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PROJECT FINANCE

NewsWire

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Master Limited Partnerships

by Keith Martin, in Washington

Some project developers in the United States have been trying to reorganize recently as "master limited partnerships" in an effort to create more value in their companies.

The move also gives them an acquisition vehicle that can afford to outbid other companies for existing assets.

Most income earned by corporations in the United States is taxed twice — once to the corporation and again to the shareholders when they receive the earnings in the form of dividends.

US and Canadian businesses have been searching for ownership structures that would subject their earnings to tax only once.

Many Canadian companies found a way to do this by converting to "income trusts." Units are traded on the Toronto stock exchange, and such trusts now account for 10% of companies traded on the exchange by market capitalization. The Canadian government became concerned about the loss of tax revenue and put a halt last fall to any further advance tax rulings that such structures work until it could complete a study. However, the government came under pressure to make a decision in the run up to the January election after realizing that as many as 60% to 80% of Canadian retail investors, many of them senior citizens, hold interests in income trusts. In late November, the finance minister made a surprise announcement that the government would resume issuing advance tax rulings, not tax trusts and instead / *continued page 2*

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WIND DEVELOPERS have been helped by two favorable tax rulings.

The United States encourages construction of wind farms by allowing anyone generating electricity from wind at a US location to claim "production tax credits" of 1.9¢ a kilowatt hour on the output. The credits are claimed for 10 years after a plant is placed in service. However, they are subject to reduction by up to 50% to the extent the project benefits from government grants, tax-exempt financing, "subsidized energy financing" — meaning financial help under a government program directed at energy projects — or "other credits."

The Internal Revenue Service ruled in February / *continued page 3*

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cut dividend taxes as a way to make corporations more competitive. The government lost the January election.

An equivalent structure in the United States is a "master limited partnership," or "MLP." MLPs are limited liability companies or partnerships whose interests are traded on a stock exchange or over-the-counter market. The United States usually taxes partnerships in which interests are publicly traded like corporations, but there are exceptions in the US tax code that let many oil, gas and timber companies operate as publicly-traded companies while being taxed like partnerships. A partnership does not pay income taxes; rather, its income is taxed directly to the partners that own it.

Companies that own wind farms, LNG regasification terminals, ethanol plants and hydroelectric projects, among other types of assets, have been asking in recent months whether they can use the same structure. Operating as a publicly-traded partnership not only eliminates one level of taxes, but it also lets the company raise equity at the higher multiples for shares in which there is a liquid market. These two advantages give MLPs higher after-tax returns and a lower cost of equity capital, making them not only good vehicles to own new projects but also good acquisition vehicles for rolling up existing assets.

There were 57 MLPs trading on the two main US stock exchanges and NASDAQ as of February 2006.

Most involve energy assets. Estimates are that only 20% of eligible energy assets in the United States are held currently in MLPs. Even in the most advanced sector for current use of MLPs — oil and gas pipelines — MLP coverage extends to only 34% of existing assets. The market capitalization of energy MLPs more than doubled from 2002 through 2005, moving from $28.9 billion to $64.4 billion. Daily trading volume in energy MLP interests went from 88,300 shares to 128,600 during the same period. The two largest MLPs — Kinder Morgan and Enterprise Products Partners — have market capitalizations of more than $10 billion each. Another 20 MLPs have market capitalizations of more than $1 billion.

Master limited partnerships can afford to outbid other companies for existing assets.

Eligible Income?

The key to qualifying as an MLP is to make sure that at least 90% of the gross income the MLP earns each year is considered eligible income.

The types of eligible income are mostly various forms of passive income. Examples are interest, dividends, rents from leasing out "real property" (as opposed to equipment), and gains from the sale of capital assets and real property.

Congress said that, in general, it wanted MLPs to be used only by passive investors rather than to engage in real operating businesses. However, it made an exception that is at the core of most energy MLPs. The exception treats as eligible income

> income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber).

The key is the MLP must do something to a "mineral or natural resource."

Geothermal energy, fertilizer and timber are considered natural resources, but Congress said that "fishing, farming . . . [and] hydroelectric, solar, wind, or nuclear power production" are not activities that deal in minerals or natural resources. Inexhaustible resources, even if natural resources, do not qualify. Examples of inexhaustible resources are soil, sod, turf, water, air and minerals from sea water.

Thus, wind farms, solar power plants and hydroelectric projects are generally not suitable assets for MLPs.

It may be possible for an MLP to own a hydroelectric project, but lease it to someone else and receive earnings from the project in the form of real property rents. Most other power projects are not considered "real property." Internal Revenue Service officials have left open the possibility that a hydroelectric plant is such property. The rents could be tied to gross receipts from electricity sales, but not to profits. The lessee could not have an ownership interest in the MLP.

Landfill gas projects are not suitable for MLPs because gas from decomposing garbage is not considered a "natural" resource.

The US tax authorities have not addressed whether power plants that convert fossil fuels into electricity are suitable assets. Such plants arguably process coal, gas or oil by converting it into electricity. However, while energy MLPs that process oil and gas clearly qualify, IRS regulations draw a line at downstream processing from the point where the product is no longer recognizable as oil or gas. Thus, refining oil or gas to produce butane, propane or diesel fuel is a suitable MLP activity, but not further processing to make plastics. The IRS has also not addressed whether transmission lines that transport electricity made from burning fossil fuels are suitable assets. Income from transporting processed products of minerals or natural resources is good income, but not from the last stage of transportation to retail customers. IRS regulations make clear that a utility buying natural gas to fuel its power plants is not considered a retail customer.

Most existing MLPs involve oil and gas pipelines, gas storage facilities, non-producing interests in oil and gas properties, ships for transporting oil and liquefied natural gas, fertilizer factories, timber land, lumber mills and factories that make wood products, interests in coal mines and commercial real estate properties. The assets do not have to be in the United States. MLPs have also been used to roll up lots of small propane distributors.

The IRS has issued a series of private letter rulings that shed additional light on what kinds of businesses may be engaged in by MLPs.

An MLP may own an aluminum / continued page 4

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that state or local tax credits are not "other credits." It said Congress had in mind only other federal tax credits.

The ruling is Revenue Ruling 2006-9. It represents a welcome change in position by the IRS. The agency's view previously had been that state tax credits that are tied to the capital cost of the project cause a haircut in the production tax credits that can be claimed, but state tax credits that are tied to output do not.

Some projects in California, Hawaii, Montana, North Carolina, Oregon and Utah may be entitled to tax refunds from the US government.

In another significant development, the IRS ruled privately that the standard "partnership flip" structure that many wind developers use to "monetize" tax credits on their projects works. In the transaction at issue in the ruling, the sponsor brought an institutional equity investor who can use the tax credits into a partnership that owns a wind project. The partnership allocates all the cash flow to the sponsor until it gets back its capital. It allocates the institutional investor all the taxable income, depreciation deductions and tax credits — and cash once the sponsor has gotten back its capital — until a "flip date" after the tax credits have run. After that, the investor's interest in the partnership flips down to less than 10%. The IRS ruled essentially that the institutional investor is entitled to all the tax credits.

The ruling is significant for three reasons. First, while most tax counsel in the industry had been taking the position that production tax credits must be shared among partners in the same ratio they share in taxable income, this was not absolutely clear. IRS regulations require credits to be shared in the same ratio as the partners share in "receipts" from electricity sales. Partnerships where cash is allocated differently than taxable income tested the proposition that / continued page 5

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smelter that buys alumina made from bauxite from other companies and turns it into aluminum.

Fees that blenders earn from mixing ethanol or biodiesel with petroleum fuels and fees earned by pipeline operators are good income. However, fees earned arranging oil or gas hedges for third parties are not from an eligible activity.

At least 90% of the *gross* income the MLP earns each year must be eligible income. Losses are ignored in doing this calculation. The MLP adds up all of its income from all sources during the year and tests whether at least 90% of it is eligible income. Once the MLP fails this 90% test in a year, then it loses its status permanently as an MLP, unless the failure to qualify was inadvertent and the MLP takes steps within a reasonable time after learning of the problem to correct it. The MLP will also have to pay a tax charge to put it in the same position as if it had been taxed like a corporation during the period it failed the 90% test. Congress said the IRS can refuse to accept screw ups as inadvertent if they occur in each of "several successive years, or in several years within a longer period." A footnote in a Congressional committee report suggests that there should be a three consecutive-year limit on relief. Congress said action within one year after discovery to correct a problem is "within a reasonable time," unless the IRS says otherwise in regulations.

Practical Considerations

Many MLPs are organized as two-tier businesses. A holding company owns interests in operating companies. The reason for this is archaic statutes in some states where there are operating businesses that require the names and addresses of all the limited partners be filed with state authorities. Trading is limited to interests in the parent holding company.

In most MLPs, the general partner or managing member takes an increasing share of cash distributions as an incentive to try to increase the annual distributions per unit. Thus, for example, a general partner might receive a 2% share of the first dollar in cash distributed per unit, increasing to 15% of the next dollar, 25% of the next dollar, and 50% of annual distributions above $3 a unit. General partners have an incentive to increase cash distributions until the company is operating in the "high splits" tier.

Only 20% of eligible energy assets in the United States are held currently in MLPs.

MLPs have not traditionally tried to raise capital from pension plans and other tax-exempt investors or from retail investors investing through mutual funds. The problem mutual funds faced is that MLP income was not among the kinds of "qualifying income" that a mutual fund can earn and retain its tax status. This changed in the JOBS Act in October 2004, with the result that more mutual fund money is expected to flow into MLPs. A mutual fund may still not invest more than 25% of its total assets in MLPs and more than 10% of assets in a single MLP.

The problem pension plans and other tax-exempt investors face is that their income from energy MLPs that are real operating businesses is classified as "unrelated business taxable income" — it is not related to their tax-exempt missions. Such investors can earn passive income without problems, but they must pay income taxes on any active income from operating businesses or else they could compete against private-sector companies and have a competitive advantage because their earnings go untaxed. Active income from an energy MLP retains its character as active income as it passes through the MLP.

Only about 10% of money invested in MLPs is from institutional investors. Another deterrent to such investors is the potential need to file state income tax returns in states where the MLPs are doing business. Two large MLPs — Kinder

Morgan and Enbridge Energy — have attempted to deal with this problem by allowing pension funds and other institutional investors to invest through special "i-units." The holders of the i-units are not allocated any taxable income or loss by the MLP, and distributions to them are in the form of additional units rather than cash. Such investors earn their returns by selling their units.

Since MLPs are transparent for tax purposes, any depreciation, depletion and other tax losses pass through to the investors. MLPs that are growing through acquisitions typically have lots of tax write offs that provide shelter against income taxes. The tax shield in the case of most energy MLPs is on the order of 80 to 90%. In other words, the taxable income reported each year by investors is only 10% to 20% of the cash distributed. The tax shield is "recaptured" at ordinary income tax rates later when the investor sells his or her interest. Gain from the sale of units is recharacterized as ordinary income to the extent of the depreciation and depletion from which the investor benefited earlier.

The combination of transparent tax treatment and public trading of units gives MLPs a much lower cost of equity capital than corporations with whom they might compete. However, the cost advantage erodes somewhat over time as the MLP moves toward the "high splits" on sharing cash with the general partner.

One problem that regulated businesses face when operating as MLPs is the inability to pass through taxes to ratepayers when the taxes are imposed one tier up on the owners rather than on the business directly.

However, the Federal Energy Regulatory Commission directed in 2005 that partnerships that own regulated businesses should be able to pass through taxes that are imposed on the partners. The partnership must calculate the average income tax rate of all the partners. The FERC order has direct application only to businesses whose rates are set by the federal government. Retail utility businesses tend to be subject to state rate regulation. Electric transmission, interstate gas transportation and wholesale electric and gas sales are subject to federal regulation.

Publicly Traded?

The IRS has a fairly technical definition of what it means to be publicly traded. Thus, a company worried about whether at least 90% of its gross income each year will be eligible income might focus instead on ensuring / continued page 6

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"receipts" from electricity sales are taxable income rather than cash. The IRS now agrees the word "receipts" means taxable income.

Second, many tax counsel take the position that investors in wind farms and other assets that throw off large tax benefits must expect at least a modest pre-tax return from the investment; their return cannot be solely in the form of tax benefits. The IRS acknowledged in the ruling that production tax credits can be treated like cash for purposes of any pre-tax return calculation. Finally, the ruling also acknowledges that the post-flip percentage interest owned by the institutional investor can be in the single digits.

In related news, Union Bank of California, N.A. secured an opinion from the US comptroller of the currency that it can invest as an equity participant in wind farms because the partnership flip structure that project developers use to "monetize" tax credits is merely a form of financing rather than a true equity investment. Banks can finance — but not own — real estate, except in limited situations.

At first glance, the conclusion is at odds with the position that the parties to these transactions are taking with the US tax authorities. However, inconsistencies are possible where two laws — for example, the tax code and the banking regulations — define terms differently. In this case, it appears that the bank had to make promises to the comptroller that will strain the tax analysis.

The bank said that it would take nonvoting interests in wind farms. It also assured the comptroller that it would hold an interest in a project only for 10 years until the tax credits have run and that, "promptly on expiration of this holding period, the Bank would sell its interest" in the project back to the sponsor. The comptroller based his conclusion that the bank is merely providing financing — and not taking a real ownership interest in the project — in part on a finding that the bank will not share in the appreciation or / continued page 7

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that ownership interests in the company are not considered "publicly traded." It is possible to allow some trading of the interests without causing the company to be taxed like a corporation. The interests could not be listed on a stock exchange or NASDAQ.

Restricting trading may not be a satisfactory approach since the company will not benefit fully from the higher multiples for publicly-traded shares.

Thus, knowledge of the rules in this area is probably more useful to ensure that a limited liability company or partnership does not become taxed like a corporation *inadvertently* due to limited trading in its shares.

In general, shares are considered publicly traded if they are listed on a stock exchange or are "readily tradable on a secondary market (or the substantial equivalent thereof)." Congress said shares are not be considered "readily tradable" on a secondary market unless the share prices are regularly quoted by someone who is making a market in the shares. Also, the time frame to complete a trade must be comparable to trading on an established exchange. Thus, interests are not readily tradable where one can find a quote on a computer system, but the interests cannot be sold within the same time frame as on an over-the-counter market.

The LLC or partnership must also facilitate the trading. It must have listed the shares or at least accept investors who buy shares as new partners for the shares to be considered publicly traded.

Share redemption or repurchase plans are potentially a problem. These are arrangements where the partnership stands ready to buy back interests from any partner who wants out. "Closed-end" redemption plans are okay. That is where a partnership may buy back shares but does not issue any new ones after the initial offering. Alternatively, it is okay if the MLP makes partners trying to cash out wait at least 60 days after giving notice. The redemption price must be set at the time of redemption or on no more than four dates during the year, and no more than 10% of partnership profits or capital interests can be transferred during the year.

The fact that LLC or partnership interests are sold in a private placement is not a problem, as long as the company will not have more than 100 partners. ◎

Energy MLPs must earn at least 90% of gross income from producing, processing or transporting a "mineral or natural resource."

FERC Moves to Require Rate Filings by QFs

by Robert F. Shapiro, in Washington

Owners of some US power plants — called "qualifying facilities" or "QFs" — will have to make rate filings with the federal government under new rules issued by the Federal Energy Regulatory Commission on February 2.

The requirement affects all new QFs and all existing QFs that are not selling all their output under existing contracts.

QFs whose existing contracts expire will have to make rate filings for wholesale sales even if they renew their contracts or sign new ones.

QFs are two kinds of power plants whose construction the US government encouraged under a 1978 law called the Public Utility Regulatory Policies Act or "PURPA." The two are cogeneration facilities that produce two useful forms of energy from a single fuel — an example is a power plant that produces steam and electricity by burning coal — and small power plants of up to 80 megawatts in size that use renewable or waste fuels.

The immediate effect of the new rule is that QFs that are not selling all of their output under contract will have to make a FERC filing for market-based rate authorization promptly. The rule takes effect 30 days after publication in the *Federal Register.*

FERC also made it harder for cogeneration facilities to qualify in the future as QFs.

Rating Filings

The requirement that QFs make rate filings was not dictated by the new Energy Policy Act that President Bush signed last August. The fact that the FERC took this action, which removes the QF exemption from rate regulation that was contained in FERC's original rules implementing PURPA, serves as additional evidence that the commission intends to do what it can to dismantle the PURPA program.

In other respects, the new rules issued by FERC on February 2 merely implement what FERC was directed to do by Congress.

FERC claimed that eliminating the QF exemption from rate regulation would not "cause undue uncertainty or upset the legitimate expectations of QF owners and lenders." FERC reasoned that, since the exemptions were always subject to revision, QFs "had no justifiable expectation that, no matter the change in circumstances, changes in the regulatory regime would not occur." Notwithstanding FERC's argument, FERC appears to have ignored the US Supreme Court's finding in *FERC v. Mississippi* that the principle reasons for reluctance to develop alternative energy facilities were the developers' fear of *traditional* rate regulation and the utilities' refusal to buy power from developers.

FERC also argued that removal of the exemption from rate regulation does not affect QF status or a utility's purchase obligation. This response is disingenuous at best since, while technically true, it ignores the fact that FERC, in another rulemaking, has proposed to eliminate the QF purchase obligation in four key regions and QF status is of little value if there is no assured market and if a QF's rates must be filed just like every other private utility in the country.

There is also a serious question whether the application to existing QFs of a new rule eliminating regulatory exemptions violates the rule against retroactive rulemaking. FERC has chosen not to explain why it believes a QF developer had no reasonable basis to believe it could rely on the ratemaking exemption in making its decision to / continued page 8

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depreciation in value of the project.

The bank will need to show the US tax authorities that it is not legally compelled to exit the project after 10 years in a manner that leaves it unexposed to any change in value of the wind farm.

PROJECT DEVELOPERS must apply to the Internal Revenue Service by October 2 to claim two new federal tax credits for "advanced" coal-fired power plants and gasification projects.

The credits pay as much as 20% of the cost of a project. They are not limited to projects that gasify coal, but can also be claimed on projects to gasify biomass, petroleum residues and other materials. Gasification means conversion into a synthesis gas composed primarily of carbon monoxide and hydrogen.

Applicants will be informed by November 30 whether they have been awarded credits.

The new US energy law enacted last August authorized a 20% investment tax credit for new IGCC (integrated-gasification combined-cycle) power plants. The credit can be claimed only on part of the plant — the equipment that is "necessary for any coal handling and gas separation equipment." There is a 15% investment tax credit for other power projects that use "advanced" technology to generate electricity from coal. In such other projects, the credit can be claimed on the entire plant. The project can be a new power plant or a retrofit or repowering of an existing plant.

The new law also authorized a separate 20% investment tax credit for gasification projects.

Total credits are limited to \$1.3 billion for advanced coal-fired power plants, of which \$800 million is supposed to be set aside for IGCC plants and \$500 million for other coal-fired power plants. Credits for gasification projects are limited to \$350 million.

Project developers / continued page 9

QF Rates

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invest in a QF project, particularly in light of the Supreme Court's pronouncement in *FERC v. Mississippi*.

Small QFs will not be subject to this new rate regulation. FERC determined that QFs that are 20 megawatts or smaller in size will remain exempted from rate regulation. In addition, a QF selling energy pursuant to a state regulatory authority's implementation of PURPA will be exempted from FERC rate regulation.

Owners of many so-called QF power plants in the United States must make rate filings with the Federal Energy Regulatory Commission by March 17.

Even QFs with existing contracts, who will therefore be exempted from rate regulation while the contracts are in effect, will be subject to new Federal Power Act requirements banning market manipulation and mandating market transparency rules.

New Cogenerator Standards

The other important component of the new rules issued on February 2 involves the new criteria for new cogeneration facilities. A facility is "new" if it was not certified as a QF before February 2, 2006.

Under the new Energy Policy Act, the output from the QF must be used "fundamentally for industrial, commercial, residential or institutional purposes" and not be intended fundamentally for sale to an electric utility. The QF must show this on a case-by-case basis.

However, FERC established a "safe harbor" — that creates an irrebuttable presumption — that the "fundamental" test is satisfied if at least 50% of aggregate annual energy output of the facility is to be used for industrial, commercial, residential or institutional purposes. If the new QF does not meet the safe harbor test, then it must provide support for its claim that it meets the "fundamental" test.

FERC will also require new cogeneration facilities to demonstrate in their filings that the thermal output will be used in a productive and beneficial manner. Among the factors FERC will look at include whether the product produced by the thermal energy is needed and whether there is a market for the product. Further, if the cogeneration facility is five megawatts or smaller in size, then there will be a rebuttable presumption that the thermal output from the new cogeneration facility is used in a productive and beneficial manner.

FERC also declared that there will be a rebuttable presumption that an existing QF does not become a new cogeneration facility merely because it files for recertification of QF status. However, FERC cautioned that a change to an existing cogeneration facility could be so great that the applicant claiming to be an existing facility should, in fact, be considered a new QF. (As an example, FERC suggested that an increase in capacity from 50 megawatts to 350 megawatts would qualify as a new QF.) The creation of only a *rebuttable* presumption raises the question whether a QF's loss of its steam host and replacement with a new thermal use would risk a finding by FERC that the existing QF was transformed into a new one.

FERC resisted requests by some utilities that the commission impose the new QF criteria on existing QFs.

FERC also decided not to revise the operating and efficiency standard percentages on QFs or to impose an efficiency standard on coal-fired QFs. In addition, the criteria for qualifying small power production facilities — projects fueled by renewable energy or waste — remain unchanged.

Finally, FERC will require all QFs, existing or new, to file a self-certification notice or application for certification.

An existing QF that has never filed either one must do so within 60 days of publication of the new rules in the *Federal Register*. Previously, QF status attached to a project if it met the requirements of the QF rules, whether or not it filed for

QF status. In addition, notices of self-certification will be published in the *Federal Register*. The new rules also codify the elimination of the restriction on utility ownership of QFs as required by the new Energy Policy Act.

FERC Implements PURPA Repeal

by Robert F. Shapiro, in Washington

The Federal Energy Regulatory Commission proposed in mid-January to remove the obligation of US utilities to purchase electricity from "qualifying facilities" in four key regions of the country.

Utilities had been required by a 1978 law called the Public Utility Regulatory Policies Act, or "PURPA," to buy electricity from two types of power plants at the "avoided cost" the utility would have to pay to generate the electricity itself. The two types of power plants are "cogeneration" facilities that produce two useful forms of energy from a single fuel, like electricity and steam produced by burning coal or natural gas, and power plants of up to 80 megawatts in size that burn renewable or waste fuels. These two types of power plants are called "qualifying facilities."

The new Energy Policy Act, enacted last August, gave FERC the authority to terminate a utility's obligation to buy electricity from qualifying facilities in workably competitive regional markets.

The FERC proposal does not affect existing QF contracts or QF contracts entered into with utilities before the rulemaking becomes final. Comments on the proposed rulemaking were due February 27, 2006.

What Regions Are Affected

FERC determined that each of the four regions — the mid-atlantic states, much of the midwest, New England and New York or, more technically, those regions containing the regional transmission groups PJM, MISO, ISO-New England and ISO-New York — met one of three alternative statutory tests for a FERC determination that the utility's purchase obligation can be lifted. At the same time, the agency noted that other utilities or regional transmission organizations, including the California ISO and the / continued page 10

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must apply to the IRS for an allocation. The IRS envisions potentially three rounds of awards in 2006, 2007 and 2008 for the advanced coal credits, but there is a risk that all of the credits will be allocated in the 2006 round. The gasification credits are expected to be fully allocated in 2006.

The IRS issued two notices at the end of February that explain how to apply and how it will choose which projects are awarded credits.

The information about credits for advanced coal-fired power plants is in Notice 2006-24. IGCC plants that have greenhouse gas capture capability and "increased byproduct utilization" will be given first claim on the $800 million in credits that have been set aside for IGCC projects. The IRS said it will award credits among priority projects to the person asking for the smallest dollar amount of credits in relation to the nameplate generating capacity on his or her power plant, then to the next in line on that basis, and so on. Credits for other projects will also be awarded using the same approach. The window for applications opened on February 21 and will close on October 2.

Developers must have their projects certified by the US Department of Energy as both feasible and consistent with US energy policy goals. Both applications to the IRS and the Department of Energy can be submitted at the same time. There is an enormous amount of information that must be submitted as part of the application. The farther along a project is in terms of having project contracts signed and financing commitments in place, the better its chances of winning an award.

IGCC and other advanced coal projects that are allocated credits must be put in service within five years after the award.

The rules for applying for gasification credits are in Notice 2006-25. Most of the rules and deadlines are the same as for advanced coal projects, except that priority will be given to projects that have / continued page 11

PURPA

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Southwest Power Pool, are free to seek to eliminate the mandatory purchase obligation on a case-by-case basis by making an application to FERC.

It seems that FERC is eager to do what it can to eliminate the mandatory purchase obligation.

The Energy Policy Act did not direct FERC to issue any rules or make any immediate findings about competitive markets or the elimination of obligations. Rather, the law seems to contemplate that utilities would file an application to end the mandatory purchase obligation and that FERC would rule on the application. FERC's decision to let the world know about its thoughts on competitive marketplaces is a clear signal that it wishes to unwind a key component of PURPA as soon as possible.

Although the timing seems a bit accelerated, the action itself seems to reflect the views of Congress as embodied in the law. On the one hand, Congress used the law to encourage renewables with production tax credits. On the other hand, it largely gutted PURPA, the statute that created and encouraged the renewable power industry. The message seems to be that Congress wants to encourage renewables under the tax laws, just as it did for the nuclear powered and coal-fired industry, but wants to eliminate market incentives that might give renewables a competitive advantage over fossil-fueled competitors. Congress appears to be leaving it to individual states to create a new type of mandatory purchase obligation in the form of renewable portfolio standards — called "RPS" for short — for the regulated utilities in those states. About half the states have been filling the federal vacuum with RPS mandates of differing magnitudes.

FERC determined that, once a QF contract expires in a part of the country where it has lifted the mandatory purchase requirement, the purchasing utility will not be required to enter into a new or extended contract with the QF. This is a major issue in California. The California Public Utilities Commission ("CPUC") has recently directed the regulated utilities to sign extensions of expiring QF contracts for up to five years, pending the conclusion of a new avoided cost pricing proceeding. Pacific Gas and Electric Company has argued before the CPUC that the California ISO satisfies the test for a regionally competitive market, and a near-term FERC filing by PG&E to push the point would not be a surprise.

Utilities are no longer required to buy electricity from QF power plants in four key regions of the United States.

FERC disagreed with the view of "some" that the grant of QF status means that electric utilities have an "obligation to purchase from that QF in perpetuity." This view of "some" apparently comes from the grandfather clause in the new law that says that the law does not "affect the rights or remedies of any party under any contract *or obligation* in effect . . . on the date of enactment . . . to purchase electric energy or capacity from . . . a qualifying cogeneration facility or qualifying small power production facility (emphasis added)."

It can be argued that utilities had an obligation to purchase from existing QFs on the date of enactment of the new law, even without a contract, due to PURPA's general requirement that utilities must offer to purchase QF energy. On this theory, the utilities in regions where FERC has lifted the purchase requirement would only be permitted to refuse to purchase QF energy from new QFs; that is, from entities that became QFs after the date of enactment. This interpretation would appear to be at odds with the portion of the new law that eliminates a utility's obligation to sign a new contract with *any QF*, without distinction between old and new, upon an appropriate commission finding of regional competitiveness.

How the Test Was Met

The commission stated that each of the four regions met the following two-pronged test: QFs had "nondiscriminatory access to (i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy."

It is not difficult to understand why FERC found that the first test was satisfied. MISO, PJM, ISO-New England and ISO-New York all have operating real-time and day-ahead markets. The crucial issue is whether QFs have access to long-term sales in the wholesale markets. In each instance, FERC rested its determination of long-term sales availability on the fact that "bilateral contracts exist" in those markets. That's it, ladies and gentlemen. While it may be possible for FERC to demonstrate empirically that QFs have access to long-term sales in those markets, the mere assertion of the existence of an unspecified number of bilateral contracts in that market would not seem to form a rational basis for the commission's conclusion. For example, FERC did not even attempt to determine if any QFs had long-term contracts in the region, or if so, whether they all pre-dated the creation of the regional transmission organization or day-ahead markets. Responses to the rulemaking are certain to attack this conclusion.

FERC also declared that the requirement of nondiscriminatory access to long-term sales in the wholesale market does not require a finding that there is a competitive market for such sales. This conclusion also has its weaknesses. In *FPC v. Conway Corp.* in 1976, the US Supreme Court found that competitive impacts of a utility's decision on rates was a factor in determining whether its actions were unduly discriminatory.

Interestingly, FERC made no mention of the ERCOT system and whether ERCOT met this competitive test. In 2001, FERC denied a request by the Texas Public Utility Commission to waive the mandatory purchase obligation in Texas. Utilities in ERCOT are free to file an application under the new law to eliminate the mandatory purchase obligation.

Workable Competition

By naming four regions and not others, FERC was in essence declaring that other regions would have trouble meeting the first test on a generic basis, but would */ continued page 12*

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carbon capture capability, use renewable fuel, or have project teams that have successfully and reliably operated the type of project the applicant proposes to build. Gasification credits will be allocated to projects within this priority grouping first to projects asking for the smallest number of credits in relation to the amount of synthesis gas to be supplied. Gasification projects must be put in service within seven years after an award.

The IRS is expected to be heavily lobbied before the awards. Both it and the US Treasury Department have already been receiving letters from members of Congress and governors interested in particular projects in their states.

PROJECTS ON INDIAN RESERVATIONS may find it less attractive to use lease financing after two private letter rulings.

The United States encourages investment on Indian reservations by offering special tax breaks. One is a tax credit tied to the wage and health insurance costs to employ members of the Indian tribe in connection with a project. The other is the ability to depreciate the cost of assets used in a trade or business on the reservation more quickly. For example, a wind farm on a reservation can be depreciated in three years rather than the five years that must be used elsewhere. The cost of a coal-fired power plant can be written off over 12 years rather than 20 years.

The deadline has passed for making investments that qualify for these tax breaks — it was December 2005 — but the Senate voted in February to extend the deadline another two years through December 2007. The issue is now in the hands of a group of Senate and House negotiators.

The IRS said in two private letter rulings that the lessor of a project on an Indian reservation can only claim the more rapid depreciation on the part of the project that is "real property" — for example, a */ continued page 13*

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have to satisfy FERC, if at all, on a case-by-case basis, by meeting one of two other tests for workably competitive markets.

In the second test, there must be an approved regional transmission entity with open transmission access and competitive markets that provide a meaningful opportunity for short- and long-term sales of capacity. In the third test, there must be wholesale markets for the sale of capacity and energy that are at least of comparable competitive quality as the markets described in the first two tests.

FERC asked for responses to a number of questions related to these tests. One is whether there are any circumstances in which a QF's rights to service under an open access transmission tariff, or"OATT," would be an insufficient showing of nondiscriminatory transmission access. It would seem, at first blush, that a utility with little or no available transmission capacity for short-term or long-term transmission in peak periods would make service under an OATT problematic. FERC also sought advice on whether non-jurisdictional utilities, like municipal and cooperative utilities, that file reciprocity transmission tariffs — which is a FERC condition to allow the municipality or coop to receive OATT service from a regulated utility — satisfy the nondiscriminatory access requirement.

Another question FERC asked is whether the second test's "meaningful opportunity"-for-short-or-long-term-sales requirement would be met outside of regional transmission markets "if there is a demonstration that an organized power procurement process exists in which QFs can participate (albeit not an auction-based process)." FERC made no attempt to explain what an "organized power procurement process" is that would not involve some sort of auction. Would it have to be nondiscriminatory? Would there have to be a level playing field if the host utility is allowed to sell power to itself or build a rate-based plant? Is FERC suggesting that the so-called *Edgar* standards for a utility's affiliate purchases be loosened?

FERC also sought comments on whether certain small renewable QFs, and perhaps certain small cogeneration facilities, may be so unique that the mandatory purchase obligation should remain in effect for them, and, if so, how small the QFs would have to be.

However, utilities in the four regions must still honor any existing contracts.

Mandatory Purchase Obligation

Once the mandatory purchase obligation has been removed, the law provides that it can be reinstated by the commission if a QF applies to FERC and can make a factual showing that there has been a material change in circumstances warranting relief. This right has been added to the proposed rules.

In addition, the commission proposed to incorporate into its regulations language from the Energy Policy Act that gives the commission the right to terminate a utility's obligation to sell electricity to a QF if there are competing retail suppliers willing and able to sell energy to QFs and the utility is not required to sell electric energy in its service territory. As in the case of the mandatory purchase obligation, FERC has the power to reinstate the utility's obligation to sell energy to a QF upon a QF filing and a factual showing that the basis for the termination of service no longer exists.

Passthrough Payment Protection

Ironically, in addressing the one component of the new PURPA section that actually suggests that FERC issue regulations to carry out the will of Congress, FERC has chosen not to do anything yet. The new law contains a provision that directs FERC to issue and enforce regulations to ensure that a utility recovers all prudently-incurred costs associated with a QF purchase under the contract. This provision was intended to codify case law that has held that state commissions cannot disallow the pass through to a utility's ratepayers of QF payments made by the utility if they were made at or below the utility's avoided costs at the time the purchase obligation was established.

This issue is important not only to purchasing utilities, but also to QFs whose contracts contain so-called "regulatory-out" clauses.

Regulatory-out clauses permit the purchasing utility to reduce payments to QFs to the extent that the utility cannot pass through the QF payment to the utility's retail customers. Since issuance of the *Freehold Cogeneration* decision in 1995 by a US appeals court, which held that such pass through of payments was required by federal law, states have generally refrained from challenging the pass through of QF payments in retail rates, although a few have made statements that suggest that a future challenge may be in the offing. In the proposed rulemaking, FERC concluded that no regulations on this issue "were necessary at this time," but sought comments about the need for such a regulation. ◎

California: The Promised Land for Renewable Energy?

by William Monsen, Heather L. Mehta, David Howarth and Robert B. Weisenmiller, with MRW & Associates, Inc., in Oakland, California

A new mantra can be heard these days in California: renewable energy is good, and more renewable energy is better.

In California's post-crisis energy market, there is nearly unanimous consensus that renewable energy should play a greater role. In 2002, the legislature passed Senate Bill 1078, which set a goal of obtaining 20% of the state's electricity from renewable energy sources by 2017. Regulators pushed to advance the goal by seven years to 2010. More recently Governor Schwarzenegger challenged the state to raise the goal to 33% by 2020. Politicians and regulators now find themselves in an unlikely competition to / continued page 14

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building — and not the part that is equipment. Usually no more than 5% of a large power plant is considered real property. The rest is treated as equipment.

The rulings involved two factories that a developer wanted to finance using lease financing.

The problem is the special depreciation can only be claimed on property that is used in a trade or business *of the taxpayer* on the reservation. In a lease, the lessor is the taxpayer. The standard triple net lease of a project — where the lessee treats the project essentially as its own during the lease term — does not put the *lessor* in an active trade or business on the reservation.

A special rule in section 168(j)(5) of the US tax code makes an exception for leases of real property. A lessor of real property is viewed as engaged in an active trade or business on the reservation.

The lessor argued that it should be able to look to Oklahoma law, where the factories are located, for direction on how much of each factory is real property. However, the IRS said that it would determine what is real property by looking instead at the rules for investment tax credits. These rules treat projects like factories and power plants largely as equipment. The rulings are Private Letter Rulings 200601019 and 200601020. The IRS made them public in January.

In related news, an Indian tribe is potentially in hot water for issuing tax-exempt bonds to finance a hotel and convention facility on a reservation.

Tribes have the power — like state and local governments — to issue tax-exempt bonds to finance public facilities. However, the power given tribes is more limited. The bonds must be used for an "essential governmental function." The IRS told the tribe on audit that it had questions about the tax exemption for the bonds the tribe issued. The issue went to the IRS national office in / continued page 15

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be the strongest advocate for renewable energy, while both buyers and sellers of renewable energy are challenged to respond to this opportunity.

With the legislature's passage of Senate Bill 1078, California enacted one of the most aggressive renewable portfolio standards in the nation. The statutory RPS mandate calls for certain types of electricity providers to meet 20% of their electricity load with eligible sources of renewable energy by 2017. Regulators and the state's three major investor-owned utilities have committed to meeting that goal by 2010.

California is embarking on a path that could deliver a robust market for providers of renewable energy technologies and numerous project and financial opportunities to the investment community.

Nevertheless, California's renewable energy goal — whether it be 20% or 33% — is a "stretch" goal for the utilities and the renewable industry. Before this promised land arrives, challenges must be met.

Progress over the past two to three years has been disappointing and is forcing some critical thinking about the regulatory framework being constructed to support California's grand vision for renewable energy. Although there have been numerous workshops and regulatory proceedings to implement the RPS, relatively few contracts have been signed and approved. Many of those contracts are for projects that are turning out to be infeasible. Some form of mid-course correction is likely over the next couple of years. Achieving these goals will require a heady mixture of technology advances, economies of scale, high alternative fuel costs, and federal incentives. If achieved, the goals may prove to be a "tipping point" for renewable energy technologies and the industry.

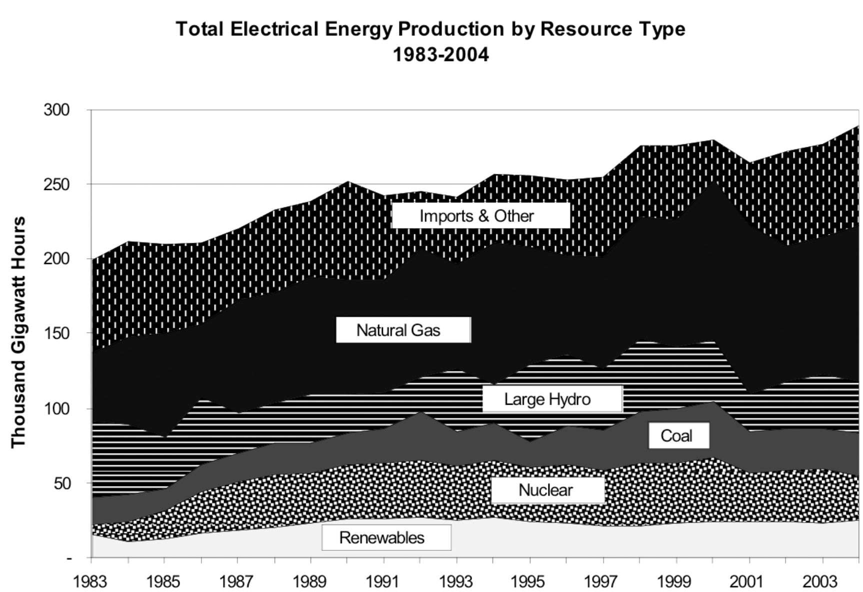
Deep Roots and a Grand Future

California has long been at the forefront of promoting renewable energy technologies. Hydroelectric generation and the combustion of forest products for electricity generation date back many decades. Pacific Gas and Electric and Magma/Unocal pioneered the use of geothermal steam to produce electricity at the Geysers more than 50 years ago. In the late 1970s Governor Edmund G. ("Jerry") Brown promoted energy efficiency, cogeneration and solar, wind and biomass technologies as alternatives to building more nuclear and coal-fired power plants. By the mid-1980s generous tax credits and standardized power sales agreements with the state's investor-owned utilities had sparked a new phase of renewable energy development. Large-scale development of cogeneration and biomass combustion facilities, the commercialization of modern wind machines, the development of geothermal facilities using the Imperial Valley's low-temperature and high-brine resource anomalies, and research into experimental facilities such as parabolic trough solar power plants and an integrated gasifier combined-cycle power plant all benefited from California's support of renewable energy development.

Renewable energy as a percentage of California's overall electricity supply mix reached nearly 13% in 1993. (See Figure 1).

Readily available, low-cost natural gas, high-efficiency combined-cycle power plants and surplus power in the western US power markets eroded the competitive position of renewable energy in the 1990s.

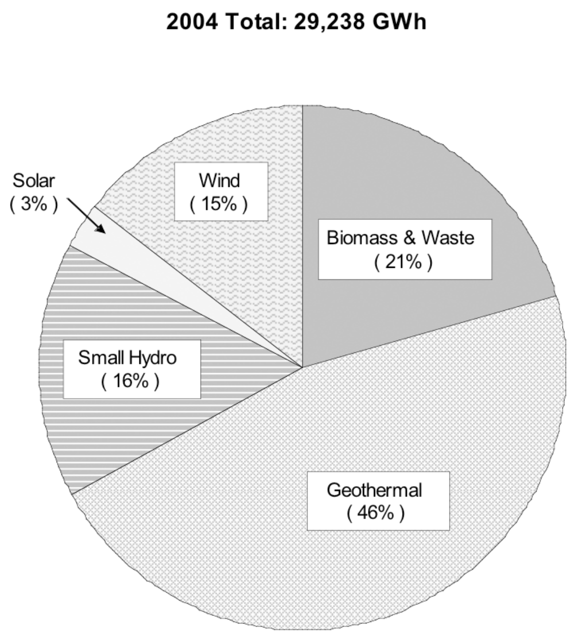
Figure 1



Moreover, the public policy debate shifted focus to a reliance on market signals to lead development of new electricity supplies. As a result of these factors, renewable energy development experienced a setback in the mid-1990s. Efforts to revive renewable energy development began again in 1998 when the California Energy Commission launched its renewable energy program with funding derived in part from a public goods surcharge assessed on ratepayers' utility bills. When the energy crisis rocked California in 2000-2001, renewable energy generation accounted for approximately 10% of total generation, a three-percentage point drop in one decade.

Soaring oil and gas prices, concern for climate change and lingering fears of adequate energy supply have led to renewed support for renewable energy. In 2004 California produced nearly 30,000 gigawatt-hours of renewable energy. Figure 2 provides a breakdown of California's renewable energy production in 2004 by resource type.

Figure 2



As one of California's responses to the energy crisis, legislators and regulators have taken steps to increase the number of renewable energy resources that supply electricity to California. One of the most significant steps was the adoption of the 20% renewable portfolio standard in September 2002. The law requires that 20% of the energy supplied by certain retail suppliers to */ continued page 16*

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Washington for resolution.

The national office confirmed in a "technical advice memorandum" — or ruling to settle a dispute between a taxpayer and an IRS agent in the field — that the tribe may only use tax-exempt bonds to finance essential governmental functions that are customarily performed by state and local governments. The ruling is Technical Advice Memorandum 200603028.

US POWER COMPANIES complain that proposed IRS regulations would deny them a special tax break for domestic manufacturing in cases where a power plant is owned by two or more companies through a partnership or limited liability company, and each company takes and sells its share of the electricity in kind.

The corporate income tax rate in the United States is 35%. However, income from domestic manufacturing is taxed at a lower rate. Generating electricity or producing natural gas or potable water is considered "manufacturing." Moving these items across power lines or through gas or water mains is not. Companies that do both must allocate their earnings.

A company can exclude 3% of its domestic manufacturing income from federal income taxes in 2006, 6% in 2007 through 2009, and 9% thereafter. This translates into a 34% tax rate in 2006, 33% rate in 2007 through 2009, and a 32% rate thereafter. Even a 1% rate reduction can be worth several million dollars in tax savings.

To qualify for a rate reduction, the company selling the output must have done the "manufacturing" itself. The IRS takes the position in proposed regulations that where a power plant is owned by a partnership, the partnership does the manufacturing. The individual partners do not. This is not a problem if the partnership sells the electricity and allocates income from */ continued page 17*

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their electricity customers must come from renewable resources by 2017. (See the sidebar for an overview of the California RPS.) As an interim measure until the RPS legislation could be implemented, regulators ordered the investor-owned utilities to solicit contracts in 2002 for electricity generated by renewable energy resources.

Not content with the proposed pace of renewable resource development implicit in the RPS, the California Energy Commission, the California Public Utilities Commission, and the now-defunct California Power Authority authored an energy action plan in 2003 that established a more aggressive RPS target date of 2010 by which renewable energy would supply 20% of electrical load. (An updated energy action plan was released in 2005). Governor Schwarzenegger endorsed the accelerated schedule and also called for a *statewide* goal that 33% of the energy supplied should come from renewable energy resources by 2020. California's RPS target is among the most aggressive targets adopted by any of the other 21 states and the District of Columbia that have adopted RPS mandates. The IOUs have publicly expressed their intention to meet the more aggressive target established in the 2003 energy action plan.

In addition to promoting the development of utility-scale renewable energy through implementation of the RPS, the California Public Utilities Commission recently authorized approximately $2.9 billion in funding for an initiative to install thousands of megawatts of roof-top photovoltaics throughout the state. This program is similar to the "million solar roofs" legislative initiative supported by Governor Schwarzenegger that stalled in the legislature. The goal of the CPUC's program is to stimulate demand for photovoltaics through a subsidy with guaranteed funding for ten years. It replaces a smaller program administered by the California Energy Commission. The size of the new program and its regulatory stability is expected to support investment in manufacturing that may lead to a reduction in costs. Similar programs have been successful in reducing photovoltaic costs in both Japan and Germany. As the market grows and costs decline, the amount of the subsidy is reduced.

The program is expected ultimately to result in up to 3,000 megawatts of new roof-top solar capacity.

Renewable Energy Targets

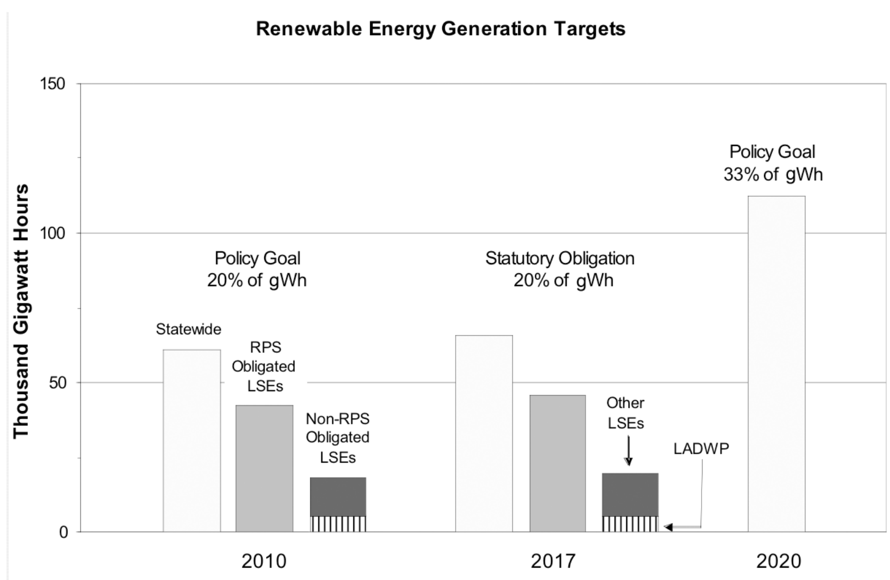
The California RPS legislation established renewable energy targets for three classes of retail sellers of electricity: the investor-owned utilities, energy service providers — called "ESPs" — and community choice aggregators — or "CCAs."

Up until the end of 2005, only California's three major utilities — PG&E, Southern California Edison and San Diego Gas & Electric — had to comply with the state-mandated RPS target. The CPUC recently extended the RPS policies to ESPs and CCAs.

Publicly-owned utilities such as the Los Angeles Department of Water and Power are not required under the law to meet a specific renewable energy target, but they are required to develop their own RPS policies. Many publicly-owned utilities, including Sacramento Municipal Utility District and Silicon Valley Power, have aggressive renewable energy procurement policies in place. LADWP, under the new leadership of Mayor Villaraigosa, has also committed to increase its purchases of renewable energy significantly.

California's electric loads are currently split about 70:30

Figure 3



between the investor-owned utilities that are regulated by the CPUC and publicly-owned utilities. Each of the IOUs' customer bases includes bundled electric customers who procure their power from the IOUs, but also so-called direct access customers who buy their power from ESPs. In the near future, cities may begin to procure power for their residents and businesses, forming an entity known as a "community choice aggregator." (San Francisco and Chula Vista are two cities pursuing this option.) ESPs currently provide electricity for about 13% of the IOUs' loads; CCAs could serve another 5% by 2010.

Based on electricity demand projections made by the California Energy Commission, California's total electricity demand in 2017 is expected to be approximately 330,000 gigawatt-hours. If the 20% RPS target is achieved, renewable energy resources would be generating 66,000 gWh of electricity in 2017. Twenty percent of expected electricity demand in 2010 is 61,100 gWh, and 33% of expected electricity demand in 2020 is 112,700 gWh. Figure 3 provides a breakdown of how the different targets for renewable energy translate into the need for renewable generation. (It uses the acronym "LSE" for load-serving entities.)

How the amount of needed renewable *energy* translates into the amount of new renewable generation *capacity* depends on which resources are developed and other factors. The key variable is the blend of the new renewable generation portfolio, since different renewable generators produce very different amounts of energy per unit of installed capacity.

Assuming that the energy targets for new renewables are met by a portfolio consisting of 50% wind, 30% geothermal, 10% biomass and 10% solar, we estimate that the state will require approximately 8,600 megawatts of additional renewable generation between now and 2010.

This would consist of about 5,200 megawatts from wind, 1,200 megawatts from geothermal, 400 megawatts from biomass and 1,800 megawatts from solar.

According to a study prepared for the California Energy Commission, a majority of this additional supply, roughly 6,000 megawatts, can be provided by resources located in California that can be delivered with little change to the existing transmission system. In order to meet the RPS target using in-state renewable resources, California will require investment in transmission capacity to enable delivery from additional resources.

Of course, the amount of new renew- / *continued page 18*

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the sale to the partners. The sales revenue is domestic manufacturing income to the partnership, and it retains that character when distributed to the partners. The problem is where electricity is distributed in kind and the partners sell their shares of the electricity individually. The sales revenue does not qualify in that case since the *partner* was not the manufacturer of the electricity.

The IRS proposed a special rule for partnerships engaged solely in the extraction, refining or processing of oil or natural gas. Partners in such partnerships can take their shares of the oil or gas in kind, sell it and still qualify for the rate reduction.

Electric utilities, mining companies and petrochemicals companies are urging the IRS to adopt a similar exception for their industries. Final regulations are expected in early May.

SYNFUEL AND LANDFILL GAS PRODUCERS are fretting about whether high oil prices will cause federal tax credits for their projects to phase out.

In the meantime, two synfuel plant owners received good news in their audits with the IRS.

The US government allows anyone producing synthetic fuel from coal or landfill gas to claim tax credits of $1.13 an mmBtu on the output. This is the credit amount for output during 2004. The synfuel plant or gas collection system must have been put into service by June 30, 1998 to qualify for credits. The credits run through 2007. However, they phase out if oil prices return to levels reached during the Arab oil embargo in the mid-1970's. Credits would have phased out during 2004 as oil prices moved across a range of $51.35 to $64.46 a barrel. Both the tax credit and the phaseout range are adjusted each year for inflation. The 2005 figures will be announced by the IRS around April 1. The relevant oil price is the average wellhead price for / *continued page 19*

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able generation capacity will also depend on a number of other factors, including load growth and the amount of existing renewable capacity that remains online after current contracts with the investor-owned utilities expire. Much of the IOUs' current eligible renewable generation comes from "qualifying facility" projects, so a significant loss of these plants would result in the need for a much more rapid development of new generation, especially between 2010 and 2020, which is when most of the contracts with renewable energy QF resources expire.

To go beyond the 20% in 2010 goal to the much more aggressive target of 33% by 2020 would require a redoubling of new resource development and will require investments in transmission to access additional resources. Figure 4 presents annual capacity additions for a potential renewable development plan using the same assumptions for the new renewable portfolio as used above.

As this figure shows, the state will require over 12,000 megawatts of incremental renewable capacity between 2010 and 2020 to achieve 33% renewable supply by 2020. California certainly has the technical potential to meet these targets using native resources; the California wind potential is estimated at over 15,000 megawatts with another 15,000 megawatts available from solar resources. However, given transmission constraints and other factors that limit the availability of cost-effective in-state renewable resources, the state may need to consider allowing out-of-state resources to be used to meet the 33% goal. It is important to keep in mind that the 33% target is only a policy goal at the present time and has not been fully defined. Shifting political winds, changes in fuel prices and the cost recovery associated with the state's renewable program will all play an important role in whether the current policy goal persists over time.

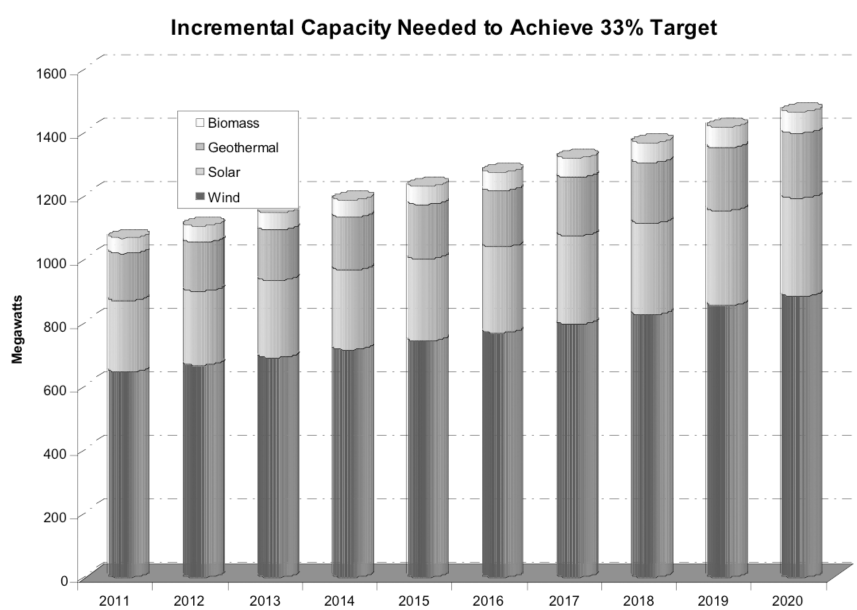
Early Results

Implementation of the California RPS legislation has not proceeded smoothly, and initial timelines have been extended repeatedly to account for delays.

Regulatory proceedings to establish implementation policies have been fragmented and contentious. The CPUC has issued at least eight separate decisions over a three-year period that rule on key structural issues for implementing the RPS. Some elements of the RPS legislation are only now being considered, three years after the passage of the legislation. Moreover, unlike RPS statutes in other states, California's RPS legislation delegated regulatory oversight to two state agencies, the California Energy Commission and the CPUC. Utilities, project developers and other stakeholders must navigate a multi-year, dual-agency regulatory process in order to understand and comply with the California RPS.

Although the regulatory process has not been straightforward, the investor-owned utilities have completed several rounds of competitive solicitations for renewable energy since 2002. They have also negotiated bilateral contracts outside the solicitation framework. As a result of these efforts, the combined purchases of renewable energy for PG&E, Southern California Edison and SDG&E have increased from over 19,000 gWh in 2002 to just over 23,000 gWh in 2005.

Figure 4



Source: *Achieving a 33% Renewable Energy Target*, California Public Utilities Commission, 2005, p.43.

Purchases of renewable energy in 2004 accounted for 13.9% of the three utilities' combined load.

These initial results, while promising, may not be sufficient to keep the utilities on track to meet the 20% goal by 2010. In fact, PG&E under-procured renewable energy by 884 gWh relative to its procurement target in 2004 and by 1,177 gWh in 2005. Southern California Edison has also fallen short, missing its 2005 target by 274 gWh.

In addition, much of the purchases of renewable energy during the first three years of the RPS program came from existing renewable energy generation capacity. Thus, the early stages of the California RPS have not led to development of new renewable generation capacity, but rather have resulted in the diversion of sales from other buyers to the IOUs. As the annual incremental targets increase and other load-serving entities are brought in under the RPS umbrella, there will be greater dependence on new projects.

The bidding and contracting process has proven to be cumbersome as well. Early experience from the IOUs' renewable energy solicitations shows that it takes about two years between the time that a solicitation is held until construction on a project begins. A large portion of the delay can be attributed to utility administration of the procurement process rather than regulatory delay. For example, PG&E held a round of solicitations in July 2004 but only completed negotiations with bidders in April 2005. Southern California Edison did not complete negotiations with bidders following an August 2003 solicitation until 2005.

The California RPS legislation requires the use of a "least-cost, best-fit" criteria in the procurement of renewable energy resources. The CPUC defined "best fit" as the resources best able to meet the utility's energy, capacity, ancillary service and local reliability needs. Because the least-cost, best-fit criteria is unique to each utility, the utilities have developed their own methodologies for how the criteria should be applied. However, the utilities provide only general, qualitative descriptions of their methodologies, creating a lack of transparency in the application of the criteria that has become quite controversial.

Contract failure is emerging as a potential major stumbling block to the achievement of California's renewable energy goals. Southern California Edison recently reported to the CPUC that at least six of eight projects that received contracts following its 2003 solicitation, and that were expected to be operational in 2006, */ continued page 20*

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domestic crude oil for the entire year, which has historically been 85% to 89% of the price for oil contracts traded on NYMEX.

The IRS has disallowed tax credits at a number of synfuel plants on various grounds. Some of the audits are still moving through appeals. In two of the audits where the sole issue was whether the plants were put into service in time, the IRS field teams handling the audits agreed to submit the issue to the IRS national office for a ruling. The national office ruled for the taxpayer in one of the audits — involving three synfuel plants — last June. The IRS has now also ruled for the taxpayer in the second of the two audits, according to the taxpayer involved, Progress Energy. The result is good news for synfuel plant owners. The first case decided last June involved synfuel plants that had some of the strongest facts of any synfuel plants. The latest batch of four plants that were the focus of the second audit had weaker facts.

Duquesne Power & Light said within days after the Progress announcement that the IRS field team had decided to give up on its audit, apparently after learning of the result in the Progress audit.

Other cases are still pending, but are working their way through appeals rather than the IRS national office. The IRS field teams handling those audits have refused to let the cases be heard in Washington. In some of the audits, IRS agents have raised additional grounds beyond whether the plants were put into service in time.

Meanwhile, synfuel and landfill gas producers are waiting to see whether a tax reconciliation bill that is in the final stages of moving through Congress will include language the Senate added to the bill last November that would change how the oil price phaseout works. The current phaseout is linked to oil prices during the current year. The Senate voted to link it to oil prices the year before. Thus, whether credits */ continued page 21*

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may not achieve commercial operation until 2010. Additionally, a 5 megawatt solar project and a large biomass plant signed bilateral contracts with Southern California Edison, but then failed to gain regulatory approval. Given the likelihood of additional contract failures, it has been recommended that California regulators require that utilities contract for supplies in excess of their projected needs to ensure that the energy targets are met according to schedule and contract failure is not used as an excuse for failure to comply.

California has set a goal of generating at least 20% of its electricity from renewables by 2017, but the utilities are trying to reach this goal within the next four years.

Transmission Expansion and Policies

Even if sufficient contracts for renewable energy are signed, delivering the energy and capacity from those contracted projects poses significant challenges.

Among the most critical challenges to overcome are transmission planning and permitting policies, transmission system expansion and transmission cost recovery policies. Achieving California's renewable energy goals will require resolution of a variety of transmission bottlenecks in 2006.

The regulatory responsibility for transmission planning, permitting and ratemaking is spread across federal and state agencies and at the state level among a number of state energy agencies. In California, three state agencies have various responsibilities for transmission planning and permitting. The California Energy Commission conducts resource planning studies that identify the potential need for and size of transmission upgrades. Under its Federal Energy Regulatory Commission-approved tariffs, the California ISO has jurisdiction to approve any needed transmission projects. The CPUC has jurisdiction over the siting of transmission lines and must issue a certificate of public convenience and necessity for any California ISO-approved project that is not exempted from siting requirements. Finally, FERC must approve the inclusion of a transmission project's costs in transmission rates. Concerns about under-investment in California's transmission infrastructure have led to consideration of jurisdictional reform and public disagreements between the California Energy Commission and the CPUC about the need for such reforms.

In December 2005, Southern California Edison reported to the CPUC that although its baseline renewable energy position in 2003 was about 18%, it was unlikely to meet the 20% by 2010 goal because licensing and constructing new transmission facilities necessary to interconnect new renewable generation projects likely would not be completed in a timely manner. According to Edison, many generation projects are located in the California ISO interconnection queue ahead of eight renewable energy projects with which Edison has signed contracts.

The typical length of time from when a generator applies to the California ISO for interconnection to the completion of the transmission upgrade ranges from approximately five to seven years.

In late January, the investor-owned utilities filed supplemental material with the CPUC concerning the implications of transmission issues for successful implementation of their renewable plans.

Southern California Edison's quandary may have shocked California policymakers, but they should not be surprised about the pivotal role that transmission infrastructure will play in achieving the state's renewable goals. For example, SDG&E has frequently said in filings before regulatory authorities that significant new transmission capacity in its service area is needed to achieve the 20% renewable goal. All three IOUs may need to expand transmission capacity into areas with substantial renewable resources.

A significant amount of California's renewable energy potential exists in areas far from the transmission system. In order for the state to achieve its aggressive renewable energy goals, at least some portion of this geographically remote potential must be tapped. However, expanding the state's transmission system within the proposed RPS timeframe is a formidable challenge.

A number of transmission projects that would tap into California's diverse mix of renewable resources have been proposed, including the following:

Tehachapi Transmission Plan: An area of California known as Tehachapi contains the largest wind resources in the state. Existing wind facilities have a total capacity of about 645 megawatts. The California Energy Commission estimates that the area's undeveloped wind potential totals 4,500 megawatts (peak capacity) or 14,000 gWh per year. A group known as the Tehachapi Collaborative Study Group that includes representatives of PG&E, Edison, developers and regulators has been attempting to develop and to implement a consensus transmission plan for the Tehachapi resources. The CPUC concluded that a traditional "application-based" approach to siting transmission lines for individual projects in the Tehachapi area would not be cost-effective nor would it likely yield the level of infrastructure needed to take full advantage of Tehachapi's wind resources. The CPUC encouraged Southern California Edison to apply to FERC for innovative rate treatment of a comprehensive approach to transmission needs for this area, but Edison received only partial approval from FERC. Consequently, Edison has applied for CPUC approval only for a first phase project known as the Antelope transmission project.

Imperial Valley Transmission Upgrade: California's Imperial Valley contains sizable geothermal and solar resources. Existing geothermal generation capacity totals about 450 megawatts. Developers estimate there is potential to develop an additional 1,350 to 1,950 megawatts over the next 15 years. Large-scale solar thermal electric projects have also been proposed in the Imperial Valley. A group known as the Imperial Valley Study Group, comprising the Imperial Irrigation District, LADWP, SDG&E, developers and regulators is studying options for developing trans- / continued page 22

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phase out during 2006 would be linked to oil prices during 2005. The Senate "paid" for the provision by dropping the inflation adjustment for the credit itself. Thus, the credit amount would remain fixed at the 2004 level of $1.13 an mmBtu. However, the oil price phaseout range would continue to be adjusted for inflation.

The industry benefited from a good lobbying strategy and fortunate timing. The Joint Tax Committee staff, which scores tax proposals for their revenue effects, said last November that the Senate provision would raise money for the government. The forecast of oil prices that it was using at the time suggested prices would not reach the phase-out range during 2006 or 2007. Therefore, it concluded that the government would collect an extra $151 million in revenue over five years as a consequence of freezing tax credits at the 2004 amount.

The debate has now shifted to a House-Senate conference committee. The House did not have a similar oil price provision in its version of the tax reconciliation bill. House negotiators are expected to resist including the provision in the final bill. A hostile news article in *Time* magazine in late February appears to have been planted by opponents of the Senate provision either at Treasury or in the House. Two coalitions of synfuel plant owners are lobbying hard to keep it.

In another development, the owners of five synfuel plants failed in an effort to have a federal district court in Pennsylvania declare that their plants were put in service in time to qualify for tax credits.

The IRS does not usually rule outside of a tax audit about when plants were put into service because it considers the issue too factual. A prior owner of the five plants went into bankruptcy. The bankruptcy court involved at the time recited in the fact portion of an opinion on unrelated bankruptcy issues that the plants qualify for tax credits. The current owners of the plants tried / continued page 25

An Overview of California's Renewable Portfolio Standard

Senate Bill 1078, approved in September 2002, established a renewable portfolio standard. The RPS legislation requires all retail energy providers, including electrical corporations, community choice aggregators and electric service providers, to increase their procurement of renewable energy by at least 1% each year so that 20% of their total energy is procured from renewable sources by 2017. In 2003, the California Public Utilities Commission adopted regulations implementing the RPS for investor-owned utilities under its jurisdiction.

CPUC regulations require the utilities to administer annual RPS solicitations according to CPUC prescribed rules. Winning bids are selected by the utilities using "least-cost, best-fit" criteria, and contracts must be approved by the CPUC. The evaluation of bids must include estimated transmission costs based on a transmission ranking cost report issued by the CPUC. The selected bids are compared to a CPUC-calculated market price referent, or "MPR," that estimates a long-term market price for electricity from conventional sources. Contracts at or below the MPR are automatically determined to be reasonable. Any approved bids requiring payments above the MPR will be considered by the California Energy Commission for supplemental energy payments using funds collected through the public goods charge. To date, all winning contracts have been priced below the MPR. In 2005 the 20% RPS requirement was extended to all load-serving entities under the CPUC's jurisdiction, including direct access providers and community choice aggregators.

The California RPS legislation established which renewable */ continued page 23*

California Renewables

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mission capacity that could deliver up to 2,200 megawatts of geothermal and solar generation output to electricity customers. Plans to expand transmission access in this region have proceeded along two independent but closely linked paths.

One is the "green path project." In November 2005, Los Angeles Mayor Villaraigosa announced that the city had entered into a partnership with the Imperial Irrigation District and the non-profit organization Citizens Energy to build the "green path" project. The project seeks to upgrade existing transmission lines and create new interconnection points that will enable LADWP to tap into the Imperial Valley's renewable resources at the Salton Sea. The green path project would make a substantial contribution to the mayor's goal of LADWP supplying 20% of its power from renewable energy in 2010.

The other option is the "Sunrise power link." SDG&E recently proposed a new 500 kV transmission line, known as the Sunrise power link, to connect its service territory to the Imperial Valley. SDG&E has not determined the specific location the transmission line would travel, and the earliest projected in-service date is 2010. SDG&E contends this new transmission line is necessary in order for the utility to access much of the renewable resources that it has under contract and also to meet its RPS obligations of 20% in 2010. SDG&E has advocated use of renewable energy credits as another way for it to meet its RPS obligations, but this proposal is controversial.

Out-of-State Renewable Resources: PG&E has advocated that California evaluate its need for transmission infrastructure based upon resource availability throughout the west. Governor Schwarzenegger has led efforts by the Western Governors' Association to plan and develop energy resources on a regional basis. PG&E is concerned that California's efforts to find transmission solutions to access its remote renewable resources in the Tehachapi area and Imperial Valley may lead to suboptimal transmission investments relative to a plan that considers transmission solutions across the western United States. The Northwest Transmission Assessment Committee has identified large amounts of renewable resources outside California. Thus, PG&E's ratepayers may find enhanced transmission capability to the pacific northwest more attractive than upgrades south to the Tehachapi area. In November 2005, PG&E announced a partnership with Sea Breeze Pacific West Coast Cable to study a 650-mile undersea high-voltage direct current cable that would connect the San Francisco area with the Portland area in Oregon.

The final issue that must be addressed in order to ensure needed transmission investments are made is cost recovery. Historically, federal and state policies concerning cost responsibility for transmission upgrades have laid the burden on the developer whose project causes the need for an upgrade. This first developer ends up footing the bill for a transmission upgrade that subsequent developers can utilize for their projects. This cost responsibility policy traditionally was not a problem because developers of large-scale fossil-fueled projects generally had the financial resources to absorb the costs. Developers of smaller-scale renewable energy generation projects may not have the financial wherewithal to fund a needed transmission system upgrade to accomplish project interconnection. Moreover, a series of incremental interconnection projects may have a relatively high cost relative to a comprehensive approach.

In March 2005, Southern California Edison proposed a new type of transmission line that it called a "renewable-resource trunk line."

As proposed, the trunk line would have interconnected about 1,100 megawatts of mostly wind plants located in areas remote from major load centers. Costs of constructing the trunk line were to be recovered through general transmission rates. Although the trunk line was proposed by Edison, the line would have been operated by the state's transmission system operator, and utilities other than Edison would be able to use the trunk line to tap renewable resources to meet their RPS goals. California's regulators supported the proposal, but FERC did not approve the trunk line. Instead FERC provided Southern California Edison with advance cost recovery assurances for the Antelope transmission projects portion of the more comprehensive transmission plan for the Tehachapi. According to California regulators, FERC's rejection of the proposed trunk line removes "the primary instrument the state could have used to address transmission constraints for renewables."

The experience with Edison's */ continued page 24*

An Overview of California's Renewable Portfolio Standard

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resources are eligible to be counted toward the RPS targets. Qualifying technologies are biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuel, hydroelectric generation with capacities less than 30 megawatts, digester gas, municipal solid waste conversion using a non-combustion thermal process, landfill gas, ocean wave, ocean thermal and tidal current. An eligible renewable resource must also be located in California or near the state border so that the first point of interconnection to the transmission system is within California. Existing resources under the control of the investor-owned utilities count toward the baseline for each utility. The amount of renewables that must be purchased each year is equal to the baseline from the previous year plus 1% of the utilities' retail sales for the previous year. Utilities may bank renewables purchases to count towards future periods, and may carry forward shortfalls of up to 25% of their annual target for up to three years. Any shortfalls not fulfilled within the three-year make-up period will incur a penalty of 5¢ per kWh. ◎

A Financial Boost to California's Renewable Energy Goals

In 2004, the California Public Employees Retirement System — called "CalPERS" — approved plans to invest as much as $200 million in "clean" technologies, including renewable energy technologies, through private equity, project finance and venture capital investments. (CalPERS also gave approval to invest $500 million in public stocks of companies that produce environmentally-friendly products and technologies or demonstrate a commitment to protecting the environment.) CalPERS made its first investment in May 2005 when it committed $15 million to NGEN Partners, LLC, a venture capital firm that makes early-stage investments in energy and environmental technologies. The Carlyle Group and Riverstone Holdings received funds from CalPERS for a $300 million investment fund targeting renewable energy power projects. ◎

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proposed renewable resource trunk line illustrates not only the challenge that cost recovery policies pose to transmission system development, but also how competing jurisdiction over transmission planning, policies and rates acts as a roadblock to achieving California's RPS goals.

Other Implementation Issues

There are many issues that threaten to slow if not derail California's progress toward its RPS target.

Renewable energy credits are in use elsewhere in the US, but their role in California continues to be hotly debated. Uncertainty over future extensions to federal tax incentives will continue to plague project development. Land use and other environmental quality issues may emerge during the permitting process as the number of projects seeking permits escalates. Supplies of renewable energy equipment could tighten as other states and countries step up their own efforts to develop renewable energy projects.

California does not permit unbundled, or tradable, renewable energy credits to be used by a retail seller of electricity to meet an RPS target. (A renewable energy credit, or "REC," represents the environmental attributes of the electricity produced. An unbundled REC separates these environmental attributes from the underlying electricity, allowing the environmental attributes to be sold, or traded, separately from the electricity.) The ability to use tradable RECs to meet an RPS target could ease the pressure for transmission investments and would make meeting RPS targets easier for ESPs and CCAs. But RECs have limitations as well. Because RECs are generally traded in short-term markets, they may not provide the type of long-term financial surety that renewable energy generators historically have needed. SDG&E has sponsored controversial legislation to allow RECs to be used to comply with the RPS requirements as part of a package to move the statutory RPS date from 2017 to 2010. Governor Schwarzenegger wants to broaden the eligibility for out-of-state renewables, while consumer advocates have been concerned that REC trading would expose California ratepayers to future market abuses by REC traders akin to the electricity crisis market manipulation allegations.

An obstacle to using tradable RECs to satisfy California's RPS targets is the current lack of a REC verification and tracking system. California's energy agencies are collaborating with other states in the West to establish the Western Renewable Energy Generation Information System (WREGIS). The system, which is expected to be operational in 2007, would serve as an independent data clearinghouse to facilitate verification, tracking and trading of RECs.

Even if a tracking system such as WREGIS was in place, there is debate within California as to whether the RPS legislation permits trading of unbundled RECs. New legislation may be required to provide the clear statutory foundation for using unbundled RECs to meet the RPS goals.

Production and investment tax credits provide critical financial support for renewable energy technologies. In 2005, Congress approved an extension of the 1.9 cent-per-kilowatt-hour tax credit for electricity generated with wind turbines over the first ten years of a project's operations. Without these financial incentives, the cost-effectiveness of some renewable energy projects would suffer. Congress periodically reviews these incentives and has approved extensions, but not without bruising political battles first taking place. These incentives have very specific eligibility requirements, so it will be crucial for developers to have competent tax attorneys.

A provision in the federal tax code concerning eligibility to receive the federal production tax incentive has become a major stumbling block to repowering. A repowered wind facility with a pre-1987 standard offer contract cannot receive federal tax incentives without a contract amendment. Current short-term avoided costs are much lower than many existing contract prices. Thus, wind facilities have little incentive to repower. According to the California Energy Commission, up to 1,000 megawatts of wind facilities in the state are candidates for repowering.

Most of California's new renewable projects will be located in relatively remote locations, which may simplify land use and permitting issues compared to more urban environments. However, renewable developments in these remote locations may well have significant adverse environmental impacts, so that land use planning and environmental mitigation issues are likely to become more widespread as renewable development expands.

A related issue is the high level of bird mortality associated with the operation of wind facilities. / continued page 26

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to force the IRS to acknowledge in new court proceedings that the plants were in service in time by forcing the agency to acknowledge that the owners of the plants during 1998 were entitled to depreciate them that year. This would have established that the plants were in service.

The IRS refused to be drawn into the case, and the federal district court declined to issue an order finding that the IRS was bound by its failure to challenge the earlier depreciation deductions. The case is Dycoal v. Internal Revenue Service. *The court released its decision on February 15.*

OUT-OF-STATE LENDERS financing equipment in North Carolina must pay an annual tax on the face value of the loan, an appeals court said.

North Carolina taxes anyone engaged in the "business of dealing in, buying, or discounting installment paper, notes, bonds, contracts, or evidences of debt" that are secured by liens on equipment located in North Carolina. The tax is .277% of the face value of the debt. It is collected annually.

Navistar, a truck manufacturer, has a finance subsidiary that lends dealers and customers the money they need to purchase Navistar trucks. The finance subsidiary is based outside North Carolina. It has no office in the state. It brought suit in an effort to get back $700,000 in taxes paid on installment paper over roughly a two-year period, arguing that it has too little "nexus" — or connection — with the state for the state to be able to tax it.

A state appeals court disagreed in a decision released in late February. The US constitution bars states from taxing persons who have little connection to the state or in a manner that discriminates against out-of-state residents or specially burdens interstate commerce. The court said the fact that the company holds liens over equipment in North Carolina gives it a substan- / continued page 27

Research suggests that bird deaths would be reduced if older, smaller wind turbines were replaced with fewer, larger wind turbines. Local officials in the Altamont area in northern California are particularly concerned with this issue and have limited the number of permits they will issue for new and repowered wind facilities.

The markets for renewable energy technologies are global and thus will be subject to the pressures of supply and demand in markets throughout the world. High oil prices have motivated many countries to push the development of renewable energy projects, resulting in a shortage of and increasing prices for certain equipment such as wind turbines. Promotional programs in certain markets may pull critical supplies from other markets. For example, the photovoltaics market has been strong in Japan and Germany in recent years as a result of government support for this technology.

Conclusions

Implementation of the California RPS legislation has not proceeded smoothly, and initial timelines have been extended repeatedly to account for delays. Regulatory proceedings to establish implementation policies have been fragmented and contentious. The IOUs have increased purchases of renewable energy, but their solicitations have not yet generated substantial new project development activity.

In short, the initial exuberance that led policymakers to propose the "20% by 2010" target has given way to growing concerns that procurement of renewable resources is taking too long.

Patience may be the key. California has significant, untapped renewable energy resources, so while the 20% by 2010 or 33% by 2020 goals are big, they are not unachievable. Planning for the necessary transmission upgrades is ongoing, so although the timing may not be optimal, transmission lines should eventually get built. The RPS framework needs fine-tuning, but it provides a regulatory push to develop renewable energy projects. As buyers and sellers gain experience with the RPS procurement process, they should be able to anticipate problems better and develop workable solutions. Finally, when a broad view is taken of the long-term social and environmental benefits of a greater reliance on renewable energy, California needs the RPS program to succeed. ◎

Mexico Encourages Renewables

by Mario E. Juarez and Hernando Becerra, with Ritch Muller, S.C. in Mexico City

Mexico has taken the first step toward providing incentives to use renewable energy.

The Mexican House of Representatives (*Cámara de Diputados*) passed a "Law for the Use of Renewable Energy Sources" (*Ley para el Aprovechamiento de Fuentes Renovables de Energía*) in December, and the measure has now been sent to the Mexican Senate for its review and approval. Many believe that the law will be enacted this year.

Mexico has effectively committed, by ratifying the Kyoto protocol, to use more renewable energy as a source of electricity.

The installed generating capacity worldwide from renewables is 50,000 megawatts. Mexican installed capacity from renewables is just two and three megawatts. This leaves enormous room for growth. The Mexican Ministry of Energy estimates that there is potential to generate approximately 5,000 megawatts from wind power, 1,000 megawatts from biomass and 150 megawatts from biogas drawn from landfills.

The measure the House passed in December would favor seven kinds of renewables: wind, sunlight, water, the ocean, and biomass, biofuels or organic wastes.

The measure authorizes incentives to promote the use of such renewables, but it is vague and ambiguous about the type of incentives. This will be left largely to the Ministry of Energy — called SENER — to decide. The measure directs SENER to work with state and municipal governments. SENER is also supposed to coordinate with the Ministry of Economy on a package of incentives to encourage manufacturing of renewable energy equipment in Mexico.

Some of the incentives will be given only to Mexican utilities, like the *Comisión Federal de Electricidad* and *Luz y Fuerza del Centro,* and to Mexican-domiciled electricity generators (defined as Mexican individuals or entities organized under Mexican law and domiciled in Mexico).

It is not only the incentives that have been left vague, but the other details of the program to encourage renewables also remain to be worked out. The measure directs SENER to set goals for renewable energy usage and then list actions that will be taken to achieve the goals. SENER will manage a trust from which grants will be made (*Fideicomiso para el aprovechamiento de fuentes renovables de energía*). The House said that the funding for the trust would be drawn from a number of sources, but the total peso amount is unclear. The funds are supposed to come from federal appropriations, certain duties to be identified in the future, contributions from state governments and municipalities, voluntary contributions by individuals and companies, contributions by international organizations and proceeds from the sale of renewable energy certificates to individuals or entities in Mexico and abroad.

The amounts in the trust will be further divided into a number of subaccounts. These subaccounts are a "green fund," an "emerging technologies fund," a "rural electrification fund," a "biofuels fund," a "general renewable energy fund" and a "renewable energy technology research and development fund."

The funds in the various subaccounts would be used to make grants to eligible projects.

For example, the green fund would be used to make grants to power projects that will supply their output exclusively to the national grid. The only projects that qualify potentially are those developed by Mexican utilities or Mexican-domiciled generators of electricity. SENER would have discretion about how large a grant to award a project, but in theory the grant is supposed to close the gap between the cost of the renewables projects and what a lower-cost power plant that uses fossil fuel would cost. "Self-supply projects," also known as inside-the-fence projects, would be ineligible for grants from the green fund.

The other funds — apart from the green fund — would be used to make grants to a wide range of projects. Grants would be given to develop renewables technology, especially in isolated areas, supply renewable power to isolated and low-income communities, promote the commercialization of biofuels for use in gasoline and diesel fuel sold domestically by PEMEX, promote new technologies that use renewables in other sectors besides electricity generation, and promote the use of biofuels and solar energy (for example, for heating water).

Projects that receive grants would have to use at least 2% of the grant money to support community development in the areas where the projects are located. / *continued page 28*

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tial enough connection to the state.

The court also said there is no risk of Navistar having to pay the same taxes to multiple states, since the trigger for the North Carolina tax is holding a note secured by a lien over equipment in North Carolina. The case is Navistar Financial Corporation v. Tolson.

CORPORATE TAX SHELTER reporting triggers have changed.

IRS regulations contain a list of six factors that the agency believes are possible signs that a transaction is a corporate tax shelter. If one of these six factors is present in a deal, then the transaction must be reported to the IRS.

The list keeps being revised. The latest revision occurred in January, when the IRS announced that it is dropping one of the six triggers for reporting from the list. A deal no longer has to be reported as a possible tax shelter just because there is a difference in how it is reported for book and tax purposes. The IRS made the announcement in Notice 2006-6.

The remaining triggers for reporting are the transaction is on a list of known tax shelters, the advisers offering the transaction require that it be kept confidential, the fees paid to advisers are tied to the tax results, the transaction produces loss deductions under section 165 of the US tax code of at least \$10 million in a single year or \$20 million in a combination of years, or the transaction generates more than \$250,000 in tax credits for a taxpayer holding an asset for 45 days or less.

PROPERTY TAXES do not have to be paid in Arizona on certain utility property whose cost is reimbursed by customers.

Utilities collect from customers for the cost of extending power lines and gas and water mains to a customer's property so that the customer can receive service. The customer pays the cost. The payment / *continued page 29*

Mexico

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The projects must also meet minimum national integration percentages and encourage local community participation.

The measure that passed the House is a good start for developers, even if many details remain to be worked out by the Senate.

Renewable energy is often intermittent in supply. The measure would commit the national grid to take all energy supplied from eligible renewables projects at prices to be determined under future guidelines set by law. The measure also lets the government show that Mexico is taking steps to implement its obligations under the Kyoto accord. This should help Mexico qualify for financial assistance from the multilateral lending agencies. ◎

Mexico is debating new incentives for developers of renewable energy projects.

Toll Road Update

by Jacob S. Falk, in Washington, and Lauren R. Garsten, in New York

The new year got off to a quick start for the US private toll road market.

The winning bidder was selected for the Indiana toll road, which will be the largest privatization of an existing asset in the United States to date, and the Texas Department of Transportation unveiled two new projects for which it will solicit proposals this spring.

Texas also announced the preliminary terms for a standardized "comprehensive development agreement" that it would like to use for all of its public-private partnerships, and the US Department of Transportation solicited applications for the use of tax-exempt private activity bonds for projects utilizing private financing.

Indiana Toll Road

Governor Mitch Daniel's plan to lease the Indiana turnpike to the private sector for 75 years is almost a reality. On January 23, the governor announced the winning bidder for the concession, a Macquarie-Cintra consortium that offered an upfront payment for the privatization of $3.85 billion.

The Indiana legislature must still approve the proposed concession agreement with the winning bidder. The House passed it by a 52-to-47 vote on February 1. It must still pass the Indiana Senate. The current legislative session is scheduled to end by March 14. Not surprisingly, some state lawmakers were waiting to see the proposals, and specifically the amount of money that would be paid to Indiana up front, before taking a position. The $3.85 billion winning proposal from Macquarie-Cintra seems to have helped push many of these lawmakers toward privatization.

The governor appears willing to compromise to win support. The governor has apparently earned the support of the Indiana Motor Truck Association by agreeing to spread over the next several years an increase in truck tolls on the Indiana turnpike instead of implementing the increase all at once this spring. The governor has also agreed that certain revenue from the deal would be used to jump start improvements to the I-31 corridor, which had been delayed until 2011. One state senator said that prioritizing the I-31 corridor is the "carrot we need to even consider this deal."

Proposals for the lease were solicited and short-listed by Indiana at the end of last summer, and the deadline for submitting detailed proposals was January 20. The governor continues to stress that the state intends to move quickly on the lease.

Two Texas Projects

The Texas Department of Transportation (TxDOT) announced in mid-January that it will be launching two new projects over the next three to four months.

An initial request for qualifications from TxDOT is expected in March for the TTC-69, or trans-Texas corridor/I-69 project. TTC-69 will be part of a 1,600 mile national highway system connecting Canada, the United States and Mexico. The section comprising TTC-69 would extend approximately 650 miles from Texarkana and Shreveport (along the Texas border with Arkansas and Louisiana) to Mexico. TxDOT indicated that it is looking for a long-term strategic partner for this corridor, and the state's standardized "comprehensive development agreement" for the project is likely to be similar to the agreement signed with Cintra-Zachry in connection with the I-35 corridor — meaning a pre-development agreement that gives rise to a number of additional procurements as the full scope of the corridor is nailed down. Texas expects to have the comprehensive development agreement negotiated and executed by the end of 2007.

The second project TxDOT announced is a procurement for SH161 that is expected to be initiated in May 2006. The SH161 project would be an extension of SH161 west of Dallas from SH183 north of Dallas to I-20 south of Dallas through the cities of Irving and Grand Prairie. The right-of-way for this project has already been acquired and environmental approval has been secured, but is being updated to incorporate tolling. An unsolicited proposal for this project was received in August 2005.

TxDOT has created a public master schedule of all comprehensive development agreement projects and will update each project's status as it progresses.

Texas CDAs

TxDOT hosted a workshop entitled "Launching the Next Generation of CDA Projects" in mid-January.

The state emphasized that it is "open for business," and expressed a desire to create a streamlined program that speeds up the process and saves developers money. By providing greater consistency in the procurement process and using a standardized "CDA" (comprehensive development agreement), Texas hopes to bring consistent and predictable deal flow to the market.

At the workshop, TxDOT distributed a / continued page 30

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is called a "contribution in aid of construction." The utility pays taxes on the payment. It does not put the equipment for which the customer paid into its rate base. Its rate base is the sum of its investments on which state regulators allow it to earn a return.

Arizona Public Service and the Salt River Project both pay property taxes in Arizona. Salt River does so voluntarily, since it is exempted from taxes as a government agency. The state tax department billed Arizona Public Service in 2003 for property taxes on $2.8 billion in assets. It did the same for the Salt River Project on $2.4 billion in assets. Both utilities appealed, arguing that they should not have to pay property taxes on so-called CIAC assets — or assets whose cost customers paid through contributions in aid of construction. After a roller coaster ride through the appeals process, an Arizona appeals court said in mid-January that it agrees with the two utilities. The case is *Arizona Department of Revenue v. Salt River Project, et al.* The utilities had won an earlier appeal to the state board of equalization, but then lost in the state tax court.

Arizona said it follows the uniform system of accounts used by the Federal Energy Regulatory Commission for property tax purposes. FERC does not let a utility count CIAC property when reporting its total investment in plant and equipment because the utility did not pay the cost.

Interties that connect independent power plants to the utility grid might also be considered CIAC property under this logic.

CONNECTICUT is considering whether to impose a "windfall profits" tax on power companies.

The state attorney general, Richard Blumenthal (D), called on the legislature in late February to enact such a tax. Blumenthal said a tax of 25% on revenue earned above a 20% profit level at just three power plants in Connecticut — Millstone II, / continued page 31

Toll Roads

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CDA term sheet that summarizes the key terms and conditions, including the risk allocations, Texas would like to see in a CDA for a roadway concession. TxDOT asked for industry comments on the term sheet by February 8. The term sheet contains provisions for developer and TxDOT compensation, toll rates, tolling systems, financing and refinancing, environmental risk, design and construction, operations and maintenance, insurance and bonding, excused performance, defaults, disputes and termination.

TxDOT indicated that the CDA concept will apply to a broad range of public-private partnership models in addition to roadway concessions. CDA agreements will also be used for "pre-development" projects. An example is use of a CDA for the TTC-35. The CDA model will be modified to fit specific project requirements in accordance with the nature of the project.

To further streamline the request-for-proposals process, TxDOT plans to apply in advance for TIFIA funding. 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 costs from the federal government. TxDOT will take the lead in procuring conditional loan approvals for projects from the TIFIA office in the US Department of Transportation before projects are put up for bid. This will give bidders an early sense of whether TIFIA financing will be available for a project and some idea of the terms and conditions on which such financing would be available.

TxDOT indicated that it will make similar efforts to determine whether tax-exempt private activity bonds are available for a project before putting the project up for bid. TxDOT expects to analyze whether tax-exempt bonds make sense on a project-by-project basis and to be the conduit issuer of bonds for Texas projects that mix tax-exempt financing with private financing.

Private Activity Bonds

The massive federal highway bill that was enacted last August authorizes $286.4 billion in spending over the next six years on highway and transit programs. While most of this money will be spent on roads funded exclusively with federal, state and local government money, the new law also makes available a new category of tax-exempt private activity bonds that can be used for certain highway and rail-truck transfer facilities that are privately financed. Private activity bonds are bonds issued by state or local governments to finance facilities that will be put to private business use. Tax-exempt bonds are usually supposed to be limited to use for schools, hospitals, free-access highways and other public facilities.

The bonds will be exempted from general state volume caps on private activity bonds, but there is a $15 billion national cap on the aggregate amount of such bonds that can be issued over the next 10 years. Before the highway bill, tax-exempt financing was not available for highway projects over which a private party has a concession.

The US Department of Transportation published a notice in January soliciting requests for allocations of scarce bond authority. (The highway bill gives the secretary of transportation authority to allocate the bonds.) While the standard rulemaking process usually includes an official comment period after which the rules will be revised, the department will be collecting public comments on the bond allocation process on an ongoing basis.

Indiana was paid a stunning $3.85 billion for a 75-year concession to run the Indiana turnpike. Other states have taken note.

The department did not explain in the January notice what standards it will use to evaluate applications. Applications must comply with relevant statutory requirements and the department will take into account tax-exempt authority otherwise available for the type of project and location, but the secretary of transportation has broad decision-making authority in making bond allocations. The notice said the department is "particularly concerned that once it makes an allocation, tax-exempt facility bonds are issued in a timely fashion." If agreed-upon financing schedules are not met, then allocations may be withdrawn.

There is also no prescribed form for applications, but the notice asks for the following information to be included in the application: the amount of allocation requested, the proposed date of bond issuance, the date of inducement by the bond issuer (including a copy of the state or local resolution authorizing the issuance), a draft bond counsel opinion letter, information about the financing and development team, information about the borrower, a description of the project, the proposed project schedule, the financial structure of the project (including a breakdown of the sources and uses), a description of federal funding that the project is already receiving or that the project is due to receive, project readiness and signatures and declarations. Applications should be submitted with 10 copies to: Mr. Jack Bennett, US Department of Transportation, Office of the Assistant Secretary for Transportation Policy, P-20, Room 10305E, 400 7th Street SW, Washington, DC 20590.

While the bond program is fundamentally designed to encourage private investment in transportation projects, a number of its provisions may prove restrictive.

One such provision is the requirement that each project applying for a bond allocation must include federal assistance in its financial structure. This requirement is restrictive because any project receiving federal assistance must comply with additional federal rules, such as Davis-Bacon wage rate requirements, Buy America Act requirements and federal-aid procurement regulations. Under the Davis-Bacon Act, federal contracts worth more than $2,000 for the construction, alteration or repair of public buildings or public works (including roads and bridges) must contain provisions ensuring that certain minimum wages be paid to various classes of workers employed under the contract. Wages are determined by a listing of wage rates and fringe benefit rates determined by the US Department */ continued page 32*

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Millstone III and Bridgeport Harbor — would bring in $178 million in additional taxes in 2006. He wants to use the revenue, in part, to seed a new public agency that would go into the business of building, owning and operating power plants. The legislature is scheduled to adjourn by May 3.

RELATED PARTIES cannot deduct interest on cross-border inter-company debt until the interest is actually paid, a US appeals court confirmed in February.

IRS regulations require US companies making payments to affiliates in other countries to wait to deduct the payments for tax purposes until they are actually paid. Most US companies use accrual accounting. They deduct amounts when the obligation to pay them becomes legally fixed, even if the money is not paid until later. This does not apply to payments across the border to a related company.

French corporation Schneider S.A. acquired a target company in the United States for $2.25 billion. It formed a separate US subsidiary to acquire the target, and lent it $328 million to help make the acquisition. After the acquisition, the US acquisition subsidiary and the target merged. The target was left owing its now French parent company the $328 million. It also borrowed another $80 million directly from Schneider. Interest accrued on the loans at the rate of $21 million to $38 million a year.

Section 1.267(a)-3 of the IRS regulations requires a US taxpayer to wait to deduct amounts owed to a related foreign person until the amounts are actually paid. However, it does not apply to amounts on which the foreign recipient is exempted from US taxes by treaty — except for interest. Schneider argued in court that the exemption should also apply to interest. It is exempted from US withholding taxes on the interest payments under the US-French tax treaty.

A US appeals court said */ continued page 33*

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of Labor. The Buy America Act provides a preference for domestically-produced goods over foreign goods in US government procurements. Under the federal-aid procurement regulations, state and local agencies must adhere to certain requirements — for example, using a competitive bidding process to award construction contracts — when procuring projects with federal-aid highway funds.

Another statutory restriction that may prove a hindrance to private investment is that companies benefiting from bonds are not able to use an accelerated depreciation schedule to realize certain tax benefits that might otherwise be available. Whether the savings on lower interest rates provided by the bonds will offset the lost tax savings to be gained from use of an accelerated depreciation schedule will probably need to be analyzed on a case-by-case basis. In general, there are three situations in which the savings to be gained by the lower interest payments associated with tax-exempt financing would be worth the lost tax subsidies of accelerated depreciation schedules: where the interest savings exceed the lost tax savings, where the developer cannot use the tax subsidy because of an inadequate tax base, and where the road is not considered privately owned but rather the private party has a concession to maintain the road and collect tolls. If the concession does not confer ownership, then there is no loss of depreciation when improvements are financed with tax-exempt debt because the concession owner was not entitled to claim accelerated depreciation in any event.

One issue related to the bonds that has not been addressed yet by the transportation department is whether private developers or operators may receive bond allocations for privatizations of existing public roads. So far there has been no agreement on this in the transportation sector, although some have suggested that the purchase of existing public roads will not be allowed under the new private-activity bond guidelines. This issue may become important as more and more states consider privatizing their existing assets on the heels of the Chicago Skyway lease in 2005, the potential privatization of the Indiana turnpike discussed earlier and the potential privatization of the Dulles toll road in Virginia.

The US Department of Transportation is collecting applications for allocations of scarce tax-exempt bond authority for road projects with private participation.

The highway bill last August also requires that 95% of the net proceeds from a bond issuance must be spent within five years of the date of issuance. Otherwise, the issuer has 90 days from the end of the five-year period to use all unspent proceeds from the bond issuance to redeem the bonds. An exception to this rule is established for circumstances beyond the control of the issuer, but this provision may still prove to be problematic. An effective five-year call on the bonds is not typical in capital markets and may create pricing issues that offset any benefit to be gained from tax-exempt financing. ◎

Intercreditor Issues in Complex Financings of Joint Ventures

by Denis Petkovic, in London

Intercreditor arrangements have always been a feature of secured lending and structured finance, but the relationships and accommodations among lenders have become more important with the growing diversity of capital providers.

There has been an explosive growth in the project finance market in hedge fund activity as these funds participate as lenders under a "second lien financing" or "term B loan." Both terms describe financings that are essentially secured junior debt. Emerging market funds, distressed debt funds and other non-bank financial intermediaries have also been stepping in to provide different layers of capital to projects. The upshot of this is an increasing concern in project documents about investor exit, capital and debt layering and intercreditor terms.

This article covers two topics. The first part of the article discusses issues that should be addressed in joint ventures to undertake projects and emphasizes the impact that admitting fund investors has on joint venture documents. The second part addresses some of the new challenges posed by increasingly complex intercreditor relationships.

Joint Venture Structures

There are certain basic structuring aspects to consider when setting up a joint venture to undertake a project.

Choice of project entity is probably the first big issue. One may choose to use an incorporated entity for the joint venture in order to insulate the sponsor and investors from personal liability to creditors of the project company. However, a partnership often has more appeal. The main benefit of using a partnership is that it is usually transparent for income tax purposes. There is no income tax at the entity level; the partners are taxed directly on their shares of income. The risks associated with fiduciary duties owed by one partner to the other can be minimized by using companies as partners and tightly regulating what such entities may do in a joint venture agreement.

Unincorporated or contractual joint ventures are also popular in some industries and in some countries — for example, in the mining sector. Their essential element is that each joint venturer is entitled to (and can take in kind) its share of product derived from the project. Unincorporated joint ventures are similar to partnerships in many respects, but are nevertheless considered to be a different legal creature. Each venturer generates a separate profit, maintains separate accounting, obtains separate tax treatment and appoints a separate manager as its agent. This suggests that separate businesses are operated. A guiding principle of such joint ventures is that expenses are shared, but revenues are not. Expenses are funded by cash calls in agreed proportions. In addition, parties hold joint venture assets as tenants in common, pay */ continued page 34*

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the IRS regulation is a reasonable interpretation of the US tax code. The case is Square D Company v. Commissioner.

A "LOAN" OF EQUIPMENT was a "sale" for state sales tax purposes.

Two coffee companies lend coffee grinding and brewing equipment to customers who buy their coffee beans and other products. The customers are not charged for use of the equipment, but they end up being charged more for the coffee beans. The amount charged for the beans varies with the cost of the equipment they are given for use. When the customer stops buying beans, it must return the equipment.

Missouri tried to collect use taxes from the coffee companies on the machines. Most US states collect sales and use taxes on purchases of equipment. Sales taxes are collected on equipment bought in the state. Use taxes are collected on equipment bought outside the state but imported for use in the state, as a way of preventing consumers from doing all their shopping elsewhere.

The coffee companies argued that they should not have to pay use taxes because the coffee machines were imported into Missouri for "resale" to customers. Missouri, like other states, has a "resale exemption" that exempts purchases from sales and use taxes where the equipment is purchased to resell to someone else. The Missouri statute defines "sale" broadly to include any transfer of "the right to use" property.

The court said that even though customers are required to return the machines once they stop buying coffee beans, this "does not defeat the fact that customers give consideration for the right to use the equipment." The case is Ronnoco Coffee Company v. Director of Revenue.

LUXEMBOURG is under pressure from the European Union to do more */ continued page 35*

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expenses proportionately and appoint a manager to run the joint venture. Default by a joint venturer will usually result in dilution of the defaulting party's interest or the granting of cross-security to the other party that can be enforced on default.

If a local concession is held by a project company or operator, then it may be sensible to insulate the concession-holding company from shareholder disputes and changes in control by putting the concession into a subsidiary company. If cross-border withholding taxes will apply to dividends or interest then, if possible, one should try to invest into the project company from a jurisdiction with a favorable tax treaty. Investors may want to invest through one or two layers of companies to enable them to exit the project by disposing of an intermediate company rather than the direct interests in the project for political, regulatory or tax reasons.

Another important issue concerns the structure of the managing board and the degree of control that will be exercised by investors. The composition of the board of directors will usually reflect the size of the parties' respective interests in the company. Where ownership is equally divided between two owners, board representation will also usually be equal. In such cases, the parties must decide what role the chairman of the board will have and how deadlocks on urgent matters will be resolved. Other important governance matters are who to appoint as directors, how board decisions will be made, what constitutes a quorum, the exact voting rights of directors, and who will handle legal compliance, budgets, reporting and health and safety matters.

While issues of relative shareholder control are matters for negotiation among the parties, project lenders and sponsors should be alert to the laws in the jurisdiction where the project company is located, laws that may operate to give default powers or protections to majority or minority holdings. For example, under English law, a shareholding of 26% is strategically important because it permits the blocking of special and extraordinary resolutions. Other rights or protections apply under English law to shareholders owning 95%, 75%, 51%, 15% and 10% of equity. In some jurisdictions, default legal rights or protections may be overridden by express contrary contractual provisions.

The huge range of banks, private equity and hedge funds, export credit agencies and others providing financing is complicating the intercreditor arrangements in deals.

Another issue is what actions are so important as to require the consent of the minority shareholders or owners. Typically, the agreement of all owners is required in order to approve a business plan, incur material expenditures not on the approved business plan, change the company's constitutional documents, legal forms or share structure, including the issuance of shares, incur any loan or give any guarantee, indemnity or security not envisioned by the business plan, transfer all or any material part of the company's assets, appoint or dismiss key personnel, change auditors or acquire or dispose of equity in another company.

Where the parties have agreed that specific matters require unanimous approval of the shareholders or directors and there is a failure to obtain any such approval, a deadlock results. It is extremely important to include in a shareholders agreement the means by which such a deadlock may be broken. Financiers will insist on some means to break the deadlock.

One common mechanism is for the organizational agreement to provide for the adjournment of the board or other meeting at which the deadlock has arisen for a period of 30 days, and if after that period a resolution is not found the company is to be wound up. This is a draconian result that serves as a strong commercial incentive for the parties to resolve their differences. Or, alternatively, the dispute can first be referred to an outside "swing man" director, who only acts as a director when there is a deadlock.

Another way to resolve deadlocks is for each party to have the right to exercise cross-"call" and "put" options upon the happening of a deadlock. This is often called "Russian roulette." One party is permitted to serve notice on the other either to sell his shares to the other or to buy the other's shares at the same price. The party receiving the notice then has the choice of either buying or selling, but if he fails to make a choice, the party serving the notice can require the other to buy or sell his shares at the price in the original notice. As the price must be one at which the party serving the notice is prepared to both buy and sell, it usually follows that a fair price is chosen. The arrangement works well if both parties have or can raise the resources to buy out the other. It is capable of being abused when one of the parties to the joint venture knows that the other does not have the resources to cope with service of such a notice.

Rights of preemption are very important in most joint ventures. Typically, shareholder agreements provide that any shareholder who wishes to transfer his shares will first have to offer them to the other shareholders at the offer price or a price set by the company's auditors. If the shares are not taken up by the other shareholders, then they usually may be sold freely to third parties. In some cases, it may be prudent to include an initial period during which voluntary transfers are absolutely prohibited, emphasizing the shareholders' commitment to the joint venture for at least a particular period — the "lock-up period." Common exceptions to the lock-up period include permitted transfers to affiliates or to existing unrelated shareholders.

The joint venture agreement should discuss how to handle the default by a shareholder. Shareholder default could result from the shareholder's failure to meet a cash call or its experience of an event specified in the agreement, like bankruptcy. During a period of default, the defaulting shareholder should be blocked from exercising voting rights except, perhaps, where a matter would increase its own financial commitments. However, blocking voting on matters pertaining to transfer of shares, assignments of shareholder loans and receipt of dividends can be contentious issues.

Different consequences can flow from different events of default. If a payment default occurs */ continued page 36*

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to limit the use of 1929 holding companies.

A 1929 holding company is a type of holding company that is exempted from Luxembourg corporate, municipal business and net worth taxes. It is subject to capital duties and an annual subscription fee. Dividends and interest paid by such companies do not attract a withholding tax at the Luxembourg border. The holding companies are not considered tax residents of Luxembourg for purposes of tax treaties. Therefore, their use is pretty much limited to situations where a multinational corporation using a holding company in Luxembourg establishes a two-tier holding company structure, with the 1929 holding company as the parent with a second Luxembourg company below it as a subsidiary.

The European Union has been trying to rid the region of tax regimes that introduce "harmful competition" among member countries. It has set a goal of getting rid of regimes like 1929 holding companies by 2010. Luxembourg amended the holding company law in April 2005 to deny exempt 1929 status to any company if more than 5% of the dividends it receives are from companies that are not subject to income taxes at least at a level equivalent to the Luxembourg corporate tax.

This change did not go far enough for the European Commission. It informed Luxembourg on February 8 that it is launching a formal investigation. The investigation is expected to lead to an order from the commission to take more significant action.

US MULTINATIONAL CORPORATIONS with European subsidiaries may have trouble claiming some foreign credits in the United States after a decision by the European Court of Justice in the *Marks & Spencer* case.

The United States taxes US companies on worldwide income, but lets them claim credit for income taxes paid on */ continued page 37*

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(which could include an initial subscription of capital) and other shareholders step in to pay the cash call, dilution of the non-payer could follow according to a formula such that the proportion of shares to be sold to the non-defaulting investor has a correlation to the proportion of defaulted debt. If a willful default in respect of shareholder obligations occurs, then voting rights may be blocked and executive committee nominees of the defaulting shareholder may be precluded from acting. If a bankruptcy event occurs, then a buy-out procedure may be activated at the fair market value or other value of the shares. In such a case, the shareholder may be treated as having offered all of its shares to the other shareholders pro rata — not necessarily at a fair market value, but perhaps at par or some discounted price reflecting that the shareholder is being penalized due to default.

The involvement of a financial investor such as a fund that is particularly interested in exit and returns on exit will cause special provisions to be included in a joint venture agreement. First, the agreement will probably require a lock-up period that lasts until project completion and during which no share transfers may be made by key sponsors. Second, in the event of a default by a key sponsor, the fund will likely be entitled to "put" its interest to a third party without activating the preemption rights of other investors. Third, it is typical to see "tag-along rights" in these agreements — whereby all shareholders are entitled to sell their shares at fair market value if the sponsor or financial investor has this right — or "drag-along rights" that require a party to make the same offer to purchase shares to all shareholders if it makes the offer to any shareholder. Lastly, often a financial investor will insist that the agreement prescribe when a public listing must take place and what the mutual obligations of the shareholders are at that time. Invariably, the financial investor will wish to control the listing process.

Another important item is planning for dispute resolution. If court judgments from one jurisdiction will not be enforceable in another, then the agreement should provide for arbitration and ensure that any arbitration award will be enforceable in all relevant jurisdictions or as desired. Also, where a party to the joint venture is a government or governmental instrumentality (not always easily determined), nongovernmental parties should be sure to get waivers of sovereign immunity.

Understanding the four legal concepts used to construct any mezzanine layer of finance is helpful in negotiating with mezzanine lenders.

Complexity Tied to Mezzanine Debt

There is an increasing complexity in the layering of capital and the intercreditor arrangements involved in project joint ventures. This increased complexity results from the growing use of mezzanine financing.

Mezzanine financing is often the final layer of debt in an acquisition financing and, increasingly, an important layer in project finance.

"Mezzanine finance" describes a range of financing arrangements, including second-lien financings, term B loans and the issuance of high-yield bonds. It is a mid-level or hybrid financing somewhere between higher-grade debt and equity. Economically, it can perform in the same way as equity while legally constituting debt (or vice versa). This type of financing carries a higher risk and a higher rate of interest or yield than senior secured commercial bank term loans, and historically has involved fixed-rate, seven- to 10-year financings. Mezzanine debt is junior to other debt, generally meaning that it is unsecured or subordinated or both and, increasingly, subject to intercreditor priority ranking arrangements.

Mezzanine debt such as "high-yield bonds" has traditionally been long term, fixed rate and less intrusive in terms of covenant control than commercial bank debt. Cash flow control ratios such as interest rate coverage ratios have been uncommon. Such finance also typically contains a call option entitling the borrower to call in the bonds early and repay the outstanding indebtedness. Mezzanine finance can be arranged in the public markets or privately through private placements to sophisticated investors and lenders.

In recent years, however, mezzanine with other characteristics has become more prevalent and known as "second-lien financings" or "term B loans." Second-lien financings are generally bond transactions utilizing a priority arrangement between senior secured creditors and junior creditors; term B loans are a similar animal financed mainly in the bank market rather than the bond market.

In understanding the legal tools used to construct mezzanine finance, there are four key legal concepts to appreciate. They are subordination arrangements, priorities arrangements, preference shares and convertible notes. Interconnected with most of these topics (although less so with preference shares) is the issue of intercreditor arrangements. Indeed, subordination and priorities arrangements are intercreditor arrangements in their own right.

Intercreditor Arrangements

Where two unsecured creditors (or creditors sharing the same security) agree that in the winding up of a borrower, one creditor will rank behind all or certain other debts of the company, such an arrangement is known as subordination and the various categories of creditors, often with the company, enter into a subordination deed or agreement to document that arrangement and to regulate pre-insolvency credit arrangements.

One method of achieving subordination is structural subordination. A senior lender can achieve subordination without a junior creditor contractually giving up any rights, by restricting the recourse the junior creditor has to obligations and assets of particular companies in a group. Such a structural subordination is still sometimes a feature of transactions involving second-lien financings and term B loans leading, in the view of some lawyers, to complexity and confusion in structuring.

Structural subordination involves, for example, an interim or other holding company of a borrower issuing high-yield debt to investors or lenders and relending the proceeds to an operating or project company. Senior */ continued page 38*

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the same income to other countries. However, taxes that a company pays voluntarily are not creditable. IRS regulations require a company to make a reasonable interpretation of foreign law, to avail itself of treaty benefits, and to take "all effective and practical remedies" to minimize its tax burden in other countries.

In the *Marks & Spencer* case, the European Court of Justice said that the United Kingdom must let Marks & Spencer use tax losses from subsidiaries in other member countries of the European Union to reduce the taxable income the parent company must report in Britain. This is one of the consequences of the treaty creating the European Union. However, losses must be allowed to the parent in Britain only in situations where the losses cannot be used in the country of residence of the subsidiary in any past or future year, including future use by a purchaser of the subsidiary. Thus, for example, a group of companies could not simply choose to use losses anywhere in the group in the country where the tax rates are highest.

The decision appears to be retroactive, opening the door to refund claims for taxes paid in past years. It has created uncertainty about when losses can be used across borders within Europe. US companies could find foreign tax credits disallowed if they fail to take full advantage of the decision.

MINOR MEMOS. Two class action suits have been filed in the US courts to force the IRS to refund the 3% excise tax that the federal government collects on long-distance telephone calls. The government has lost a string of court cases filed by individual companies to get back the taxes they paid. The problem is the tax statute is out of date because it requires the tax be paid on calls that are charged on the basis of time or distance. Phone companies no longer charge for calls on that basis . . . . First Energy Corporation, a holding company for utili- */ continued page 39*

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lenders, however, will lend to the subsidiary project company on a secured basis. Upon insolvency of the project company, the high-yield bondholders will not be creditors of the operating company and are unlikely to recover anything after the subsidiary's secured creditors are satisfied. If guarantees are issued by an operating company to the high-yield bondholders, they are likely to be subordinated to the senior debt being incurred at the operating company level.

Subordination can also be contractual. It may be achieved by a simple contractual undertaking under English law. Governing law should be checked to be sure that this contract term will be respected.

The junior creditor may also agree with a senior creditor that any dividend received in respect of a claim in a winding up of the debtor company or any other amount received will be held in trust for the senior creditor to the extent of its debt.

Lastly, the senior creditor could seek an assignment of the junior creditor's loan or take a charge over the rights of the junior creditor against the borrower. Obviously, if there are restrictions on the junior creditor's ability to assign its loan, contractual subordination could be used instead of an assignment. Note that unlike contractual subordination, an assignment agreement will not necessarily terminate on repayment of the senior creditors' debts and may also be subject to registration as a security under local law.

Any of the above methods should be effective in the insolvency of the debtor company or the junior creditor to achieve the junior ranking of a junior creditor's indebtedness. Quite often, several of these methods can be used in tandem.

Under English law, "priorities arrangements" have traditionally applied to categories of secured debt and are usually the subject of a "deed of priorities" between two secured creditors under which they agree that one creditor's security shall have priority over another's. This means that on disposition of the security, proceeds will be applied first to satisfy the indebtedness of the senior creditor and only next to satisfy the indebtedness of the junior creditor.

Historically, the purpose of an English law priorities deed was to fix priorities over the same asset, usually by altering the default priorities that applied under law. Now with second-lien financings and term B loans, traditional provisions in priorities deeds are being incorporated into intercreditor arrangements that include wider and more extensive clauses defining the commercial obligations and rights of junior and senior creditors.

Many hedge funds are precluded from investing in subordinated debt.

Under English law, the borrower does not need to be a party to intercreditor agreements in order for them to be valid. If a borrower wants to prevent its secured creditors from rearranging their respective priorities, restrictions to such effect should be included in its loan documents.

An arrangement that does not alter priorities, but that deals with sharing of realization proceeds, is often called a sharing or pro-rata sharing arrangement.

Many hedge funds are precluded from investing in subordinated debt and are forced to consider secured second-lien debt documented by intercreditor agreements. Unlike subordinated debt, such secured second-lien debt qualifies as "senior secured debt," providing priority over the interests of trade creditors and other unsecured creditors. In the US and in some other jurisdictions, secured second-lien debt gives priority over unsecured liabilities of an environmental nature. Also, a secured junior creditor has a more comfortable collateral position in negotiations during a work out, which has increased the popularity of this type of financing.

For the borrower, the interest expense on mezzanine debt is generally tax deductible and repayment is easier to effect than it would have been if preferred equity had been issued instead. Also, payout of interest for the investors is, as a legal matter, certain whereas payment of dividends is not.

Senior creditors often object to a secured second-lien deal as they do not want collateral shared with a junior lender, and they do they want any practical interference in managing collateral. However, this is sometimes the only way to finance the project.

There is a view among some market analysts, however, that too much debt is being imposed on companies with the result that deals that would otherwise not get done are being undertaken, potentially jeopardizing the market over the long term. The alternative argument is that there is a market for mezzanine debt and that many investors are willing to accept its higher risk for a higher return.

Senior lenders (including multilateral lending agencies) and sponsors should approach transactions with the knowledge that the terrain has changed since 2003, at least in Europe. In that year, high-yield investors boycotted the leveraged buyout of LeGrand SA, an electronics equipment supplier in France, and increased the pricing on the deal by 100 to 150 basis points in order to have it close. Since then, most larger European leveraged transactions have been structured so as to allow more rights in collateral to junior creditors. Pricing of deals is often in the range of 5% to 6.5% above LIBOR, and equity kickers in the form of warrants may become more of a major feature. The term of the junior debt usually follows the maturity for the senior debt.

Common Provisions

The following is a list of provisions that are usually found in intercreditor agreements for a second lien financing or term B loan.

Payments. Interest payments on junior debt are payable on a *pari passu* basis with senior debt for as long as the senior debt is performing, meaning that no outstanding payment default has occurred on the senior debt and no "stop notice" is outstanding. Principal payments on junior debt should be prohibited or limited until the senior debt is repaid. Second-lien and term B financings are thus not, strictly speaking, junior in debt priority to senior debt where senior debt is performing.

Lien priority. Collateral subject to / continued page 40

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ties in Ohio, Pennsylvania and New Jersey, is still fighting a class action lawsuit by shareholders who believe the company overstated the amount of its dividends in 1986. Distributions that a corporation makes to shareholders are treated as dividends to the extent the corporation has "earnings and profits." The shareholders claim that First Energy made a $1.5 billion mistake over several years in calculating its earnings and profits and are looking for damages for the federal and state taxes they say they overpaid as a result, plus attorney fees. The suit was originally brought in state court and then moved — at the request of the utility — to a federal district court that dismissed the lawsuit after deciding the shareholders should ask the IRS directly for refunds of the taxes they overpaid, but acknowledged they were out of luck because refund claims must usually be filed within three years of the tax year in question. A US appeals court reinstated the suit in late January, but sent it back to state court . . . . Antarctica is not a foreign country, the US Tax Court ruled in late January. The decision is important to Americans working at scientific bases near the south pole. They cannot take advantage of a so-called section 911 exclusion in the US tax code that lets Americans working overseas exclude part of their "foreign earned income" each year from US income taxes. The court said Americans working in Antarctica do not earn any of their income in a "foreign country" defined as a "territory under the sovereignty of a government other than that of the United States." Antarctica is controlled by an international treaty among countries with an interest in the region. The US Tax Court reached the same conclusion in an earlier case in 1968. The latest case is *Arnett v. Commissioner*.

— contributed by Keith Martin and Laura Hegedus in Washington.

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security interests in favor of the senior lender and junior lender will be subject, generally, to exclusive priority in favor of the senior lender. Until the senior creditor is fully repaid, all proceeds derived from such shared security are applied to the senior debt. The terms of the two creditors' securities should be virtually identical to minimize documentation mismatch.

There are eight standard provisions that should be included in intercreditor agreements for deals with a second-lien financing or term B loan.

Payment blockage. If the borrower defaults, then the senior lender will have payment blocking rights activated. A typical provision may be that on any covenant default, the senior lender may serve a stop notice following which payments to the junior creditor may be blocked for approximately six months so that the borrower and senior lender may rectify any problem. Likewise, a payment blockage will be activated for so long as there is a payment default on the senior debt, in which case no payments to the junior creditor can be made. Moreover, if there is not a payment default on the senior debt, but there is a payment default on the junior debt, then the senior lenders may require financial tests to be satisfied in the intercreditor agreement for a payment to be made to the junior creditor. Such a financial test may be higher than those required to be satisfied in the borrower's loan documents.

Enforcement standstill. What is the length of time the second lien holder is subject to enforcement standstill on its security after it serves notice of default on the junior creditor? In Europe in the case of a payment default, the standstill typically runs for 90 days. For a less serious financial covenant default, it runs for 120 days and for a less serious default still on some other covenant, the standstill runs for 150 days. In some deals, there may be a correlation between the standstill times and the payment blockage times. In the US, an absolute bar on the junior creditor's rights to enforce collateral typically prevails whereas no bar applies to rights unconnected with collateral (for example, increased covenant protection or insisting on information to be supplied). Also, standstill provisions should terminate when the senior lender enforces its security interests.

In the United States, it is common to have separate security trustees looking after the rights of second lien holders and the rights of senior debt holders because of perceived conflicts of interest. This is less of an issue in practice in Europe; under English law, fiduciary duties operate to protect the interests of all beneficiaries for whom collateral is held by a security agent or trustee, although there have been exceptions to this practice.

Purchase of senior debt. What rights do junior creditors have to purchase senior debt? In Europe, they may have a right to buy out the senior debt for a period of 60 days following enforcement by the senior creditor of its lien (at par plus accrued interest). This is not really a feature of US practice.

A "silent lien." As mentioned above, it is typical that the junior debt is subordinate to the senior debt insofar as the collateral is concerned. This is a generally accepted principle reflected in the expression that the second lien is "silent" to the interests of the senior lenders. A matter of negotiation is how "silent" the junior debt should be. Some junior lenders will try to obtain a first ranking security interest on limited collateral and a second ranking security interest on other collateral.

Elements of a "silent lien." A senior lender would typically require that an intercreditor agreement at least contain the following elements of a silent lien. First, the junior creditor will not challenge the validity of the senior lender's security or its priority. Second, on a release of the senior lender's collateral, the junior creditor will release its security interest. Third, the senior lender will have exclusive rights to deal with secured assets prior to any standstill period ending in respect of the junior creditor's security. Fourth, trust obligations will be imposed on the junior creditor for mistaken payments and unauthorized receipts backed up by an obligation to "turn over" or pay the same to the senior lender.

Amendments. Junior creditors are very concerned with amendments to the senior debt terms. A priority amount is not uncommon over which the senior debt will not rank ahead of the junior debt and which amount may not be amended. The amount may be up to 20% more than the prevailing amount of the senior debt principal together with hedging liabilities, fees, an estimate of enforcement expenses and, of course, interest. Prohibition or restriction on changes to the maximum principal sum of the senior debt and its interest rate are common. Shortening the term for scheduled repayments of senior debt may also be prohibited in the intercreditor agreement. In addition, senior debt holders may be required not to change their borrowing base and may be prevented from using cash or other reserves of the borrower.

Further advances. Sometimes junior creditors try, usually unsuccessfully, to have further advances by the senior debt holder treated as junior debt, but treating these advances as junior debt does not usually make sense if the purpose of the advances is to preserve collateral. ◎

Importing LNG into the US? A Few Pointers

by David Levin and Ariel Ezrahi, in London, and David Schumacher, in Houston

Companies planning to import liquefied natural gas into the United States should consider in advance the various US corporate, legal and regulatory risks and liabilities that may arise in connection with this business.

These risks are manageable for any sophisticated company. There may be multiple solutions to some of the issues, depending on the company's business model. What is important is that care be taken in considering the issues and thought be given to the implications of selecting particular approaches.

Choice of Entity

There are advantages to the importer in conducting the business through a separate subsidiary. Such a structure may enable the company to allocate risks, and thus liabilities, among separate entities. For example, one "importer" entity can be established to purchase LNG receiving terminal capacity, import the LNG into the US, and own the LNG while it is held in storage at the LNG receiving terminal, while a separate entity can be established to purchase the regasified natural gas, enter into gas transportation contracts, and sell the regasified natural gas to end users. The importer need *not* be a US entity, although there will often be good commercial reasons to establish such an onshore entity.

The type of entity selected — for example, a corporation or partnership — and jurisdiction of formation also raise important tax issues. If the entity importing the LNG into the US is an offshore entity, then tax treaties between the US and the jurisdiction where the entity is formed may determine whether the entity's activities are subject to US taxation. Typically, where a non-US company undertakes all of the activities related to the importation and sale of the LNG without these activities being "attributable" to a permanent establishment in the US, it should not be subject to US federal income tax on the income from the LNG sales or importing business.

Various taxes, duties and fees may apply in connection with the importation of LNG into the US, including US customs and border protection duties on imported LNG, US customs reporting and documentation requirements and US customs bond requirements. In addition, a US customs broker's power of attorney must be given. There may be additional fees payable to US customs. There may also be state taxes or fees for port or harbor use, as well as tonnage tax assessments, pilotage costs and harbor tug and other assist-vessel charges.

Before importing LNG into the US, the importer should review US customs requirements for importing LNG into the US. Moreover, it is important to under- / continued page 42

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stand any rules, regulations, fees and expenses that a port authority may apply or impose on LNG vessels berthing at a particular port.

Regulation

The federal government regulates both the importation of LNG into the US and the siting, construction, expansion and operation of LNG receiving terminals. The federal government's regulatory authority is found in section 3 of the Natural Gas Act.

Any entity seeking to construct an LNG receiving terminal located on shore or in state waters must get approval from the Federal Energy Regulatory Commission. FERC will not regulate the commercial terms of service, such as rates that will be offered at a proposed LNG receiving terminal. Thus, new LNG receiving terminal owners and their users are free to negotiate terminal use agreements without regulatory oversight.

As a result of the recent Energy Policy Act, FERC has exclusive authority over the siting, construction, expansion, and operation of LNG receiving terminals. Despite FERC's exclusive jurisdiction, interested state and local agencies may participate in any FERC proceeding in which the construction of an LNG receiving terminal is at issue. Moreover, state governments still have authority to act under certain federal environmental laws. The process for obtaining authority to construct an LNG terminal will take at least a year. FERC is implementing a prefiling procedure that is supposed to streamline the process.

FERC considers environmental issues as part of its permitting process. FERC takes the lead in evaluating the potential environmental and safety impacts under the National Environmental Policy Act and incorporates the minimum safety standards of the US Department of Transportation.

Section 3 of the Natural Gas Act also requires the LNG importer, as opposed to the LNG receiving terminal owner (if different), to obtain from the US Department of Energy authorization to import LNG into the U.S. The importer may be a joint stock company, partnership, association, business trust or organized group of persons, whether incorporated or not. The importer does not need to be a US entity to obtain DOE import authorization. DOE issues import permits in a relatively short period of time.

The legal terms for LNG sales in the United States differ significantly from the terms for natural gas sales.

An LNG importer that plans to market the regasified natural gas may need to enter into gas pipeline transportation agreements with one or more interstate pipelines to transport its natural gas to end-users spread throughout the US. FERC has jurisdiction under the Natural Gas Act over transportation (which includes storage) of natural gas in interstate commerce. Unlike with LNG receiving terminals, FERC regulatory oversight includes jurisdiction over the rates and terms of service for interstate transportation and storage service. These terms of service are typically found in tariffs that are on file with, and have been approved by, FERC. The pipeline company and its customers are bound through individual contracts that incorporate the tariff terms. If the contract is materially consistent with the contract form that FERC has pre-approved, no further FERC approval is required. The Natural Gas Act does not require the entity using interstate transportation or storage service to be a US entity.

FERC does not regulate the price of natural gas.

However, the Energy Policy Act gives FERC the authority to take action against practices in connection with the sale or interstate transportation of natural gas that are manipulative or deceptive. The primary purpose of this new legislation was to prohibit certain activities that were undertaken by gas marketing companies at the beginning of the decade that threatened the transparency of the interstate gas markets. FERC has the authority to request information from market participants and seek imposition of criminal and civil penalties for violating its anti-manipulation rules. Thus, companies seeking to market natural gas in the US should be aware of these rules and prepared to provide information on their gas marketing activities if requested by FERC.

The US Commodity Futures Trading Commission also has regulatory oversight with respect to certain activities commonly connected with the natural gas market. The CFTC has jurisdiction over accounts, agreements and transactions involving contracts for sale of a commodity for future delivery, including natural gas, electricity and any other energy product traded or executed on or subject to the rules of a designated contract market, registered derivatives transaction execution facility, or any other board of trade, exchange or market described in the Commodities Exchange Act.

An LNG importer intending to market its commodity in the US may be subject to CFTC regulation, depending on the scope of its marketing activities, particularly if they involve trading in financial derivatives.

Contractual and Commercial Issues

There are significant differences between LNG and natural gas in respect of how they are bought and sold in the United States.

LNG historically has been sold pursuant to long-term contracts, often 15 to 20 years in duration. LNG buyers are required to make significant take-or-pay commitments. The LNG buyer must agree to take delivery of a significant portion of the annual quantity of LNG available for purchase (often 90% or more) or nevertheless pay for the minimum purchase quantity. Often, the price of LNG is tied to world oil prices. These long-term, take-or-pay contracts are necessary to justify the substantial capital commitment necessary to construct and operate LNG liquefaction projects. With oil the competing fuel in many markets, the use of an oil price index ensures that LNG is priced competitively with oil.

Conversely, the US gas market has, over the last 10 to 15 years, been largely based on short-term contracts. Take-or-pay commitments often depend on the quantity of gas that a buyer nominates for delivery during a month, week or day. The price for gas is usually based on a spot market price that reflects the price of gas at a particular point on the interstate pipeline grid. This price may or may not reflect changes in world oil prices.

LNG importers must be prepared to manage the risks arising from these differences. For example, an LNG importer must be able to manage the risk arising from significant take-or-pay obligations under its LNG supply contract in a market that relies on short-term gas supply arrangements. Moreover, the LNG importer must be able to manage potential mismatches between the LNG price and the price at which gas will be sold in the US. These mismatches arise not only from differences in the basis for the price (*i.e.*, an oil price forming the basis for the price of LNG and a US gas price based on natural gas prices in the US), but also the difference when the price for the commodity is determined. For example, the price of LNG will be determined when the cargo is delivered, while the price at which the regasified natural gas is sold will be determined at a later date.

Because LNG is lighter than air and possesses half the density of water, no residual environmental impact should result from a spill or release of LNG. The LNG, once it warms, would evaporate. Unlike an oil spill, there would be no contamination to remediate, and the super-cooled LNG would not move far from the vessel or terminal before becoming airborne. LNG is also believed not to be toxic or carcinogenic. In the absence of any threat of environmental contamination or harm to human health, the US environmental laws do not impose standards or requirements for managing this material, and remedial liability under such laws would be remote.

The US Coast Guard has established safety standards for the design and operation of commercial vessels in US territorial waters. Any vessel to be used for transporting LNG into the US would have to comply with these requirements as a prerequisite to being allowed into US territorial waters and harbors. This has typically not been a problem for LNG vessels, because they tend to be newer and well-constructed, for example, using double-hulled designs. ◎

Environmental Update

Greenhouse Gases

Seven northeastern states have taken a major step toward constructing the largest greenhouse gas emissions control program in the United States.

The states entered into a memorandum of understanding in December for a new regional program to combat global warming by reducing carbon dioxide emissions from power plants. The states would establish a cap for CO_2 emissions and create a program for trading CO_2 offset credits to achieve compliance with emission requirements.

The memorandum of understanding caps two years of negotiations among nine northeastern states and was approved by seven states (New Jersey, New York, Delaware, Connecticut, New Hampshire, Vermont and Maine). Massachusetts and Rhode Island chose not to join the program at this time.

The new program, known as the "regional greenhouse gas initiative," or "RGGI," calls for a mandatory cap on CO_2 emissions, coupled with a market-based trading program to reduce compliance costs. Under RGGI, regional CO_2 emissions will be capped at 121.3 million tons per year beginning in 2009 through 2014. This is a level equal to 1990 emissions. A further 10% reduction is required by 2018.

The cap-and-trade program established in the memorandum of understanding sets limits on regional emissions, but allows companies to trade emissions allowances. Companies that do not have enough allowances to cover their CO_2 emissions must either reduce their emissions or purchase allowances from other plant owners who are able to reduce their emissions below their prescribed caps. The RGGI agreement also provides that at least 25% of the emissions allowances will be used to benefit energy consumers. Under this mechanism, electric generators would purchase these allowances and the funds generated would be used to support energy efficiency and clean energy projects. States are free to set aside a larger portion of the allowances if they wish.

Various US states are going their own way on pollution from power plants either because the US government is not acting or they believe it has been too lax.

The memorandum of understanding must still be signed by each state. The participating states plan to issue a detailed set of draft model regulations for the RGGI program in early 2006 for public comment. After comments are received on the draft regulations, each state will pursue the necessary regulatory and legislative approvals necessary to adopt the program. The program is slated to begin January 1, 2009.

Announcement of the program was significantly delayed as a result of concerns raised by the states of Massachusetts and Rhode Island in the regional negotiations. Ultimately, the seven signatory states chose to go forward without those two states but included provisions in the agreement allowing Massachusetts and Rhode Island to become signatories to the memorandum of understanding at any time prior to January 1, 2008.

Power Plant Emissions

The control strategy committee of the Ozone Transport

Commission proposed in late January to reduce nitrogen oxide and sulfur dioxide emissions from electric generating units to levels significantly lower than those already required by US Environmental Protection Agency regulations.

The committee is composed of northeastern state environmental officials. It said that the "clean air interstate rule" that the US Environmental Protection Agency issued in 2005 to limit NO_X and SO_2 emissions does not provide reductions that are deep enough or rapid enough to address ozone and fine particulate problems adequately in the northeast. The committee proposes to use regional partnerships and model rules to implement a program that uses the basic structure of the federal clean air interstate rule but requires tougher emissions caps.

The Ozone Transport Commission represents 12 northeastern states and the District of Columbia. The model rule for electric generating units is one of 15 model rules under consideration by the commission to achieve compliance with the US Environmental Protection Agency's strict new eight-hour ambient air quality standard for ozone. Officials from OTC member states have expressed concern that the new EPA clean air interstate rule, which establishes a two-phase program, will not reduce pollution sufficiently to achieve compliance with the eight-hour standard by the EPA-mandated deadline of 2010. The clean air interstate rule establishes a cap-and-trade program to control power plant pollution in the eastern United States. The first phase of controls under the clean air interstate rule goes into effect in 2009 for NO_X and 2010 for SO_2.

Seven northeastern states are moving to limit greenhouse gas emissions.

Under the new OTC proposal, NO_X emissions rates would be reduced to 0.12 lbs. per million British thermal units (mmBtu) in 2007 and further reduced to 0.08 lbs. per mmBtu by 2012. For SO_2 the rates would be 0.24 lbs. per mmBtu in 2009 and 0.14 lbs. per mmBtu in 2012. The proposed emissions rates are significantly lower than the rates proposed in the federal clean air interstate rule, and the second phase under the OTC program begins three years earlier (in 2012) than the second phase under the federal clean air interstate rule. The committee had previously considered starting phase I in 2008, but ultimately decided to make commencement coincide with the commencement of the federal clean air interstate rule in 2009.

The OTC committee also recommended adoption of a rule mandating control measures for "electric generating peaking units" — units operating less than 500 hours per year and less than 10 hours per day. The proposal would require that, by 2009, peaking units must perform at levels achievable through the use of water injection technology to control NO_X emissions and must install dry-lo NO_X technology by 2012.

Utility industry representatives attending the OTC committee meeting criticized the emissions control proposal as unnecessarily expensive. Representatives recommended that the OTC rely solely on the federal clean air interstate phase I program to achieve the required compliance with the 8-hour ozone standard. Areas not found in compliance in 2010 could at that time impose more stringent control requirements to achieve compliance.

Mercury

Illinois Governor Rod Blagojevich is / *continued page 46* *continued from page 45*

proposing to cut mercury emissions from coal-fired power plants in his state by 90% by June 30, 2009.

The governor's proposed rule would go beyond the requirements of the federal clean air mercury rule issued in March 2005. Phase I of the clean air mercury rule requires that coal-fired power plants reduce mercury emissions by 47% by 2010 and 79% by 2018. The proposed Illinois rules are more ambitious, demanding a 90% emissions reduction by June 30, 2009 and prohibiting power plants from purchasing allowances or trading emissions credits with other companies or states. Power plant operators would be required to reduce emissions by an average of 90% across their entire fleets of plants by 2009, and each plant must individually achieve at least a 75% reduction by that date. All plants will be required to achieve a 90% reduction by December 31, 2012. Phase II reductions under the federal clean air mercury rule are scheduled for 2018.

There are currently 20 coal-fired power plants in Illinois, the most of any state.

The proposed mercury rules must be submitted to the Illinois pollution control board for approval, where approval is expected, and would then have to be approved by a state legislative panel, where industry opposition is expected to be significant.

If implemented, the proposed mercury rule would put Illinois in the company of states like Connecticut, Massachusetts, Minnesota, New Jersey, North Carolina and Wisconsin that have sought more stringent and rapid reductions in mercury emissions than those required under the federal clean air mercury rule. These states argue that the federal rule does not go far enough in mandating reductions and, more importantly, that the federal government's nationwide emissions trading program would allow local mercury hot spots to worsen. Environmental opponents of the federal approach have long argued that mercury emissions do not disburse over as wide an area as other types of air emissions and, therefore, that it is not appropriate to allow power plants to use reduction credits from plants in different parts of the country to avoid controlling their own emissions.

Another 12 eastern states are proposing greater reductions in SO_2 and NO_x emissions than are required by a proposed federal "clean air interstate rule."

IFC Guidelines

The International Finance Corporation is expected to issue revised general environmental guidelines in February, a development that could have ramifications for more than just IFC-sponsored projects. Early indications are that the IFC intends to adopt a more "adaptable" approach to implementing its environmental goals.

The guidelines, which have been under review since 2004, are technical reference documents that address the IFC's expectations for industrial pollution management and environmental risk management at projects in which it invests. At present, they consist primarily of industry sector environmental guidelines that are in part III of the World Bank Group's 1998 pollution prevention and abatement handbook, as supplemented by IFC-published guidelines addressing a wide range of topics, including occupational health and safety.

The guidelines have become a global reference standard for private sector development, regardless whether the IFC or the World Bank is actually involved. They are frequently incorporated into international lending agreements by commercial banks and other financial institutions to establish baseline environmental requirements for borrowers. Since 2003, more than 30 leading private banks, accounting for about 80% of the global project finance market, have committed to follow the IFC's social and environmental policies and environmental review procedures by adopting the "Equator principles." In addition, 26 OECD export credit agencies have agreed to observe minimum environmental standards based on the IFC policies.

Once issued, the draft IFC environmental guidelines will be available for public comment for a period of 60 days.

The IFC issued draft policies on social and environmental sustainability and on disclosure of information last September. The draft policies were intended to better define the roles and responsibilities of IFC and its clients in the hope of increasing accountability and at the same time increasing transparency. The sustainability policy includes a performance standard for pollution prevention and abatement that is expressly based on technical and financial feasibility and cost-effectiveness.

Mohave Shutdown

Southern California Edison has shut down its 1,580 megawatt Mohave generating station in order to avoid violating a court-ordered deadline to install pollution control equipment.

The coal-fired Mohave plant, which is located about 100 miles south of Las Vegas, has been the subject of litigation with environmental groups that claim sulfur dioxide emissions from the plant caused a deterioration in visibility at the Grand Canyon. The litigation produced a 1999 consent decree under which SCE is required to upgrade emission control equipment or close the plant by January 1, 2006. The emission controls contemplated by the consent decree include a sulfur dioxide scrubber and a fabric filter "baghouse" in which SCE was expected to invest $300 million.

According to a December 29 filing with the California public utilities commission, SCE's decision not to invest $300 million in the pollution control equipment resulted from its inability to secure sufficient water to maintain plant operations. The plant uses water to turn coal into slurry. The water used to make the slurry comes from the Navajo aquifer in Arizona, which the tribe asserts is being depleted and is too valuable for this use. Negotiations to get water from an alternative aquifer, also on tribal land, are ongoing, but SCE told the public utilities commission that the process could take up to four years to complete.

SCE wants an extension of time to comply with the emission control requirements of the 1999 consent decree. Environmental groups oppose granting any extension.

Renewables in Gasoline

In January, the EPA ordered refiners, importers and blenders of gasoline to ensure that "the percentage of renewable fuel in gasoline sold or dispensed to consumers in the United States, on a volume basis, shall be 2.78% for calendar year 2006." This 2.78% minimum is the "default" percentage set by the new Energy Policy Act enacted last August.

The Energy Policy Act requires the use of ethanol and biodiesel in gasoline production, at levels starting at four billion gallons in 2006 and increasing to 7.5 billion gallons in 2012. Under the act, the EPA is required to establish an annual minimum percentage of renewable fuel that must be used in gasoline / continued page 48

Illinois wants a 90% reduction in mercury emissions, and it would bar Illinois power plants from avoiding emissions cuts by buying pollution allowances from sellers in other states.

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production. In order to ensure that the 2006 program was implemented in a timely fashion, the act established an initial default percentage of 2.78% to be used by EPA initially. The agency said that it intends in future years to adopt individual renewable fuels caps when it develops the necessary credit trading program for renewable fuels.

The 2.78% renewables standard should be easily met in 2006 by the petroleum fuels industry as a whole, primarily through the use of ethanol. Anticipated US gasoline sales of about 141.6 billion gallons will account for almost four billion gallons of ethanol — up from the 3.574 billion gallons of ethanol consumed in 2004, according to the Renewable Fuels Association. Biodiesel, on the other hand, cannot be blended with gasoline, but can be blended with diesel.

In future years, refiners and blenders that use more than the required percentages of renewable fuels in their products will receive credits that can be used in other refining or blending operations or by other refiners and blenders. Because the trading program has not yet been developed by EPA, no such credits will be generated in 2006.

New Source Review Case

A Federal district court dismissed a suit against the Tennessee Valley Authority in mid-January for alleged violations of the Clean Air Act at its Colbert plant in Alabama.

The case was brought by the National Parks Conservation Association in 2001, alleging that TVA violated Clean Air Act new source review requirements by making modifications to its Colbert plant that increased emissions without obtaining a new or modified air permit, which permit would have required the installation of advanced pollution control equipment. TVA took the position that the modifications qualified as "routine repair and maintenance" that are exempted from new source review under EPA regulations. In a 2005 ruling, the court interpreted "routine maintenance" in a light favorable to TVA. The court decided that the term refers to projects that are routine within the industry, even if they are carried out once at each individual plant. In November, the court also granted TVA's motion to dismiss the new source review claims, holding that the modifications had occurred more than five years before the lawsuit commenced and that, therefore, the claims were barred by the five-year statute of limitations period. The court ruled against the citizens' group's argument that the violations were continuous or ongoing because the resulting pollution continued to be emitted.

The decision to dismiss the case may now be appealed by the citizens' group.

— contributed by Andrew A. Giaccia, in Washington

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