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Doubts About State-Mandated Power Contracts

by Bob Shapiro, in Washington

Two recent federal district court decisions, one in Maryland and one in New Jersey, found that state programs directing local utilities to sign long-term contracts with independent power producers were unconstitutional.

The decisions raise questions about the authority of states in general to direct utilities to purchase capacity and energy at wholesale under specific state mandates, including renewable portfolio standards.

These decisions were at the trial court level and are subject to appellate review. Both decisions were appealed to US courts of appeal in late November.

Both decisions involved constitutional challenges to state programs that tried to encourage the construction of new gas-fired capacity in the portion of the PJM region where generating capacity was considered insufficient by the state. The New Jersey program was initiated pursuant to a specific state statute directing action by the New Jersey regulatory agency, the Board of Public Utilities, or BPU. The Maryland program was initiated by the Maryland Public Service Commission itself, without a specific statutory directive.

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CONSTRUCTION-START ISSUES continue to take up substantial IRS time.

Wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects must be under construction by year end to qualify for federal tax credits.

Developers were focused early in the year on "incurring" at least 5% of the project cost. This is one way for a project to be considered under construction in time. As the year draws to a close, attention has shifted to starting physical work of a significant nature on the project.

It is unclear to what extent tax equity investors and lenders will be willing to rely on the physical work test when it comes time to finance projects. Some tax equity investors have said / continued page 3

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Topping Up Revenue

In both cases, the state had conducted a competitive solicitation for the construction of new generating capacity. The winning bidders received their fixed bid price from the local utility under a long-term capacity-only contract using a "contract for differences" pricing scheme. Bidders were required to bid into and sell their capacity in the PJM market, and any revenues from that capacity sale would offset the fixed bid price. If the PJM capacity price was higher than the fixed price, then the bidder would refund the difference to the local utility. If the PJM capacity price was lower than the fixed contract price, then the utility would pay the bidder the difference. In each program, the bidder was free to sell the energy from the project (as opposed to the separate capacity) to third parties in the PJM market. The solicitation, and the contract-for-differences pricing scheme, only applied to capacity.

Two federal courts said state programs directing local utilities to sign power contracts with independent generators are unconstitutional.

The state programs that obligated regulated utilities to sign the capacity contracts for differences were challenged on two constitutional grounds in both Maryland and New Jersey federal courts.

One claim was that the pricing that resulted constituted wholesale ratemaking by the state in violation of the supremacy clause of the US Constitution. The Federal Energy Regulatory Commission has been given exclusive jurisdiction over wholesale ratemaking under the Federal Power Act.

The other claim was that the state bidding requirements unfairly discriminated against out-of-state power producers in violation of the commerce clause of the US Constitution. The commerce clause gives the federal government the right to regulate interstate commerce. The courts have also interpreted this constitutional provision in the "negative," holding that the US Constitution therefore does not allow states to interfere with interstate commerce.

Both the Maryland trial court, and two weeks later, the New Jersey trial court, found that the state requirements that utilities sign capacity contracts under the contract-for-differences pricing conflicted with FERC's exclusive right to set wholesale power rates and thus violated the supremacy clause. However, both courts found that the commerce clause was not violated.

The finding of a supremacy clause violation for these state-mandated contracts is significant in light of similar state mandates for long-term energy resources that have been implemented in many states. For example, several years ago, Connecticut implemented solicitations resulting in contracts for differences in the New England power markets. Twenty nine states and the District of Columbia have adopted renewable portfolio standards that require competitive solicitations and require regulated utilities to sign long-term contracts for wholesale power purchases.

It is unclear whether the specific solicitations are sufficiently different in those cases to warrant a different result. For example, it is unclear how much the court relied on the contract-for-differences requirement that the bidder make sales into the PJM market as a basis for its holdings, which could distinguish the New Jersey and Maryland state mandates from other state solicitations. It should also be noted that the Maryland and New Jersey court decisions are not binding in other states and are themselves being challenged in the US courts of appeal.

Setting Prices?

New Jersey and Maryland had argued that they were not in fact setting a price for energy. The states argued that they were only establishing and promoting a legitimate state policy in favor of construction of new gas-fired generating facilities. The states claimed that the contracts for differences were not wholesale power contracts at all, but only a financial mechanism. Although the bidder would be making wholesale sales in the PJM market, there would be no actual sales of capacity or energy to the utility counterparty. Under the contract for differences, according to the states, the local utility only had a financial obligation to make a payment to the bidder if that market price was lower than the contract price. In addition, the states argued that the PJM price was not set by the state, but by the PJM auction process that was regulated and approved by FERC, and that the bidder had market-based rate authority under FERC regulation. But the courts viewed the contracts for differences as wholesale power contracts, and even if they were not, the courts said that the state directive established the ultimate price received by the bidder for wholesale capacity sales.

Although the Maryland and New Jersey decisions acknowledged that the Federal Power Act did not prevent a state from having a say over the siting and construction of generating facilities within its borders, both courts said that a state cannot secure development of a new power plant in a manner that would intrude on FERC's jurisdiction by effectively setting wholesale prices. According to both courts, by approving the bid price in a contract for differences that would require the bidder to sell capacity in the PJM market and require the local utility to pay any shortfall between the PJM price received by the bidder and the bid price, the state was establishing the ultimate price received for wholesale capacity sales. Once the courts reached this conclusion, then it was clear that only FERC could do this under the Federal Power Act.

It is important to note that both court decisions relied heavily on the testimony at trial. Other independent power producers who either lost the bids or were barred from bidding due to the restrictive bidding requirements challenged the programs.

Both courts found persuasive the claims of a number of such independent power producers that the contracts for differences will undermine their ability to use the capacity auction price signal to make business decisions in the PJM market. Both decisions ignored the arguments by the proponents of the state mandates that other states have conducted similar capacity programs that required sales into the power market in a contract for differences (like Connecticut) and have otherwise required solicitations for long-term energy purchases at wholesale. In reaching the conclusion that each of the state programs resulted in an unlawful state government-imposed price, the courts seemed to ignore the arguments / continued page 4

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they are uncomfortable relying on the test. However, a prominent lender-side law firm is advising lenders that it is comfortable with physical work.

Another issue is how much physical work is required in 2013. According to the Internal Revenue Service branch in Washington that handles construction-start issues, the key is the task must be significant. All the developer must do is start on it; the task does not have to be completed in 2013. Therefore, it would be a good idea to release the contractor to work on a meaningful task even if he does only a small part of it in 2013. He should continue working into 2014 on that task until it is completed.

The developer can give a limited notice to proceed on work under a larger contract, as long as what the contractor is released to do in the limited notice is significant.

Some tax equity investors and lenders appear to be adhering strictly to examples in the IRS guidance on starting construction. The guidance gives the example of a wind company that excavates and pours concrete pads above ground in 2013 for 10 turbines at a 50-turbine project, or 20% of the pads. The IRS has said the example has a typo. It intended to say one pad in 2013 based on a similar example that was posted under the Treasury cash grant program. Another example in the guidance suggests that the start of physical assembly of the main transformer for a project at a factory is enough to qualify the project for tax credits.

A developer hiring a contractor to start physical work this year must have a "binding" contract in place with the contractor before the contractor starts work. The contract can give the developer a right to terminate the contract for convenience. It can be silent about the damages to be paid after such a termination. However, many contracts specify liquidated damages to be paid in such cases and set the amount at 5% of the total contract price. Although not required, it would be a good idea to make the damages in such contracts the fixed amount, / continued page 4

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but not less than the actual costs the contractor incurred in performing the contract. Otherwise, the work beyond 5% of the project cost may not be considered binding.

The IRS has been answering many questions informally. These informal discussions have shed light on the following issues.

In 2012, the Treasury questioned whether some projects that started physical work in late 2011 before the deadline to qualify for Treasury cash grants were truly under construction if the projects lacked basic project contracts and permits needed for construction. The Treasury dropped these inquiries after concluding that since projects relying on physical work had to show a continuous pattern of construction, if a project still lacked basic contracts and permits at the end of 2011, it would need to have them fairly soon after to be under continuous construction. The IRS has said that projects that are completed in 2014 or 2015 will be considered automatically to have been under continuous construction. Does the IRS plan to revisit the amount of physical work required in 2013 after waiving the need to show continuous construction? The answer is no.

A developer can look through a contract with a prime contractor like a turbine manufacturer and count costs that the prime contractor incurs with subcontractors and suppliers for the 5% test. Is there similar look through for the physical work test? The answer is yes.

A developer who incurs costs in 2013 by taking delivery of equipment can decide later in which projects it had under development in 2013 to use the equipment. As long as the 2013 equipment accounts for at least 5% of the cost of the project at which it is used, the project qualifies for tax credits. Does the same principle apply to turbines or transformers on which the developer had the factory start physical work in 2013? The answer is yes.

Can a developer use stockpiled 2013 equipment in projects that it acquires in 2014 from other developers and claim tax credits on those projects? If the developer selling the project

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about actions of other states as well as FERC's own statements about similar state-mandated programs, thus essentially ignoring the larger implications of their decisions.

FERC did not file a brief in either court proceeding. None of the litigants appears to have thought to ask FERC for its views on the issue, nor did the courts seek any guidance from FERC on their own. The courts may have benefited from the view of the agency charged with administering the Federal Power Act, the statute that opponents of the New Jersey and Maryland programs argued preempted the state actions.

FERC's View

Over the years, FERC has been careful to distinguish between a state's action that directly establishes a wholesale rate and an action either to hold a solicitation or direct a regulated utility to hold a solicitation that leads to a wholesale rate under a long-term contract. For example, FERC has been aware for many years that that many states have required regulated utilities under state renewable portfolio standard or RPS legislation to purchase renewable energy. Under many state RPS programs, utilities, through solicitations, bilateral contracts or tariffs, are required to sign long-term contracts with generating companies for the purchase of renewable electricity at wholesale.

For projects that are small enough to be eligible to be qualifying small power production facilities under the Public Utility Regulatory Policies Act or PURPA, the PURPA rules expressly provide that the state can set the wholesale power price, also

The Federal Energy Regulatory Commission has a more nuanced view.

known as the utility's avoided cost. But for projects that are too large to be qualifying facilities or for programs that are not based on PURPA rules, or in regions like California, New York, New England and the areas served by the PJM and MISO regional transmission organizations, where FERC has allowed utilities to eliminate their purchase obligation under PURPA with QFs that are larger than 20 megawatts in size, the state does not have the authority directly to establish the wholesale rate. Nonetheless, FERC has never indicated that a state's RPS program that includes a directive to utilities to acquire wholesale renewable energy under long-term contracts to be a violation of FERC's exclusive jurisdiction under the Federal Power Act.

FERC appears to distinguish between a state's action that actually sets a specific rate that a generator must charge and a state action that directs a competitive solicitation for specific types of preferred generating resources where generators set their own bid prices. This seemed to be the line drawn by FERC when FERC was asked three years ago to review California's feed-in tariff that was imposed by state statute. In that case, the state legislature directed the California Public Utilities Commission to establish prices for small cogeneration facilities, called combined heat and power or CHP facilities, that might or might not qualify as qualifying facilities under PURPA. After a challenge by the regulated utilities in California, FERC found that, "to the extent a CHP generator is not a QF, the [CPUC's decisions under the state statute] are not preempted by the [Federal Power Act] only to the extent that the [California Public Utilities Commission] is ordering the utilities to purchase capacity and energy from certain resources, but are preempted to the extent that the CPUC is setting wholesale rates for such transactions."

Thus, it appears that FERC's concern was that the CPUC was directing the generator to charge a specific rate that a purchasing utility must use in a long-term contract. At the time of the FERC's decision, in 2010, FERC was well aware of California's RPS law and wholesale contracts that resulted from CPUC-ordered solicitations under the state RPS law. In those solicitations, as with the Maryland and New Jersey programs, the CPUC did not directly set the rate. Rather the CPUC reviewed the rates resulting from the solicitation that the utilities conducted pursuant to a state mandate, and it approved or disapproved the pass through to the utility's customers of the rates that resulted from the solicitations. The Maryland and New Jersey district court decisions failed fully to grasp the distinction between direct establishment of wholesale rates and "ordering the utilities to purchase capacity and energy from / continued page 6

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started construction independently on the project in 2013, then the project will remain qualified for tax credits after the sale. If the project was not under construction in 2013, then there is no consensus within the IRS construction-start branch. Until a consensus is reached, the only ways to qualify such a project for tax credits would be to acquire it in 2013 or, if that is not possible, for the developer taking over the project in 2014 not to buy it, but to enter into a joint venture with the original developer, and use the stockpiled 2013 equipment to qualify the project for tax credits. The original developer would have to retain an ownership interest commensurate with the value of the development rights he contributes.

The IRS is prepared to issue private letter rulings on construction-start issues. However, it will only rule on purely legal questions and not mixed questions of fact and law. An example of a legal question is the 2014 transfer issue about which the branch is currently undecided.

TREASURY CASH GRANTS on renewable energy projects remain a hotbed of activity.

A significant number of solar companies are in discussions with the Treasury about the grants they were paid on their projects. The grants are subject not only to a 7.2% haircut due to sequestration, but also the Treasury has been taking a hard line on the basis it will accept for calculating grants.

Most disputes are over developer fees included in basis, allocation issues such as how much of the purchase price the developer paid to buy the project rights before construction or a lessor paid in a sale-leaseback should be allocated to intangibles like the power contract, and prepaid rent in sale-leasebacks.

The Treasury's current view is that developer fees should generally not be more than 2% to 5% of project cost. There are exceptions where a developer can show it had a lot of capital at risk for a long period of time. / continued page 7

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certain resources."

It is also noteworthy that, in a series of FERC orders addressing the impact of state-mandated contracts for new generating facilities on PJM capacity markets, FERC did not at any time indicate that state mandates would violate the Federal Power Act. In fact, FERC had originally approved a proposal by PJM to exempt state-mandated resources from its minimum-offer-price rule.

The two federal court decisions are being appealed.

Under the minimum-offer-price rule, in order for a new power plant to bid into a PJM capacity futures market, that owner had to bid at least a specified minimum price in order to avoid distorting the market price for capacity. FERC had approved certain exceptions to this requirement for certain power plants, including state-mandated capacity. But PJM later changed its mind and asked FERC to take away the exception for state-mandated gas-fired power plants, and FERC agreed. That decision is now on appeal.

However, the FERC decisions regarding the PJM capacity market strongly suggest that FERC viewed its jurisdiction to review how state-mandated resources can be offered in the PJM market as sufficient to maintain its exclusive jurisdiction over pricing and sales in the wholesale markets. For example, FERC said in the last order approving the requirement that state-mandated gas-fired power plants be subject to the minimum-offer-price rule: "We believe that the [minimum-offer-price rule] that we accept, subject to modification in this proceeding, including the unit-specific review process proposed in PJM's compliance filing, serves to reconcile the tension that has arisen between the policies enacted by states and localities that seek to construct specific resources, and our statutory obligation to ensure the justness and reasonableness of the price determined in [PJM's capacity pricing model for selecting capacity]." FERC went on to state that its order would ensure "that the wholesale capacity market prices remain at just and reasonable levels."

Moreover, FERC in that PJM order had no trouble affirming the PJM's exemption for a different category of power plants, renewable wind and solar projects, from the minimum-offer-price requirement, regardless of whether they are QF or non-QF projects or are or are not encouraged under state-mandated solicitations and long-term contracts. This also suggests that FERC believes that its control over PJM's rates and procedures is sufficient to maintain its exclusive federal jurisdiction over PJM wholesale rates without otherwise disturbing the states' efforts to promote preferred generating resources.

Outlook

It is not possible to predict the outcome of the federal appeals of these Maryland and New Jersey federal district court decisions. The issues may well turn on the appellate courts' assessments of the distinction between a price that the wholesale generator ultimately receives under a state-mandated contract for differences and the price that the generator receives from the PJM market and whether this is a distinction that makes a difference under the supremacy clause.

It is also not possible to predict the spillover effect of these decisions in the event that the district court decisions are affirmed on appeal. However, the mere existence of these decisions casts a shadow on existing state programs and similar programs that states might seek to introduce in the future. ◎

Yield Cos Compared

by Keith Martin, in Washington

Use of the phrase "yield co" to describe three recent share flotations by NRG Yield, TransAlta Renewables and Pattern Energy Group, Inc. masks very different business arrangements. What is interesting is the different decisions each company made in structuring a yield co that would appeal to the market.

The three companies are among five project developers that set up or attempted to set up yield cos since the summer.

Two companies – Silver Ridge Power and Threshold Power – attempted listings in Canada but withdrew the offerings. A sixth company, Hannon Armstrong Sustainable Infrastructure, converted itself into a real estate investment trust in April 2013, a structure that has features in common with a yield co.

The idea behind yield cos is to put a portfolio of projects that are already operating in a new corporate subsidiary and sell part of the shares to the general public while keeping projects that are still under development in a separate entity. The yield co can raise equity at closer to debt rates because it owns de-risked assets that throw off predictable cash flow. Investors pay a premium not only for the predictable earnings, but also for the ability to trade their ownership positions in a liquid market. The subsidiaries are called "yield cos" because they distribute most of their earnings to shareholders through quarterly dividend payments. The appeal is to investors seeking higher yields than are available in the bond market.

The NRG Yield share offering was more than 10 times oversubscribed when the company listed on the New York Stock Exchange in July. The company listed at $22 a share and a projected dividend yield of 5.45% based on the initial share price. The shares were up 64% by early December, and the dividend yield had fallen to 3.33%.

TransAlta Renewables listed on the Toronto Stock Exchange in August at an initial price of C$10 a share and a projected dividend yield of 7.5%. The stock was trading up 7% by early December. The dividend yield had fallen to 7%.

Pattern Energy listed simultaneously on the NASDAQ Global Exchange and the Toronto Stock Exchange in late September at an initial share price of $22 and a projected dividend yield of 6.25%. The share price has since increased 13.2%, causing the dividend yield to fall to 5%.

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The Treasury believes that power contracts have value to the extent they are in the money. Some accounting firms are taking the position that a contract has no value if the contract prices for electricity were market at the time the contract was signed. Treasury rejects this, and believes that the time to value the contract is when the contract was sold to the developer before construction. Tax equity transactions present more complicated issues. If the contract was sold as part of a tax equity deal at the end of construction, some accountants and counsel argue the comparison should be to electricity prices when the owner would have had to have such a contract in place to have the project in commercial operation on the date the tax equity deal closes.

The Treasury is troubled by prepaid rent in sale-leasebacks. It believes that the peculiar math in the solar market means it is in the interest of both the tax equity investor and sponsor to have the lessor pay more for the project and then have the sponsor repay the lessor immediately with prepaid rent. Thus, when the Treasury sees prepaid rent, this raises questions whether the tax basis claimed by the lessor for calculating the Treasury grant is inflated.

The Treasury has been doing a calculation to adjust prepaid rent to what it views as a supportable level and then back into the amount the lessor should have paid. It treats the prepaid rent as the lessee investment and then determines what internal rate of return the lessee is earning on that investment. The internal rate of return is the discount rate that would set the present value of the net revenue the lessee expects from use of the project during the lease term equal to the prepaid rent. If the discount rate is less than what Treasury views as a reasonable return for the lessee, then it reduces the prepaid rent.

The lessee's gain on the sale part of the sale-leaseback is not taken into account as part of the lessee benefits stream. Many lessees do the calculation, but assume they will buy the project at the end of the

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lease term or extend the lease. The Treasury does not permit such assumptions.

If the prepaid rent is too high, then the Treasury asks the lessor how much less it would have paid for each dollar reduction in prepaid rent. This backs into the lessor purchase price the Treasury will accept.

There is still the question how much must be allocated to intangibles like the power contract. Even if the power contract is retained by the lessee in the sale-leaseback and is not part of the assets that were sold to the lessor, the income method that appraisers use to value projects takes the power contract into account indirectly.

The Treasury began also using a new "upward bound" calculation in November to set a cap on how high a basis it is willing to accept in sale-leaseback transactions. The calculation is the purchase price paid by the lessor plus the present value of the after-tax net benefits stream the lessee expects over the lease term (taking into account not only the net revenue expected from electricity sales, but also the prepaid rent, reserves and lease-related transaction costs), minus the tax rate times the purchase price paid by the lessor. The entire amount is then divided by one minus the tax rate.

Two more lawsuits were filed in November by grant applicants who received less than the grants for which they applied, bringing the total number of pending cases to 12. All the suits are in the Court of Federal Claims. The oldest has been pending since July 2012. One suit was withdrawn after the government filed a counterclaim accusing the solar company that brought it of fraud.

Both new suits involve projects that were sold and leased back the same day they went into service. Treasury cut the grants by 31% in one case and 28.5% in the other. The sale-leasebacks were only of the eligible equipment at each project that qualified for a grant. Both cases raise issues about whether the Treasury can allocate part of the purchase price paid by each lessor to intangibles (that do not qualify for grants), given that the parties sold and leased back only the eligible

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Minimum Scale

In general, a developer should have at least $500 million in operating project value that can be put in a yield co and then plan to sell a large enough share to raise at least $100 to $200 million in the initial public offering.

Timing may be key. It takes months to put a filing together. Demand for yield co shares could soften as interest rates rise.

NRG raised $471 million net after underwriting discounts and commissions by selling a 34.5% interest in 1,324 megawatts of conventional and solar power projects, plus the equivalent of another 1,098 megawatts of thermal facilities that produce steam or chilled water and another 123 megawatts of small cogeneration facilities. NRG retained control over the subsidiary with a 65.5% voting interest.

The assets are in nine states. Most went into service from 2009 to 2013. They include two portfolios of rooftop solar installations on schools in California and Arizona.

The power projects (not counting the cogeneration units) are 68.7% conventional power plants. Ninety-three percent of the output is contracted under long-term power contracts. The power purchase agreements have a 16-year weighted average life. This month, NRG Yield agreed to purchase the assets of Energy Systems Co., a Nebraska-based district energy company that provides steam to buildings in Omaha.

TransAlta raised C$202.1 million against a portfolio of 28 projects with a capacity of 1,112 megawatts. The company sold a 19.3% interest. It retains control through the ability to name a majority of the six-person board of directors for as long as it retains at least 35% of the shares.

The projects are all in Canada, but the company signed an agreement recently to acquire a wind farm in Wyoming. Wind projects account for 90.7% of the portfolio by capacity. The remaining 9.4% are hydro projects. Except for one wind farm that went into service in March 2013, the TransAlta assets have been in service for between one and 22 years, with 5.8 years in weighted average years of operation. All of the output has been contracted, but some of the projects are really merchant plants with TransAlta as the offtaker. The affiliate power contracts run 20 years or, if shorter, the remaining useful life of the project, with fixed prices of C$30 a MWh for wind and C$45 a MWh for hydro adjusted annually by the consumer price index. (The company will have to be careful before entering into

The three most recent yield cos chose very different business arrangements.

affiliate power contracts on any US projects as it could lose the ability to claim net losses from depreciation.) The average remaining life of the output contracts on all the projects is 17 years.

Pattern Energy raised $318.6 million in net proceeds on the sale of a 36.8% interest in eight wind farms in the US (including Puerto Rico), Canada and Chile, with a total owned capacity of 1,041 megawatts. It retained 63.2% of the voting rights.

Six of the projects have been operating between two and four years. The remaining two were still under construction at the time of the offering and are expected to be completed by the second quarter of 2014. Ninety-five percent of the output is committed under long-term power purchase agreements with an average remaining contract life of approximately 19 years.

The three yield cos plan to distribute between 80% and 83% of cash after debt service. All three expect to grow by acquiring additional projects, but they are not typical growth companies retaining earnings to fund expansion. For NRG Yield, only 31% of projected adjusted EBITDA in 2014 is expected to be cash available for distribution and 37% in 2015, suggesting a large amount of senior debt ahead of the NRG Yield shareholders in the capital structure. The 2014 figure for Pattern is 25.4%. It appears to be closer to 62% for TransAlta.

Different Business Strategies

Pattern starts as a classic yield co with a portfolio of operating or near-operating projects, but the yield co will morph into a full-fledged development company once its market capitalization reaches $2.5 billion.

The Pattern workforce will be split between the yield co and old Pattern until this market / continued page 10

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assets while leaving the intangibles with the lessee, and whether the Treasury can omit a "turnkey fee" and a separate "developer's premium" in calculating the eligible basis in its cost-up approach. The Treasury validated the bases it was willing to accept in part by adding up the eligible costs of the lessees to build the projects rather than focus solely on the purchase price paid by each lessor.

A solar developer that filed a Freedom of Information Act request for documents relating to grants paid to another solar company was told in late October that the estimated processing fee to copy the documents would be close to $50,000. The Treasury said the cost could be cut to $6,400 if it did not have to produce lots of duplicate paperwork that appeared to be the same from one grant application to the next. Because the processing fee was more than $250, it had to be paid in advance.

UTILITY REBATES to customers to induce them to install rooftop solar can be deducted when paid by the utilities, the IRS ruled privately, and are not advance payments for renewable energy credits, even though the customer must assign all of his renewable energy credits to the utility.

The ruling is at odds with an earlier ruling the IRS released in 2010. It is not clear to what extent the utility arrangements the IRS analyzed differ.

The new ruling is Private Letter Ruling 201341031. The IRS made it public in October. The agency issued at least one other identical ruling at the same time. Both the latest rulings and the one in 2010 appear to involve utilities in Arizona.

The state has a renewable portfolio standard requiring a certain percentage of the renewable energy that regulated electric utilities are required to supply customers to come from "distributed energy," meaning electricity generated by equipment located on its customers' premises. Utilities have to turn in renewable energy credits at year / continued page 11

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capitalization is reached, after which all the employees will move to the yield co. Until then, the project development, legal, finance and administrative staff will stay in old Pattern with the operations and maintenance personnel in the yield co and the top executives splitting their time between the two companies.

NRG Yield and TransAlta Renewables are classic yield cos in that they will own solely operating assets.

NRG Yield has a right of first offer or ROFO for the next five years to make bids on six projects from NRG that are expected to go into service during the period March 2013 through early 2014.

TransAlta Renewables agreed in a governance and cooperation agreement with the TransAlta parent company that it will rely "exclusively" on the parent to identify investment opportunities.

The Pattern yield co has a right of first offer for the next five years to make bids on any projects in the 3,000-megawatt development pipeline that old Pattern informs the yield co it plans to sell. The option is extended automatically for additional five-year periods unless terminated by old Pattern or the yield co. It will terminate early if the yield co fails to make offers on at least three projects that old Pattern is able thereafter to sell. The yield co also has an option to buy old Pattern if the current owners of old Pattern, including private equity fund Riverstone, decide to sell a material portion of the equity or substantially all of the assets.

Unlike the other yield cos, old Pattern has promised not to compete with its yield co for acquisitions of generation and transmission projects for as long as the yield co retains a ROFO over old Pattern projects.

Management Fees

Each of the developers will earn fees for managing its yield co.

NRG will earn $4 million a year, plus be reimbursed for its costs (but not employee salaries or overhead). The fee is adjusted annually for inflation and will also increase by 0.05% of the enterprise value of each future project acquired.

TransAlta will earn C$10 million a year, adjusted for inflation, plus be reimbursed for costs including employee wages and benefits "not captured by the fee." The fee will increase or decrease by 5% of the projected change in the yield co's EBITDA as a consequence of buying or shedding assets. It will also be reset no less frequently than every five years to take into account changing economic circumstances, regulatory requirements and general workload to manage the company.

Unlike the other two yield cos, the Pattern yield co will have its own employees and pay them directly, but will also compensate old Pattern for any use of legal, finance and administrative staff until the entire work force is reassembled under the yield co.

The NRG and Pattern yield cos have complicated ownership structures.

There are A and B shares in the NRG yield co. The NRG parent company, NRG Energy, Inc., which is also a publicly-traded company, owns all the B shares, giving it a 65.5% voting interest in the yield co but no economic interest. The public shareholders own all the A shares. They have all the economics, but only 34.5% of the vote.

Immediately below the yield co is a partnership. The NRG parent company owns a 65.5% economic interest in the partnership. The yield co owns the balance and is the managing member, but since the yield co is controlled by NRG, NRG also controls the partnership. All the projects are at least two tiers down from the partnership.

Dividend yields for yield cos have fallen as low as 3.33% as share prices rise.

NRG can exchange units in the partnership for A shares in the yield co. When these exchanges occur, the yield co will redeem and cancel a corresponding number of B shares that NRG holds in the yield co. Over time as the yield co raises more equity to make acquisitions, the share of the partnership held by the yield co will increase, either because the yield co will make capital contributions for more partnership units or pay the money to NRG to buy part of its partnership units.

The Pattern yield co will also have A and B shares. Old Pattern will hold all the B shares. The public will own the A shares. No dividends are paid on the B shares, but the shares have identical voting rights. According to Pattern, the A and B share structure is being used to mitigate risk to the public shareholders on one of the two projects that is still under construction: the South Kent wind farm in Ontario, Canada. The B shares will convert automatically into A shares at the end of 2014 or, if later, when construction of the South Kent project has been completed.

Benefits and Drawbacks

The TransAlta and Pattern yield cos own largely wind farms, which have variable output. Both intend to pay quarterly dividends in equal amounts during the year.

Combining renewable energy facilities with fossil fuel-fired power plants, as NRG has done, creates a tax base within the yield co to use tax benefits from the renewable energy projects.

NRG Yield does not expect to owe significant federal income taxes for approximately 10 years, perhaps longer if it grows by acquiring additional renewable energy projects. This means that not only will there be no taxes taken out at the company level, but also distributions to shareholders should be treated as returns of capital until the shareholders get their investments back. Distributions after that would be reported by shareholders as capital gains.

The market sometimes refers to a yield co in this position as a "synthetic MLP." Master limited partnerships, which require a statutory change before they can be adopted widely in the power industry, do not pay taxes at the entity level on earnings. Any tax is solely at the owner level. The fact that their earnings are subject to only one level of tax allows them to raise capital more cheaply.

In addition to providing access to cheaper capital, yield cos offer other benefits.

They provide a developer with a captive outlet into which to sell operating projects for cash, with the / continued page 12

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end reflecting the amount of renewable energy they supplied.

The latest rulings were issued to utilities. The utilities asked for rulings about up-front payments they make to both residential and commercial customers as an inducement to install solar. The amount of each up-front payment is a function of potential energy production. The customer must agree to purchase, install and maintain an eligible system.

The IRS said the payments are not forward purchases of renewable energy credits. It pointed to the fact that the customers do not promise to produce any particular number of RECs (although each payment is tied to projected output). It also said the RECs have no value to anyone other than the particular utility because the utility can only count RECs from its own customers for purposes of complying with the distributed energy part of the state RPS target. There is no possibility of selling distributed energy RECs to anyone else.

The 2010 ruling was issued to a homeowner who bought a rooftop solar system and then agreed to transfer the rights to all "environmental credits, benefits, emissions reductions, offsets and allowances" associated with the electricity produced to the local utility for a fixed term of years for a one-time payment. The utility reported the payment as a forward purchase of RECs. The IRS said the homeowner had to report it as income from the sale of RECs.

Most homeowners do not report up-front payments from utilities as income. Section 136 of the US tax code says that any payment a homeowner receives from his or her local utility as an inducement to take energy efficiency measures to reduce consumption of electricity or natural gas does not have to be reported as income.

Solar companies who lease solar systems to homeowners or sign power contracts to sell them the electricity from such systems were troubled by the */ continued page 13*

Yield Cos

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project valuation determined at a low discount rate. However, the sale is of only a fraction of each project.

Because of its low capital cost, the yield co is a good vehicle for bidding on projects put up for sale by others. The winning bidder is usually the one with the lowest cost of capital. A yield co also gives a developer a currency in the form of publicly-traded shares that might be used to make acquisitions. Private equity funds holding projects directly or through private-equity-backed developers may be reaching the end of their desired hold periods for projects that went into service before 2009.

There are also potential drawbacks.

Moody's flagged a potential drawback in a posting in November. The rating agency warned that moving a portion of a developer's most reliable cash-flow producing asssets to another entity cannot help the parent company's credit profile.

A sale of more than 20% of a subsidiary corporation will prevent a US parent from filing a consolidated federal income tax return with a US yield co, with the result that there will be some double taxation of earnings once the yield co moves out of a tax loss position.

Canadian investors buying shares in US yield cos listed on the Toronto exchange will be subject to a 15% withholding tax at the US border on any cash distributions that are considered dividends for US tax purposes. (There is no withholding tax on cash distributions considered returns of capital.) Dividends paid to non-Canadians will not be subject to any withholding or other taxes in Canada.

The newest yield cos have many antecedents even within the power industry. At least seven other companies fit the pattern to varying degrees, including Algonquin Power & Utilities Corp., Atlantic Power Corporation, Brookfield Renewable Energy Partners, Capital Power Corporation, Capstone Infrastructure, Innergex and Northland Power. Greenbacker Renewable Energy Company said in a filing with the US Securities and Exchange Commission that it plans to form a "yield co" to raise a minimum of $2 million and as much as $1.5 billion to make investments initially in pipelines of solar projects in an effort to connect smaller- to medium-sized developers to public markets. The company suggested in the SEC filing that it plans operate as a partnership, despite US tax rules that normally treat partnerships whose units are publicly traded as corporations. The investors would be investing into a blind pool. ◎

US Tax Changes Start to Take Shape

by Keith Martin, in Washington

Accelerated depreciation would be eliminated under a draft tax bill the Senate Finance Committee released in November.

The bill is one of three drafts that Senator Max Baucus (D.-Montana) released for public comment after a closed-door meeting of committee members on November 19. Comments are due by January 17.

Another draft dealt with international tax reform for US companies with assets or investments outside the United States.

The drafts are part of a gathering set of corporate tax reform proposals that Baucus intends to package into a major overhaul of the US corporate income tax laws. Baucus chairs the Senate tax-writing committee. Republicans who attended the committee meeting were critical of the decision to release the bill drafts and, in many cases, also of the proposals.

Most lobbyists remain skeptical that the current Congress will be able to reach agreement on corporate tax reform, notwithstanding that both political parties say they want to reduce corporate income tax rates. Republicans want to take the current 35% rate to 25%. Democrats want to go to 28%. This can only be done by stripping the tax code of most deductions and tax credits or by finding new sources of revenue.

Baucus has not set a timetable yet to "mark up" the bill in his committee.

Forward motion also remains stalled in the House where the House tax committee chairman was told by Republican leaders not to move forward on tax reform in late 2013 for fear of diverting the attention of the news media away from the flawed Obamacare rollout.

Depreciation Rewrite

Under the Baucus bill, all equipment would be put into four asset pools. Each year, a company would deduct a fixed percentage times the aggregate unrecovered cost of assets in the pool. Any new capital spending on equipment during the year would be added to the pool. When assets are sold, the sales price would be deducted from the pool.

This would simplify not only how depreciation is calculated, but also the calculation of gain or loss on asset sales. A company would report gain only to the extent the balance in a pool is driven negative by asset sales in a year. The negative balance would be reported as ordinary income. Asset sales would not trigger losses.

The depreciation percentages are 38% for assets in pool 1, 18% for pool 2, 12% for pool 3 and 5% for pool 4.

Wind and solar projects would be in pool 4. The 5% depreciation percentage for assets in that pool would be applied against a declining balance. Thus, for example, if a wind farm cost \$100X, depreciation the first year would be \$5X and the second year would be \$95X x 5% = \$4.75. However, if the company added another \$100X wind farm in year 2, depreciation that year would be \$195X x 5% = \$9.75.

Accelerated depreciation will probably be eliminated if Congress overhauls corporate income taxes.

It would not matter when during the year assets are put in service.

Most other power plants and LNG terminals would be considered real property and be depreciated on a straight-line basis over 43 years.

The depreciation on a wind or solar project is currently worth about 23¢ per dollar of capital cost if an investment credit is claimed on the project and 27¢ if production tax credits are claimed (for wind only). That is the present value of the tax savings assuming a 35% tax rate and / continued page 14

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2010 ruling. Any rebates that a homeowner has to report as income from the sale of RECs could end up being taxed twice — once to the homeowner and again to the solar company — when, as typically happens, the homeowner assigns its right to the rebate to the solar company.

RESIDENTIAL SOLAR CREDITS will suffer a haircut if the homeowner engages in net metering, the IRS said.

The agency also said that residential solar credits can be claimed by homeowners who own solar panels in a community solar array, at least under the right conditions.

The IRS made the statements in November in Notice 2013-70.

Homeowners can claim a tax credit for 30% of the cost of solar equipment that they own and use to generate electricity or supply hot water to their own homes. The equipment must be put in service by December 2016.

The IRS said that if the homeowner generates "more than a minimal amount of excess electricity" that is sold to the local utility through net metering, then he or she can claim the residential solar credit on only a fraction of the equipment cost that corresponds to use of the equipment to generate electricity for the homeowner's own use. The IRS did not explain whether to look at how electricity is used in the year the equipment is put in service or to make a forward calculation about what use is expected in the future.

Solar residential credits can be claimed on solar panels a homeowner owns in a community solar array whose electricity goes directly into the grid. However, the homeowner must have a direct contract with the utility allowing the homeowner to supply electricity to the utility through net metering and tracking his or her use of electricity from the grid compared to what is supplied from the homeowner's share of the array. The contract must also say that the homeowner owns the electricity transmitted / continued page 15

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using a 10% discount rate. The depreciation under the Baucus bill would be worth only 11¢ to 13¢, before any reduction in the corporate tax rate.

Cars, computers and nuclear fuel assemblies would be put in pool 1.

Pool 2 would have trucks, railroad equipment (but not track) and equipment used by construction contractors and timber, trucking and telephone companies (other than poles and lines).

Pool 3 would have in it office furniture, airplanes, ships and equipment used by turbine manufacturers and mining, oil and gas drilling, petroleum refining, paper and chemical companies. It would also have assets like landfill gas facilities to which the Internal Revenue Service has not assigned a "class life."

Pool 4 would include inside-the-fence power plants and boilers that a company uses to generate electricity or steam for its own use, railroad track, pipelines, transmission and distribution lines, gas mains, gas storage facilities and water utilities, steam boilers and all the equipment through the boiler at small biomass power plants of up to 80 megawatts in size.

The new depreciation percentages would apply starting after 2014.

Transition Relief?

Congress usually writes transition rules to give companies that already own or have made binding commitments to invest in assets before the tax changes are first approved by one of the Congressional tax-writing committees the chance to see the investments through with the existing tax subsidies. There is no such transition relief in the Baucus bill. The bill says the pools would start with the adjusted bases of a company's assets at the start of its 2015 tax year. Transition relief could still be added. However, an issue will be whether to let companies keep existing subsidies while also benefiting fully from lower corporate tax rates.

A special rule would apply to assets sold in sale-leasebacks, to related parties or in tax shelter transactions. Such sales would be more likely to trigger taxable income. The pool balance would be reduced by the "recomputed basis" or the gross sales proceeds, whichever is less. However, any shortfall between the amount subtracted from the pool and the fair market value of the asset at time of sale would be taxed as ordinary income. The "recomputed basis" is the basis that the seller would have had in the asset if it had been in the pool all by itself.

Geothermal (and oil and gas) companies would no longer be able to deduct intangible drilling costs. The costs would have to be amortized ratably over five years.

Percentage depletion would be repealed. All taxpayers would have to use cost depletion to recover their investments in minerals and natural resources.

Intangible assets would be amortized ratably over 20 years rather than 15 years as under current law.

Energy Credits?

The Senate Finance Committee staff asked for comments on a number of issues by January 17, including on "whether and how tax incentives . . . such as tax credits for clean energy . . . should be adjusted in light of" the cutbacks in depreciation. The staff also asked for comments on whether the alternative minimum tax should be repealed and on what transition rules ought to be included.

Baucus may still release a specific tax reform proposal related to energy, but nothing firm has been decided.

The Obama administration

"Pooled" depreciation would allow deferral of gains on asset sales.

also called for scaling back depreciation in a white paper on corporate tax reform in 2012. House Republicans have not taken a public position.

Transition rules are potentially a huge issue. The last time Congress did a major overhaul of the US tax code in 1986, the tax committee chairmen included generous transition relief, also handing out so-called "rifle shot" transition rules that covered just a few situations at a time in order to win votes for the bill. The committee staff expects people to come in and tell it where the bill drafts cause problems.

In partnership flip transactions in the tax equity market, the tax equity investor's interest in a wind or solar project flips down to a smaller interest once the investor reaches a target return. Depreciation is taken into account in calculating when the target return is reached. The depreciation periods and methods are usually a "fixed tax assumption," meaning the tax equity investor will flip down on the original timetable notwithstanding a change in law for calculating depreciation. In a sale-leaseback, a change in law is not usually grounds for the lessor to be entitled to a tax indemnity payment from the lessee.

The existing "normalization" rules for regulated utilities do not work for depreciation under the new regime. Utilities are not able to claim accelerated depreciation under current law if their regulators require the benefits be passed through too quickly to ratepayers. The staff asked for comments about whether normalization rules will still be needed and, if so, how they should work.

A technical correction in the bill would make clear that section 1603 payments on renewable energy projects do not have to be reported as income for purposes of calculating corporate minimum taxes.

Foreign Income

Turning to the international tax reforms, the United States taxes US companies on their worldwide earnings. It is one of the few countries to do so, and US companies complain that it puts them at a competitive disadvantage.

The US taxes foreign corporations only on income from US sources. Therefore, US companies with projects in other countries set up offshore holding corporations to hold the projects. This blocks the earnings from being taxed in the US until the earnings are repatriated. However, the US looks through offshore holding corporations that are majority owned by US shareholders and taxes the US / *continued page 16*

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by the solar panels to the utility grid until drawn from the grid for use in his or her residence. The homeowner should also represent in the contract that, absent unusual circumstances, the panels will not generate more electricity over each time period — for example, each quarter or year — than the homeowner expects to use in his or her residence.

Some manufacturers of solar attic fans have been advertising that the fans qualify for tax credits for energy efficiency improvements. The IRS made clear such credits can only be claimed on the solar element and not the entire fan.

TAX EQUITY investors may find low-income housing deals more attractive than renewable energy after a decision by an emerging issues task force of the Financial Accounting Standards Board in November.

The task force unanimously recommended to FASB in November that tax equity investors in low-income housing deals should be able to amortize the investment "below the line," meaning against after-tax earnings, over the same period tax credits are available. In the past, the investment had to be amortized "above the line" against pre-tax earnings while the tax credits showed up below the line. This meant that such transactions were pre-tax negative and after-tax positive. The new method is called the "proportional allocation method." It will leave the transactions pre-tax neutral and after-tax positive. Management bonuses are sometimes tied to pre-tax earnings, and they are also a key metric for analysts who follow publicly-traded companies. FASB is expected to approve the new method on December 11.

The decision will apply for now just to low-income housing investments and not also to renewable energy. FASB is working on an exposure draft that will consider application of the same principle to other tax equity transactions that meet qualifying criteria.

The criteria may be ***/ continued page 17***

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shareholders on any interest, dividends or other passive income it sees earned by the offshore company. The theory is that there is no need to defer taxing passive income since the US owners of this income could just as easily have invested directly from the United States. US taxes are deferred until repatriation only on active income from real business operations overseas; that is the only kind of income that, were it taxed currently without waiting for repatriation, would put US companies at a competitive disadvantage.

Baucus would simplify these rules to a degree. All foreign income would either be taxed when earned or treated as exempted from US taxes.

He is concerned about the "lock-out" effect of the current rules. US companies have an incentive to keep reinvesting their income from active business operations outside the US to keep it outside the US tax net as long as possible.

Under the Baucus bill, passive and highly-mobile income would be taxed annually at full US rates. Income from selling products and providing services to US customers would be taxed annually at the full US rate with limited exemptions.

He is proposing two options for taxing income from products and services sold into foreign markets. One is a minimum tax of 80% of the maximum US corporate income tax rate — 28% if the rate remained at 35% — with full foreign tax credits for taxes already paid on the income to foreign countries.

The other option is a minimum tax of 60% of the maximum US corporate income tax rate — 21% if the rate remained at 35% — if the income is from an active business outside the US, but at the full US rate if it is not.

Earnings of foreign subsidiaries for periods before 2015 that have not already been taxed in the US would be subject to a one-time tax at a reduced rate of, for example, 20%, payable over eight years.

(House Republicans are also proposing to tax that income, but only 5% of it at a 5.25% rate.)

The international tax reforms were not well received by Republicans and business and labor groups or several former international tax counsels at Treasury. The AFL-CIO said it leaves too many loopholes intact that lead US companies to shift jobs overseas. ◎

Agreements to Negotiate in Good Faith May Mean More Than You Think

by Kevin Smith and Thomas Watson, in New York

Term sheets, letters of intent and other preliminary agreements are often useful in complex negotiations because they allow negotiating parties to focus first on the major deal issues before getting tripped up in the details.

While such preliminary agreements or term sheets are often expressly non-binding, contractual obligations to negotiate in good faith to reach a final deal based on preliminary terms are typically binding. A Delaware Supreme Court decision in a case called *SIGA Technologies, Inc. v. PharmAthene, Inc.* earlier this year puts parties on notice that any agreement to negotiate a final agreement based on preliminary non-binding terms that is governed by Delaware law may have more teeth than the parties realize or intend.

The court held that a breach of such an agreement to negotiate in good faith may, in certain circumstances, result in liability for expectation ("benefit-of-the-bargain") damages from the breaching party, the same damages that would arise had the parties signed the final, definitive agreement.

Background

In late 2005, SIGA Technologies, Inc., a company engaged in biodefense research and development, was developing an antiviral drug that had "enormous potential," but it was having trouble financing the remaining development costs. It sought to partner with PharmAthene, Inc., another company engaged in biodefense research and development, to help fund these costs.

PharmAthene wanted a merger between the two companies, but SIGA preferred a license arrangement before discussing a merger because it needed an immediate cash infusion and prior merger talks between the companies had failed.

In January 2006, the companies reached an agreement on a license term sheet. The license term sheet was unsigned and the footer on each page had the legend "Non-Binding Terms," but the term sheet included many material provisions of the license, including a worldwide exclusive license, upfront cash payments, funding guarantees, cash milestone payments, creation of a research and development committee and sublicensing rights.

After reaching agreement on the unsigned license term sheet, the parties began merger negotiations. Because of SIGA's precarious financial position, it asked PharmAthene to provide bridge financing to continue development efforts while negotiating the merger.

In March 2006, SIGA and PharmAthene signed a merger letter of intent that attached the license term sheet and also entered into the bridge loan agreement that SIGA needed to cover costs during the merger negotiations. The bridge loan agreement was governed by New York law and contained a mutual covenant of the parties to negotiate a license agreement in good faith "in accordance with the terms" of the license term sheet (that was attached to the agreement) in the event the merger was not consummated.

The parties then focused on negotiating the terms of the merger and, in June 2006, entered into a definitive merger agreement that was governed by Delaware law. The merger agreement provided a substantially identical covenant to the covenant contained in the bridge loan agreement requiring the parties to negotiate a license agreement in good faith based on the license term sheet (that was attached to the agreement) if the merger was not consummated. It also included a covenant that the parties use their "best efforts" to consummate the transactions contemplated by the merger agreement. Those provisions, among others, were specifically identified as surviving the merger agreement's termination.

Subsequent to the execution of the merger agreement, SIGA's financial position improved and it began experiencing seller's remorse.

SIGA received grants from the National Institutes of Health to fund the drug's development and achieved several developmental milestones. By the time the merger agreement's drop-dead date of September 30 arrived, the US Securities and Exchange Commission had not approved SIGA's proxy statement, and PharmAthene asked for an extension of the drop-dead date. On October 4, SIGA's board met and decided not to agree to an extension, but instead to terminate the merger agreement. Shortly thereafter, SIGA announced that it had received another NIH grant as well as other positive updates on development efforts. It then sold / *continued page 18*

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hard to meet for renewable energy. They include that the investor will not have a significant say over the operating and financial policies of the tax equity partnership and "substantially all" of the return is in the form of tax credits and other tax benefits. The investor must also expect a positive yield "based solely on the cash flows from the tax credits and other tax benefits."

PURCHASE OPTIONS could become an Achilles heel in some transactions.

The Court of Federal Claims found fault in October with a lease transaction that Anaheim, California used to finance the arena that is home to the Anaheim Ducks, the city's National Hockey League team. The city leased the arena to Union Bank for 39 years and subleased it back for 19.93 years with an option to extend the sublease through year 31. The transaction is called a LILO. Congress shut down such transactions in 2004, and a series of courts have found fault with them.

The transaction was supposed to let Union Bank deduct the rents it paid under the head lease on an accelerated schedule, while the rental income it received under the sublease accrued in a back-ended pattern.

Union Bank was required to make two rent payments: a payment of $132.3 million at inception in advance rent, and a payment of $975.8 million in deferred rent in 2043 five years after the head lease ends. AIG lent part of the money Union Bank used to make the advance rent payment.

Anaheim had an option at the end of the initial sublease term of 19.93 years to buy out the remaining head lease term for a fixed price. If Anaheim failed to exercise the purchase option, then Union Bank could require it to renew through year 31, sublease the arena to someone else or require Anaheim to return the arena to Union Bank.

The IRS argued that Union Bank did not acquire a genuine interest in the arena. The court agreed.

The central question in the court's view was whether Anaheim could ***/ continued page 19***

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two million shares of stock at more than three times its 2005 share price.

After the merger agreement was terminated, PharmAthene quickly turned its attention to the license term sheet, and it sent a draft license agreement, based on the license term sheet, to SIGA's outside counsel. SIGA responded by asking for a new partnership structure and for substantial revisions to the underlying economic terms to reflect the advances in the drug's development process. The revised economic terms included, among others, a materially different profit split between the companies, upfront payments of $100 million (instead of $6 million in the term sheet), milestone payments of $235 million (instead of $10 million in the term sheet), significantly increased royalty payments and greater SIGA control over development and distribution. SIGA further made clear its intention to renegotiate the terms contained in the term sheet by issuing an ultimatum requiring PharmAthene to submit to negotiations "without preconditions" regarding the terms in the license term sheet by December 20. On December 20, PharmAthene filed suit in the Delaware Court of Chancery.

What the Courts Said

After an 11-day trial, the Court of Chancery found under Delaware law that SIGA was liable for breach of its obligation under both the bridge loan agreement and the merger agreement to negotiate a definitive license agreement in good faith in accordance with the terms of the license term sheet. The court said SIGA was liable under the doctrine of "promissory estoppel," or the idea that PharmAthene had already taken steps, like making a bridge loan, that SIGA wanted based on the expectation that SIGA would follow through on its promises, and it was now too late for SIGA to renege.

The court said the appropriate remedy was an equitable payment stream approximating the terms of the license agreement that the parties would have reached had they negotiated in good faith. SIGA appealed the decision.

The Delaware Supreme Court reaffirmed that an express contractual obligation to negotiate in good faith is binding on contracting parties under Delaware law. It said the express language in the bridge loan agreement and the merger agreement obligated the parties to negotiate a license agreement in good faith "in accordance with the terms" in the license term sheet. It said the trial record supported the Court of Chancery's finding that, despite the fact that the license term sheet was unsigned and contained a footer stating "Non-Binding Terms," the bridge loan agreement and merger agreement language created a duty for the parties to negotiate "a license agreement with economic terms substantially similar" to the terms of the license term sheet and was not merely intended by the parties to be a "jumping off point" for future negotiations.

> A company that agreed to negotiate in good faith, but then tried to alter the deal, had to pay damages.

The Delaware Supreme Court said the trial record also supported the Court of Chancery's finding that SIGA's counterproposal to the license agreement not only had dramatically different economic terms from those in the license term sheet, but that SIGA also made those counterproposals in bad faith. The Supreme Court overturned the Court of Chancery's finding that SIGA was liable on the basis of promissory estoppel because promissory estoppel does not apply where an enforceable contract governs the promise at issue. The bottom line is SIGA breached its contractual obligations under both the bridge loan agreement and the merger agreement to negotiate the license agreement in good faith in accordance with the terms of the license term sheet.

The Supreme Court then turned to the question of proper remedy. There was previously some ambiguity under Delaware law as to what is the proper remedy for a breach of an agreement to negotiate in good faith. The court said that although Delaware law applied, New York law was instructive on the point. New York law distinguishes between "type I" and "type II" preliminary agreements. Type I preliminary agreements are fully binding agreements, where the parties agree on all points that require negotiation, but commit to memorialize their agreement in a more formal document. Type II preliminary agreements only list major terms and leave other terms open for further negotiation. Such an agreement commits the parties to an obligation to negotiate the open issues in good faith to reach the ultimate contractual objective within the previously-agreed framework.

The Supreme Court held that a party may recover expectation damages — that compensate the non-breaching party as if the breaching party performed the contract and include, in addition to direct damages, any incidental or consequential damages (as opposed to reliance damages that only compensate the non-breaching party for its actually incurred costs and expenses) — under a type II preliminary agreement where a court finds that the other party breached its obligation to negotiate in good faith and that the parties would have reached an agreement but for the breaching party's bad faith.

It then held that expectation damages were warranted in this case based on the trial record. The record showed that the parties memorialized the basic terms of the license in the license term sheet and expressly agreed in both the bridge loan agreement and the merger agreement to negotiate a final license in good faith in accordance with those terms. It also suggested that but for SIGA's bad faith negotiations, the parties would have entered into a definitive license agreement.

Key Takeaways

The *SIGA* opinion makes clear that Delaware courts will enforce agreements to negotiate in good faith and will award expectation damages for a party's failure to do so. In SIGA's case, it meant that they had to pay benefit-of-the-bargain damages as if the parties had actually executed the definitive agreement.

Not all states follow Delaware's approach on this point. New York, for instance, enforces agreements to / *continued page 20*

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be expected to exercise the purchase option because, if so, then it would treat Anaheim as if had collapsed the lease arrangement from inception. The court said the standard is whether exercise is "reasonably expected."

The money needed by Anaheim to exercise the purchase option was set aside from the start in a defeasance account. The financial advisor that conducted annual reviews of Union Bank's lease transactions observed in a memo involving a similar deal that the "fully defeased" structure "protects equity investments and compels a purchase of the facility." If Anaheim failed to exercise, then it would lose control over the facility, but still be on the hook for significant financial obligations since the city issued $126.5 million in certificates of participation that were still outstanding to refinance the arena after the original construction.

The court said the transaction had been designed strongly to discourage alternative outcomes to exercising the option and, if nothing else, civic pride would also have compelled it to exercise.

The arena was paid for with public financing. The city charter required annual financial reports by the city's Department of Finance. The court said they telegraphed Anaheim's true intentions by repeatedly noting that the option was fully funded and relied on that fact to exclude various potential liabilities from the city's financial statements. Babcock & Brown said in a message to the city's financial director that the "buyout option which allows the City to purchase Union Bank's position . . . is the expected case." Babcock was the city's financial adviser.

The court also found fault with the appraisal produced when the deal closed. It called the appraisal "little more than a boilerplate effort."

> *The appraisal addressed not only whether the city was likely to exercise the purchase option, but also whether it was economically compelled to do so. However, the court said the appraisal failed to consider the pre-funded nature of the option or* ***/ continued page 21***

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negotiate in good faith, but limits parties' recovery to reliance damages, meaning in most cases just the costs of the negotiations. Other states will not enforce agreements to negotiate at all. Therefore, it is very important that companies understand and control which law will govern their preliminary agreements.

Further, companies should be wary of committing themselves to a contractual obligation to negotiate a definitive agreement in good faith with respect to transactions contemplated by a preliminary agreement because a failure to reach an agreement may result in liability for breach as if the definitive agreement had been reached.

When companies do commit themselves to negotiate a definitive agreement in good faith with respect to transactions contemplated by a preliminary agreement, they should consider, if desired, including provisions that qualify that obligation to ensure flexibility in negotiations, such as strengthening the disclaimer language to state expressly that the terms included in the preliminary agreement are non-binding and are open to further negotiation. They should also consider limiting the remedies available for breaches of the covenant to negotiate in good faith, such as providing exclusively for liquidated damages. ◎

Ethanol Loses Steam, But Only in Part

by Todd Alexander and David Lamb, in New York

A proposal by the US Environmental Protection Agency in November to reduce the amount of renewable fuels that must be blended into US transportation fuels in 2014 is a blow to corn ethanol producers, but may not impede the up-and-coming cellulosic ethanol market.

EPA proposed to reduce the renewable fuel standard from 18.15 billion gallons in 2013 to 15.21 billion gallons in 2014. A final decision is expected after a 60-day public comment period that ends on January 28, 2014.

EPA resets the standard annually.

This is the first time that it has proposed to set the standard below the statutorily-mandated level.

New RFS Targets

There are separate standards for each of four categories of biofuels: cellulosic biofuels, biomass-based diesel, advanced biofuel and total renewable fuels. The categories are overlapping. The advanced biofuel category includes cellulosic biofuels and biomass-based diesel, as well as biogas and other biomass fuels. The total renewable fuel category is the total of the advanced biofuels volume and corn-based ethanol volume.

For 2014, EPA has proposed reducing the total renewable fuel mandate from 18.15 billion gallons to 15.21 billion gallons. It also wants to reduce the advanced biofuel mandate from 3.75 billion gallons to 2.20 billion and to reduce the cellulosic biofuel mandate from 1.75 billion gallons to 17 million gallons. Table 1 shows the proposed volume reductions for cellulosic ethanol and conventional corn-based ethanol.

Table 1

Category	Statutory Volume	Proposed Volume
Cellulosic biofuel	1.75 billion gallons	17 million gallons
Corn-based ethanol	14.4 billion gallons	13 billion gallons

The proposed reductions are a reaction to current market conditions, the limited capacity of existing fuel infrastructure to handle blends of gasoline containing more than 10% of ethanol, and the paucity of cellulosic ethanol. At the proposed volumes, there would be a surplus of ethanol production capacity in the United States. The mandated volume would fall below the total amount of ethanol expected to be produced in 2013. In contrast to the mandate for corn ethanol, EPA has a long history of requiring high volume levels for cellulosic ethanol and then waiving non-compliance with the mandated level due to lack of supply of cellulosic ethanol.

Effect on Corn Ethanol

Before assessing the effect of the EPA proposal on cellulosic ethanol, it is useful first to evaluate the effect on conventional corn ethanol because, for cellulosic ethanol to become a viable fuel source, the corn ethanol industry must remain a viable industry until cellulosic ethanol is produced in large enough quantities to displace corn ethanol.

There are 211 corn ethanol plants in operation currently in the United States with a capacity to produce a total of 14.71 billion gallons a year. The reduction in the renewable fuel standard to 13 billion gallons of corn ethanol a year will require a portion of the ethanol produced be sold for discretionary blending. This will put downward pressure on prices overall. Many of these projects have outstanding project-level debt. The industry should expect to see a further deterioration in the ability of marginal plants to service their debt service, which may continue the trend toward further consolidation of the industry.

However, the proposed fuel standards for 2014 reflect the realities of the ethanol and petroleum markets. Gasoline consumption is falling. Fuel distributors are facing an ethanol "blend wall" in the sense that they have reached the limit on the amount of ethanol they can mix at a 10% blend. There are not yet much cellulosic and advanced biofuels to blend.

Most of the debate about the "blend wall" surrounds the question of whether the transportation fuel infrastructure, both gas pumps and vehicles, can support levels of E10 (gasoline with a 10% ethanol blend) or E15 (gasoline with a 15% ethanol blend). The exact percentage level that the existing fuel infrastructure in the United States can support has been a highly debated topic in recent years.

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to monetize the costs to Anaheim of not exercising. Deloitte, the appraiser, was specifically asked to consider non-economic factors, but it expressly declined to do so.

LIABILITIES ASSUMED BY A PURCHASER of three nuclear power plants to decommission the plants cannot be added to the cost basis in the plants, a court said.

Exelon bought three nuclear power plants in 1999 and 2000 for $93.3 million in cash and the assumption of $1.687 billion in decommissioning liabilities. In addition to the plants, it also received funds that had been set aside for decommissioning. Normally, when someone buys assets and also assumes liabilities to which the assets are subject, the liabilities are included in asset basis and can be recovered through depreciation or amortization. An example is where a power plant is purchased subject to outstanding project-level debt to a bank syndicate.

The court said various accountants and lawyers whom Exelon consulted warned that the IRS would probably not allow the decommissioning cost to be included in basis. Exelon tried to get a private letter ruling from the IRS, but was told the IRS does not believe the liabilities can be put in basis. The company took the position anyway on its tax return.

The case ended up before the Court of Federal Claims. The court said there is no dispute that assumed liabilities go into cost basis, but the issue is when. The court said the obligation to pay the decommissioning costs needs not only to have "accrued," meaning that there must be a legal obligation to pay and the amount can be determined with reasonable accuracy, but also there must be "economic performance" before it can be added to basis. The court said decommissioning is a service. There is no economic performance of services until they are actually performed.

The case is AmerGen Energy Co. v. United States. *The court released its decision in October. Special rules* / continued page 23

Ethanol

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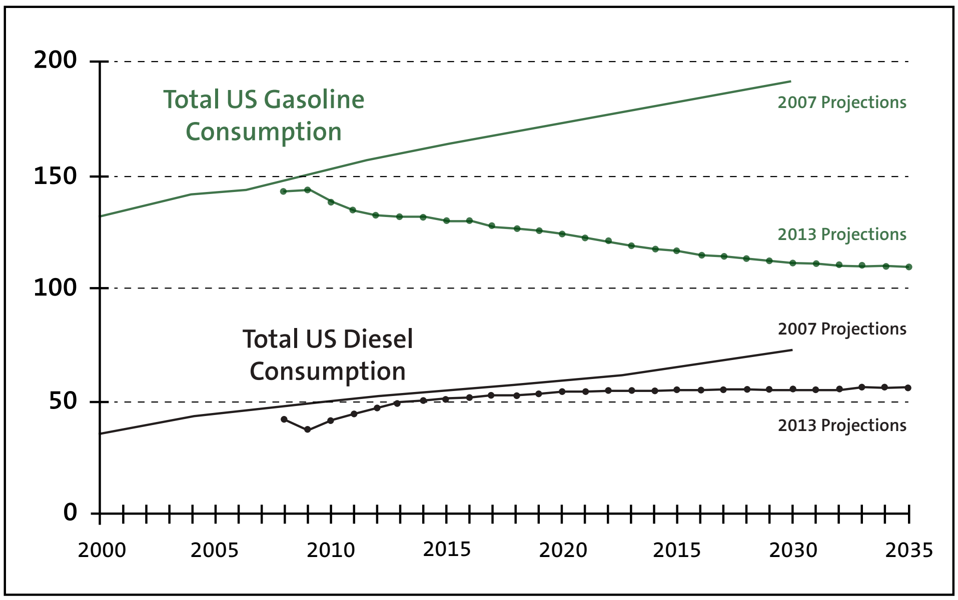
When the renewable fuel standard volumes were mandated in 2007, Congress anticipated rising consumer demand for gasoline. However, the consumer demand for gasoline has fallen since 2007.

The drop in consumer demand since 2007 has been matched by an increase in production of renewable fuels.

This unanticipated inverse pattern, in combination with a fuel infrastructure not built to support more than E10, has created a marketplace that cannot currently support higher levels of ethanol adoption, whether they be derived from cellulosic sources or corn.

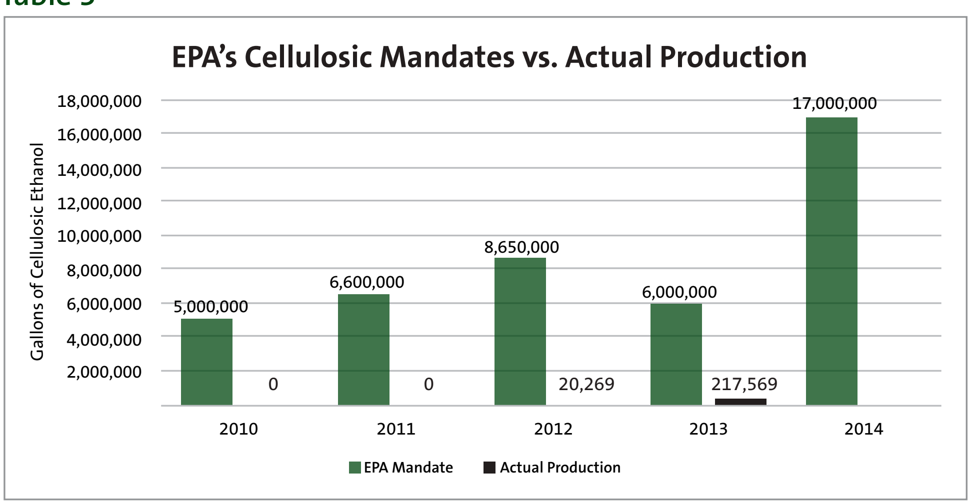
While the current marketplace may appear bleak for growth in ethanol, EPA says it is committed to promoting further growth in renewable fuels in the future. It says the reductions in mandated volumes "[are] intended to put the RFS program on a manageable trajectory while supporting continued growth in renewables over time." Additionally, surplus ethanol production capacity in the marketplace may support growth in E85 consumption, which is gasoline that is blended with 85% ethanol and can be used by a small number of specialized hybrid vehicles.

Table 2: Numbers in Billions of Gallons



Source: Renewable Fuel Standard (RFS): Overview and Issues (CRS Report No. 7-5700)

Table 3



Source: http://www.instituteforenergyresearch.org/2013/11/15/epa-ignores-reality-with-2014-ethanol-mandate/

Effect on Cellulosic Ethanol

Cellulosic ethanol is a biofuel that is produced from plant fibers in grasses, woods and other inedible parts of plants. President George W. Bush made it a goal in his State of the Union message to Congress in 2006 for the United States to produce cellulosic ethanol on a commercial scale within six years. The federal government's commitment to cellulosic ethanol was reaffirmed by the Obama administration in 2010 when it adopted a renewable fuels standard known as RFS2 that required distributors of US transportation fuels to be mix 16 billion gallons of cellulosic ethanol annually by 2022.

Lower US renewable fuel standards are a blow to corn ethanol, but not necessarily to cellulosic ethanol.

However, US cellulosic ethanol production has been slow to get off the ground. There were no commercial volume producers of cellulosic ethanol in the United States before 2013.

The EPA proposal would reduce the required volume of cellulosic biofuels in 2014 from the statutory level of 1.75 billion gallons to 17 million gallons. Cellulosic biofuels include any renewable fuel derived of cellulose, hemicelluloses or lignin that also has a life-cycle greenhouse gas emission-reduction threshold of 60% as compared with petroleum-based motor fuels.

While by the numbers, the EPA proposal may appear to be a drastic reduction, this type of reduction is not unprecedented for EPA. EPA has authority to set the mandated volumes of cellulosic ethanol below the statutory minimums if the projected production of cellulosic ethanol is below the statutorily-mandated minimum. In fact, since the implementation of the mandated volumes, the EPA has consistently set the volume of cellulosic ethanol at a level far below the statutorily-mandated minimum. Even with these significant reductions, petroleum refiners have still been unable to meet the mandated volumes due to a lack of supply of cellulosic ethanol in the market.

As an example, in 2012, the EPA mandated a volume level for cellulosic ethanol of 8.65 million gallons, but only 20,269 gallons were produced for sale. Despite the lack of supply, petroleum refiners have still been required to meet the mandated volumes of cellulosic ethanol by purchasing renewable identification numbers, called RINs, to fill the void of cellulosic ethanol. Not surprisingly, petroleum refiners were angered by having to purchase RINs when there was no actual renewable fuel supply to purchase. Refineries and other petroleum organizations have had to petition EPA each year for waivers.

There is so little existing production capacity that the proposed volume reduction for cellulosic ethanol is unlikely to have any effect on cellulosic ethanol output. */ continued page 24*

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in the US tax code allow utilities to deduct — not add to basis — amounts set aside for decommissioning when they are deposited in qualified decommissioning funds.

ARIZONA settled only half the issues in a dispute between solar rooftop companies and Arizona Public Service, and then only temporarily.

The case is a test for what may end up a larger fight with utilities nationwide.

Arizona Public Service asked permission to charge customers who install rooftop solar systems to generate their own electricity $50 to $100 a month for the right to remain connected to the grid for backup power. It also complained that it is required to pay customers who sell it excess electricity from rooftop systems a retail rate for the electricity when the utility can buy the same power more cheaply from wholesale suppliers. It asked to be able to credit such customers at only the wholesale price.

The Arizona Corporation Commission in November by a 3-2 vote said APS can charge a monthly fee of 70¢ per kilowatt, which works out to roughly $4.90 a month for the average solar customer. The fee will be effective from January 1, 2014. Current solar customers and those who submit an application and a signed contract with a solar installer by December are not subject to the new charge.

The charge will remain in effect only until the next APS rate case, which the commission directed APS to file in 2015, at which time the commission will revisit the fee and also address the net metering issue.

APS estimates that solar installations are reducing load growth by about 0.5% a year. Only about 1.9% of APS customers have solar rooftop systems currently. About 80% of APS customers who add solar lease the systems. APS says the average homeowner saves about $70 a month by switching to solar. ***/ continued page 25***

Ethanol

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However, it could reduce new investments in US projects.

There has been meaningful progress toward commercialization in the last two years. New investments have been made in multiple countries in various technologies. Beta Renewables opened a second-generation biorefinery in Italy and announced plans to open another in North Carolina. KiOR, the largest US cellulosic ethanol producer, pioneered catalytic conversion technologies at one existing facility in Mississippi and plans to use it at another facility. In addition, INEOS Bio announced this past summer that it is now producing cellulosic ethanol on a commercial-scale at a facility in Florida.

The real impact of the proposed reductions is the signal it gives to future investors that the US commitment to the renewable fuel standard is wavering. While EPA reiterated its commitment to renewable fuels, if the federal government takes any more steps to undercut the RFS program, then the entire biofuel industry may be in trouble. The best thing that the industry can do to prevent this is to show that commercial-scale production is feasible.

One indication that the federal government will continue to support biofuel is the section 9003 biorefinery assistance program. The biorefinery assistance program guarantees loans for construction and development of biorefineries that make advanced biofuels. The program is currently soliciting bids for $181 million in funding until January 30, 2014.

State government initiatives are also important. In 2007, California adopted a low carbon fuel standard or LCFS that requires the state to achieve a 10% reduction in the carbon intensity of transportation fuels. Like the RFS program, the LCFS is a mix of command and control regulation that requires certain volumes of low-carbon fuels to be mixed into the transportation fuel supply. Also like the RFS program, the mandated volumes under the LCFS increase over time. While corn ethanol has a lower carbon-intensity than petroleum, forms of cellulosic ethanol have an even lower carbon-intensity and widespread usage of cellulosic ethanol could make compliance with the LCFS easier for refineries. Although California is the only state officially to adopt an LCFS, other states have considered similar programs. ◎

South Africa: Lessons From Projects Financed to Date

by Yasser Yaqub, in Dubai

South Africa has gone through two rounds of procurements for renewable energy projects. Another two to three rounds are scheduled, with procurements for fossil fuel plants to take place in parallel. It is not too soon to take stock of lessons learned from the activity to date.

The renewables procurement program is being bid for in four to five phases, with the second phase of projects having achieved financial close in May and June 2013. The third phase is scheduled for later in 2013 going into 2014; preferred bidders for projects other than solar thermal were announced in November 2013 with document close in July 2014. The bid submission deadline for solar thermal projects is March 2014 with an announcement of preferred bidders in June 2014 and document close in February 2015.

Submission of bids for the fourth phase is tentatively scheduled for August 2014.

The procurements are for technologies as diverse as solar thermal, biomass, onshore wind, solar photovoltaic and small-scale hydro.

While the current procurement program focuses on renewable power, South Africa is also expected to develop fossil fuel plants, coal in particular, in order to try and meet the expected surge in demand of 50,000 megawatts by 2030.

The first two fossil fuel peaking power plants tendered on a competitive basis achieved financial close in September 2013, after considerable delay, clearing the way for additional independent fossil-fuel power projects.

Several issues have come up in the procurements to date that are specific to the jurisdiction. This article focuses on two such issues: first, the extensive economic development obligations that are placed on developers by the tendering authority, and second, changes in the financing security structure necessitated by South African law. Both points are likely to be relevant not just for power projects, but also for other infrastructure projects in South Africa in sectors such as transportation, hospitality and mining.

Local content and economic development obligations are not peculiar to South Africa, but the scope and extent of the obligations in South Africa are greater than in most other jurisdictions in the wider region. The obligations broadly fall into three categories: ownership, job creation and local content.

Ownership

Any developer setting up a project company must ensure specific levels of shareholding and voting rights for black people and local communities. For the renewables procurement program, these levels have been set at 30% shareholding and voting rights for black people with 5% shareholding and voting rights for local communities. A similar percentage applies to the "economic interest" to be held by black people and local communities. This has probably been put in place to protect against any subversion of the obligations where parties may implement the required shareholding and voting rights but contractually or otherwise siphon off the whole or a portion of the economic benefit attached to the shareholding.

For black people, shareholding is typically organized through the participation of what are referred to as black economic empowerment or broad-based black economic empowerment — BEE and BEEE for short — corporate entities in which the shareholding is held by persons of black, Indian or other colored racial make up. To qualify for BEE or BBBEE accreditation, requirements relating to ownership, management, employment equity, skills development, preferential procurement, enterprise development and corporate social investment must be fulfilled to minimum specified levels.

While BEE or BBBEE accreditation is not obligatory, only BEE and BBBEE accredited entities are entitled to do business with the South African government or state-owned entities.

The term "local communities" refers in the renewables procurement program to towns and villages located within 50 kilometers of the project site or the closest such settlements regardless of distance if there is none within 50 kilometers. A trust is usually set up for the benefit of the local communities, and it is the trustees who then participate in the shareholding of the project company and distribute dividends and administer other funds.

Apart from the logistics of organizing BEE and BBBEE entities and setting up local community trusts, the main issue with the involvement of such entities is one of money: they usually do not have the funds to make any capital contributions to the project company. / continued page 26

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Analysts are maintaining a "buy" rating on the APS parent company, Pinnacle West, because of disproportionate load growth expected over the next decade.

FOREIGN CORRUPT PRACTICES ACT investigations are multiplying.

The Foreign Corrupt Practices Act makes it a crime for any US company, citizen or resident to offer anything of value to a foreign government or an employee of an international public organization in an effort to win or retain business or secure any improper advantage. The statute also applies to foreign companies that raise capital in the US securities markets.

The Department of Justice has 150 active FCPA investigations, according to Charles Duross, deputy chief of the FCPA unit at Justice. The Securities and Exchange Commission, which administers a separate part of the FCPA that requires accurate reporting of payments in company accounts, has 100 active investigations, according to Kara Brockmeyer, chief of the FCPA unit at the SEC.

The largest penalty imposed to date is $398.2 million that French oil company Total S.A. agreed to pay both government agencies in May. Duross and Brockmeyer made their comments at an FCPA conference in Washington in November.

About 60% to 70% of the SEC's FCPA actions involve third-party intermediaries — payments to agents who then pass money to government officials. Brockmeyer said "red flags" to be alert for are vaguely-worded services contracts, payments to agents who are not legitimately in the business or where the amounts significantly exceed what others charge for the same services.

She said gifts of travel and entertainment to government officials also remain a problem.

INVESTMENT TAX CREDITS were awarded to two advanced coal projects in October.

The credits are 30% of the eligible project cost. They are special credits under section 48A of the US tax code that / continued page 27

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This issue has been addressed in a number of ways, a couple of which are the project sponsors provide the funds to the black and local community entities, and the funds are then paid back to the sponsors through dividends earned once the project starts generating revenue, or a development financial institution steps in and either guarantees any financing obtained by the entities or provides the financing required directly to such entities.

Under the first approach, the sponsors are spared having to introduce an additional layer of financing. However, in doing so, they assume a greater part of the risk by having to put in all the equity.

Under the second approach, the involvement of a development financial institution has time and cost implications with a whole layer of financing and security structure having to be negotiated and put in place subordinate to the senior debt. In the South African market, where projects are not necessarily friendly to foreign lending and local banks have firm notions as to the precedent to be followed in the financing documentation, the decision to opt for mezzanine-level financing should not be undertaken lightly.

South Africa imposes tough local content and economic development obligations on developers.

The ownership obligations do not end at the project company. The renewables procurement program, for instance, specifies shareholding and voting rights requirements of 20% of the engineering, procurement and construction contractor as well as the operations and maintenance contractor.

In instances where foreign contractors are involved, it then becomes mandatory for them to set up a South African entity with the appropriate shareholding levels in order to be able to work on the project. This has tax implications that will add to the drag on the contractor's return.

For management control, under the renewables procurement program, 40% of the "top management" of the project company must be black people. Members of the top management are those who have responsibility for the overall management and for the financial management of the project company and who are actively involved in developing and implementing the overall strategy of the project company.

Depending on the sector, it can be challenging to fulfill the management control obligations given the dearth of qualified and suitably experienced black personnel. However, the pool of candidates eligible for top management roles is expected to rise rapidly in the coming years.

Job Creation

Job creation obligations, while steep, are not exceptional in terms of their scope.

For instance, under the renewables procurement program, 80% of employees must be South Africans of whom 50% must be black. There is an emphasis on the use of skilled labor with 30% of all skilled persons employed for a project required to be black. Local communities must also contribute 20% of the work force. (This falls within the 80% requirement pertaining to employees having to be South Africans.)

Such job creation obligations are generally a positive force in the development of South Africa where black unemployment levels are still high at approximately 30%. In addition to simple job creation, developers must also pay attention to the levels of compensation and work-place conditions offered to black people as these have been a prominent source of friction with employers as in the case of the 2012 riots at South African platinum mines that led to dozens of casualties.

Local Content

Requirements as to local content and preferential procurement are fairly common in numerous jurisdictions in the wider region of Africa and the Middle East. The obligation to spend on local content is set as a percentage of the project costs, which in the case of the renewables procurement program is 18% of the construction costs of the project. Local content covers costs attributed as having been spent on South Africans or South African products, excluding finance charges, land fees, mobilization fees of the operations contractor and any imported goods and services.

In addition to local content, the project company must also give preference to suppliers with "BBBEE" recognition levels. In the renewables procurement program, at least 60% of the "total amount of procurement spend" must be with vendors who fall within one of the eight BBBEE recognition levels. The levels reflect different degrees of black economic empowerment compliance.

The "total amount of procurement spend" is the amount spent by the project company or its contractors on goods and services in undertaking the project, excluding imported goods and services, taxation, salaries and wages.

For a project using foreign vendors for high-value portions of the project such as wind turbines or solar panels, the vendors would then have to ensure that they manage to fall within at least one of the BBBEE recognition levels to enable compliance with the preferential procurement obligation.

Levels of Compliance

It is important to note that all the percentage figures quoted are merely recommended figures set out in the request for proposals for the renewables procurement program. Developers can propose their levels of compliance and will be evaluated accordingly.

Under the renewables procurement program, developers are also required to demonstrate the level at which they will contribute to enterprise development and socio-economic development, each expressed as a percentage of the revenue of the project. The project company and sponsors also have significant reporting obligations. The project company must ensure that it has a monitoring and compliance system in place in order to fulfill its many economic development obligations

There are significant penalties for failing to reach the required levels of economic development.

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require one apply for an allocation.

The projects are the Texas Clean Coal project near Odessa, Texas, a 400-megawatt integrated-gas combined-cycle facility, being developed by Summit Power, that will use coal as fuel and capture and store a large share of the carbon emissions, and the Hydrogen Energy California project, a fossil-fuel gasification project with carbon capture and sequestration in Kern County, California.

The IRS allocated $324 million in tax credits to the Texas project and $334.5 million to the project in California.

Hydrogen Energy California was awarded another $103.6 million in tax credits in January. The IRS announced the latest awards in Announcement 2013-43.

The challenge now will be to raise enough tax equity to cover the credits. The developers will probably have to do sale-leasebacks of the projects to get value for the credits. The alternative is to find strategic investors who can use the credits and claim them on progress payments to contractors during construction.

A BUSTED "MIDCO" TRANSACTION shows both the perils of such deals and the reach of "transferee liability" for taxes.

The Diebold family, through a trust and a separate foundation, owned all the shares of Double D Ranch, a C corporation that owned $319 million in assets, primarily publicly-traded securities. The assets had appreciated by approximately $230 million in value. Thus, an asset sale would have triggered a substantial tax.

Mrs. Diebold was getting old and was interested in starting to make cash gifts to her three children.

Tax counsel suggested that there are parties who would buy the stock at a price that would leave the shareholders with more money after taxes than they would have after a sale of assets. Typically, the buyer, known as a "midco," would resell the assets after its stock purchase and use losses or other shelter to ***/ continued page 29***

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The levels of economic development to be obtained are set out contractually within the implementation agreement. Non-compliance results in the accumulation of "termination points." The accumulation of nine termination points in any consecutive 12-month period will allow the government counterparty (in this case the Department of Energy) to terminate the concession.

Termination is not always an ideal recourse for the government, especially since the primary objective of the public sector in projects such as the IPP procurement program is to harness the resources of the private sector for the creation of much-needed infrastructure. Many parts of South Africa still suffer from brown-outs during periods of peak demand.

A less severe and permanent recourse available under the current documentation is the system of deductions and credits based on an evaluation of compliance with the economic development obligations each contract quarter. The credits or deductions are based on specific formulas that take into account deviations from the contracted levels of development obligations. A reconciliation of all credits and deductions takes place at the end of the construction period and thereafter at the end of each contract year.

The economic development obligations emanate from the need to redress the significant socio-economic disparity among South Africa's racial groups. However, the requirements can present significant challenges. They require careful consideration and planning.

Security Structure

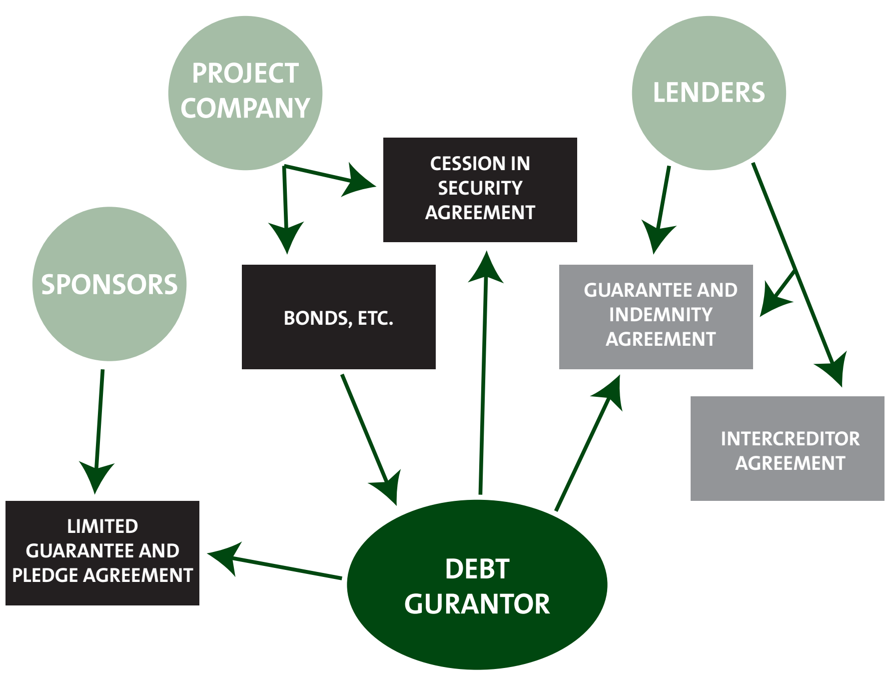
A typical financing structure involves a security component that complements the financing documentation and provides support to the lenders should the project run into difficulty before the project company has paid off the debt.

While many of the project financings undertaken in Africa and the Middle East involve the use of English law as the governing law of the financing documentation, the security documentation is often governed by local law due to reasons of ease of enforcement or local law requirements over security granted by the project company as a local entity.

Notwithstanding scenarios where local law governs the whole or part of the security documentation, the project company is ordinarily able to establish a security structure involving the appointment of a person or entity as security trustee to hold in trust the various securities for the benefit of the lenders that is in line with what is practiced in English law project financings.

Security documentation for South African infrastructure projects is governed by South African law. This has been the case for each of the first two rounds of the IPP procurement program. There are a few exceptions where some of the security documentation has been governed by English law such as in relation to security over reinsurance proceeds or rights under contracts (such as construction contracts) that are not governed by South African law.

Diagram of Security Structure



Having the security documentation governed by South African law can present issues to lenders who are used to dealing with the English law structure of security documentation. For instance, it is not clear under South African law whether a security trustee may hold security on behalf of more than one lender. There also does not appear to be any legislation that would govern the role of the security trustee within the context of a financing. Accordingly, the most common practice in South Africa in relation to power and infrastructure projects has been the creation of a special purpose vehicle (commonly referred to as the "debt guarantor" in the project documentation) for the handling of the security to be created.

The diagram on the previous page shows the contractual structures that the debt guarantor enters into with the various stakeholders in the project.

The debt guarantor is typically constituted as a proprietary limited company, which is a private company. Directors of the company are responsible for the management of the debt guarantor and are appointed with the approval of the lenders.

In order to ensure the integrity of the security that will be held by the debt guarantor, the debt guarantor is set up as a ring-fenced entity, and the only assets it holds are those related to the project for which it has been set up.

The actions of the directors of the debt guarantor are governed by the debt guarantor's constitutional documents as well as the contractual arrangements into which it enters.

Documentation

The constitutional document of the debt guarantor is the memorandum of incorporation, which sets out the purpose, scope and powers of the debt guarantor and its directors. This document is finalized, and can only be changed, with the approval of the lenders to ensure that the debt guarantor only involves itself in business related to the project, does not jeopardize the security it holds and does not act contrary to the intent and provisions of the finance documentation.

The debt guarantor is given security over the main assets and rights of the project company and then, on a contractual basis, agrees on how it will administer the security.

The project company issues a series of bonds in favor of the debt guarantor conferring security over the project's tangible assets (including land, plant and machinery) and also enters into a cession in security agreement that operates under South African law to cede the project / *continued page 30*

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offset the gain. The typical midco is a shell company that is not good for the tax on gain if the strategy used to shelter the gain does not work.

The Diebolds interviewed two financial firms that arranged midcos and chose one called Sentinel Advisors. The midco Sentinel formed bought the shares in Double D for 97% of market value. The discount was Sentinel's profit. The midco borrowed $297 million from Rabobank with the understanding that the loan would be repaid within five days out of the sales proceeds from selling the assets. The assets were sold to Morgan Stanley for $309 million. The midco retained the difference as profit after repaying the Rabobank loan.

The midco filed a consolidated tax return that included Double D and reported the gain on sale of the assets. It had enough losses to shelter the tax on gain. Double D was liquidated into the midco the day after the sale.

The IRS claimed $100 million in unpaid taxes, interest and penalties against Double D. It said the transaction was in substance an asset sale by Double D to Morgan Stanley, followed by a liquidating distribution to the Double D shareholders. Double D did not contest the assessment, but the IRS was unable to find any Double D assets from which to collect since the company had liquidated.

The IRS attempted to collect from the shareholders under section 6901 of the US tax code, which allows the IRS to pursue both the transferees of the taxpayer who owes the taxes (Double D) and transferees of the transferees. It went after Mrs. Diebold and the foundations, but lost in the Tax Court. The IRS appealed only with respect to the foundations.

A US appeals court said that the determination whether the foundations could be held accountable had to be made under state law in New York. New York does not allow a creditor to go after a transferee unless the transferee had "actual or constructive knowledge of the entire scheme that renders ***/ continued page 31***

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company's contractual rights under South African law-governed project documentation in favor of the debt guarantor. Any rights under English law documentation can be assigned in favor of the debt guarantor under a typical English law governed deed of assignment.

The two main documents that govern the contractual relationship between the debt guarantor and the lenders are the guarantee and indemnity agreement, or "GIA," and the intercreditor agreement.

The GIA is used to have the debt guarantor guarantee the obligations of the project company under the finance documentation in favor of the lenders (including any hedging banks). In the event of a default by the project company, the lenders would be entitled to issue an enforcement notice to the debt guarantor requiring the debt guarantor to enforce the security it holds and make payment of realized amounts to the lenders. The intercreditor agreement operates in the normal manner in defining the relationship between, and priorities of, the various finance parties.

The South African project finance market is not geared toward accommodating foreign lenders.

As a backstop to the guarantee and indemnity granted by the debt guarantor under the GIA in favor of the lenders, each sponsor is usually required to enter into limited guarantee and pledge agreement, or "LGPA," with the debt guarantor. The sponsor guarantees the performance of the project company's obligations under the finance documents. As security, each sponsor pledges its shares in favor of the debt guarantor. The liability of each sponsor under a LGPA is limited to the proceeds realizable from the rights attached to the shares that the sponsor holds or is otherwise entitled to, in the project company.

This form of limited recourse to the sponsors bolsters the security held by the debt guarantor, although it may not be palatable to sponsors who are not used to being subject to such recourse.

Related Concerns

Sponsors or lenders coming into the South African market will find that the finance and security documentation is to a large extent set in stone. There are a number of reasons for this.

First, the IPP procurement program has gone through the financial close of two rounds of projects and the precedents of the finance and security documentation are fairly well established. The South African finance market is a small one in terms of the number of lenders, and given the paucity of foreign lenders in the market, the South African banks have been able to establish and largely maintain a precedent that they are comfortable with and that some foreign sponsors may find too lender friendly.

While it may be possible for export credit agencies and other similar international financial institutions to get involved in lending on infrastructure projects in South Africa, the South African project finance market in general is not currently geared towards accommodating foreign lenders. For instance, it is a requirement of South African law that special permissions be obtained before security can be created over South African assets in favor of a foreign bank. Another example can be found in a clarification made by the Department of Energy during the second round of the IPP procurement program. It said termination amounts payable by the government to the project company under the project documentation exclude breakage costs payable in connection with hedging arrangements put in place to facilitate the servicing of principal and interest payments on foreign debt or to cover exchange rate fluctuations.

Given that the South African banks have so far been able to absorb the funding requirements of the IPP procurement program, there appears to be little appetite for facilitating the entry of foreign banks. This may change once we get to the third and fourth rounds of the IPP procurement program and other infrastructure projects come on line, saturating the primary and secondary finance markets in South Africa.

Power Africa: Market Reactions to the Obama Initiative

Six Africa veterans talked during a Chadbourne webinar in October about market reaction to the Power Africa initiative that the US government is making to help Africa double access to electricity within the next five years. The program aims to partner up to $7 billion in federal funding with $9 billion of private sector funding. There are six target countries initially: Ethiopia, Ghana, Kenya, Liberia, Nigeria and Tanzania. The panelists are Paul Hinks, CEO of Symbion Power, Steve Howlett, managing director for government, finance and advocacy of General Electric, Kwame Parker, head of project finance at Standard Bank East Africa, Obinna Ufudo, CEO of Transnational Corporation of Nigeria PLC, which is the project development company of Nigeria-based private equity fund Heirs Holdings, Justin DeAngelis, a director at Denham Capital, and Sean Long, CEO of Endeavor Energy Holdings. The moderators are Ken Hansen with Chadbourne in Washington and Ikenna Emehelu with Chadbourne in New York.

MR. EMEHELU: What about the Power Africa initiative most interests your company?

MR. HOWLETT: We are interested in Africa because the emerging middle class is demanding more infrastructure. The key infrastructure sectors are transportation, electricity and clean water. Having invented the light bulb, GE is very interested in electricity.

MR. HINKS: Organizations from the west find it increasingly difficult to get business in Africa because Asian governments and companies have monopolized the business in recent years. The Power Africa initiative gives a chance for companies like Symbion and Endeavor to get in on the act and do some real business in Africa. We have not done / continued page 32

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[its] exchange with the debtor fraudulent."

The US Tax Court heard the case first and said the shareholders did not have actual or constructive knowledge of the entire series of transactions. It said section 6901 cannot place the federal government in a better position than any other creditor of Double D under state law. However, the appeals court disagreed. It said constructive knowledge only requires a showing of "inquiry knowledge": they knew enough that should have led them to inquire further. It sent the case back to the Tax Court.

The case is Diebold Foundation, Inc. v. Commissioner. *Among other things, the Tax Court will have to decide whether a 3-year or 6-year statute of limitations applies to the IRS's ability to pursue the claim.*

CALIFORNIA is working on a ruling to address when out-of-state members in limited liability companies doing business in California must file state income tax returns. The ruling, by the Franchise Tax Board, is expected in early 2014.

THE MAURITIUS-INDIA tax treaty is expected to be amended before April 2016 to make it harder for companies making inbound investments into India to take advantage of the treaty.

A large share of US companies investing in India set up Mauritius holding companies to hold the investments. Such a holding company is considered a Mauritius tax resident. When shares in the Indian project company are sold, there is no capital gains tax because of the treaty. Singapore has a similar exemption from capital gains taxes in its treaty with India, but it is harder to qualify as a tax resident in Singapore due to a "limitation of benefits" clause in its treaty. A Singapore-like limitation of benefits clause needs to be added to the Mauritius treaty before a general anti-tax avoidance rule goes into effect in India that would override the treaty protections for companies using bare holding companies in Mauritius to take advantage of the treaty.

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well to date chasing after projects in competition with Asian companies.

MR. UFUDO: Power Africa may make it easier for investors to commit funds to the power sector. Having US agencies involved will shine a light on both the challenges and the opportunities in the sector.

MR. DEANGELIS: We believe Africa is at an inflection point in terms of the ability to get power projects built. Not too long before the announcement of the Power Africa initiative, Denham announced an investment in our third portfolio company focused on African power development. What Power Africa does for us is provide additional US cover to help move projects from the idea stage to completion. It is an additional push to get projects completed.

The Power Africa initiative is focused initially on six countries.

MR. LONG: I have been looking at energy infrastructure and power in Africa for a long time, and one of the pieces to the puzzle that had been missing had been a heavy US government focus on helping the continent develop and build out its infrastructure. When I heard about the Power Africa initiative, I was excited because one of the largest economies in the world was now adding financial strength to solve a problem in Africa for which attention is long overdue.

MR. HANSEN: What do you see as the key impediments and challenges in developing projects? How is the Power Africa initiative relevant to those key challenges?

Developer Challenges

MR. HOWLETT: What is significantly different about Power Africa compared to previous initiatives is that it is more of a partnership with the private sector. GE is looking to put our own equity into many of these projects to give them a real kick start. We have experience working with the different agencies, and the agencies are not perfect. They have their own quirks, strengths and weaknesses. The key here is they will partner with the private sector actually to get things done. One of the things about which we are most encouraged is the ability to do real projects with both the local government and the US government behind them.

After the financial crisis, the real problem in the world was liquidity. Now the world is awash in money, but regulators are strangling the ability of the private sector to move money around efficiently. The only way to get tenor and risk taken care of in these types of markets is to partner with international lenders to free up the capital. You can find three-year money in Nigeria, but you cannot pay for a power plant in three years. You need 12 or 15 years. That is where the international piece is critical.

MR. HINKS: Symbion is operating three projects in Tanzania currently. We also have one project in a partnership with Transcorp and one we are just taking over in Nigeria. Plus, we have done a lot of work with US government agencies, such as the Millennium Challenge Corporation, building power projects, distribution lines and substations.

The big challenges are not in the will of the US government agencies but navigating the bureaucracy in many African countries where the inactivity can appear to be lack of interest, but it is just the old-style bureaucracy. If you recall when President Obama announced Power Africa in Tanzania, he said that Power Africa was also about speed. If we are going to show results on Power Africa, speed is key. Power projects take a long time to develop. They do not happen in three months. Non-governmental participants can also be sand in the gears as they want to check all the boxes.

In Nigeria we opted, because of speed, not to go to the traditional agencies for acquisition financing and decided, instead, to work with the local banks. That was the only way we were going to be able to do the deal in the time allotted for the privatization process that Nigeria had adopted.

So for me the biggest challenges are government bureaucracy, checking boxes and achieving speed.

MR. UFUDO: In an environment like Nigeria, which I suspect is the same as the rest of the continent, the biggest problems are in the early development stage before the private sector is ready to invest. The Power Africa initiative can help provide funding for things like environmental studies and pre-feasibility studies for which it has been impossible to raise money. It can also help governments set the right policy environment to support private capital.

MR. HANSEN: It is interesting that there is a definition of success for Power Africa — doubling access to power in five years — and also that the initiative is a public-sector partnership with people that the US government does not control. How will the initiative affect the decisions that private developers make whether to spend their time and resources chasing projects? It sounds like we might be inclined to avoid the official resources in order to move the project forward more quickly by tapping local resources.

MR. HINKS: We have managed to get where we are in Africa so far with four power plants and some contracting work without any involvement by US government lending agencies. However, there is a big role for them when we get to the stage of long-term project developments. The issue in Nigeria was that the government has a timetable for the privatization. You had to submit a bid on day one, they would evaluate it and you had to then post bonds and letters of credit during the bidding process. We had the option of relying on local financing. Twenty years ago it may have been more difficult. Nigeria is an exception compared to most countries in sub-Saharan Africa because it is awash with money. However, in many countries it is possible to work to an extent with the local banks. They understand the utilities, the risks and the local environment. Their analyses of risk is very different from that of a foreign entity.

MR. HOWLETT: The US government agencies are better informed and more knowledgeable than many agencies. They understand the landscape. The issue with those agencies is the process of checking the boxes. It is not exclusively their issue, but speed is where we all have a problem.

MR. HANSEN: So one thing the participating agencies could do to make their support of the Power Africa initiative effective is to work on expediting reviews. / *continued page 34*

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According to an August 2013 report by the India Department of Industrial Policy, 38% of foreign direct investment into India comes through Mauritius. Singapore accounts for 11%.

A third of outbound investment from Mauritius went into India in 2010, but it fell to 16% by 2012. Today, 51% of outbound investment from Mauritius is into Africa.

Mauritius is having to defend itself from charges by the UK charity ActionAid that it is complicit in draining African countries of needed tax revenue after Deloitte handed out a document entitled "Investing in Africa through Mauritius" at a conference in China in June. The document explained how investing in Mozambique through Mauritius can reduce withholding taxes by 60% and eliminate capital gains taxes.

CFIUS has the last say — so far.

Ralls Corporation lost another round in its effort to block a government order forcing it to shed rights to four wind farms in Oregon that it bought from Greek Company, Terna Energy, in March 2012.

A federal district court judge in Washington rejected the company's claim that it was denied due process in November.

She also declined to force President Obama to elaborate on the national security concerns that led him to block the sale. She said Ralls was not denied due process because it went ahead with the purchase of the four wind farms without making a CFIUS filing. CFIUS is an inter-agency committee that the US government set up to review acquisitions of US companies or assets by foreign buyers that have potential national security concerns. Careful foreign buyers make a filing with CFIUS before closing on transactions to make sure there are no national security issues. (For more background, "But I'm Canadian!" and Other CFIUS Dilemmas" in this issue starting on page 40.)

Ralls Corporation is a Delaware corporation owned by two Chinese / *continued page 35*

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MR. HINKS: I would like to see more delegation of authority, especially on smaller transactions that are moving more quickly. It would help if they could empower others to do smaller things on their behalves and focus their limited resources on the major issues.

MR. DEANGELIS: Paul Hinks really hit the nail on the head. There is a massive opportunity in Africa. All the signs say that you should be able to build multiple gigawatts every year. The US can help by getting projects to close more quickly and by cutting through the bureaucracy and making sure that there is a clear regulatory environment. The US can get the structure in place to allow private investors like ourselves to invest.

Lack of clarity of process in African countries is a major impediment to development.

It is not happening. Projects are dying on the vine. The capital is there, but it is a matter of getting from A to B. In Africa, it is not a question of just development 101. It is development 101 in an emerging market. Power Africa can help ease some of the commercial issues and bring real solutions to a region that is in dire need of new power generation.

MR. HANSEN: The challenge and opportunity for the US government are not only to bring its lending programs to bear, but also to deal government to government on the regulatory environment and rule-of-law issues broadly.

MR. DEANGELIS: Any developer starting on a project has an execution plan. If you execute correctly, you get to financial close. The issue is that development is never that easy. Part of the problem is clarity around how to get from A to B. There are thousands of development projects in Africa. Part of the art and science is figuring out which are the ones that are going to get to financial close at the end of the day.

MR. LONG: Ultimately, what is slowing the development of power infrastructure in Africa is the need for rationalization of power markets. You need appropriate tariffs for end users. You need the ability to transmit the power efficiently. You need efficient forms of power generation. All that is done in developed markets by private industry with some regulatory oversight. What most people forget is that the developed countries did not start that way. The issue is how to get from where we are today in Africa to an effective and rational market. Unfortunately, we cannot wait to get the market structured properly before the investing in infrastructure starts.

Power Africa can serve two roles. It can enable infrastructure to be put in place with private investors today while governments try to rationalize power markets. The strategy of teaming up or partnering with private industry was a wise one because it will help the US government see exactly what the impediments to investment are. At the same time, the US government can help African governments develop and implement plans a rationalize their energy markets so that we no longer need the US government to address our needs. Many countries are trying to do that, but it is a process and it takes time.

MR. PARKER: It cannot be repeated enough that every country has a different regimen for independent power projects and its level of sophistication and maturity around private sector involvement in the power sector. Kenya is relatively mature in that there are already several IPPs and more are added every year. Impediments remain around getting power purchase agreements signed, but even that is improving. We are not at the point where there are completely standardized PPAs, but things are moving faster.

The other issue is how much new power should be sourced. Africa needs tons of power. The question is what comes first: do you build capacity and hope that it draws demand, or do you wait for new industry to demand more power? We are all a little nervous about how much more power we should even be financing.

Power projects are capital intensive, and the number of banks today that lend to projects in a country like Kenya is relatively small. A bunch are lending, but with country risk the number of players is limited. With Power Africa, the US government focus on putting dollars to work in Kenya becomes very important because the US government can provide a lot of financing in a market where we need more lenders. However, no matter how much capital is available, at the end of the day you need private-sector developers on the ground working through the issues to get a project to long-term financing.

The US government should also spend a little more time thinking about how to let Kenya Power stand on its own two feet as the demand rises in response to the availability of power.

Payment Guarantees

MR. HANSEN: How can the US government do that? Are you thinking of the equivalent of a multilateral development bank partial risk guarantee, but coming from the US government to stand behind Kenya Power's offtake obligations?

MR. PARKER: Something like that. Ultimately, if Kenya Power is unable to pay, then the US government stands in for it. The guarantee would be in place for a limited amount of time.

MR. HANSEN: OPIC can provide political risk insurance against breach of contract by government entities. OPIC would have to decide that it is a situation that passes the underwriting criteria for non-coal projects, but it already has authority to stand behind Kenya Power payment obligations.

OPIC is one of the best in the world at doing wind and solar projects, but because of the politics of the carbon cap, it can only do one 300- to 400-megawatt thermal project per year worldwide. It restricted that to sub-Saharan Africa, but it should not have to make those kinds of choices because need in Africa for basic economic development is so great.

MR. HINKS: We still struggle with this. At the end of the day, how much renewable energy can go on the grid, especially a relatively unsophisticated grid?

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nationals. The US Navy expressed concerns soon after Ralls closed on the purchase about the location of the one of the projects. Ralls agreed to move it to a different site. CFIUS then contacted Ralls and suggested it file a notice. It did so in June 2012. CFIUS decided after an initial review that an investigation was needed. At the end of the investigation, it made a report to the White House. On September 28, 2012, President Obama issued an order blocking the sale. The order required Ralls to remove everything from the sites within 14 days and divest the projects within 90 days. It also blocked the future use of any turbines made by Sany — a Chinese manufacturer — to any third party for use at the project sites. The two individuals who own Ralls also run Sany.

The order also blocked sale of the projects to any third party unless it complies with the same conditions.

The case is *Ralls Corporation v. Committee on Foreign Investment in the United States*. Ralls has filed an appeal.

Ralls is stuck now having to make a fire sale. It sued Terna in an attempt to undo the purchase and block Terna from selling land in Texas that Ralls pledged as collateral for the Oregon purchase, but that suit was also rebuffed. The suit was originally filed in a federal district court in Washington, DC, but the court dismissed it for lack of jurisdiction. Ralls then refiled the suit in federal district court in New York.

The failure to file with CFIUS has also proven costly for Terna Energy. Terna has had to spend money defending itself, and the effort may not be at an end. Aggrieved buyers usually try to find representations and warranties that may have been breached in connection with the sale.

This is the fourth time CFIUS has ordered closed transactions unwound. Special care should be taken with projects near US military installations.

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Kenya already has enough wind projects, but it does not have enough base-load power. We need to be more practical. OPIC will not allow coal, but might allow natural gas-fired projects. If the US government wants to help Africa, it needs to be more flexible with regard to fuel. It should set policy behind the needs of the country.

MR. HANSEN: Basically, neither OPIC, the US Export-Import Bank, the US Trade Development Agency nor the US Agency for International Development is going to support coal-fired projects. The Chinese do not have that limitation. I do not know whether anyone else on the planet does. Will the inability to support coal impair the effectiveness of this initiative?

MR. HOWLETT: The key for Africa is indigenous fuel sources. Many countries with natural gas and hydro are going to be fine. The key is balance. Coal has to be in the mix because Africa has coal as an indigenous fuel source. Some countries are going to be heavily dependent on coal. If the US unilaterally disarms from coal, then naturally coal-fired power plants will be built, but with Chinese, Korean or Japanese technology. So it does handcuff the US initiative by taking that fuel out of the mix.

MR. HINKS: I have been fortunate to have been involved with Power Africa since before there was a Power Africa team. The Power Africa team is in listening and learning mode, looking at what it can do to help. We have an opportunity to convey the concerns that the private sector has. The team is sensible in terms of what can and cannot be achieved. It is putting staff in the US AID offices across the six Power Africa countries. It is looking at putting project delivery people in ministries.

Corporate Council on Africa has a Power Africa working group. That working group is going to be very much a voice and conduit for a coherent discussion with Power Africa. The problem right now is that the Power Africa team gets 20 calls a day from different people saying different things, and the message is not coherent. There is a need to coordinate.

It is crazy that we have coal-fired baseload power in the United States, Britain and Germany, but the minute that people start talking about coal-fired generation elsewhere, everybody throws his arms up. Africa will use its own natural resources and get coal-fired plants built by the Chinese or Indians. The Indians are quite interested in coal-fired plants in Africa.

MR. DEANGELIS: Planning in each of these countries for a balanced power supply is critical. Because of their small size, renewables allow you to electrify distant locations, and they can be delivered in an incredibly quick time frame. Two of our Denham portfolio companies have multiple development opportunities on wind and solar projects in many different countries in sub-Saharan Africa. The impediment is a log jam trying to get things done. You do need baseload power, but in countries that have 30% electrification rates, renewables certainly will help.

The US might help cut through local bureaucracy.

MR. EMEHELU: Is there anything in the Power Africa initiative that could help with micro grids or distributed generation development in Africa?

MR. DEANGELIS: The impediment to any project at the end of the day is lack of clarity of process, whether the project is a 10-megawatt solar project or a 300-megawatt combined-cycle project. We have the capital and resources to realize those projects. The good thing about sub-Saharan Africa is that it has excellent renewable energy resources. You can have a really competitive power price at the end of the day, but to deliver those projects, you need a clear path to get them closed or they will die on the vine.

MR. PARKER: There is also the question of whether Power Africa will survive our current president. Right now, we have project developers who spend weeks and months in country running from government office to government office trying to get various people to agree to sign things. If there is a way for Power Africa to end up with an office where you can go and, based on a set of completely clear criteria, get the signatures you need and you are done, that would be a tremendous help. It would also address the problem with corruption in some areas.

MR. HINKS: You are absolutely right. The ministers in these countries have signed up to Power Africa, and they will not want to be embarrassed. The low-level problems delaying things can make a huge difference.

MR. HANSEN: Are we creating an opportunity for our Chinese and other competitors by not supporting coal projects? How can we compete effectively given the resources that we do have available?

MR. HOWLETT: There are two areas where the US fits very well with where Africa is. One is on leapfrog technology. We have seen it in Africa with mobile phones and cellular networks. Africa did not build a lot of landlines and leapfrogged right to the latest technology. In Africa, smart grids are defining the way power works. You do not have to build large centralized power plants. The technology exists to build a more distributed network. In the near term, we should look at the Turkish model where, 20 years ago, Turkey did a lot of inside-the-fence power projects partnering with local industry in the private sector. That will be a way to move forward.

MR. LONG: Ultimately, we need to find the best solutions for the country or region. For example, instead of doing a coal plant in Ghana, there may be an opportunity to bring LNG from the US to Ghana and provide even a lower-cost solution in the medium term.

MR. PARKER: The answer is relatively simple. If you look at Chinese lenders to independent power projects, there have been very few examples of direct Chinese lending. The only example I know of was a situation where, for the first time, a Chinese lender used MIGA cover, which is not normal. Chinese lenders want either to go straight to a government loan or to get a full government guarantee on a project. US government agencies are willing to lend to an IPP in many cases without a government guarantee, but they know how to look at projects and take project-related risks. OPIC is probably the agency that can provide the cheapest financing at the longest tenor. Its terms are better than the Chinese. OPIC understands projects in a way that Chinese commercial / continued page 38

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A DISGUISED SALE AND LACK OF ECONOMIC SUBSTANCE prevented losses from being claimed on utility receivables.

BDO Siedman marketed "tax solutions" from 2000 through 2003.

It strongly encouraged its employees and partners to help sell them by sending firmwide emails every time such a product was sold announcing the sale, the accountants who made the sale and the fees earned. Bonuses were paid based on such sales.

One of the products was a highly-structured distressed debt product. BDO teamed up with Gramercy, a fund manager that specialized in distressed sovereign and major corporate debt. Its funds were focused on debt that is distressed but likely to be restructured. It holds the debt expecting to profit from reselling it before or after the restructuring. It dealt only in debt that is dollar denominated, issued in international capital markets, and is subject to New York or UK law and is issued by a government or a major corporation that the country has a strong interest in seeing survive.

Two BDO clients, who were executives of a company that Eastman Kodak was acquiring, had large amounts of income that they wanted to shelter from taxes.

The BDO product focused on customer receivables. BDO arranged to refer its clients interested in the product to Gramercy. In the particular transaction, OAO Saratovenergy, the electric utility for the Saratov region in Russia, contributed receivables from 46 commercial customers to a "master" LLC with Gramercy as a 1% managing member. The receivables were denominated in rubles, had a face amount equivalent to $368.8 million and were at least four years overdue. The master LLC contributed them to sub 1 LLC that was owned 99% by the master LLC and 1% by Gramercy, again as managing member.

The parties recorded a tax basis in the receivables of the face amount. The actual value was far less: about $3.9 million. / continued page 39

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lenders today do not understand.

MR. EMEHELU: What is the future of natural gas project development in Africa?

MR. DEANGELIS: We know there is gas available, and it could be a significant game changer. Unfortunately, it will not happen overnight. A tremendous amount of infrastructure, like gas pipelines and electric transmission lines, must be built first. We are at least five years away from having the infrastructure in place. South Africa is the largest power market on the continent. It is continuing to build coal plants and thinking about nuclear projects because there is no other alternative for an economy of that size. It has a large renewable energy program relatively speaking. That program has been a resounding success. But the gas reserves are tremendous and will be a huge game changer.

MR. PARKER: We will start to hear about a trickle of gas-fired power plants in the next 12 to 15 months on the east coast of Africa. The region will hit its stride with gas-fired power plants in about five years.

Power Africa may prove an inflection point in terms of ability to get projects built.

Political Risk

MR. HANSEN: Are participants thinking about OPIC or MIGA or the commercial political risk insurance providers when putting together deals or are you just deciding either to step up to the risk yourselves or pass on the project?

MR. LONG: When we first started looking at opportunities to invest in Africa, our initial thought was not to go after political risk insurance. We are learning that it really depends on the country and the structure within the country. At the end of the day, you have to see what a government guarantee really means. I think most African countries are making a strong effort to try to shore up credit ratings, and a lot of the countries are listing bonds and doing the things that they need to do to help this process. Ultimately, those will help reduce the cost of power in the country.

In terms of a bridge situation where we are trying to invest today, we are looking increasingly at political risk insurance as a downside protection to our investment to allow us to move forward with investments where the environment is not yet ideal. Our hope is that, as projects get done and payment records are established, we will no longer need political risk cover.

MR. PARKER: Political risk cover can entail no civil disturbance, no inconvertibility, etc. It would be interesting to hear what the experience has been. What does not seem to happen too often is the government showing up and taking the project. In sub-Saharan Africa, there have not been many cases of that. Even in countries where there are civil wars, the power plants usually remain intact. The bigger issue is breach of contract. The risk is payment risk, and that is the cover you need. If Power Africa can help governments create entities that will have both the ability and the willingness to honor their payment obligations under power purchase agreements, that would be optimal.

MR. DEANGELIS: The way to deal with credit risk effectively is to ensure that the entities are creditworthy.

MR. HANSEN: What do you with folks who are not there yet?

MR. DEANGELIS: Part of the solution is to reduce the cost of electricity. In almost all these countries, new generating facilities will reduce power cost and spur industry. You still have to deal with loss of power and theft, but over the long run. Power Africa can help in setting up supporting things like partial risk guarantees and escrow accounts so that monies are available and projects can get done in such a way that mitigates some of the payment risk. We have investments all over the world in power, but Africa has a reputation for all of these problems. The reputation is based partly on actual events, but some of it is undeserved. Power Africa can help to mitigate some of the risks and maybe have a snowball effect of improving Africa's reputation.

MR. HINKS: I am very involved with an organization called the Milken Institute that represents probably the biggest group of financial investors. It has conferences a couple times a year. Two years ago, it did not have any coverage of Africa. Recently, it set up an Africa working group and has started having its first Africa sessions. Those sessions were filled with investors. These are the traditional investors investing in power projects around the world, but Africa is a scary new territory for most of them. The rooms were full. One thing that was loud and clear is that the Power Africa initiative is giving them some degree of peace of mind and security. There is a serious interest in project investments on the continent.

MR. HANSEN: What concrete progress have we seen since the announcement of the Power Africa initiative?

MR. HINKS: We have not been doing anything differently. We look at every deal on the merits of that deal. All of the things that have been said before about assessment of risk and political risk insurance are valid comments, but in the end you have to face those risks and feel confident that the utility will be able to pay you. The six focus countries were selected because the host government is willing and the utilities are strong. In the six countries, breach of contract is less of an issue than cash flow. The utilities in these countries have a problem because they sell electricity at cheaper rates than the cost to generate the electricity. That is the fundamental problem, and you cannot change that over night.

The fact that the US government has endorsed a country to be in Power Africa says something to the investors. If these countries do not show any interest in working to improve the environment, then they may not remain on the Power Africa list, and there will be other countries coming in to Power Africa.

MR. HOWLETT: Washington can agree on very few things right now, but we have seen the radical right and the radical left agree that Power Africa is a priority and that this is something they want to support. It is the one thing that I have seen in 25 years in Washington that has true bipartisan support right now. There are always folks that oppose anything new, but such opposition is minor right now. This gives us some real hope that this initiative has some legs and will remain on track. ◎

Nothing was ever collected on them.

The BDO clients acquired 90% of the sub 1 LLC by paying the master LLC 90% of the actual value, and the master LLC distributed the money to the Russian utility. Sub 1 LLC then dropped the receivables into sub 2 LLC and exchanged sub 2 LLC with Gramercy for assets equivalent in actual value, triggering the loss.

The US Tax Court denied the losses in a decision in November. The cases are *UniteBuyuk LLC v. Commissioner* and *Beyazit, LLC v. Commissioner*.

The court said the transaction was a disguised sale of the receivables by the utility to the master LLC. The master LLC is a partnership. IRS regulations make clear there is a presumption that a partner who contributes property and is distributed cash by the partnership within two years made a sale of the property.

This meant the partnership took 90% of the receivables with a basis equal to their actual value so that the later exchange could not have triggered a loss.

The court also said the entire transaction lacked economic substance. The two executives claiming the losses had no possibility of earning a profit on the receivables. Gramercy worked out an agreement for the utility to continue trying to collect, but Gramercy was to receive the first $37 million in collections and then split any additional collections 25% for Gramercy and 75% for the utility. The court said the utility had no incentive under this arrangement to spend time trying to collect. The court saw no business purpose for the investment by the two BDO clients other than to generate a tax loss.

The IRS slapped a 40% penalty on the taxpayers, not the usual 20% penalty, due to a "gross valuation misstatement." The tax basis claimed on the property was at least 400% more than the amount the IRS considered correct. The court said the penalty was warranted.

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"But I'm Canadian!" And Other CFIUS Dilemmas

by Amanda Forsythe, in Washington

A little known committee within the US Treasury Department could have a big impact on deals involving a foreign acquisition of a US business. The Committee on Foreign Investment in the United States – CFIUS – reviews such transactions for national security concerns. Notifying CFIUS of a transaction is voluntary; however, the committee can initiate reviews in some cases. CFIUS is also known to request "voluntary" filings from parties to a transaction that raises national security considerations.

Sales of US companies or projects to foreign buyers should be run by CFIUS.

If CFIUS is notified of and clears a transaction, then the transaction is in the clear assuming there were no material mistatements in what was submitted to CFIUS. If the committee finds that the deal could impair US national security, then it can involve the President, who has the power to prohibit the transaction or order a divesture if the deal has already closed.

The regulations governing CFIUS are opaque and purposefully broad, leaving many companies with questions about whether to notify the committee about a transaction.

Nationality

One of the most common questions that arises is whether the nationality of the acquirer is relevant in determining whether a CFIUS filing should be made. People think that acquirers from friendly or allied nations may get a pass. The short answer is no. CFIUS may review a transaction regardless of the acquirer's origin. From 2009 through 2011, more than half of CFIUS filings dealt with acquirers from Canada, France, the United Kingdom and the Netherlands. During that period, one quarter of the transactions had a UK acquirer. In 2009, CFIUS approved the acquisition by Electricité de France of a 49.99% interest in Constellation Energy's nuclear assets.

However, although the acquirer's nationality does not matter when determining whether the committee has the authority to review a transaction, the nationality of the buyer could be an important factor when analyzing whether the transaction raises national security considerations. For example, Chinese companies have received heightened attention from CFIUS in recent years. CFIUS filings for transactions involving a Chinese acquirer have increased from one filing in 2005 to 10 filings in 2011. Several of the filings have been submitted at the committee's request.

Last fall, in a rare move, President Obama issued an executive order that said the acquisition by the Ralls Corporation of four wind projects located near a US naval facility in Oregon threatened to impair national security and ordered Ralls to divest itself of the wind farms. Ralls is owned by executives at Chinese manufacturer Sany Group, a Chinese state-owned entity. Other Chinese companies have abandoned deals, divested assets or instituted other mitigation efforts before deals have reached the point of a presidential decision.

That is not to say that all deals involving a Chinese acquirer will face problems. Early this year, CFIUS approved the acquisition of lithium ion battery manufacturer A123 Systems, Inc. by a US subsidiary of Wanxiang Group, a Chinese auto parts manufacturer. A123 had military and government contracts and had been awarded a Department of Energy grant of approximately $250 million. For these reasons, some politicians opposed the deal. Despite political opposition to the acquisition, CFIUS approved the deal. Reports indicate that the deal was structured so that A123 divested its government and military contracts and Wanxiang would not have access to A123's technology or assets. Such structuring helped alleviate the anticipated national security concerns. Recently, CFIUS approved the largest-ever takeover of a US business by a Chinese company. Shanghui International Holding Ltd acquired US pork processer Smithfield Food Inc. for $7.1 billion. Reports indicate that the CFIUS approval was not conditioned on any mitigation requirements.

Red Flags

Another common question is what characteristics of a company or transaction raise a red flag to the committee. "National security" is not defined for CFIUS purposes. However, the enabling statute lists factors considered by CFIUS in determining whether a transaction poses a national security risk. Such factors include the potential national security effects on US critical technologies, the long-term projections of US requirements for sources of energy and other critical resources and critical infrastructure. Critical infrastructure means a physical or virtual system or asset so vital to the United States that its incapacity or destruction would have a debilitating impact on national security. It includes major energy assets. However, the rules do not specify what is a major energy asset.

Guidance issued by Treasury makes clear that the concept of national security should be broadly interpreted and that it includes acquisitions of US businesses outside of the traditional defense sector. The guidance focuses on two characteristics of a deal: the nature of the US business being acquired and the identity of the foreign person acquiring control of the business. The committee does not focus on any particular US business sector. CFIUS has found that transactions present national security considerations because the transaction involves a US business that provides goods or services that directly or indirectly contribute to US national security. The acquirer's identity is particularly relevant if it is controlled by a foreign government.

A more in-depth review is required if the transaction is a foreign-controlled transaction or the / continued page 42

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ECONOMIC SUBSTANCE was at issue in another case, only this time the taxpayer won.

The US government has won two cases involving a complicated transaction called STARS for "structured trust advantaged repackaged securities" that KPMG arranged between Barclays Bank in the UK and various banks in the United States. The courts said the transactions lacked economic substance and had as the main aim generating foreign tax credits for use in the United States. (For prior coverage, see the April 2013 *NewsWire* starting on page 31.)

Sovereign Bank won a partial judgment in the third such case to reach the courts in October. Its case is before a federal district court in Massachusetts.

The judge called the transaction "surpassingly complex and unintuitive; the sort of thing that would have emerged if Rube Goldberg had been a tax accountant."

Barclays made a loan to Sovereign Bank. However, the loan was set up as a transaction run on paper through a trust in the United Kingdom with an elaborate series of agreements a number of which involved circled cash. The main reason for interposing the trust and for some of the arrangements surrounding the trust was to trigger taxes at a 22% rate in the United Kingdom on earnings on $6.7 billion in Sovereign collateral held by the trust over the term of the loan, but to allow Sovereign to claim foreign tax credits for the UK taxes in the United States. Barclays received tax benefits from the arrangement in the United Kingdom. It reimbursed Sovereign for roughly half the UK taxes Sovereign paid in the form of a "Barclays payment."

In a similar case before the US Tax Court last February, the government persuaded the court to view the foreign tax credit leg of as a separate transaction that lacked substance. In order to have substance, the taxpayer must expect a profit from the transaction apart from tax benefits and there must be a business purpose apart from generating tax benefits.

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transaction would result in foreign control of any critical infrastructure of or in the US if the committee determines that the transaction could impair national security and the risk has not been mitigated. However, there is no mandatory investigation if the Treasury Department or the lead agency determines that the transaction will not impair national security.

Recent reports of CFIUS actions suggest that the proximity of the acquired assets to military or defense installations is relevant. The wind turbines in the Ralls case were located near a naval facility where drones are tested. Several Chinese companies have divested or abandoned acquisitions of mining assets near US military bases in Nevada and Arizona due to CFIUS concerns.

Questions also arise regarding when a transaction is a "covered transaction." A covered transaction is a transaction where a foreign person will acquire control of a US trade or business. Control is broadly defined in the CFIUS regulations but, essentially, means the power to direct or decide important matters affecting the business. For example, the power to appoint and dismiss officers, select new lines of business or control the finance of the company are indicative of control. The control can be direct or indirect. Side agreements or disproportionate voting rights could cause a minority interest holder to control the business. However, the regulations specify certain minority shareholder protections that do not convey control, such as the power to prevent the sale of all or substantially all of the company's assets.

Timing

At a more basic level, companies often wonder how long the process will take. Although there are statutory deadlines for certain phases of the process, the exact timing of the process is hard to predict.

The CFIUS process breaks down into four phases. First, there is a pre-filing stage during which the parties to a transaction prepare the notice and preliminary consultations with committee staff may occur. Such early engagement of CFIUS staff is advisable, including the submission of a draft filing. CFIUS does not issue advisory opinions. However, the pre-filing period gives CFIUS staff an opportunity to familiarize itself with the transaction and ask questions, which helps submitters prepare and file a complete notice.

The second phase — a 30-day review period — begins once parties submit the notice and CFIUS decides it is complete enough to disseminate to CFIUS members. If after the initial review period unresolved national security issues remain, then there is a 45-day investigation. An investigation is mandatory in certain circumstances.

If a company files a notice and CFIUS concludes that there are no unresolved national security considerations, then the transaction is cleared. If national security concerns remain, CFIUS may enter into mitigation agreements with the parties or impose conditions on the transaction to address the national security risks. Following an investigation, CFIUS may send a report to the President recommending that the President suspend or prohibit the transaction. Such a report may also be sent when the members of the committee are unable to reach a decision on whether to recommend blocking the transaction.

If CFIUS refers a transaction to the President, then the President has the authority to block the transaction if he has credible evidence that the foreign investment could impair national security. However, to invoke this authority, the President must determine that other US laws are inadequate or inappropriate to protect the national security. The President's decision must be made within 15 days after CFIUS completes its investigation.

If the review process or investigation is not going well, then the parties will often voluntarily withdraw their notice rather than risk presidential suspension or prohibition. Thus, it is rare for CFIUS to complete its review with a recommendation that the President block a transaction. From 2009 through 2011, 269 transactions were reported to CFIUS. Of those, 12 were withdrawn during the initial review. There were investigations of 100 transactions with 13 notices withdrawn during the investigation.

All information submitted to CFIUS, including during the pre-filing stage, is confidential.

Although no assurances can be given when it comes to a CFIUS review, analyzing and weighing these issues and engaging CFIUS counsel early will help parties navigate the complicated process. ◎

Energy Storage on the Cusp

by Shellka Arora, in New York

The storage industry is progressing, slowly but surely.

In the United States, policy initiatives are beginning to shape the market. A twin picture is emerging as a result of incentives or lack thereof.

The market for ancillary services is growing in places where incentives exist and resources are being diverted from places where incentives lag. The recent shift by AES Energy Storage LLC of a 40-megawatt battery from Houston to the PJM region is one example. The company is responding to incentives set by independent system operators or ISOs as a result of FERC Order No. 755, notably PJM Interconnection, the New York ISO and the California ISO, that reward power providers for the quality of their responses to signals from the operators. The Electric Reliability Council of Texas, or ERCOT, is not governed by FERC Order No. 755. It is moving to make its own rules.

Another example is Stem Inc., a California-based leader in advanced energy storage systems, which has secured $5 million in financing from Clean Feet Investors, to bankroll installation of up to 15 megawatts of customer-sited systems with no down payment. Stem Inc. is focusing on California which has relatively high demand charges, subsidies for energy storage and a 1,300 megawatt mandate for grid storage.

Yet another example is General Electric's largest grid-scale application of its sodium-nickel-chloride Durathon battery to back up the Discovery Science Center in Santa Ana, California. As part of California's permanent load shift program, the array is meant to shift 10% to 20% of the building's electrical load from expensive peak times to cheaper, off-peak use, while also providing power when the grid goes down. It is one of the first deployments of battery technology aimed at such a large-scale shifting of power in a behind-the-meter setting.

In Germany, the energy storage subsidy, which has been available since May 1, 2013, is forecast to kick start the adoption of solar photovoltaic energy storage systems very much as the feed-in-tariff boosted the photovoltaic industry eight years ago. The subsidy provides a grant of up to 30% of the storage cost, lowers the cost of installing a storage component in a photovoltaic system up to 30 kilowatts in size and enables a photovoltaic system owner to / continued page 44

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Sovereign moved for a partial summary judgment on the issue whether the payment it received from Barclays for half the UK taxes it incurred should be counted as revenue in assessing whether Sovereign had a reasonable prospect of profit from the transaction. The IRS argued the amount should be excluded as a "tax effect" of the transaction.

The judge sided with Sovereign. It would have been different if the payment had come actually or constructively from the UK government because a US foreign tax credit cannot be claimed on taxes that are not paid in fact. However, this was a payment from a private party. The judge declined to analyze each leg as if it were a separate transaction.

The case is Sovereign Bank v. United States. *At issue are $234 million in taxes, penalties and interest.*

REIT CONVERSIONS may move forward again after the IRS sent an email in November to say that it will resume ruling on what qualifies as "real property" for REIT purposes.

The agency had stopped ruling for the last five months while it studied the issues.

Several companies that own data centers — large buildings with lots of computer banks for storing data — have moved or are considering moving the buildings into real estate investment trusts or "REITs" and then leasing the facilities to an operating company that pays a share of the revenue from users to the REIT as rent. REITs do not pay tax on earnings to the extent the earnings are distributed to their shareholders. The only tax is at the shareholder level. REITs cannot be used for operating businesses and must own largely real property and be careful about the types of income they receive. Rent from leasing "real property" is good income.

The IRS has been receiving many requests lately to rule on cell towers, data centers, billboards and other assets that have not traditionally been owned by REITs. The agency said in the email that it had / continued page 45

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increase the level of self consumption from 30% to 60%. A total of €18.7 million has already been allocated from the €25 million budget for 2013. The subsidy, coupled with winding back of feed-in-tariffs, potentially makes self consumption and energy storage an attractive business model. While the cost of Germany's renewable energy policy, which is expected to soar to more than €20 billion this year, has become a growing concern, return to nuclear power is inconceivable and the broad goals of its renewable energy law are expected to remain unchanged.

In the United Kingdom, distributed energy storage is expected to become a major growth sector as the country attempts to maintain grid stability. The market is set to reach US$1.2 billion by the end of the year. The government has set a target for more than 23,000 megawatts of renewable energy generation by 2020. A modernized grid is contemplated to require a minimum of 2,000 megawatts in new distributed storage for cost effective delivery of variable generation from renewables. The grid is facing an ever-increasing need for balancing power to handle wind variability. The present practice of curtailing wind energy output at times of high output and low demand, which cost a record £1.8 million in "constraint payments" in Scotland alone this year, no longer seems feasible.

In Canada, the Ministry of Energy has updated Ontario's long-term energy plan that includes Canada's most significant commitments to energy storage. The ministry announced, among other things, storage technologies will be included in procurement processes starting with 50 megawatts by the end of 2014, a study will be commissioned to establish the value of storage technologies on the electricity grid, and the ministry will work to address regulatory barriers that may limit energy storage from competing in the market.

On the technical front, the recent successful commissioning of the Solana Generating Station is noteworthy. Solana is the world's largest parabolic trough solar plant with a total capacity of 280 megawatts and also the first solar plant in the United States with thermal energy storage. The plant has passed commercial operation tests that included operating the plant at the turbine's full capacity while charging the thermal storage system, continuing to produce electricity after the sun went down, and starting up the plant and producing six hours of electricity using only the thermal storage system. The project is located near Gila Bend, Arizona and Arizona Public Service, the state's largest utility, will purchase all of the electricity produced by the plant for 30 years through a power purchase agreement.

> Energy storage projects are starting to gain traction in the US, Germany, the UK and Canada.

Likewise, UL 1778 certification procured by Sunverge Energy Inc., a leading California-based developer of distributed energy storage solutions, from Intertek Testing Services for its Solar Integration System is a step forward. The certification signifies that the system meets the product safety standards for connection to a utility power grid anywhere in the United States or other countries where UL standards are accepted.

The industry seems to be on the cusp. As storage technologies mature and costs fall, even with lagging policy initiatives, the global markets will present opportunities due to increasing grid challenges and existing inefficiencies. ◎

China Moves to Ramp Up Shale Gas Production

by Edwin Lee, in Beijing

The National Energy Administration published a set of guidelines for the shale gas industry in late October. The guidelines follow publication of a five-year plan for development of shale gas last year.

China considers shale gas development of national strategic importance, and more financial support for exploration and development of shale gas is expected from governments on both the local and national levels.

Environmental pressures are forcing large Chinese cities to switch from coal and oil to natural gas for heating and generating electricity. Beijing has already completed most of its transformation. However, this has put strains on gas supply. The three main gas suppliers in China — CNPC, Sinopec and CNOOC —lack the production capacity to meet the skyrocketing demand. China is expected to face a gas shortage this coming winter of more than 10 billion cubic meters.

The Chinese authorities are now blocking any further fuel switching to gas without first obtaining approval and sourcing the gas supply. The supply to some industrial users has been limited and even terminated in areas with the worst shortages, such as northern and eastern China. This is one reason why there is such strong interest in shale gas. The Chinese have watched the shale gas boom in the United States with great interest. China has the largest technically recoverable shale gas reserves in the world.

Output Figures

There have been two rounds of public tenders for shale gas. CNPC and Sinopec have already reached production targets in their respective blocks.

CNPC has built two national shale gas demonstration areas in its blocks in Changning, Weiyuan and Zhaotong. Its total investment to date is above RMB4 billion. Well #201 in the Changning block is the first commercial horizontal shale gas well in China. CNPC had completed 44 wells by the end of August, 20 of which are horizontal wells. Of the 44 wells, only five of them can reach production

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"temporarily placed pending ruling requests concerning [such] assets . . . on hold to allow for a thorough review to ensure a uniform and consistent approach to addressing the definition of REIT real property based on applicable law." It said it "has completed its review and is ready to resume ruling on these requests consistent with existing law . . . ."

Some analysts said after talking to the IRS that no change is expected in the agency position that cell towers and data centers can be owned by REITs.

BIODIESEL BLENDERS do not have to report refunds of excess excise tax credits as income, the IRS concluded in an internal memo in October.

The US government encourages biodiesel to be mixed into diesel fuel to produce a blend for use in trucks. Refineries and distributors doing the blending have a choice of claiming an income tax credit of 50¢ per gallon of biodiesel used ($1 for "renewable biodiesel" from agricultural sources) or alternatively of claiming a tax credit of $1 per gallon of biodiesel against the federal excise taxes on the blended fuel. The excise taxes are 24.3¢ a gallon.

Many blenders who claim the excise tax credit and then get a refund for the excess credit have been reporting the refunds as income, but they have been filing amended tax returns lately asking to get back the taxes they paid on the refunds. Section 87 of the US tax code requires anyone claiming the income tax credit for blending biodiesel must report the tax credit as income, but it says nothing about the excise tax credit or refunds of the excise tax credit. The IRS personnel handling the refund claims asked the IRS national office for guidance.

The national office said refunds of excess excise tax credits do not have to be reported as income. The advice is in Chief Counsel Advice 201342010.

SWAPS can trigger income when a counterparty assigns his position to someone else.

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levels of 100,000 cubic meters per day. The total annual commercial gas production in these blocks is around 60 million cubic meters. According to CNPC's plan, gas production in the two demonstration areas will be 2 to 3 billion cubic meters a year, of which 1.5 billion cubic meters will be commercial gas.

Sinopec has increased its production estimate dramatically to 4 billion cubic meters a year by 2015 from its blocks in Fuling in Sichuan province and the blocks have been approved as a national shale gas demonstration area. The 30 test wells in the Fuling block should produce 500 million cubic meters in 2013. The daily production of one of the wells reaches 547,000 cubic meters, which is the highest output of all 150 existing shale gas wells in China as of September. These output figures should help Sinopec greatly out distance the other major players in shale gas such as CNPC, CNOOC and Yanchang Oil.

China has set a goal of producing shale gas at a rate of 6.5 billion cubic meters a year by 2015.

China is blocking fuel switching to gas while it tries to encourage shale gas producers.

Impediments

Most winners in the first two rounds have not begun their drilling work yet due to funding or technology limitations.

Funding and technology are still big barriers to entry. The new national guidelines require that anyone engaging in exploration and development of shale gas in China must have the financial capability to do so, sound financial standing and a sound accounting system. One of the reasons that winners in the first two rounds of tenders have not moved quickly is that they are mostly local state-owned enterprises without strong financial capability. They do not have the financial means to support high-risk exploration. It will be difficult for them to find a financial footingin the short term since China does not have a well-developed project finance market. Many are trying to raise money by transferring part of their interests in exploration blocks or by making other arrangements such as joint ventures or production sharing arrangements.

The new guidelines emphasize that the government encourages multiple investors, including private enterprises, to invest in shale gas exploration. In the second round tender, two private companies were granted blocks in Guizhou province that have the most difficult geographic conditions among all the offered blocks that round. One of the two private companies has been trying to transfer its rights due to lack of funding and exit the industry, but no buyer wants to take on the challenge. The company faces a potential loss of all its investment if it cannot find a buyer. The government will get the blocks back for free if the holders breach their investment commitments.

No private companies are allowed to do conventional oil and gas exploration in China. The technology related to conventional gas exploration is controlled by state-owned oil and gas companies. These companies have developed technologies that are specially adapted to the geology in China. Although private companies can obtain the rights to shale gas blocks, they have to rely on state-owned companies for access to technology, and the state-owned companies charge as much as foreign technology owners for licenses. Foreign technology holders have not been interested in licensing to private companies, preferring instead to partner with the major state-owned oil and gas companies.

The technology and equipment to be used in shale gas exploration receives a lot of attention in the new guidelines. China is interested in developing technologies that are suited for Chinese geological conditions and then keeping the intellectual property rights in the hands of Chinese companies. However, it is also interested in using advanced new technologies from places like the United States to increase the success rate in exploration.

The new guidelines encourage local manufacturing of equipment in order to save on cost and reduce dependence on foreign companies. Due to the limited research and development budgets of Chinese companies, the government established a National Energy Shale Gas R&D Center in 2010 as a department under CNPC's research institution in Langfang in Hebei province. The center needs to be made independent from CNPC. Otherwise, CNPC might be the only beneficiary of the center.

Foreign companies that possess advanced shale gas technologies are encouraged to cooperate with Chinese companies so that the Chinese companies can learn about the technologies and gain operational experience. At a China mining conference in November, officials from the Ministry of Land and Resources welcomed foreign investors who can enter the industry through cooperation with Chinese companies.

In the short term, there are not likely to be many private players in shale gas. Although shale gas is a new and open industry, it is still bound by the old regimes in oil and gas. Private participation may rise along with the energy industry reforms in China, but the reforms will take a while. Compared to foreign investors, private companies are in a much weaker position in terms of funding and access to technology.

Gas Shortage

Gas consumption is increasing by around 15% a year in China. China has been a net importer of gas since 2007. Gas imports accounted for 28.9% of Chinese gas consumption in 2012 and are expected to account for 35% by 2015 when 18% of the population, equal to 250 million people, will use gas. Currently, gas is only 5% of energy usage compared to the average international standard of 23.8%. Chinese gas consumption increased to 107.5 billion cubic meters in 2010 from 24.5 billion cubic meters in 2000. Gas consumption is growing currently by 20 billion cubic meters a year. At this rate, total consumption will be 230 billion cubic meters by 2015 and 350 to 400 billion cubic meters by 2020.

By 2015, domestic gas supply will be around 176 billion cubic meters, of which conventional gas will be 138.5 billion cubic meters, coal-to-gas 15 to 18 billion cubic meters and coal-bed methane 16 billion cubic / *continued page 48*

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That's because the assignment is considered an exchange of the old swap for a new one with a different counterparty for the person still holding the swap. Any exchange of one instrument for another has the potential to trigger income if the new instrument is considered more valuable than the old one.

However, the IRS said in regulations that it finalized in November that an assignment of a swap or other derivatives contract by a dealer or clearinghouse to another dealer or clearinghouse will not be treated as a taxable exchange. This is true only if the transfer is permitted by the terms of the contract and the terms are not otherwise modified. The regulations can be found under section 1001 of the US tax code.

The implication is that there could be a taxable exchange in other circumstances.

It is potentially a taxable exchange if the holder of a swap or other derivatives contract ends up with a "materially different" credit on the other side of the contract.

MINOR MEMOS. There were 43 utility-scale solar projects in operation in the United States at the end of the second quarter 2013. Sales of solar electricity from such projects were 59% higher than the year before. Twenty-five companies owned the 43 projects. The top five solar power sellers were NRG, Sempra Generation, Mid-American, Exelon and Consolidated Edison . . . . The Agua Caliente project was the largest operating solar facility in the United States in Q2 2013. It accounted for roughly 15% of all US utility-scale solar sales. It is 250 megawatts, but is expected to reach 290 megawatts by early 2014 . . . . Partnerships and other "pass-through" entities are getting more attention from the IRS. Between 2007 and 2011, the number of partnerships grew 15.3%. Many IRS agents lack the training to audit partnerships. The IRS now sees partnerships with as many as 82,000 partners and from 125 to 182 tiers of entities.

— contributed by Keith Martin in Washington

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meters.

China is planning to build 39 coal-to-gas projects with total production of around 176.5 billion cubic meters per year. This plan has come in for criticism because of the carbon emissions, high water consumption and pollution.

New rules for coal-bed methane were published in September. The estimated annual grant to this industry will be RMB7.5 billion. Despite this level of government support, most of the coal-bed methane producers have not achieved their production goals this year.

A projected 23% gas shortfall in 2015 could grow to more than 50% by 2020.

The rest of the 6.5 billion cubic meters will be filled in by shale gas, according to the national shale gas plan released last year.

The shortfall between demand and domestic supply will be filled in part by importing gas through pipelines between China and central Asian countries, Russia and Burma, as well as by sea shipment. China has signed import contracts for gas that will deliver 93.5 billion cubic meters in 2015. Russia will supply another 38 billion cubic meters of gas to China annually beginning in 2018 for 30 years. During Chairman Xi's visit to Turkmenistan in September, the two countries signed an agreement for Turkmenistan to supply 65 billion cubic meters of gas a year starting in 2020.The China-Burma gas pipeline was completed in late October. The third central Asia-China pipeline C will be completed at the end of this year and pipeline D is in design now.

Matching supply to demand will remain not only a challenge, but also a risk to domestic shale gas producers. Considering the increase in other alternative energy supplies (such as wind and solar) and projected rate of growth in the Chinese economy, the oversupply of gas like in the United States might happen in China in 10 to 15 years. According to the new shale gas guidelines, shale gas prices at the well will be determined by the market. However, the retail price is still regulated. Gas prices for residential users are expected to remain stable. Retail prices for industrial users can be increased by 0.4RMB per cubic meter.

Shale gas has to compete with conventional gas. The shale gas extraction cost is around RMB1.40 per cubic meter, which is more than the costs to produce conventional gas of RMB1.28 per cubic meter in Sichuan province and RMB1.00 per cubic meter in Xinjiang. How to reduce the extraction cost will be a challenge for shale gas to be competitive.

Another big cost in moving shale gas to market is the cost of connecting to pipelines. CNPC has built and controls 70% of oil pipelines and 90% of gas pipelines in China. Recent corruption scandals involving CNPC have led to a debate on whether the pipelines should be removed from CNPC. The National Energy Administration published draft opinions for public comment in late October proposing that the pipelines should remain with CNPC. However, the pipelines and other related infrastructure are supposed to be open to third parties on a non-discriminatory basis, and the National Energy Administration will enhance its regulation of pipelines.

It is hard to establish a forward price curve for gas. Shale gas producers will not have a predictable and transparent price until gas pricing reforms are completed in a couple years.

Environmental Challenges

Air, soil and water pollution are a major concern for the shale gas regulators. The new guidelines require that equal stress be placed on shale gas exploration and ecological protection.

During drilling, fracturing and other processes, and in the construction of ground works, land occupation should be kept as minimal as possible.

Drillers have to recycle the drilling and fracturing fluid and any gas that escapes during production must be flared.

An environmental impact assessment must be conducted in accordance with the environmental law.

Chinese environmental laws are weak, as the deterioration of the environment in the past 35 years proves. China lacks the assessment technologies it needs to evaluate the effects of shale gas exploration on the environment. It will be difficult for the environmental authorities to implement the new guidelines formulated by the National Energy Administration.

Shale gas exploration is forbidden in natural preserves, scenic spots, areas that provide drinking water and geologic-disaster-prone areas.

Opportunities

Investors should keep an eye on the full industrial chain related to shale gas.

Equipment is one of the reasons that drilling wells costs so much in China. China has no ability to manufacture most of the equipment or its own equipment cannot meet the technical and environmental requirements. CNPC and Sinopec have some alternative equipment used in conventional gas or oil exploration that could be adapted for use in shale gas exploration. Some equipment cannot physically be transported to sites due to road and other geographic limitations. China has set a goal of developing shale gas equipment that is suitable for the geological conditions in China and that is light, can be carried by vehicles, is easy to transport and is low in pollution and cost.

By 2020, assuming that shale gas production reaches 60 billion cubic meters a year, 40,000 wells will need to have been drilled and the total equipment demand will be around RMB200 billion. In the following nine years, the demand for shale gas equipment is expected increase by 50% annually. By 2020, demand for shale gas equipment will account for one fifth of total oil and gas equipment needs.

Foreign investors need to move quickly if they want to build market share. The Hong Kong-based TSC Group, a one-stop solutions service provider to the oil and gas sector and a highly-respected manufacturer of drilling equipment, has committed to start its third marine and shale gas industrial base of 100,050 square meters in Qingdao in Shandong province soon. TSC aims to achieve US$1 billion in revenue by the end of 2016.

The third round public tender for shale gas is expected to be announced in 2014. The tender procedure and requirements for participants are expected to be revised dramatically with the goal of encouraging more private and foreign investor participation in the bidding.

Due to environmental concerns, the proposed shale gas blocks will be limited to Sichuan, Chongqing and Hubei. The shale gas rich areas such as the Erdos basin may not be included in the proposed blocks list due to its weak ecological condition and shortage of infrastructure.

New measures, such as new tax subsidies, are expected to be issued in the near future for shale gas. The new measures will be aimed at increasing foreign investor interest in the sector.

There are multiple potential points of entry for foreign investors. They need not limit themselves to exploration. Shale gas will be a test laboratory for experiments with market pricing. The Chinese government is trying to withdraw its "visible hand" from the economy as quickly as possible. ◎

Environmental Update

New standards have been released for phase I environmental site assessments that must be done on project sites as a condition to closing on financing.

The new standards are in ASTM E1527-13. ASTM is the American Society for Testing and Materials, an international standards organization. The new standards apply to phase I assessments done on or after November 1, 2013 and update earlier standards that had applied since 2005.

Key changes are to require consultants making phase I assessments to do a more detailed review of public records, classify environmental conditions that may be found on the project site under three new headings, and take a closer look at potential vapor intrusion from petroleum products and other hazardous substances.

The new standards may increase the cost of phase I assessments and add slightly to the time it takes to complete such assessments. However, in most cases, the effects should not be significant.

Anyone buying commercial real estate should make an "appropriate inquiry" into the environmental condition and current and past uses of the property to assess environmental risks. Lenders and tax equity investors require that these diligence efforts meet certain standards. The goal is not only to identify potential environmental risks, but also to qualify for certain defenses against liability under the federal Superfund law for contamination that the buyer did not cause or make worse. In particular, the buyer wants to be in a position to claim protection under the "innocent landowner" or "bona fide prospective purchaser" defenses to environmental claims under federal law. A buyer may benefit from these protections by doing enough diligence to qualify under an "all appropriate inquiry" rule. However, what qualifies as enough diligence may change over time.

The US Environmental Protection Agency, which administers the Superfund law, had found that environmental diligence that adheres to the prior ASTM standard qualifies as "all appropriate inquiry." In August 2013, EPA confirmed that the new E1527-13 standard meets the all appropriate inquiry threshold.

New standards took effect on November 1 for phase 1 environmental site assessments.

In a surprise move, the agency also suggested that it will continue to allow the use of the less stringent 2005 version to qualify. However, EPA now appears to be reconsidering this dual-track qualification after the proposal came in for criticism during the public comment period. EPA expects to reach a final decision by the end of the year, so the fate of continued qualification of the old ASTM standards remains in limbo until then. Conservative lenders may require borrowers to use the more stringent version no matter what EPA decides because two qualifying standards could lead to different conclusions about the environmental risks associated with a site and potentially increase a borrower's litigation exposure outside of the Superfund context.

A phase I environmental assessment includes a physical inspection of the site and adjacent properties, interviews, and review of historical information and agency regulatory files and databases. Although a phase I assessment requires an inspection of the property, no invasive sampling is typically performed. The inspection identifies visual evidence of environmental contamination associated with the property and the potential risk for such contamination. It also makes recommendations for further investigation, if warranted.

The new ASTM standards clarify language that was unclear in the prior version. None of the changes is seismic. The substantive changes require environmental consultants preparing the reports to gather more information and make a more thorough the review of certain types of risks.

The three most significant changes from the previous version are as follows.

Important Definitional Changes: The new standards simplify the definition of a "recognized environmental condition" or "REC." The identification of such conditions is the main goal of a phase I assessment. The new standards also revise the definition of "historic recognized environmental conditions" or "HREC" to include past releases that have already been addressed to the satisfaction of regulators or that otherwise satisfy standards for unrestricted use, but do so without the necessity of institutional controls (such as deed restrictions against digging or restrictions on use of groundwater).

A new term is added to distinguish historic conditions from "controlled recognized environmental conditions" or "CREC." A CREC is a past release that has been addressed to the satisfaction of regulators, but where some level of contamination is allowed to remain on site because institutional controls are in place to address environmental concerns. All of these conditions are distinguished from de minimis conditions, which are not viewed as posing any threat to human health or the environment or otherwise presenting any risk of an enforcement action.

Scope of Review: Environmental consultants must now review a broader range of public agency records and files in certain circumstances. For example, where a state or federal environmental database lists the site or adjoining property, the consultant must review the related regulatory files to determine whether the issue that prompted the listing is a REC, HREC, CREC or is simply a de minimis condition.

Vapor intrusion: The new standards revise the definitions of "migrate" and "migration" to include the intrusion of vapors from petroleum products or other hazardous substances. Thus, it can no longer be argued that the movement of vapor in the subsurface falls under the rubric of indoor air quality, which has been considered outside the scope of a traditional phase I assessment. This change reflects recent increased attention to vapor issues by regulators. While the new standards require consideration of potential vapor issues, they still do not require a full vapor intrusion screening as part of a phase I assessment, although a phase I may now recommend such testing.

Energy Storage

The California Public Utilities Commission set energy storage targets for the three investor-owned utilities (Pacific Gas & Electric Co., Southern California Edison, and San Diego Gas & Electric) in October. Together, these utilities are now required to procure 1,325 megawatts of energy storage capacity by 2020. The utilities must set their first energy storage procurement periods by March 1, 2014, and, together, they must buy 200 megawatts of energy storage technology during 2014 with gradual expansion over time.

For good or ill, California has a long history of setting regulatory requirements that drive technology. This latest action to push utilities into advancing energy storage is a small step toward a long-term goal that could allow greater use of renewables such as solar and wind.

It is the first regulatory mandate for energy storage in the United States. The CPUC decision fulfills the obligations of a 2010 California law called A.B. 2514 that directs the commission to try to capture excess generation for use during peak periods. If storage technology advances over time, the chief benefactor may be solar and wind projects whose output fluctuate depending on the weather and time of day.

Climate Talks

Thirteen days of UN climate talks in Warsaw ended on November 23, 2013 with several last-minute agreements.

The talks had three central goals: create a pathway to a new global climate agreement to replace the Kyoto accord by a 2015 meeting in Paris, agree on certain financial policies and agree on a "loss and damage" mechanism. While the chair person, Marcin Korolec, declared that all three goals were achieved, they were achieved only by leaving certain disputed points for later determination.

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The agreements reached in Warsaw set the stage for efforts to reach a global deal to fight climate change in Paris in 2015. The participants agreed that such a future deal would be a patchwork of offers by individual countries to curb greenhouse gas emissions. However, efforts to set a deadline by which the nearly 200 nations would set their emissions reduction targets for the post-2020 period failed. Instead, the Warsaw agreement simply calls on nations "able to do so" to submit their plans for curbing emissions by the first quarter of 2015, which would leave eight months for review and negotiation of the pledges before the Paris summit in December. If such a deal can be agreed to in Paris, the plan would be to implement it by 2020.

In 2009, developed nations promised $100 billion in aid by the end of 2020 to help developing nations adapt to climate change. Agreement was reached on a number of finance-related terms in Warsaw, but wealthier nations rebuffed requests that they agree to specific financial targets beyond the general statement that $100 billion will be made available. Decisions on deadlines for individual nations to make specific financial pledges were also deferred. The Warsaw agreement only "urges" developed nations to make explicit monetary pledges to developing nations by 2020.

A new mechanism was also adopted to help poorer nations cope with loss and damage resulting from the effects of climate change, such as rising sea levels, floods, drought and desertification. The final agreement did not include language proposed by developing countries that would have made clear that "loss and damage" funding is not a subset of adaptation funding, but the agreement does allow a review of the loss and damage mechanism during climate talks in 2016.

— contributed by Andrew Skroback in Washington

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