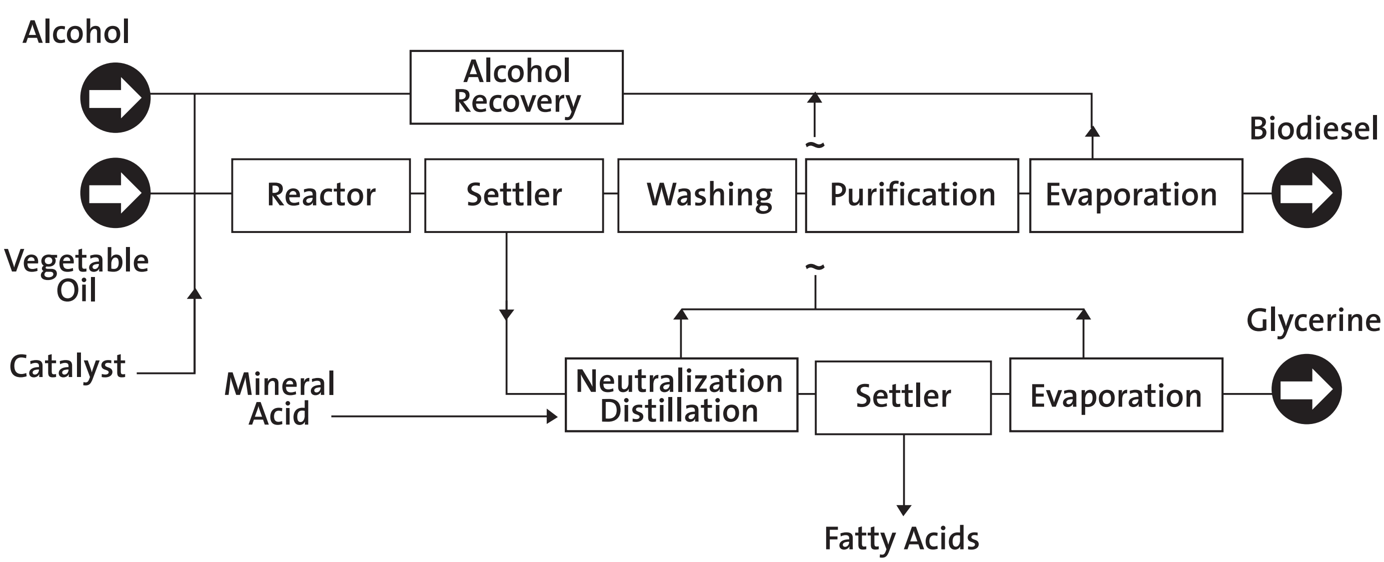
These are less expensive than soybean oil and are being considered as a way to reduce feedstock costs. Peanuts, cottonseed, sunflower seeds, and canola (a variant of rapeseed) are other candidate oil sources.

Government Subsidies

The JOBS Act last October created for the first time a federal excise tax credit for biodiesel blends, and the energy bill that President Bush signed in August extended it. The credit can be claimed on biodiesel blends sold through December 2008. The US government collects an excise tax of 24.4¢ a gallon on diesel fuel. Refiners who use biodiesel to blend with petroleum diesel can claim a credit against the excise taxes that would otherwise have to be paid on the resulting diesel fuel. The credit is $1 a gallon for "agri-biodiesel," and it is 50¢ a gallon for other biodiesel. This is the amount of tax credit for each gallon of biodiesel used in the blend. Thus, for example, if a B5 blend is used, then 5% of a gallon of biodiesel was used to make the diesel fuel. A credit of 5¢ or 2.5¢ could be claimed against the 24.4¢ tax on diesel fuel, depending on whether agri-biodiesel was used. "Agri-biodiesel" means biodiesel derived solely from virgin oils, including oils from corn, soybeans, sunflower seeds, cottonseeds, canola, crambe, rapeseeds, safflowers, flaxseeds, rice bran, mustard seeds or animal fats.

Potential US Market

Biodiesel has several advantages over traditional petroleum diesel fuel. First, it is a cleaner burning fuel than petroleum diesel, even in low blends. According to the US Department of Energy, pure biodiesel can reduce air toxics and cancer-causing compounds by 94%, while B20 results in a 27% reduction. Second, biodiesel has a much higher flashpoint than petroleum diesel fuel. As such, it is not considered a flammable fuel and, therefore, is not considered a hazardous material by the National Fire Protection Agency,



Source: National Biodiesel Board

and no hazardous-material labeling is required during transportation and storage. Third, biodiesel maintains all of the lubricity benefits of petroleum diesel, and even low-level blends, such as B20, result in minimum degradation of power and range when compared with traditional petroleum diesel. For instance, the power of B20 is only about 2% less than that of regular diesel. Fourth, biodiesel has many proponents in the environmental community. Biodiesel is made from natural and renewable sources, is biodegradable and non-toxic and is not harmful to the environment in the event of a spill. In fact, accidental spills of pure biodiesel take only four weeks to decompose completely. This is approximately four times faster than the rate at which petroleum diesel decomposes.

Biodiesel production is expected to reach 124 million gallons this year compared to 30 million gallons during 2004. This is still a very small percentage of the potential US market. On-road petroleum diesel consumption totaled approximately 36 billion gallons in 2004, and the total US diesel market (which includes on and off-road uses) is estimated at $160 billion.

US refiners have been slow to recognize the potential. European biodiesel production for 2004 was estimated at 500 million gallons.

Several government actions are expected to give a boost to the US market.

One is a renewable fuels standard in the new energy bill that became law on August 8 that requires refiners to blend minimum volumes of either ethanol or biodiesel with US motor fuels through 2012. The other is a new small producer tax credit of 10¢ per gallon.

The states are also providing support for biodiesel. Approximately half of US states sponsor alternative fuel vehicle programs that promote the use of blends of B20 or greater. For example, Missouri requires that at least 75% of government vehicles use biodiesel, if available. Many states also make grants to school districts to buy biodiesel fuel for use in school system vehicles.

Perhaps most significantly, biodiesel blends may become the fuel of choice to comply with new ultra-low sulfur diesel regulations. The US Environmental Protection Agency is requiring refiners to produce highway-grade ultra-low sulfur diesel starting in June 2006.

Refiners have the option to produce ultra-low sulfur diesel by "de-sulfurizing" the diesel using a "hydro-treating" process. Hydro-treating is the process of replacing sulfur in diesel fuel with hydrogen. This process requires boiling base oil stocks at temperatures ranging from 500° to 600° Fahrenheit and then subjecting them to high pressure. Although most refineries already use "hydro-treating" technology to produce the current standard of diesel fuel with 500ppm of sulfur, it requires a significant capital investment and ongoing expense to reach the new standard of 15ppm. In addition, during hydro-treating, nitrogen and oxygen, which provide a natural lubricity to the diesel, are removed from the fuel. Unless a lubricant, like biodiesel, is added, the reduced lubricity could damage engine parts.

Risks

Biodiesel is not economic to produce currently without government subsidies. In such a market, there is obviously risk. The price differential between biodiesel blends and petroleum diesel fuel is small in blends such as B5, and any price advantage enjoyed by petroleum diesel fuel is eliminated as long as the current excise tax credit remains available. However, these calculations assume that the price of soybeans will remain stable. It may not if demand increases significantly due to use of soybeans to make biodiesel. One gallon of biodiesel requires 1.5 bushels of soybeans to make. More than 20% of the entire soybean crop in the United States would have had to have been used in 2002 to provide a 2% blend for all diesel fuel consumed in the US that year.

Fortunately, one characteristic that distinguishes biodiesel from other fuel replacements, such as ethanol, is that various feedstocks can readily be substituted for one another without significantly modifying the design of the production facility or process. For example, other oil-producing crops that can be readily substituted for soybeans include oil palm, jatropha, canola, peanuts, sunflowers, safflowers, mustard, corn and algae. Many industry participants are aware of this issue and are looking at the economics of importing palm oil from Asia as a soy oil substitute

Producers may also be able to reduce their feedstock costs in the longer term if scientists are able to engineer soybeans or other crops to produce more oil. This approach has already led to corn with a higher starch content, which lowers the cost of producing ethanol. ◎

Ocean Energy: Whose Approval is Needed?

by Roy Belden, Robin Schafer and Tracy Horton, in New York

Energy projects in the oceans off the coast of the United States raise interesting questions about whose permission one needs to build. It can also be challenging to work through US environmental laws and figure out how they apply to such projects.

In general, US territorial waters extend 200 miles offshore. The same federal laws that apply to projects on land usually apply to projects in US waters. Except in the Gulf of Mexico, states claim jurisdiction up to three miles offshore.

Investor interest in ocean energy projects is increasing. The industry held its second annual conference in the US last spring in Washington. Of the various types of projects, offshore wind farms are the most advanced. Various developers are moving to build prototype facilities to harness the tides, waves, currents or the heat in ocean waters. Most of the developers of these projects are still at the venture capital stage.

There is no one government agency in the United States with jurisdiction over all or even most of the permits that a developer needs to do a project. Ocean waters within 200 miles offshore and major rivers, lakes, and other bodies of water in the United States are considered public resources that are overseen by the federal government or the applicable state government as stewards for the general public. Numerous federal, state and local agencies can have jurisdiction over permitting for different aspects of a single project.

Types of Projects

The US has lagged behind other countries in turning to the oceans for energy. There are five main types of technologies: tidal, wave, subsurface current, ocean thermal energy conversion and offshore wind turbines. Operating projects using most of the technologies can be found in other countries.

US developers are moving to catch up. Ocean energy projects under development in the United States include two significant offshore wind farms along the east coast, a demonstration wave energy project in Hawaii, a prototype tidal current project in New York, and a prototype subsurface current project off Florida.

Tidal power: To harness tidal power, a dam is typically built across a river estuary or tidal basin. The tide flows through tunnels or channels in the dam, and the water is captured so that traditional hydropower technologies can be used to turn a turbine as the water level drops. The ebb and flow of the tides can also be used to push air through a pipe, which then turns a turbine. Large lock gates, like the ones used on canals, allow ships to pass. A major drawback of tidal power stations is that they can only generate when the tide is flowing in or out, which is usually only for about 10 hours each day. A large increase between high and low tides is also generally required. Nevertheless, tides are predictable; thus, utilities can plan to have other power stations generating at those times when the tidal station is unavailable.

Changing tidal flows by damming a bay or estuary could do harm to aquatic and shoreline ecosystems, as well as restricting navigation and recreation due to reduced tidal flow and silt buildup. There are three operating tidal plants. The La Rance plant in France installed in 1966 generates approximately 240 megawatts of power from 24 turbines. A 20-megawatt tidal power plant installed in 1984 is situated in the Bay of Fundy off the shore of Nova Scotia, and a small 0.5-megawatt tidal energy plant is located on the White Sea in Russia.

Wave energy: Wave energy can be used to generate electricity using various technologies that are still in the development stage. The Electric Power Research Institute, or EPRI, reported on an "offshore water power feasibility demonstration project" on January 14 this year. The report identifies eight wave energy conversion devices that will probably be ready for demonstration projects in the next few years. The devices include a floating cylinder system using hydraulic power conversion modules, an oscillating water column where air flows generated by the waves drive a turbine, a swinging pendulum system, and a floating buoy system. The energy in waves comes from the movement of the ocean and the changing height and speed of the swells. Though the kinetic energy in waves varies in intensity, it is available 24 hours a day and 365 days a year. Wave energy typically works best in ocean depths of at least 50 meters before waves lose energy to the friction of a shallow sea bottom. A prototype 50-kilowatt floating buoy system was recently tested off the shores of Hawaii.

Wave devices raise potential environmental issues, including possibly effecting a change in the flow patterns of sediment and serving as artificial habitats for aquatic organisms. Many of the wave energy systems must be anchored to the sea bed, and undersea cables are needed to bring power to the mainland.

Subsurface current energy: Areas that typically experience high marine current flows are in narrow straits, between islands and around headlands, and energy can be generated by using submerged turbines comprised of rotor blades and a generator. Verdant Power is developing a 10-megawatt tidal current project that will be located in the East River off Roosevelt Island in New York City. The project will consist of approximately 494 underwater free-flow hydro turbine-generating units that will be deployed below the water surface. The tidal current would turn rotor blades that are similar to a wind turbine blade and a generator in each unit would produce electricity. Earlier this year, Verdant Power received approval from the Federal Energy Regulatory Commission to install a temporary demonstration project of six units to test the technology and determine the feasibility of going forward with the large scale project.

Underwater current projects may affect aquatic organisms and ecosystems within the project footprint, and because the rotor blades would be about eight feet under the surface, navigation and recreational activities in the area would generally be prohibited.

Ocean thermal energy conversion: OTEC taps the difference in temperatures between different layers of water to produce steam to drive a turbine that produces electricity. OTEC plants can be land-based, near shore or floating. Floating plants have the advantage that the cold water pipe is shorter, reaching directly down to the cold water, but the electricity generated must be brought to shore using an undersea cable, and moorings for the OTEC plant are likely to be in water depths of approximately 2,000 meters.

Land-based OTEC plants have the advantage of not needing a power transmission cable to shore, and there are no mooring costs. However, the cold water pipeline must cross the surf zone and then follow the seabed until the depth reaches approximately 1,000 meters. The use of a much longer cold water pipe generally has greater friction losses, and the cold water may warm up before it reaches the heat exchanger, which makes such plants less efficient. No large-scale OTEC projects have been built to date, but the US Department of Energy funded small-scale OTEC demonstration projects in waters near Hawaii in the late 1970s and early 1980s.

Offshore wind energy: Offshore wind technology is the most advanced of the ocean energy technologies. According to the British Wind Energy Association, wind turbines with a capacity of 587 megawatts have been installed off the coasts of Denmark, Holland, Ireland, Sweden and the United Kingdom, and several large-scale offshore wind projects are under development in Europe and the United States. To date, the largest offshore projects are the 158-megawatt offshore wind farm in Nysted, Denmark, and the 160 megawatt offshore wind farm in Horns Rev, Denmark.

Offshore wind turbines are similar to onshore wind turbines with a few design modifications, including strengthening the tower to handle wave action and protecting the nacelle components from sea air. Most offshore wind turbines are anchored to the seabed using steel monopoles or concrete gravity foundations. There are two large offshore wind farms under development in the United States: the 420-megawatt Cape Wind project off Nantucket Sound and a 140-megawatt project proposed by the Long Island Power Authority off the south shore of Long Island.

Because offshore wind turbines are anchored to the seabed, potential environmental impacts include possible effects on marine mammals, marine birds, fish and shellfish. Potential visual impacts may also need to be evaluated.

Right to Use Seabed

In the United States, there is no one federal law that encompasses all types of ocean energy projects. Every ocean energy project is different and the necessary permits and approvals depend on the location, size, and potential environmental impacts of the project.

Key considerations in developing an ocean energy project are the following: what real property interests, such as a lease, easement, right of way or / continued page 56

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license, are required to install structures or cables in the seabed or in coastal waters, what environmental impact reviews are necessary, and what federal, state and local permits or other approvals are needed. Another consideration is whether there are streamlined procedures available for testing prototype ocean energy technology before entering into a full-scale development.

Energy projects in the oceans raise interesting questions about whose permission one needs to build.

Regulation of property rights differs by jurisdiction. Under the Submerged Lands Act, states have jurisdiction over submerged lands for up to three nautical miles offshore, except for Florida and Texas, which have jurisdiction beyond three miles into the Gulf of Mexico. State jurisdiction makes it likely that a lease, easement, right of way or license from a state agency will be required for any ocean energy project within three miles from the shore. For example, in New York, the New York Office of General Services is charged with issuing easements for the use of submerged state lands. In New Jersey, the Tidelands Resource Council in the Department of Environmental Protection is authorized to approve grants, leases, licenses and easements for lands that are now or formerly under tidal water. In Washington state, the Department of Natural Resources will issue an aquatic lands lease. Other states have created similar programs to grant property rights in submerged lands.

Some states are taking a more active role in reviewing offshore energy projects. In March 2005, Massachusetts Governor Mitt Romney asked the state legislature to consider legislation that would prohibit certain ocean projects unless they conform to an "ocean use management plan" to be developed by the Massachusetts secretary of environmental affairs. In developing the plan, the secretary must take into account the "existing natural, social, and economic" characteristics of the ocean planning area. New Jersey imposed a 15-month moratorium on offshore wind farms last December by executive order of the governor while a state panel studies the issue more thoroughly. The order stops projects from obtaining permits or financing from the state during the moratorium.

The federal government has jurisdiction over the outer continental shelf beyond three nautical miles. Before the US enacted a new energy bill in August, there was no clear federal statutory regime for the use of submerged lands for ocean energy projects, other than the authority for the Minerals Management Service in the US Department of Interior to issue leases for oil and gas projects. A US appeals court in New England held earlier this year that one temporary offshore wind data tower placed on the outer continental shelf was not an infringement on federal property rights in the submerged lands, but the question of a larger-scale project was not before the court.

The new energy bill authorizes the US Interior Department to grant leases, easements and rights-of-way for activities that produce or support production, transportation or transmission of energy from sources other than oil and gas. The department can now grant formal property rights to develop ocean energy projects on the outer continental shelf in exchange for a fee, and 27% of the revenue received from a lease, easement or right-of-way will be paid to the state where the project is wholly or partly located within the three-mile state jurisdictional limit. The leases, easements and rights-of-way will be awarded on a competitive basis unless the Interior Department determines that there is no competitive interest. This new statutory program is not exactly a "one-stop" permitting regime for ocean energy projects. The effect is actually to add another federal government approval that must be obtained before developing a project in federal waters. The Department of Interior is directed to issue final regulations implementing the new submerged lands property rights program by late April or early May 2006.

Most projects need transmission lines and cables to move the electricity generated to shore. These require additional permits. For example, the undersea cable may make landfall on state lands, necessitating a separate lease or easement from the applicable state.

Myriad Other Federal Permits

Other federal, state and local permits will also be required.

The Federal Energy Regulatory Commission has jurisdiction over wave, tidal and current projects under the Federal Power Act. The Federal Power Act covers projects that use water to generate electricity. In a 2003 decision in a case called *AquaEnergy*, FERC decided that offshore ocean energy projects may require federal licenses. The AquaEnergy project involves the installation of a one-megawatt floating wave buoy project in Makah Bay about 1.9 nautical miles off the coast of Washington. AquaEnergy argued that the project did not need a federal license because it is located in water over which the state of Washington has jurisdiction, it is not in a navigable water of the United States, and it is not a hydroelectric project since it does not use surplus water or water from a federal dam.

FERC disagreed. It said that the area within 12 miles offshore is within "navigable waters" as defined by the Federal Power Act and that floating wave buoys are "power houses" under the Federal Power Act because buoys are structures containing equipment for the generation of electric power. The agency concluded that the project had to be licensed as a hydroelectric project.

FERC does not have jurisdiction over OTEC (ocean thermal energy conversion) projects, which are subject to a separate statutory scheme. Nor does FERC have jurisdiction over offshore wind turbines, since they do not involve the use of water to generate electricity.

The Federal Power Act requires FERC to give equal consideration to environmental and energy concerns when it considers whether to grant a license. Section 10 of the Federal Power Act requires that the proposed project must be

> best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce, for the improvement and utilization of water-power development, for the adequate protection, mitigation, and enhancement of fish and wildlife (including related spawning grounds and habitat), and for other beneficial public uses.

FERC is also required by the National Environmental Policy Act to evaluate the environmental effects of a proposed project before issuing a license. The NEPA review process can be very involved and time consuming. FERC must solicit suggestions from various federal, state and local agencies for how to protect, mitigate and enhance the environment. For example, it will look to the US Fish and Wildlife Service, the National Marine Fisheries Service and state fish and wildlife agencies for suggestions about how to protect aquatic life that might be disturbed by a project.

The Federal Power Act "preempts," or rules out, any separate review by a state or local siting board. Projects in US navigable waters normally require a "section 10 permit" from the US Army Corps of Engineers. However, projects that come under FERC jurisdiction do not need a separate section 10 permit. The US Army Corps will provide FERC with recommended conditions to be incorporated into the FERC license to address the requirements of the Rivers and Harbors Act of 1899.

Other federal, state, and local / *continued page 58*

There are four main categories of permits required at the state level.

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permitting requirements are *not* preempted by a FERC licensing procedure. For example, a "section 404 permit" authorizing the discharge of dredge and fill material into a water of the United States must be obtained from the US Army Corps.

In April 2005, FERC addressed whether an ocean energy demonstration project requires a FERC license. It does not, provided certain conditions are met. The case involved Verdant Power. FERC said that small experimental testing projects do not require a FERC license provided that the test project is installed for a fixed period and that no power generated by the prototype is supplied to, or displaces power from, the grid.

FERC recently clarified that no license is required if there will be no net economic effect from displacing power on the grid. Verdant Power will need to hook its six underwater turbines up to the grid in order to test them. In a clarifying order, FERC acknowledged Verdant Power's need to supply test power to the grid and agreed that as long as there is no net economic effect from supplying power to the grid, then the experimental project remains exempt from the licensing requirements. Verdant Power committed to providing the power to end users at no charge and agreed to compensate the local utilities for the costs of the power that would have otherwise been supplied to ratepayers but for the power generated by the experimental units. The *Verdant Power* decision provides some much-needed relief for the permitting of small prototype ocean energy projects because obtaining a FERC license can be a lengthy process. Nevertheless, other federal, state and local permits may be required even for a small-scale demonstration project.

The National Oceanic and Atmospheric Administration, or NOAA, has jurisdiction over ocean thermal projects under the Ocean Thermal Energy Conversion Act. The OTEC Act was enacted in 1980 to establish a comprehensive licensing scheme for OTEC plants. After preparing some initial environmental studies and developing regulations to implement the licensing program, NOAA has not received a single license application for an OTEC project.

The new energy bill gives the US Interior Department the ability to lease land to projects on the US continental shelf. The effect is to add another layer of government approval.

NOAA removed the OTEC licensing regulations from the code of federal regulations in 1996. At the time, NOAA said that once interest in OTEC projects more fully develops, it will reevaluate whether the withdrawn regulations are still appropriate or require further updating. Under the OTEC Act, a NOAA-issued license was intended to be largely a one-stop permit. However, the OTEC Act does not preempt the need for a "section 10 permit" from the US Army Corps.

Offshore wind projects need a section 10 permit under the Rivers and Harbors Act of 1899 for installations in a navigable water of the United States. The US Army Corps of Engineers has jurisdiction over artificial islands, installations and other devices located on the outer continental shelf.

The authority of the US Army Corps to issue a "section 10 permit" for a data tower installation on the outer continental shelf was challenged in a case called *Alliance to Protect Nantucket Sound, Inc. v. US Department of the Army* in early 2005. A citizens group argued that the US Army Corps should not have issued a permit for an approximately 170-foot wind data collection tower to be built off Massachusetts because the Corps had authority only to issue permits for activities associated with minerals extraction. A US appeals court disagreed. However, the decision makes clear that offshore wind farms will require section 10 permits to start construction. Both the Cape Wind project and the Long Island offshore wind park are in the process of obtaining section 10 permits.

A section 10 permit may also be required for installation of an undersea cable to carry electricity back to shore. Also, because laying cable will require dredging, projects may also have to get "section 404 permits" to authorize the discharge of dredge or fill material into a water of the United States. The US Army Corps is responsible for issuing section 404 dredge and fill permits.

All ocean energy projects require approval for navigation markers from the US Coast Guard. In addition, the Endangered Species Act requires a "section 7 consultation" with the Department of Interior before a project is built if the project might affect an endangered or threatened species. To the extent that incidental fatalities of an endangered or threatened species are anticipated, then the project will also need an "incidental take" permit from the US Fish and Wildlife Service. An application for an incidental take permit must include a conservation plan that explains what impact the project is likely to have on endangered species and what steps will taken to minimize harm to such species.

The Fish and Wildlife Coordination Act also requires consultation with federal and state agencies with jurisdiction over fish and wildlife for any project that affects a body of water. The Marine Mammals Protection Act may be triggered if marine mammals will be potentially "harassed" as a result of the project. The National Historic Preservation Act may also come into play if historic sites are affected. For example, undersea cable projects typically require an archeological survey to identify potential shipwreck locations along the cable route.

State and Local Approvals

It goes without saying that the state and local permitting requirements vary considerably from state to state. In general, there are four categories of permits: state siting board approvals, waterfront development and coastal wetland approvals, state consistency determinations with federal programs, and local zoning board approvals and building permits.

Several states have energy generation siting boards, and a "certificate of public necessity and convenience" (sometimes called a "certificate of environmental compatibility and public need") may be required. Small ocean energy projects would typically fall under the size cutoff for most state siting board approvals. However, a few states even regulate small projects. For example, renewable energy projects over one megawatt in Connecticut must be approved by the state siting council. In contrast, the Massachusetts Energy Facilities Siting Board regulations apply to power projects of 100 megawatts or more, and the California Energy Commission has exclusive jurisdiction to certify sites and related facilities for power plants in California that generate 50 megawatts or more of electricity.

While the power generation components of an ocean energy project may be exempted from a siting board process, the undersea cables or overland transmission lines that connect the project to the grid usually must be approved by a state siting board or public utilities commission.

Ocean energy projects may also need permits under state specific waterfront development acts. For example, projects affecting coastal waters require a waterfront development permit in New Jersey and a "chapter 91" permit in Massachusetts. There may also be restrictions on ocean energy projects under state wetlands laws. The Massachusetts Coastal Wetlands Restriction Act restricts development in selected wetlands in more than 50 communities.

If an ocean energy project will require a section 404 permit from the US Army Corps, then the state agency with jurisdiction over discharges into water bodies will also have to issue a "water quality certificate" under section 401 of the federal Clean Water Act. Under section 401, the state certifies that the discharge will meet applicable state surface water quality standards. Most ocean energy projects also will need a "coastal zone consistency determination" from the applicable state coastal zone agency. The Coastal Zone Management Act gives the US secretary of Commerce authority potentially to overrule any state determination that a project is inconsistent with requirements of the Act. State endangered species acts and state historical and archeological preservation programs may also impose permitting or consultation requirements on ocean energy projects.

Regional and local land use agencies may require zoning approvals, special use permits or building permits for onshore transmission interconnections and substations. Other local agencies have exercised jurisdiction over projects due to potential impacts on waters or coastal areas. For example, the New York City */ continued page 60*

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Environmental Protection Agency is involved in evaluating the potential impacts of the Verdant Power subsurface current project in the East River. Where an undersea cable or transmission line will be installed, state or local approval may also be needed for disposing of dredging spoils.

Environmental Impact Statements

All ocean energy projects will require some type of environmental impact review.

The energy bill requires the US government to buy at least 3% of its electricity from renewable energy suppliers, increasing to 7.5% within eight years.

The National Environmental Policy Act requires an environmental assessment or environmental impact statement be done before the federal government will issue permits or provide federal funding for a project. NEPA applies to "major" federal actions. The term covers all projects that receive federal funding or require a federal permit or license to be built. For ocean energy projects, a NEPA review will usually be triggered by the need to obtain a permit from a federal agency such as the US Army Corps of Engineers, the Department of Interior or the Federal Energy Regulatory Commission.

The threshold issue under NEPA is whether to prepare an "environmental assessment" and issue a "finding of no significant impact" or to prepare an in-depth "environmental impact statement." The level of review depends on the likelihood of a significant impact on the environment. For large-scale projects, the lead agency will typically go straight to a full-blown environmental impact statement.

A total of 17 states have state environmental policy acts or so-called Little NEPAs that are triggered if there is a similar state "major action." For example, California, Massachusetts and New York have state environmental policy acts that implement similar NEPA-type requirements.

An environmental assessment or environmental impact statement can be time-consuming and costly to prepare. Some of the issues addressed include air quality, water quality, visual impacts, noise impacts, navigation, sediment deposition, archeological and cultural resources, and potential impacts on marine mammals, birds, shellfish, fish habitats and commercial and recreational fish populations. Other issues that may also have to be addressed include dredging impacts, utility line crossing agreements, local economic impacts, and recreational impacts.

NEPA requires the lead agency to take a "hard look" at the potential environmental consequences and, if there are significant impacts, evaluate what can be done about them, including potential mitigation measures. A full-blown environmental impact statement takes at least a year to complete. Courts do only a limited review of any conclusions that the lead agency reaches after looking over the environmental impact statement. The agency can be overruled only if its conclusions were "arbitrary and capricious, an abuse of discretion or contrary to law."

The NEPA and state environmental impact review proceedings and numerous federal, state and local permits and approvals have public review periods. There is often a 30- to 60-day public comment period for most permits and approvals. In some situations, affected community groups may petition for party status before FERC or a state siting board.

Project developers do best to develop a proactive strategy for handling permitting issues and anticipating areas of concern that may be raised by regulators or the local community.

One approach is actively to engage the local legislators and regulators, and schedule pre-application meetings to identify potential areas of concern. Public open houses may be used to educate the local community. The project should also keep in mind that potential project changes or mitigating measures may be necessary to secure local support.

Renewable Portfolio Standards

An increasingly important consideration in financing ocean energy projects is eligibility for renewable energy certificates, or "RECs." There are basically two types of RECs: compliance RECs that are bought and sold to satisfy a particular state renewable portfolio standard or voluntary RECs in states where there is no RPS. So far 20 states and the District of Columbia have adopted mandatory RPS requirements and more are expected to follow. While each state RPS is unique, all require that utilities and other retail electricity suppliers in the state increase the electricity that they sell from renewable fuels over time. For example, Connecticut requires that by 2005, in-state utilities must generate 4.5% of electricity from renewable energy, by 2007, 6.5%, and by 2010, 10%.

Most coastal state RPS measures identify certain ocean energy projects as renewable energy. For example, California, Connecticut, Massachusetts, New York, Rhode Island and Texas generally list wave, tidal and ocean thermal as qualifying renewable energy.

While REC markets are still in a formative stage, prices for compliance RECs in certain states have recently traded at very favorable prices. For example, vintage 2005 Massachusetts RECs reached $51 in April, and Connecticut RECs were trading at $33 in May. One REC corresponds to one megawatt hour of electricity produced from a renewable energy source.

Energy Bill

The energy bill that President Bush signed on August 8 provides some important incentives for ocean energy projects.

It makes ocean energy projects (including tidal, wave, current, and thermal) eligible for renewable energy production incentive, or REPI, payments from the US Department of Energy. The projects would be "tier 1 technologies." The tier 1 program directs the department to use 60% of the money it has available for REPI payments for payments to utilities. Utilities can apply for direct payments of about 1.5¢ a kWh.

The bill also creates a mandatory federal purchase requirement of not less than 3% of the electricity the government uses from renewable sources during 2007 to 2009. The percentage increases to not less than 5% between 2010 to 2012 and not less than 7.5% from 2013 and thereafter. Tidal, wave, current and ocean thermal technologies qualify as renewables for this purpose.

Finally, the bill authorizes federal grants to help fund research, development, demonstration and commercial application projects for various renewable energy technologies. Ocean energy projects qualify potentially for these grants. The bill also authorizes federal loan guarantees for up to 80% of project costs for renewable energy projects, including ocean energy. A project must use new or significantly improved technologies that are not yet in commercial service to qualify. ◎

Toll Road Update

by Jacob S. Falk, in Washington

States looking to use public private partnerships — called "PPPs" — to maintain existing roads or develop new toll roads are finding that no one model fits all needs. States have very different road infrastructure needs, and the PPP programs they implement reflect these realities.

New Jersey

New Jersey announced in July that it would like to lease portions of its major toll roads to private entities.

New Jersey has two developed toll highways running the length of the state. The New Jersey Turnpike runs north-south along the I-95 corridor, which connects Washington, Baltimore and Philadelphia in the south with New York City and Boston in the north. The Garden State Parkway also runs north-south but follows the Atlantic coast for most of its length. New Jersey's primary road infrastructure needs are to maintain its developed corridors and to protect the integrity of a transportation trust fund that funds all roadwork in the state.

The main problem is the transportation trust fund is expected to run out of money in just under a year. Beginning in July 2006, the entire $805 million budget of the fund will be needed just to pay debt service on existing loans, and there will be no money left over to maintain roads or build new highways. The New / *continued page 62*

Toll Roads

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Jersey Turnpike and the Garden State Parkway earn the state approximately $829 million a year, but they also currently carry approximately $5 billion in debt.

New Jersey said in July that it would address the transportation revenue shortfall by raising gas taxes and leasing portions of its two major toll roads to private entities. Richard Codey, the acting governor, floated the idea of privatizing the New Jersey Turnpike last March. The latest proposal is to lease a portion of either the New Jersey Turnpike or the Garden State Parkway to a private operator and to make up the rest of the revenue by raising gas taxes from the current rate of 14.5¢ a gallon (which is low even by US standards).

New Jersey is taking inspiration from the Chicago Skyway deal in which Chicago leased a 7.8 mile "Skyway" to a Cintra-Macquarie consortium for 99 years for an upfront payment of $1.83 billion. New Jersey could probably raise $20 billion if it did a similar lease of its main roads.

Other states along the I-95 corridor are considering the Chicago Skyway model for similar reasons. Delaware is working on a proposal to privatize the State Route 1 toll road that runs from Dover in the south to I-95 in the north. In New York, Governor George Pataki has floated the idea of privatizing state-owned bridges.

The Pennsylvania Senate created a committee recently to study private involvement in toll roads. The committee has been directed to study the feasibility of creating more tolls and using PPPs to raise money for highway projects. The committee must submit a report by August 15, 2006. The report is expected to focus on I-76, among other roads, but lawmakers stress that the report will most likely be broad and lead to further analysis before enabling legislation is passed.

The Chicago Skyway model appears to be most appropriate for states that have well developed corridors and existing toll roads with relatively predictable revenue streams, but that find themselves short of money.

North Carolina

A bill pending in the North Carolina legislature would revamp the PPP highway program in the state. North Carolina has two big interstate highways — I-95, which runs north-south, and I-85, which connects Atlanta, Charlotte and other cities to I-95. There are no toll booths currently on these roads. The politics of adding tolls are difficult; tolls for roads that have already been paid for are often seen as double taxation by opponents.

> A highway bill that President Bush signed in August will let states issue tax-exempt bonds to finance private road projects.

North Carolina has experimented with two ways to encourage private investment in state roads. The first is a PPP program administered by the North Carolina Turnpike Authority that allows for construction of three turnpike projects that use private money and charge tolls. The second method was a "private pilot toll project" that was run by the state department of transportation. It was supposed to lead to construction of one pilot toll road using solely private resources, but no road was built and the authority expired in 2003.

In June, both houses of the North Carolina legislature passed a bill that would increase the number of PPP turnpike projects that the Turnpike Authority may undertake from three to nine. One of the nine projects would have to be a toll bridge to the Outer Banks recreation area in Currituck County.

The move in North Carolina from wholly-private pilot projects toward establishment of public-private partnerships is similar to the evolution of toll road programs in two other states in the southeast. Virginia was one of the first states to enact a private toll road bill in the late 1980's, and it was also one of the first states to supplement its private toll road program with a PPP program in 1995.

Georgia also passed PPP-enabling legislation in 2003, five years after enabling wholly-private toll roads.

The North Carolina Turnpike Authority is currently studying four projects that could involve partnerships with the private sector. The projects are the Garden Parkway/US 321-74 bypass in Gaston and Mecklenburg Counties, the Cape Fear Skyway in Wilmington, the Monroe connector in Union County and the Triangle Parkway in the Research Triangle area (running parallel to US 40).

North Carolina does not have existing tolled corridors to privatize like New Jersey does. While New Jersey can leverage existing assets to raise funds, North Carolina can only offer the private sector a right to build new projects and collect a reasonable return on the investment through tolls.

Oklahoma

Oklahoma has no pressing need to look at PPPs, but it is doing so anyway.

Texas has embarked on an ambitious new transportation corridor that will provide a point of entry for trucks traveling from Mexico to the rest of the United States. This is expected to spill major truck traffic directly on to Oklahoma highways. Whether Oklahoma will move forward with new road development using PPPs depends on what happens to the south in Texas. Not only Oklahoma — but also Arkansas and Louisiana — may be forced to turn to the private sector to help develop the transportation infrastructure needed to handle the traffic heading north and east along the new Texas transportation corridors, which are being built to accommodate four lanes of purely truck traffic and six lanes of passenger car traffic.

Other States

Both Utah and Alaska recently expressed interest in engaging the private sector for road development. Utah appears interested in passing comprehensive legislation after consulting with experts from other states. Alaska hopes to procure the Knik Arm bridge project as a PPP.

In June, Utah announced that it will consider a full range of PPPs for future road construction. Utah needs $16.5 billion for road development over the next 25 years. State Senator Sheldon Killpack has promised that, despite voter distaste for tolls, someone on the transportation committee will sponsor a bill in the next legislative session allowing Utah to partner with private entities on toll roads.

Utah already has experience with PPP roads. Utah used a design-build procurement for reconstruction of the I-15 corridor in time for the 2002 winter Olympics. The PPPs currently under consideration would not be limited to design-build, but would include PPPs for the financing and operation of toll roads. Utah lawmakers have asked for advice from specialists in Texas and Colorado who have experience engaging the private sector.

An Alaskan road authority, the Knik Arm Bridge and Toll Authority (KABATA), is looking to build a $400-$600 million bridge from Anchorage to Mat-Su borough on a PPP basis. The authority is authorized to sell revenue bonds and to collect tolls. KABATA received preliminary funding from the legislature and expects to present the legislature with a detailed financing plan by February 2006. The project, which may be tendered in the first half of 2006, will be funded by a combination of federal, state and local grants and public and private sector loans, including TIFIA loans. TIFIA — the "Transportation Infrastructure Finance and Innovation Act of 1998" — provides public and private sponsors of road projects with supplemental subordinated credit, loan guarantees or loans of up to 33% of project cost from the federal government.

Federal Highway Bill

A massive highway that Congress passed in late July encourages states to implement PPPs.

The bill would let state and local governments issue tax-exempt "private activity bonds" to finance highway projects and certain freight transfer facilities. "Private activity bonds" are bonds whose proceeds will be put to private use — for example, to finance a road that will be privately owned. The bill authorizes a total of $15 billion of such bonds to be issued. All such bonds must be issued by December 2015. All projects that benefit from the bonds must pay workers prevailing wages in accordance with the Davis-Bacon Act.

Another provision in the bill reduces the required minimum project cost for a project to qualify for TIFIA funds from the federal government. The rule had been that a project had to cost at least $100 million or, if less, half the federal funds apportioned to the state in which the project is located. These figures have now been reduced to $50 million or, if less, a third of the apportioned funds. The bill also makes clear that public-private partnerships can apply for funds under the TIFIA program. ◎

Environmental Update

Clean Air Interstate Rule

Utilities and environmental groups wasted little time in challenging the "clean air interstate rule" that requires 28 eastern states and the District of Columbia to reduce nitrogen oxide, or NO_X, and sulfur dioxide, or SO_2, emissions from power plants and other pollution sources by 2015.

The groups filed a series of lawsuits in June and July in the US appeals court in Washington. The US Environmental Protection Agency published the clean air interstate rule in May.

The rule assigns each of the 28 affected states an emissions budget. Each state must comply in one of two ways. It can participate in an EPA-administered cap-and-trade program that ratchets down NO_X and SO_2 emissions from power plants in two stages starting with an initial NO_X cap in 2009 and an SO_2 cap in 2010 followed by lower caps for both pollutants in 2015. Alternatively, a state may propose other emission reduction measures, including roping in other sectors besides power plants to spread the reductions across a wider number of facilities.

EPA says the clean air interstate rule will reduce NO_X emissions by more than 60% and SO_2 emissions by more than 70% in the 28 states from 2003 levels. The rule is really aimed at reducing the amount of NO_X and SO_2 that cross state lines and contribute to air pollution in states that are downwind from large fossil-fuel power plants. NO_X and SO_2 are precursors of fine particulates, or PM2.5, and NO_X is a precursor of ozone or smog.

The parties challenging the clean air interstate rule have various complaints. For example, environmental groups complain that the rule exempts power plants from a separate "regional haze rule" that is supposed to protect visibility near national parks and federal lands. North Carolina sued to block two parts of the rule that could allow more pollution from neighboring states. One utility charged in its lawsuit that states that rely heavily on natural gas and oil to generate electricity are being required to make more significant reductions in NO_X emissions than states that use coal. This is due to the way EPA calculated the fuel adjustment factors in calculating state NO_X budgets. Other plaintiffs in the lawsuits argue that all or at least a portion of Florida and western Texas should be excluded from the clean air interstate rule because emission sources in those areas do not contribute significantly to air pollution in downwind states. The Integrated Waste Services Association is arguing that the clean air interstate rule should not apply to waste-to-energy facilities. Some of the complaints are in petitions filed with the Environmental Protection Agency asking the agency to reconsider parts of the clean air interstate rule. The cases filed in the US appeals court in Washington have been consolidated into a lead case titled *North Carolina v. EPA*.

For the time being, the lawsuits and the petitions for reconsideration filed with EPA will proceed on parallel tracks. At the end of the day, only selected provisions in the clean air interstate rule are really at issue. The rule is expected largely to survive the legal challenges since it is modeled after a "NO_X SIP call rule" that remained largely intact after a protracted legal battle.

However, the US government is not taking chances. In early August, EPA proposed a "federal implementation plan" as a backstop to ensure that the clean air interstate rule will be implemented on time by the 28 affected states and the District of Columbia. The backstop plan simply imposes a cap-and-trade emissions program to achieve the mandated NO_X and SO_2 reductions. The backstop plan does not limit the ability of each state to submit its own plan, and EPA will withdraw the federal plan for each state whose plan it approves. The federal implementation plan also cover Delaware and New Jersey — two states that are not otherwise part of the 28 states covered by the clean air interstate rule. The federal implementation plan is merely proposed at this point. EPA hopes to adopt a final plan by March 15, 2006.

In related news, seven Canadian environmental groups petitioned EPA to require Ohio, Illinois, West Virginia, Indiana, Kentucky, Michigan and Pennsylvania to reduce NO_X and SO_2 emissions beyond what the clean air interstate rule requires. The petition also calls for reductions in carbon dioxide, or CO_2, from emission sources in the seven states. The Canadian groups complain that pollution from 250 coal-fired power plants in the Ohio valley and nearby states is contributing to smog, acid rain and climate change in Canada.

The petition was filed under section 115 of the Clean Air Act, a seldom-used provision that allows EPA to act after a report from an international agency concludes that air pollution originating in the US may reasonably be endangering public health or welfare in a foreign county. Section 115 authorizes EPA to direct states that are the source of the pollution to take action.

At the end of the day, the US government is unlikely to order the seven states to take further steps in response to the Canadian petition beyond what they are already required to do by the clean air interstate rule. The Canadian case could end up in the US courts. The Canadian groups would probably have "standing" to pursue a case there.

Climate Change

President Bush acknowledged that climate change is "a serious long-term issue that needs to be dealt with" before heading to the G-8 economic summit in Scotland in July. Bush said the US will continue to focus on research on climate science and on developing new technologies to address global warming. He remains steadfast in his opposition to mandatory reductions in greenhouse gases.

Climate change issues were one of the key topics addressed at the summit. The communiqué released at the end reaffirmed that the G-8 countries want to stabilize greenhouse gas concentrations in the atmosphere and find ways to achieve substantial reductions in emissions. The G-8 countries include the United States, Japan, Germany, France, Italy, Canada, Russia and the United Kingdom.

In late July, President Bush announced a new partnership among Australia, China, India, Japan, South Korea and the United States that is supposed to "develop, deploy and transfer cleaner, more efficient technologies" to reduce greenhouse gas emissions and other air emissions. The partnership does not commit the six nations to any mandatory greenhouse gas reductions.

In related news, the European Commission has now approved national allocation plans for all 25 member countries that are participating in the European Union greenhouse gas emissions trading scheme. The first phase of the trading program covers 2005 to 2007, and 11,428 industrial facilities in the member countries are subject to the program. The second phase of the trading program will cover 2008 to 2012 and will be the primary mechanism for the European countries to comply with mandatory reduction targets in the Kyoto protocol. In June, European Union greenhouse gas allowance prices spiked at an all-time high of more than €30 per ton of CO_2 emitted, and since then the price has fallen back to around €20 per ton.

The US Congress rejected several attempts this summer to impose controls on greenhouse gases in the United States as part of an omnibus energy bill. The final bill went to the president in late July, and he signed it on August 8. It includes a section on "climate change." The bill provides for the creation of a "committee on climate change technology" charged with implementing a national climate change technology strategy. The strategy is supposed to promote commercialization of new greenhouse gas reduction technologies. It will also include standards and best practices for calculating, monitoring and analyzing greenhouse gas *intensity*, or the amount of greenhouse gases that US emits per dollar of gross domestic product. The US Department of Energy will have money to pay part of the cost of demonstration projects that show off new technologies.

The climate change section of the energy bill also directs the US State Department to *coordinate* assistance to developing countries for projects that reduce greenhouse gas emissions through a new "greenhouse gas intensity reducing technology export initiative." The details of the new initiative have been left to an interagency working group. The State Department is supposed to carry out projects to demonstrate new technologies in at least 10 developing countries. The eligible technologies include coal gasification, clean coal projects, carbon sequestration, cogeneration technologies, renewable energy projects and low-emission transportation.

In July, a US appeals court in Washington sided with the US government on the issue whether the government should set motor vehicle emission standards for CO_2 and other greenhouse gases. The Environmental Protection Agency has declined to set such standards. The court said, in a 2-1 decision, that EPA exercised its discretion properly when it denied petitions by a number of states and environmental groups urging it to do so. The court did not address whether EPA has legal authority to regulate CO_2 and other greenhouse gases as "air pollutants" that might adversely affect "public heath or welfare" under the Clean Air Act. The one dissenting judge said that EPA not only has the authority but also the "obligation" to regulate greenhouse gas emissions from motor vehicles. The plaintiffs are expected to seek a rehearing */ continued page 66*

before all 11 judges of the US appeals court in Washington, and possibly pursue an appeal to the US Supreme Court if the rehearing request is unsuccessful.

Mercury

The Environmental Protection Agency agreed in June to take another look at whether the regulation of mercury and other hazardous air pollutants from coal-fired utilities is "necessary and appropriate." This follows on the heels of an EPA announcement in March that the regulation of mercury from coal-fired plants under the section 112 air toxic provisions of the Clean Air Act is no longer "necessary." EPA is under pressure from 14 states and five environmental groups to reconsider its March decision.

The March decision was of critical importance because it paved the way for issuing a "clean air mercury rule," which uses a two-phased "cap-and-trade" approach to achieve reductions in mercury emissions from existing coal-fired power plants instead of the "command-and-control" regime that that would typically have been imposed under section 112.

In the letter granting reconsideration, EPA said that its "preliminary review of the petitions has not convinced us that our final decisions were erroneous or inappropriate." It refused to delay implementation of its mercury rule in the meantime and suggested that people not conclude from its actions that "we agree with the petitioners' claims."

Most of the same states and environmental groups have also filed lawsuits with the US court of appeals in Washington challenging the clean air mercury rule. The appeals court will make a decision whether to "stay" enforcement of the rule while it reviews what EPA has done.

The clean air mercury rule is controversial, and there is an effort in Congress to overturn it using the Congressional Review Act of 1995. That statute lets Congress overturn an agency regulation by a majority vote. Resolutions calling for reversal of the clean air mercury rule have been filed in both the House and Senate, and the issue will probably be put to a floor vote in the Senate.

Senators Patrick Leahy (D-Vermont) and Susan Collins (R-Maine) are leading the effort in the Senate. They and 30 other Senators filed a "discharge petition" to send the resolution directly to the Senate floor without requiring a vote in the Senate environment committee. The resolution is unlikely to get a vote in the House where Republican leaders have more control over the floor schedule. Nevertheless, the congressional efforts to overturn the clean air mercury rule keep the pressure on EPA, and provide another forum for critics of the agency decision to deviate from the more traditional approach 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." Strict MACT limits would probably require reductions in mercury emissions by as much as 90% at 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 the clean air mercury rule, the first phase of the mercury reductions commences in 2010 with a 38-ton cap followed by a reduction to a 15-ton cap in the second phase starting in 2018.

Under the clean air mercury rule, states have the option of participating in a model EPA cap-and-trade program or of electing to adopt their own state programs to reach mercury reduction targets.

Decisions in the lawsuits challenging the EPA actions in this area are not expected until late 2006 or early 2007.

New Source Review

After more than 12 years of rulemaking deliberations and litigation, a decision by the US appeals court in Washington in *New York v. EPA* added some much-needed certainty to determining which air emission sources are subject to the "new source review," or NSR, air permitting program. Most new power plants and factories — including improvements at existing facilities — must undergo an NSR permit review before construction can start. The Bush administration made changes to the NSR rules in December 2002, and the changes were immediately challenged by 14 states and various environmental groups.

The US appeals court in Washington upheld the more controversial parts of the rule, including the government's approach to calculating baseline emissions and measuring a significant net emissions increase. The court also agreed that EPA's "plant-wide applicability limitation" or PAL provision was not arbitrary and capricious. The PAL provision allows a company to take an emissions cap at a facility and make necessary changes to emission units without going through NSR permitting so long as the emissions stay under the cap.

However, the court set aside two parts of the EPA rules that let certain "clean units" and "pollution control projects" avoid NSR permitting. EPA has allowed certain exceptions to NSR permitting for pollution control projects for years, and Congressional action may now be required to authorize these types of exemptions. The court held that the two EPA-created exceptions to the NSR program were not authorized by the Clean Air Act.

The latest court decision brings into clear view a significant split in the federal appeals courts over whether the term "modification" as used in the NSR program has the same meaning as in the "new source performance standards," or NSPS, program. This is significant because it is much harder to trigger a "modification" under the NSPS program. Under the NSPS program, a modification occurs when there is an increase in the hourly emission rate. In the NSR program, a modification is triggered when there is a significant increase in annual emissions at a plant. For example, modifications to a boiler that restore the unit to its original hourly emission rate would not trigger a modification under the NSPS program, but they would probably trigger a modification under the NSR program.

The court said in the *New York v. EPA* decision that Congress did not require EPA to use the NSPS definition of "modification" in the NSR program. Two other courts came to the opposite conclusion in June. The US appeals court in the 4th circuit said EPA had to use the NSPS definition in a June 15, 2005 decision in *US v. Duke Energy Corp.,* and a federal district court in Alabama said the same thing in *U.S. v. Alabama Power Company* in early June. In early August, the US Department of Justice asked the entire panel of judges on the 4th circuit appeals court to review the decision. If this request is denied, then the Justice Department might try to have the *Duke Energy* decision reviewed by the US Supreme Court.

The *New York v. EPA* decision is generally a victory for the regulated community, and the NSR revisions that were upheld should be helpful in making the NSR permitting process a little less complex and time consuming.

In related news, an NSR enforcement action against American Electric Power went to trial in early July. Final briefs in the case are due by early September with closing arguments set for September 19. Pennsylvania, Connecticut, Maryland, New Jersey and New York filed suit against Allegheny Energy in a US district court in Pennsylvania alleging that Allegheny Energy undertook major modifications at six coal-fired generating units in Pennsylvania that significantly increased the emissions without obtaining NSR permits. A decision in the case is not expected until 2006.

EPA also announced in June that it plans no further changes in the types of "routine maintenance, repair, and replacement" of equipment that can be done at existing power plants without the need for an NSR permit. Several environmental groups petitioned the agency to revisit the definition. EPA said that it believes that its current definition — adopted in October 2003 — is "fully justified and will provide much needed clarification to the NSR program while still ensuring environmental protection." However, the US appeals court in Washington has put enforcement of the current definition indefinitely on hold until the court decides the merits of lawsuits filed by several state and local governments and multiple environmental groups.

Regional Haze

EPA issued a "clean air visibility rule" in early July that will require states to identify older power plants and industrial facilities that should be subject to "best available retrofit technology," or BART, requirements.

The potentially affected plants were built between 1962 and 1977 and have the potential to emit more than 250 tons a year of NO_X, SO_2, PM2.5 or volatile organic compounds that affect visibility in so-called class I areas, such as national parks or federal wilderness areas.

States will have until December 2007 to identify the facilities that will have to install BART controls. Upon approval of the state plans, there will be a five-year implementation period, and most of the required emission reductions are expected to take effect in 2014, with full implementation anticipated before 2018.

The program has the potential to affect large utility and industrial boilers as well as significant industrial plants such as pulp mills, refineries and smelters. As many as 800 power plants and 2,300 industrial combustion sources are potentially affected. The BART controls could be expensive to install.

In mid-July, EPA proposed letting states adopt an emissions trading program as an alternative to ordering BART controls. The BART requirements for affected sources in the state would be satisfied if the trading program meets or exceeds the visibility benefits resulting / continued page 68

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from BART-level controls. The proposed rule will be subject to a 45-day comment period after the rule is published in the *Federal Register*. EPA expects to take final action on the proposed BART emissions trading rule by November 2005.

Brief Updates

The Texas legislature voted to increase the amount of electricity that utilities in the state must supply from renewable fuels from 2,880 megawatts by 2009 to 5,880 megawatts by 2015. The bill also sets a target of 10,000 megawatts by 2025. Texas Governor Rick Perry is expected to sign the bill into law. The current "renewable portfolio standard" requires 2,880 megawatts from renewables by 2009, but the state is on track to reach this level by next year.

In California, the Alameda County board of supervisors gave preliminary approval in July to new 13-year permits for about 3,000 existing wind turbines in the Altamount Pass area to continue operating. The Board of Supervisors imposed nine new conditions to reduce bird deaths, including the immediate shutdown of the most dangerous 2% of wind turbines and restrictions on winter operation when turbines pose the most danger to raptor and songbird populations. All of the turbines must be shut down for two months during the winter for the first five years and 3½ months during the winter thereafter. Other conditions include a requirement that 10% of the wind turbines be repowered or removed in the next four years with 100% of the wind turbines being repowered or replaced within 13 years as well as completion of an environmental impact report for the entire area within three years. The board of supervisors will take final action on the permits in September. Environmental groups are threatening to sue to stop the permits from being issued.

The Illinois Commerce Commission approved a renewable portfolio standard in July that will require Illinois utilities to supply 2% of their electricity from renewable fuels by 2006. The amount will increase to 8% by 2013. Illinois has had only a voluntary program to date. It becomes the 20th state to adopt a renewable portfolio standard. Under the Illinois plan, at least 75% of the renewable energy must come from windpower by 2013.

The EPA staff issued a final "staff paper" that recommends revisions to the standards for fine particulates or $PM_{2.5}$ and coarse particulates or PM_{10}. Existing rules for fine particulate matter were first set in 1997. EPA now has until December 20 this year to evaluate whether the particulate standards should be revised under terms of a consent decree with the American Lung Association. A final rule must be issued by September 27, 2006. It is not clear whether the agency will adopt the staff recommendations and make the existing particulate standards more stringent.

The Bureau of Land Management has developed a model form of environmental impact statement for wind projects on public lands in 11 western states, including Alaska. This is supposed to make for faster consideration of environmental issues that must be evaluated before the Bureau of Land Management can authorize construction of a wind farm on public land. ◎

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