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More Subsidies for US Energy Projects

by Keith Martin and John Marciano, in Washington

Congress gave developers of US renewable energy projects in late December another year through December 2011 to get new projects under construction to qualify for cash grants from the US Treasury for 30% of the project cost.

The fact that Congress waited until almost the end of 2010 to let developers know they have more time—the extension became official on December 17—made for a rush by developers to order equipment and get work under way at factories and project sites. The experience provided some useful practical lessons for what to do or not to do when a similar rush is expected in late 2011.

The same bill that extended the deadline for cash grants also authorized a 100% "depreciation bonus" on new equipment put into service after September 8, 2010 through December 2011 or 2012, depending on the project. The bonus is a timing benefit. Instead of depreciating a project over the normal depreciation period, the entire cost can be deducted in the year the project goes into service.

However, projects on which work started before 2008 may not qualify.

Many developers are expected to have trouble using the bonus. There was already a 50% bonus during 2010, but many tax equity investors made developers opt out of the bonus because the investors were trying to conserve tax capacity to / continued page 2

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CALIFORNIA said it does not intend to collect taxes on Treasury cash grants paid on renewable energy projects unless instructed to do otherwise by the courts.

The Franchise Tax Board made the announcement in a notice posted to its website on January 12.

A ballot initiative that the California voters passed in November had raised questions about whether the grants are taxable in California.

The US Treasury pays owners of new renewable energy projects 30% of the project cost after the projects are completed in place of tax credits for which the owners would have qualified for otherwise. / continued page 3

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spread over a larger number of deals.

A 100% depreciation bonus is worth roughly 4.45¢ per dollar of capital cost in additional subsidy on a wind, solar, geothermal or fuel cell project. It is worth more on other renewable energy projects and as much as 18¢ per dollar of capital cost on some transmission lines, power plants that use fossil fuels and some parts of certain biomass plants.

Congress made other changes that will affect other parts of the project finance market in the same bill in late December.

Cash Grants

In early 2009, Congress directed the US Treasury Department to pay owners of new renewable energy projects that are completed in 2009 or 2010, or that start construction in 2009 or 2010, 30% of the project cost in cash as an economic stimulus measure. The grants are sometimes referred to as the "section 1603 program." Developers receiving grants must agree to forego tax credits that they would otherwise have received on the projects.

The program paid $5.8 billion through the end of 2010. The three largest Treasury cash grants to date are $276 million paid on the Meadow Lake wind farm in Indiana, $222.9 million for the Penascal wind farm in Texas and $218.5 million for the Windy Flats wind farm in Washington state.

It looked during most of 2010 that if the program were extended, it would be turned into a tax refund program in which the government would pretend that a project owner overpaid its income taxes by 30% of the project cost in the year the project is completed. The owner could then apply for the taxes back. This would have delayed grant payments compared to the current program and might have shifted administration of the program to the Internal Revenue Service.

In the end, Congress simply changed a date.

Grants will now be paid on projects that are completed or that start construction in 2009, 2010 or 2011.

Projects that merely start construction must be completed by a deadline.

The completion deadlines have not changed. They remain 2012 for wind farms, 2016 for solar and fuel cell projects, and 2013 for most other projects.

Grants are paid on equipment that uses wind, sunlight, geothermal steam or fluid, biomass, municipal solid waste, landfill gas and, in some instances, water to generate electricity. They are also paid on fuel cells, combined heat and power projects (or what used to be called cogeneration facilities) of up to 50 megawatts in size, gas micro-turbines and geothermal wells and pipes. The grants on small cogeneration facilities and gas micro-turbines are only 10% of the project cost. The deadline to put them in service is 2016. The Treasury is not sure it will pay grants on geothermal wells and pipes that are put in service to serve an existing power plant.

Developers should not assume that the cash grant program will be extended again by Congress. Republicans are now in control in the House and have more seats in the Senate. The Republican counsels to the House and Senate tax committees said at a wind industry forum in late November that their party is opposed to extending the program. They see it as part of the Obama stimulus measures against which the party voted *en masse*.

Two lessons can be drawn from the rush in late 2010 to start construction of projects to qualify for Treasury cash grants.

Practical Lessons

The fact that Congress waited until the last minute to extend the construction-start deadline acted as a stimulus as developers rushed to order equipment and start work at factories and on project sites before year end.

There are two key takeaways from that experience. Some important practical information also came out during discussions with the Treasury late in the year as the deadline was approaching.

Start planning early in 2011 how to start construction by year end. Developers who waited until the fall 2010 to start planning found equipment manufacturers had already committed their production slots to others who had gotten in line earlier.

It is better to try to incur more than 5% of the total project cost by year end than to rely solely on starting physical work at the site or a factory. Tax equity investors and lenders proved unwilling in some cases to assume that a project got underway in time if all the developer could point to was physical work at the site. Anyone relying solely on physical work must be able to prove that there was continuous construction work through completion. Some tax equity investors and lenders were unwilling to take the risk that the continuous work requirement would be met. There is no need for projects that incur more than 5% of the total project cost by December 2011 to show that the work after that point is continuous.

There are two ways to start construction.

One is to commence physical work of a significant nature on the project by December 2011. The work can take one of two forms. It can be work at the site on foundations, concrete pads for wind turbines, concrete pedestals for solar arrays or permanent roads that will be used to ferry spare parts once the project is in operation. It is also physical work of a significant nature for a turbine or module manufacturer with whom a developer has a binding contract to supply equipment to start physical assembly of the equipment at the factory.

The other way to start construction is to "incur" more than 5% of the total project cost by December 2011. It is not enough merely to make a payment in 2011. Costs are not "incurred" until equipment or services ordered under a binding contract are delivered, with one exception. A payment in 2011 counts as a 2011 cost if the equipment ordered is delivered within 3 1/2 months of the payment date.

A developer relying on the 5% test can add up the costs the developer incurs. It can also add costs that a contractor or equipment manufacturer with whom the developer has a binding contract incurs (without double counting).

There is a debate within Treasury about whether pulling components out of inventory counts toward costs incurred at the equipment manufacturer or contractor level. Until the issue is settled, developers would be wise to require equipment manufacturers only to use components that are manufactured after a binding purchase order is in place. / continued page 4

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Grant recipients do not have to pay taxes on the grants at the federal level. The tax credits for which they substitute are not taxed either.

California, like most states, has its taxpayers start with a federal definition of taxable income and then make adjustments.

The state legislature must vote periodically to move forward the date through which the state conforms to how income is calculated at the federal level.

The Franchise Tax Board concluded in the fall 2009 that grants paid on renewable energy projects in California are subject to an 8.84% franchise tax because the grant program and a separate provision specifically exempting the grants from federal income taxes were enacted in February 2009, but the state had conformed at the time to how federal taxable income is calculated only through January 1, 2005. There is an assumption, even at the federal level, that anyone receiving money must report the amount as income.

The state legislature moved the conformity date forward to January 1, 2009 in April 2010—still not far enough because the Treasury cash grant program was not enacted until February 2009—but the bill, SB 401, specifically conformed to federal treatment on Treasury cash grants.

Proposition 26, approved by the voters in November, says that any "tax adopted" earlier in 2010 is "void 12 months after" November 3, 2010 unless reenacted by then by a two-thirds vote of both houses of the state legislature.

It is unclear whether SB 401 needs to be reenacted. After spending several weeks looking at the issues, Chadbourne concluded that "void 12 months after" means a bill remains good law until then and any change only applies after that date. It also concluded that SB 401 does not have to be reenacted. Two Chadbourne memos on the subject were shared with state officials before the Franchise Tax Board posted its guidance.

Separately, California Governor Jerry Brown released a budget plan on / continued page 5

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Developers who plan to rely on the 3 1/2-month rule to count the cost of equipment delivered in early 2012 must link payments in late 2011 to the specific equipment that will be delivered in early 2012. It is not enough to make a general down payment or general milestone payment under a contract.

The Treasury is unsure how the 3 1/2-month rule works for services. It has not decided whether services can be separately delivered from the equipment to which they relate in cases where the services are part of a larger equipment supply agreement. For example, design or engineering work may be embedded in the equipment and may not be delivered until the equipment is delivered.

Private Equity Funds

Developers who are owned partly by private equity funds cannot receive Treasury cash grants on their projects unless the funds hold their interests through "blocker corporations," with one exception. The developer can benefit indirectly from a cash grant by selling the project to a tax equity investor and leasing it back. The tax equity investor can claim a full grant in that case, and the benefit is shared with the developer in the form of reduced rent for use of the project.

There had been talk at the staff level in the House tax committee about dropping the ban on cash grants for projects with private equity fund backing and moving instead to a "proportionate disallowance rule" where the grant would be lost to the extent of government and tax-exempt ownership of the project. Thus, for example, if state pension funds and university endowments own 10% of a private equity fund that owns 90% of a project indirectly through a developer, then only 9% of the grant would be lost.

Municipal utilities and electric cooperatives were also pressing to be able to receive Treasury cash grants on their projects.

The final bill was silent on these issues.

In addition to changing the deadline to start construction, the bill also changed a deadline to apply for Treasury cash grants. Grants are not usually applied for until after a project is completed. However, anyone expecting a grant had to apply to the Treasury by September 30, 2011 as a way of letting the government know how many more claims there might be on the program. That deadline has now been pushed back to September 30, 2012.

Depreciation Bonus

Companies that place new equipment in service after September 8, 2010 through December 2011 or 2012 will be able to deduct the cost immediately as a "depreciation bonus."

The bonus replaces the regular depreciation that the company would otherwise have claimed.

However, only 85% of the cost can be deducted if a Treasury cash grant or investment credit is claimed.

Equipment that is normally depreciated over five or seven years must be in service by December 2011 to qualify for a 100% bonus. Examples are wind, solar, geothermal, landfill gas and parts of biomass and waste-to-energy projects.

Equipment at such projects still qualifies for a 50% bonus if placed in service in 2012. A 50% bonus means half the cost—or 42.5% of the cost for equipment on which a Treasury cash grant or investment credit is claimed—is deducted immediately. The remaining cost is deducted over the normal depreciation schedule.

Equipment that is normally depreciated over 10 or more years qualifies for a 100% bonus if placed in service by December 2012 and a 50% bonus if placed in service by December 2013. Examples are transmission lines and power plants that use fossil fuels. For this long-lived property, both the 100% bonus and the 50% bonus can only be claimed on costs incurred through 2012.

A company can opt out of the bonus, but it cannot choose to take a 50% bonus instead of a 100% bonus.

Some careful tax lawyers have raised questions whether a Treasury cash grant can be claimed on projects on which a depreciation bonus is claimed. The Treasury cash grant program guidance says, "Costs that will be deducted for federal income tax purposes in the year in which they are paid or incurred are not includible in basis" for the cash grant. However, staff of the Joint Committee on Taxation said, after looking at the issue, that both the bonus and the grant are available on projects. Treasury confirmed this by email.

The bonus can only be claimed on equipment as opposed to buildings, land and intangible assets like power contracts and interconnection agreements. About 93% to 97% of spending at a conventional power plant is usually for equipment as opposed to a building and other improvements to real property.

The bonus can be claimed on projects in US possessions like Puerto Rico and the US Virgin Islands, provided they have US owners.

There is no bonus for investing in an existing facility, with four exceptions. "Existing" means it was already in operation when the taxpayer made the investment. First, new improvements to an existing plant qualify. Second, a tax equity investor can buy an existing project and lease it back to a developer up to three months after the developer put the project into service and claim a bonus. Third, the lessor in the sale leaseback has up to another three months after the sale-leaseback transaction closes to syndicate its position by offering interests in the lessor position to other investors. Fourth, a project developer can contribute an existing project to a partnership with a new investor at any time during the same tax year the project went into service, and the investor will get a share of the bonus. The IRS will require that the bonus be allocated between the project developer and the partnership based on the number of months that each owned the project during the year.

Project Too Stale?

Work on the project must not have started before 2008.

Most projects should qualify for a bonus as long as work "of a significant nature" did not start at the site before 2008. Site clearing, test drilling and excavation to change the contour of the land are not considered the start of work at the site. Work "of a significant nature" is considered to commence at the site once work starts on the foundation. IRS regulations say that driving pilings into the ground counts as work on the foundation. They also provide a "safe harbor" under which work is not considered to have reached the threshold "of a significant nature" until the taxpayer has incurred more than 10% of the expected total cost of the project. Spending on "land and preliminary activities such as planning or designing, securing financing, exploring, or researching" designs is ignored: it is not counted in either the numerator or the denominator. Thus, if a project is expected to cost $300 million after backing out soft costs that are not allocated to the hard assets and after backing out the cost the land, design work and other preliminary activities, work is not considered to have reached the threshold "of a significant nature" until the taxpayer has incurred more than $30 million.

The starting point for analyzing whether a project was too advanced before 2008 to qualify for a bonus is to decide whether the developer is "acquiring" the project or "self constructing" it.

"Acquired" property qualifies for a bonus only if there was no "binding" contract to acquire it before 2008.

"Self-constructed" property qualifies as long as work "of a significant nature" did not start at the site before 2008.

Most infrastructure projects are consid- */ continued page 6*

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January 10 that would require companies doing business in the state to calculate the amount of income that is subject to tax in California based solely on the percentage of total sales the company has in the state compared to outside the state. The move is expected to increase tax collections by $468 million in fiscal 2011 and $942 million in 2012.

Companies pay income taxes not only at the federal level, but also in most states where they do business. State taxes are imposed only on the share of income that has its source in the particular state. Each state has its own approach to determine how much income was earned in that state. Many use a weighted average of the percentages of the company's total sales, payroll and property in the state. However, the trend is for states to move to a single factor, usually sales.

Business groups have been urging California to allow optional use of a single sales factor. Brown said he saw no reason to make it optional.

He also wants to extend a temporary 1% increase in the state sales tax and a 0.25% increase in the corporate income tax rate that the legislature approved in February 2009 by another five years. The plan also calls for eliminating tax breaks for businesses that set up operations in low-income areas called "enterprise zones."

Brown promised during the campaign last fall not to increase taxes without a direct vote by the voters. The state faces a $25.4 billion budget deficit in 2012. States are not allowed by their state constitutions to run deficits. Brown, a Democrat, also called for $12.5 billion in spending cuts.

A TAX EQUITY TRANSACTION with some aggressive features was upheld by the US Tax Court in early January.

The New Jersey Sports and Exposition Authority, or NJSEA, took on renovation of a sport arena and exhibition hall in Atlantic City called the East Hall that was origi- */ continued page 7*

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ered self constructed. The IRS regulations have an unusually broad definition of "self constructed." Property is considered self constructed as long as the developer signed a contract with the manufacturer or contractor to have the property built for him before physical assembly of the property started. A contract is not "binding" if it limits the damages the owner must pay for canceling the contract to less than 5% of the total contract price. It is not a problem if the contract is silent about damages. There cannot be any conditions standing in the way of performance of the contract or the contract is not binding—unless the conditions are outside the control of the parties.

It is generally not possible to *create* a bonus where the project developer could not have claimed one—for example, because the project developer got started on the project too early to qualify—by selling the project to someone else during the window period and leasing it back. The IRS regulations have an "anti-churning rule." However, the anti-churning rule is not well drafted.

Some developers may have taken delivery of turbines or other equipment that they no longer need and have parked in warehouses. If another developer were to buy one of these turbines today and use it, then he could claim a bonus on the cost of it. That's because the turbine was never put into service by anyone. Property is not considered used equipment until it has been in service.

On the other hand, if a developer bought a used turbine from another developer to incorporate into a new power plant, a bonus could not be claimed on the cost of it. A bonus cannot be claimed on used equipment.

This raises the question whether companies need meticulously to catalog whether used parts are used in the construction of their facilities. The answer is no. A company should determine whether parts that are large enough to qualify as separate "components" of a project are used property. The IRS does not define "component" in its regulations. Smaller parts are considered subsumed in a larger property, and unless more than 20% of its value is tied to the cost of used parts, the larger property is considered entirely new. Thus, for example, if a developer bought an older wind farm and rebuilt it using the latest generation of wind turbines, the entire project should qualify for a bonus—including the cost of acquiring the existing project—as long as the existing equipment does not account for more than 20% of the value of the wind farm after reconstruction.

A depreciation bonus worth 4.45¢ to 18¢ per dollar of capital cost is available on new power projects in 2011 and, in some cases, 2012.

Project Sales

Many power projects are expected to be put up for sale in 2011. Many of the projects sold will still be under development or construction. Anyone who buys a project before it is completed will qualify for a bonus, not only on the amount spent to complete the project but also on the amount paid to buy the work in progress to the extent the purchase price is allocated to equipment as opposed to other assets like a power contract or interconnection agreement. It does not matter that the original developer would not have qualified for a bonus had he kept the project.

Another common situation in infrastructure projects is where someone buys into a project—for example, as a partner—during the construction period. The analysis in such situations is more complicated than where a project that is still under construction is purchased outright. Someone buying into an existing partnership can claim a share of the bonus to which the partnership is entitled. However, he ordinarily cannot claim a bonus on any premium to buy into the project. (In other words, a bonus ordinarily cannot be claimed on a "section 754 stepup.")

A developer who places a new project in service and sells the entire project later the same year to someone else cannot claim any bonus. The bonus is lost. (An exception is where the project is sold in a sale leaseback within three months after the project went into service.)

Some projects are owned by partnerships. A partnership "terminates" for tax purposes if at least a 50% interest in partnership capital and profits is sold. (The old partnership is considered to disappear and a new one to spring into being with the new partners.) If a project is put into service in a year and, later the same year, an interest in the partnership is sold causing the partnership to terminate, then the bonus is shared among the new partners—not the old ones.

Calculating the Bonus

The depreciation bonus is an acceleration of tax depreciation to which the owner of a project would have been entitled anyway.

The owner gets a much larger depreciation deduction the first year and, in the case of a 50% bonus rather than a 100% bonus, smaller ones later.

A faster writeoff can be a significant benefit. The benefit is greater the longer the normal depreciation period for an asset. A 50% depreciation bonus reduces the cost of assets that are depreciated over 20 years—for example, some transmission lines and coal- and combined-cycle gas-fired power plants—by 8.98%. It reduces the cost of gas pipelines and simple-cycle gas-fired power plants that are depreciated over 15 years by 7.54%. The cost of a generator that burns landfill gas is reduced by 3.61% (3.07% if a Treasury cash grant or investment tax credit is received on the project). Wind farms and biomass projects cost 2.61% less (2.22% for projects that receive Treasury cash grants or investment credits). These calculations only take into account *federal* tax savings from the depreciation bonus—not also the state tax savings—and they use a 10% discount rate.

The tax savings from a 100% bonus are twice these figures.

At least half of US states have "decoupled" from the depreciation bonus—they do not allow it to be claimed against state income taxes—and another group of states allows only a partial or delayed bonus.

A bonus cannot be claimed on property that is financed with tax-exempt bonds or that is leased to a government or tax-exempt entity or that is used predominantly outside the United States or US possessions.

Other Changes

Congress made a number of other changes in late December that will affect other energy projects.

The bill opened the door to place / *continued page 8*

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nally built in the late 1920's and that, starting in 1933, was the site of the annual Miss America pageant. The renovation work began in 1999. The state issued $49.5 million in bonds and used another $22 million from the New Jersey Casino Reinvestment Development Authority to fund the work.

Since East Hall is listed as a national historic landmark by the US government, the work qualified potentially for rehabilitation tax credits for 20% of the cost. The tax credits are claimed in the year the renovation work is completed. The state was not in a position to use the tax credits, so it essentially bartered them for capital to help fund the project in a tax equity transaction.

NJSEA leased East Hall from the Atlantic County Improvement Authority for 87 years at $1 a year. NJSEA then subleased East Hall to a partnership that was managed by NJSEA, but owned 99.9% by Pitney Bowes. The partnership paid $53.6 million for the property up front by giving NJSEA an "acquisition note" that bore interest at 6.09% and provided for level annual payments over 40 years. The payments were to be made on the note only to the extent the partnership had cash flow to make them. The parties reported the transaction as a sale of East Hall to the partnership for income tax purposes.

Pitney Bowes made capital contributions to the partnership of $39.4 million over four years. The partnership used the money to pay down the "acquisition note." As each payment was made on the acquisition note, NJSEA returned the amount to the partnership as a "construction loan," with the exception of $3.2 million from the second capital contribution. The partnership used the money to pay assorted fees plus a $14 million developer fee to NJSEA that stepped up the basis in the project for purposes of the tax credits.

The partnership allocated 99.9% of income and loss to Pitney Bowes. It had a more complicated arrangement for sharing cash. Pitney Bowes received cash first equal 3% of its declining capital account balance ***/ continued page 9***

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additional facilities for making "refined coal" in service and qualify for 10 years of tax credits on the output. "Refined coal" is coal that is less polluting than the raw coal used to produce it. Facilities put into service by December 2011 will now qualify for such tax credits.

It extended income and excise tax credits for ethanol, biodiesel, renewable diesel and alternative fuels at the existing rates, and the tariff on ethanol imports at the US border at the existing level, through December 2011.

Projects on Indian reservations will qualify for faster depreciation—for example, three-year instead of five-year depreciation for wind farms and solar projects—provided they are completed by December 2011.

The bill authorized another $5.3 billion in additional "new markets tax credits" in each of 2010 and 2011 as an inducement to make loans or equity investments in projects in census tracts with lower-than-average family incomes or poverty rates of at least 20%.

It gave utilities more time through December 2011 to shed transmission assets to independent transmission companies or regional transmission organizations and spread the tax on any gain over eight years. ◎

DOE Loan Guarantee Update

by Kenneth Hansen, in Washington

Negotiations with the US Department of Energy over loan guarantees for innovative and renewable energy projects have been moving much faster since a confidential White House memorandum critiquing the loan guarantee program leaked to the press in late October.

Numerous commitments to a broad variety of projects are expected to be announced in the next few weeks.

Guarantees are made in a two-step process.

First, a term sheet is negotiated leading to a conditional commitment for a guarantee. Then further negotiations of the full documents lead to issuance of an actual guarantee.

The pace of issuing actual guarantees has also picked up. The first "section 1703" loan guarantee for a project using an innovative technology (Solyndra: cylindrical solar photovoltaic panel manufacturing, $535 million) closed in September 2009. The second (Kahuku: wind power generation, $117 million) closed nearly a year later, in July 2010. Another closed in August (Beacon: a flywheel power storage plant, $43 million), with another in September (Nevada Geothermal: geothermal power generation, $98.5 million), which was the first closing under the "section 1705" program for a renewable energy power project using a commercially-proven technology (also known as the "Financial Institution Partnership Program" or "FIPP").

In December, the pace of closings accelerated dramatically, with four closings in two weeks (Abound Solar: solar panel manufacturing, $400 million; Shepherd's Flat: wind power generation, $1.3 billion; Abengoa: solar power generation, $1.45 billion; and AES Westover: battery storage, $17 million). These four projects together received $3.17 billion of the total $3.96 billion in DOE-guaranteed financing that has closed to date.

Most doors into the section 1705 program have closed for new applicants. The part I filing deadlines for all open solicitations have passed. The sole loan guarantee deadline still lying ahead is the final part II deadline under the solicitation for new manufacturing facilities that make "commercial technology renewable energy systems and components," which is January 31, 2011.

Congress recently gave a second wind to a number of section 1705 program applicants whose applications had found preliminary favor with the Department of Energy but who were depending also on section 1603 grants disbursed by the Department of the Treasury. Those grants required construction to begin by December 31, 2010, a deadline that was infeasible for some projects and required some others to commence construction ahead of what DOE's own process permitted, since projects qualifying for DOE loan guarantees must undergo a potentially time-consuming environmental review under the National Environmental Policy Act before they can start construction. With slippage of the section 1603 deadline to December 31, 2011, the critical path item has become the September 30, 2011 deadline both to start construction and to reach financial closure under the loan guarantee program.

Prospects

An intensified pace of conditional commitments and, in due course, closings should continue through the September 30, 2011 sunset for the section 1705 program. What happens then is open to speculation.

While, absent Congressional re-invigoration, the section 1705 program will pass into history, there are signs of renewed life for the section 1703 program for innovative energy projects. Unlike the section 1705 program, the section 1703 program has no legislative sunset. However, Congress must authorize additional guarantees or the program may not be in a position to invite new applicants. Whether Congress would offer fresh authorizations, and in what volume, is not clear.

Whether the section 1703 program would attract an adequate number of applicants has also been debatable as a consequence of three interplaying factors, all related to credit subsidy costs. Credit subsidy costs are premiums, like for insurance, that the government is required to pay, either from an appropriation or from amounts collected from companies benefiting from loan guarantees, to cover the cost of the program as a result of credit defaults. First, under section 1703, the applicants (rather than the Department of Energy) are responsible for paying credit subsidy costs. Second, although its credit subsidy calculations are state secrets, the Office of Management and Budget, an arm of the White House that must approve the determination of credit subsidy costs for any guarantees that are issued, is rumored to be biased toward estimating high credit subsidy costs. Third, because OMB makes those determinations only immediately pre-closing, applicants must invest in the whole DOE application and negotiation process without knowing a material cost of closing the financing.

To date, no sponsor has had to pay the credit subsidy cost for a loan guarantee. While six of the eight closed projects qualified for DOE support under the section 1703 program for innovative energy projects, all, including the two FIPP projects, also qualified under section 1705, and credit subsidy charges are paid by DOE from the section 1705 appropriation for projects qualifying for guarantees under that program. Constellation Energy withdrew its application at an advanced stage of its negotiation of loan guarantee terms for the Calvert Cliffs nuclear power generating project, reportedly because of OMB's preliminary indications of a high credit subsidy cost—which the project sponsors would have to pay. Given OMB's apparent high-balling of credit subsidy cost estimates, the prospect looms that project developers could find themselves subsidizing the government's participation in the section 1703 program more than the other way around.

In response, the renewable energy trade associations have lobbied Congress for an appropriation of funds to support credit subsidy costs along the lines of the expiring / continued page 10

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as a "preferred return." Cash was used next to pay debt service on the acquisition note and the construction loan from NJSEA plus loans that NJSEA made to cover any operating deficits in the partnership. Any cash beyond that would have gone 99.9% to Pitney Bowes.

There were two "puts" and a "call" that the IRS said meant that the Pitney Bowes interest in the partnership would be bought back by NJSEA soon after the five-year recapture period had run on the tax credits.

NJSEA had an option to buy the Pitney Bowes interest during a one-year window period starting five years after the renovated East Hall was put back into service for the fair market value of the Pitney Bowes interest, but not less than any part of the 3% preferred cash return that Pitney Bowes had failed to receive.

Pitney Bowes had two options to require NJSEA to buy it out. It could exercise one option for the first year of the deal before it had made significant capital contributions basically to get its capital back plus 15% interest. (It is not unusual in tax equity transactions that require the investor be a partner before a project is placed in service for the investor to put in just a small fraction of his eventual investment with an ability to get out if the project is not completed.) Pitney Bowes also had a put that could be exercised during a one-year window period starting seven years after the renovated East Hall was put in service if NJSEA failed to buy it out earlier. The option price was the same price NJSEA would have had to pay under its call option.

NJSEA invested $3.2 million of the amount it was paid under the "acquisition note" in a guaranteed investment contract with an insurance company and pledged it as security for its obligation to buy out Pitney Bowes should the company exercise its put.

The partnership guaranteed Pitney Bowes that it would receive the tax benefits that were promised. NJSEA was obligated to make capital contributions to the partnership to fund any payments on the guarantee. / continued page 11

DOE Loan Guarantees

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section 1705 program and as is typical in other federal financing programs.

Those prayers may be answered. The President's 2011 budget not only provides fresh authority for guarantees for qualifying projects, but it also earmarks $400 million to cover the credit subsidy costs of at least a portion of those guarantees. While that budget has not been enacted, the continuing resolution under which the government is spending money currently provided in an early version an appropriation for credit subsidy costs under the 1703 program, even though the continuing resolution that was ultimately enacted did not include that appropriation. The idea that the section 1703 program needs appropriated funds akin to other federal financing programs if it is to function effectively does, however, seem to have achieved some traction with the Congressional members and staff who have supported the DOE loan guarantee program. If such an appropriation is included in the 2011 federal budget when (and if) enacted, then the section 1703 program will have taken a huge step toward becoming part of the permanent landscape for financing innovative energy projects in the United States.

Experience negotiating loan guarantees with the US Department of Energy has taught six lessons.

Some Pointers

For those already in the loan guarantee pipeline, here are some lessons learned by your predecessors in that process.

Moderate your expectations.

Do not expect DOE to offer terms that reach to the edge of the statutory limits—i.e., leverage equal to 80% of project costs and tenor equal to the lesser of 30 years and 90% of the useful life of the financed assets. DOE's offer, if the application makes it that far, will reflect leverage based on a reasonably conservative view of the projected debt service coverage ratios and as short a tenor as negotiations (and adequate coverage ratios) will permit.

Expect cash sweeps.

Whatever DOE's offer by way of tenor, the reality will be somewhat worse. DOE has become enamored of cash sweeps, requiring a portion of cash flow available for debt service to be applied as a mandatory prepayment of the DOE-guaranteed loan. The consequence is that the applicant's base case will project less debt in place and for a shorter term than the negotiated leverage and maturity would suggest, with a possibly material adverse impact on the expected return on equity. To date DOE has resisted replacing prepaid debt with alternative project financing, absent prepayment in full of the DOE-guaranteed loan.

Section 1603 grants: what's mine is mine and what's yours is the project's.

DOE's preferred approach to section 1603 cash grants has become clear. Qualifying projects should be obligated to obtain those grants, use a substantial portion of the proceeds (at least a percentage equal to the percentage of project costs financed with DOE-guaranteed debt) immediately to prepay the DOE loan and retain the balance within the project accounts for a potentially indeterminate. That, particularly the third point, is not what project sponsors are likely to have in mind. What happens to those proceeds and when, is being hotly negotiated deal by deal. The outcome is likely to be quite different from what project sponsors imagined when they first heard about the section 1603 grant program.

Change of control matters—a lot.

The DOE wants to know with whom it is doing business. Even if successor equity holders satisfy extensive criteria addressing business qualifications and avoiding bad actors, DOE will want some level of discretion to disapprove, both before and after project completion, successors to the current project sponsors and other equity holders. While some carve outs from

DOE consent have been accepted in special circumstances (for example, public companies, investment funds and portfolios of projects), this remains a work in progress in which conventional commercial terms may not fly.

You must negotiate with people not in the room.

The project team is often in the unenviable position of relaying bad news from sources beyond its control—such as the credit committee, OMB, the Treasury Department or the program's senior management. The sponsors may have no opportunity to voice their objections to, or to make their case directly with, the source of positions that are problematic for the project. There, the experience of the DOE team can be hugely helpful as the DOE team becomes the project's advocates in navigating the inter-agency, and intra-agency, cross currents that affect the financing terms.

It's not the private sector.

That cuts both ways. That, of course, is the program's fundamental attraction, but it can also be the source of frustration. Public sector financing programs necessarily have certain non-commercial qualities. Some—like the program's motivations—will attract prospective users. The DOE's willingness to support innovative technologies and the availability of low interest rates are two non-commercial attractions of the DOE loan guarantee program.

Other non-commercial aspects are less attractive. Some of those are reflected in the "final rule," the formally-adopted federal regulations that govern the program. Although some of the more unworkable aspects of the rule (such as barriers to collateral sharing and to collective decisionmaking with co-lenders) were eliminated in amendments adopted a year ago, a number of other quirks (such as certain exclusions from the list of project costs eligible for DOE-guaranteed financing and in-kind contributions not counting as "equity" for purposes for the final rule) remain. The quirks have not proven to be fatal to the successful structuring of financings, however, and DOE has been both creative and sensible in finding ways forward notwithstanding impediments that might otherwise have been found in the regulations, which were adopted when the Bush administration opposed the legislation that originally established the program.

The program has learned some lessons—some too well.

The program is maturing. Each issue encountered in negotiating term sheets or final documentation is no longer novel. That's good news.

Not as good has been the tendency for / continued page 12

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The Internal Revenue Service made a range of arguments in an effort to deny Pitney Bowes the tax benefits. The US Tax Court disagreed with all of them.

The IRS argued that the transaction lacked "economic substance." Congress wrote a requirement into the US tax code in 2010 that transactions must have enough economic substance, apart from tax consequences, to be respected for tax purposes. This case preceded the effective date of that provision, but the courts had their own versions of the same rule. Tax Court looked to the version of the economic substance test that was being used by the US appeals court for the third circuit, which was closer to the test written into the US tax code than versions of the test used by some other appeals courts, and said it saw enough substance.

The IRS argued that Pitney Bowes was not a real partner. The court disagreed, saying Pitney Bowes was not a lender because it was not assured of repayment of its investment plus a 3% return.

The IRS argued that there was no real sale of East Hall to the partnership, the transaction was essentially a bare sale of tax credits—the offering memorandum had described it as a "tax credit sale"—and that the agency had the authority to invoke a "partnership anti-abuse rule" in its regulations to deny the tax benefits of the transaction. It also pointed to the fact that the partnership was a money loser apart from the tax credits. The court rejected all of these arguments, noting that the tax credits were supposed to induce investors to undertake what was otherwise an uneconomic activity.

The case is Historic Boardwalk LLC v. Commissioner. *It appears likely to be appealed.*

SECTION 48C TAX CREDITS may be lost if the project changes location.

The IRS awarded $2.3 billion in tax credits in early 2010 to solar panel, wind turbine blade and other manufacturers as an inducement to build new factories. The / continued page 13

DOE Loan Guarantees

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the DOE to declare as broad programmatic policies positions that were developed for the first project to pose the question. That can work well enough where what matters is that the program has a clear and consistent standard. Then one can plan appropriately. The fact that DOE now knows how it wants to approach a quite wide range of potential issues helps explain the quicker pace at which term sheets are currently being negotiated. The down side is that the program's emergent policies are at risk of being inappropriate for projects that pose similar questions in dissimilar contexts. It can be an uphill climb, and time-consuming, to persuade DOE that a predetermined policy is inappropriate in fresh circumstances.

Such growing pains are inevitable in a new financing program, but, for applicants trying to find workable terms, it can be challenging to be on the receiving end of new and unexpected policy pronouncements. An important judgment call in negotiating term sheets and final documentation is when to accept DOE policy requirements as just that—requirements that must be accommodated—and when to push back on putative policies as inappropriate for a given project. The good news there is that the loan programs office is well staffed with project finance professionals. They may not be able to address all your concerns, but they will at least understand them, which is half the battle.

A Final Note

Applicants under the commercial manufacturing solicitation will benefit from that solicitation's correction of some issues that plagued prior solicitations. Most importantly, unlike the FIPP, this solicitation permits direct borrowing from the Federal Financing Bank, an arm of the US Treasury, opening the way to attractive rates and minimizing the transaction costs of structuring a co-financing between the DOE and one or more commercial lenders. On the other hand, perhaps appropriately given the challenges of financing manufacturing projects, DOE has stepped away from presuming a limited recourse project financing model and notes a preference for projects that contemplate "full recourse to the balance sheet of the Applicant and/or a full guarantee from the Project Sponsor, a creditworthy parent or a third party acceptable to DOE." ◎

California Cap-and-Trade Program Takes Shape

by William A. Monsen, Sandhya Sundararagavan and Laura Norin, with MRW & Associates, LLC ,in Oakland, California

A cap-and-trade system for controlling greenhouse gases that the California Air Resources Board adopted on December 16 is expected to affect all GHG-emitting power plants in the state as well as companies that import power from other states for sale in California.

As this article went to press, the board—called "CARB"—had not yet published the final adopted resolution. Also, CARB staff will be developing important details of the cap-and-trade program over the next several months. Nevertheless, the broad outlines of the program are already clear enough to be able to comment on the effect on electricity generators.

The cap-and-trade system is one of the key tools CARB will use to meet strict greenhouse gas emission reduction targets that California set for itself in Assembly Bill 32. Under AB 32, California must reduce its GHG emissions to 1990 levels by 2020 and begin work toward a longer-term goal of reducing GHG emissions by 80% by 2050.

CARB expects more than 25% of the 2020 emissions reductions to come from the cap-and-trade system.

CARB expects additional emissions reductions (16% of expected 2020 emissions reductions) from a recently-adopted "renewable electricity standard" that requires both investor-owned and municipal utilities to supply 33% of their loads from renewable resources by 2020.

CARB will also rely on a massive expansion of end-use energy efficiency, GHG emissions standards for light-duty vehicles, a low-carbon standard for transportation fuels and a number of other programs to reduce GHG emissions to the levels required by AB 32.

Program Overview and Scope

The cap-and-trade program creates "allowances" for emitting greenhouse gas emissions, with the overall number of allowances being reduced each year. Each allowance represents the equivalent of a metric ton of CO_2 emissions.

"Covered entities" that are subject to the program must have allowances equal to the difference between their GHG emissions and any allowed offsets.

As the cap on the overall supply of allowances declines, the cost of allowances should increase, making emitting greenhouse gases more expensive. This, in theory, will provide covered entities with an economic incentive to improve operating efficiency or otherwise reduce emissions.

As presently structured, starting in 2012 so-called "first deliverers" of electricity (such as generators located in California or entities that sell imported electricity in-state) and certain large industrial facilities will be covered entities unless they receive exemptions from the cap-and-trade program. In 2015, the cap-and-trade system will expand to cover distributors of transportation fuels, natural gas, and other fuels. When the new covered entities join the program in 2015, the overall cap on GHG emissions will increase to accommodate the expanded program scope.

Entities that emit less than the equivalent of 25,000 metric tons of CO_2 per year are exempted from the cap-and-trade program. Exempted entities, such as low GHG-emitting renewable generators, may participate on a voluntary basis.

Mechanics

CARB will distribute allowances for free to certain covered entities.

Covered entities that do not receive from CARB enough free allowances to cover their emissions must purchase allowances from other entities. CARB will hold annual auctions at which covered entities can purchase allowances.

To reduce the cost of purchasing allowances, covered entities may use offsets to reduce the quantity of allowances needed for compliance by up to 8%. CARB defines offsets as the reduction or removal of GHG emissions not covered in the cap-and-trade program. CARB will closely scrutinize any offsets used by covered entities to ensure that the offsets are legitimate.

The cap-and-trade program is not expected currently to provide any free allowances to electric generators. However, CARB has instructed its staff to continue to consider whether it should provide free allowances to certain generators that are unable to pass the cost of allowances to their offtakers. CARB expects that these details will be worked out by July 2011.

It is expected that electricity costs will increase as generators pass along their allowance costs to their offtakers or as the utilities purchase greater levels of renewable resources under the renewable energy standard. */ continued page 14*

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credits are for 30% of the project cost. They are claimed on the cost of new equipment used to equip a factory that makes products for the new green economy.

However, a company risks losing the credits if there is a significant change from what it told the IRS it planned when applying for the credits. The IRS national office said in an internal memo written in April 2010, but not released until December 30, that companies are asking lots of questions.

Responding to the two most frequent questions, it said the credits are not at risk if the rights to the credits are transferred to a "successor in interest" to the project, including in a sale leaseback of the factory equipment within three months after it is first put into service, but what happens if the project changes location is more difficult. It said the issue when a company decides to put the factory some place else is whether that would have caused the US Department of Energy, which helped review the applications for tax credits, not to have chosen the company's project. It said the Department of Energy has promised to give a view on proposed changes on an "expedited basis."

The IRS has suggested privately that a company should compare the unemployment rates in the counties where the original project was supposed to be located and where it has been moved. If the unemployment rates are comparable and the number of jobs created in the new location is the same or greater than in the old location, then the relocation should normally not be a problem.

BRAZIL took steps in December to stimuluate the provision of long-term capital to infrastructure projects.

The country is host to the soccer World Cup in 2014 and to the summer Olympics in 2016.

It eliminated a 15% withholding tax at the border on interest that domestic borrowers pay to foreign lenders, provided the loans have an "average life," calculated ***/ continued page 15***

Cap and Trade

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The cap-and-trade program will provide no-cost allowances to the state's investor-owned and municipal utilities. The investor-owned utilities must sell their free allowances in the annual CARB auctions and use the proceeds from these sales for specific actions to help mitigate costs of the GHG program to their customers. If the investor-owned utilities' own power plants need allowances to comply with the requirements of the cap-and-trade program, the utilities must purchase these allowances in the CARB auction; they cannot use their free allowances for program compliance. Municipal utilities have the option either to sell their allowances in the CARB auction or to use them to cover the allowance requirements for their own power plants.

Costs and Cost Control

It is hard to predict how much allowances will cost. The California Public Utilities Commission has proposed using three different allowance price forecasts in its current long-term procurement proceeding, with allowance prices in 2020 ranging from \$32.44 to \$54.06 per ton (see Table 1).

Table 1: GHG Allowance Prices Assumed by the CPUC (in nominal dollars per metric ton)

Year	Low Carbon Price Estimate	Base Carbon Price Estimate	High Carbon Price Estimate
2011	0	0	0
2012	10.00	10.44	13.05
2013	13.37	17.83	22.29
2014	15.81	21.08	26.35
2015	18.26	24.35	30.44
2016	20.93	27.91	34.89
2017	23.62	31.49	39.36
2018	26.53	35.37	44.21
2019	29.47	39.29	49.11
2020	32.44	43.52	54.06

While CARB cannot directly control allowance prices in its auctions, it does have ways to try to influence the price, if needed.

To ensure that allowance costs are not so low that they provide little incentive for covered entities to reduce their GHG emissions, the cap-and-trade program has a floor price for allowances sold at auction. This floor price starts at \$10 per metric ton of CO_2 and increases each year at inflation, as measured by the Consumer Price Index, plus five percentage points.

To prevent costs from rising too high, CARB will hold a certain number of allowances in reserve (123.5 million allowances out of 2.7 billion allowances issued through 2020). CARB will use these allowances to increase market supply if allowance prices spike at auction. Some stakeholders are worried that the proposed reserve will not provide adequate protection against high prices.

CARB also established other rules to give covered entities an opportunity to control the cost of compliance. Covered entities can buy their allowances up to three years at a time rather than annually, and they may bank allowances in excess of their compliance obligation in the event that lower-cost allowances become available. They may also use offsets in place of allowances to meet up to 8% of their compliance obligations. Since offsets are expected to cost less than allowances, this could reduce overall compliance costs for some entities.

Interaction with Regional Program

The CARB cap-and-trade program is the first mandatory cap-and-trade program in the western United States, but it has not been developed in a vacuum.

California has been an active participant in the Western Climate Initiative or "WCI," a cooperative effort to reduce GHG emissions on a regional basis. California's rule development schedule is being coordinated with the WCI timeline for development of a regional cap-and-trade program.

In order to enable trading across jurisdictions, WCI has proposed a number of program elements that CARB has included in its cap-and-trade program, such as allowance banking, limited offsets, three-year compliance periods and auction floor prices. These linkages will allow California entities to trade allowances freely with entities covered by cap-and-trade programs in other WCI partner jurisdictions. It is currently expected that California entities will have trading partners in four WCI partner jurisdictions in 2012: New Mexico, British Columbia, Ontario and Quebec. CARB is working with five other states and one other Canadian province that are planning cap-and-trade programs that will not be operational until after 2012. ◎

California Settlement Settles Old Scores and Charts New Paths for Generators

by Bob Shapiro, in Washington

After a year and a half of protracted negotiations among utilities, wholesale generators and consumer advocates, the California Public Utilities Commission approved a global settlement in December about how the federal Public Utility Regulatory Policies Act—or "PURPA"—will apply in the state.

Among other things, the settlement will resolve outstanding pricing disputes with independent power plants, called qualifying facilities or "QFs," from whom PURPA requires utilities to buy electricity, establish the methodology for future energy pricing based on short-run avoided costs or "SRACs" for such power plants, establish a process for future procurement of power from QFs and CHPs—combined heat and power, or cogeneration, facilities that meet certain efficiency and environmental standards under federal and California law—and allow utilities to avoid a mandatory purchase obligation under PURPA for QF projects above 20 megawatts in size.

Background

PURPA is a federal law passed in the late 1970s that requires utilities to offer to purchase the output from QFs —generators up to 80 megawatts in size using renewable fuels and cogeneration facilities of any size—at the utility's "avoided cost," or what it would otherwise cost a utility to produce the power itself or procure it from another source.

Cogeneration facilities are facilities that simultaneously and sequentially produce electricity and a form of useful thermal energy such as steam or heat.

CHPs are cogeneration facilities that also meet more stringent California environmental and efficiency standards under a state law called AB 1613.

CHP systems under California law must be designed to reduce waste energy, must preserve at least 60% of the energy content in the fuel they use during conversion into electricity, have NOx emissions of no more than 0.07 pounds per megawatt-hour, be sized to meet the eligi- / continued page 16

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under special rules, of at least four years.

The loans must be made by December 2015. The borrower cannot have a right to prepay in the first two years. The interest payment periods must be at least 180 days. The lender cannot be in a tax haven or other country where the interest income faces a maximum tax rate of 20% or less.

Domestic individuals and corporations who make similar loans through special infrastructure funds to projects that are considered priorities by the government will also be given tax breaks. Individual investors will be exempted from the current 22.5% income tax on their returns and the corporate rate will be reduced from 34% to 15%.

In a move to attract more investment by foreign private equity funds, the government reduced a financial operations tax called the IOF tax from 6% to 2% on investments made by such funds, and it waived the five-year minimum hold period to qualify for an exemption from capital gain taxes upon exit.

Details of the new measures are in Provisional Measure 517/2010 and were published in the official gazette on December 31.

SOUTH AFRICA is moving to impose taxes on carbon emissions.

The Treasury Department posted a 75-page discussion paper to its website in early January on which it is collecting comments through the end of February.

The paper lists three options, but suggests the most likely is a direct tax on carbon emissions. The other two options are an input tax on fossil fuels and an output or sales tax on products sold by companies using fossil fuels. Any direct tax on carbon emissions is expected to start at R75, or $11.20, a ton, and escalate to R200, or $30, a ton.

The cabinet approved the paper before publication.

South Africa will host the next round of climate change talks in / continued page 17

PURPA

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ble customer generation thermal load, operate continuously in a manner that meets the expected thermal load and optimizes the efficient use of waste heat, and be cost effective, technologically feasible and environmentally beneficial.

Specifics of the Settlement

Dropping pending claims if FERC eliminates the purchase obligation:

Under the global settlement, the investor owned utilities agreed to drop claims for retroactive adjustment of payments made under certain QF contracts, provided the Federal Energy Regulatory Commission grants a request by the utilities to terminate their mandatory purchase obligations for QFs above 20 megawatts in size. The settling parties have agreed not to challenge this request. Under an amendment to PURPA in 2005, FERC was given the authority to terminate the mandatory purchase obligation if it found that the relevant energy markets are workably competitive. It is expected that FERC will grant this request.

Impact on existing PPAs:

Existing QFs with "legacy PPAs"—meaning any power purchase agreement that is in effect at the time the new settlement goes into effect—will have the option to choose to enter into a legacy PPA amendment within 180 days after the settlement takes effect. The Federal Energy Regulatory Commission must approve certain aspects of the settlement before it can take effect. This is expected in mid-2011.

The legacy PPA amendment must allow the QF to choose an energy pricing methodology option going forward until January 1, 2015. Independent generators with fixed energy rates in their PPAs will be allowed to continue to collect them until the rates expire.

There are least five pricing options, all of which are tied to the utility's delivered cost of natural gas. The generator can switch to the new SRAC methodology, which has fixed, declining heat rates, a variable operation and maintenance component, an adjustment based on location in relation to load and a price adjustment if greenhouse gas or "GHG" costs are imposed on the facility, all until December 31, 2014, after which the SRAC will be tied only to a formula with energy market heat rates, called the "settlement SRAC." Another option uses the same formula but somewhat higher heat rates and no GHG cost adder. The third option is to use the same formula but with heat rates between the heat rates in the first two options and a fixed greenhouse gas payment of $20 a metric ton for greenhouse gas emissions allowances used by the seller of the electricity. The next option is the same, but with the GHG allowance costs tied to actual GHG costs imposed on facility capped at $12.50 per metric ton. The last option is to choose a 90-day negotiation period to see whether parties can turn the PPA into a tolling agreement on agreed terms.

If a QF chooses not to enter into a legacy PPA amendment, then the pricing under the existing PPA contract will be the settlement SRAC.

Under the terms of the settlement, once the term of a legacy PPA expires, the utility will have no obligation to purchase power from the QF if it has a generating capacity above 20 megawatts, but the utilities have agreed to conduct solicitations for QF output. QFs below 20 megawatts will be entitled to SRAC pricing and capacity payments determined by the CPUC.

Impact on existing CHP projects:

Cogeneration projects with existing PPAs with utilities under a legacy PPA will be able to enter into a transition PPA until July 1, 2015. The energy will be priced at the settlement SRAC. The capacity price will be $91.97 per kW-year for firm capacity and

California approved a global settlement in December about how PURPA will apply in the state.

$41.22 per kW-year for as-available capacity, subject to annual escalation.

What happens in the longer term:

There will be no standard offer PPAs for QF projects above 20 megawatts. However, the three investor-owned utilities in California (Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric) have agreed to issue a series of solicitations for a combined target of 3,000 megawatts of QF and CHP capacity. The solicitations are supposed to result in PPAs that will meet both the megawatt target and greenhouse gas reduction goals specified under California law. The California Air Resources Board, in implementing the state's greenhouse gas law known as AB 32, set a target of installation of 4,000 megawatts of CHPs by the end of 2020. The initial program period of the Settlement is 48 months from the date the settlement takes effect. If less than 3,000 megawatts of power contracts are signed by the end of the initial program period, then the unprocured amount will be rolled over into a second program period to reach the 3,000-megawatt target.

Although not addressed in the settlement agreement, renewable QFs will continue to be eligible to participate in solicitations the investor-owned utilities are required to run to satisfy the state renewable portfolio standard.

What happens in the shorter term:

The settlement agreement includes five pro forma power purchase agreements.

There is a form of legacy PPA amendment, which, as noted earlier, relates to optional energy pricing that a QF with an existing PPA can elect to sign within 180 days of the effective date of the settlement.

There is a transition PPA that is available to any existing CHP facility with an existing PPA. The transition PPA term will begin on the expiration of the existing PPA and may be terminated upon 180 days' notice when a CHP facility has signed a new PPA resulting from either a solicitation or a bilateral negotiation.

There is a CHP request-for-offers PPA that will be used to solicit competitive offers from CHP generators. Each IOU must initiate a request for offers within 180 days after the effective date of the settlement for purchases from existing, new or expanded CHP facilities over five megawatts in size using this form of PPA. To be eligible for the solicitation, the CHP must satisfy the qualifying cogeneration facility criteria under FERC's regulations implementing PURPA. The term of the PPA will be up to seven years or 12 years, depending on the / continued page 18

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Durban in late November. The last round was in Cancun, Mexico in late 2010.

A CANADIAN APPEALS COURT allowed General Electric Capital Canada, Inc. to deduct C$136.4 million that the company paid its US parent company to guarantee debt of the Canadian subsidiary.

The Canadian subsidiary paid the US parent a fee of 1% of the guaranteed amount. The appeals court said the fee paid was reasonable after concluding that an explicit guarantee by the US parent lowered the borrowing cost of the subsidiary by 183 basis points. The Canadian tax agency had argued that the guarantee added no value.

The court released its decision in mid-December. The case is The Queen v. General Electric Capital Canada Inc. The government has 60 days to appeal.

THE EUROPEAN COMMISSION is looking into charges that a special "economic crisis tax" that Hungary imposed in October violates European Union law.

The tax applies to energy, telecom and retail companies and is a special levy on annual net revenue. It is supposed to remain in place through 2013.

Thirteen companies, including several large power companies, have complained to the commission that the tax targets sectors with fixed infrastructure investment in Hungary, while letting off other businesses that can be easily moved.

FOREIGN CORRUPT PRACTICES ACT prosecutions have stepped up noticeably in the United States.

Greg Andres, acting deputy attorney general in the criminal division at the Justice Department, told a Senate subcommittee hearing on November 30 that the US has collected more fines in the last two years for FCPA violations than in any previous period. / continued page 19

PURPA

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type of facility and credit requirements that the facility owner agrees to provide.

Alternatively, a CHP facility over 20 megawatts in size may sign an "as-available CHP PPA," provided that its average annual deliveries do not exceed 131,400 mWhs, the project host consumes at least 75% of the total electricity generated by a topping-cycle facility or at least 25% of the total electricity generated by a bottoming-cycle facility. Fora topping- or bottoming-cycle facility using supplemental firing, the facility must meet at least a 60% efficiency standard. The seller under an as-available CHP PPA will get an as-available capacity price and a time of delivery energy price and must provide performance security. If the seller is selected later in a solicitation, the seller can terminate the as-available CHP PPA.

Finally, there is also a standard form PPA that will be available for QFs that are up to 20 megawatts in size, whether or not the QF has submitted an offer in the CHP request for offers or seeks alternative contracting options. This PPA will use the settlement SRAC for the energy price and contain specified as-available or firm capacity payments.

The settlement also gives the investor-owned utilities additional flexibility to undertake bilateral contracting, use feed-in tariffs authorized by California law AB 1613 (for CHP projects), continue the PURPA program for QFs smaller than 20 megawatts in size and allocate up to 10% of the CHP capacity for utility-owned projects for GHG reduction purposes but not for meeting the 3,000 MW requirement.

The investor-owned utilities insisted that their agreement to procure new resources in this way must be conditioned on the assurance by the CPUC of a non-bypassable passthrough of PPA payments. The CPUC granted this request in its order approving the settlement.

Elimination of the IOU mandatory purchase obligation:

With the approval of the global settlement, the investor-owned utilities will file an application with FERC requesting termination of their mandatory purchase obligation under PURPA for projects with a net capacity above 20 megawatts. The other settling parties can comment on, but have agreed not to protest, the application. The settlement agreement also gives the other settling parties the right to ask FERC to reinstate the mandatory purchase obligation under PURPA if an investor-owned utility breaches its obligations under the proposed settlement or the CHP program is not successfully implemented. In the event FERC reinstates the mandatory purchase obligation, the obligation of the utilities under the settlement agreement to issue requests for offers from CHP projects to meet megawatt and GHG targets would be suspended. ◎

Master Financing Facilities for Solar Projects

Small solar photovoltaic systems mounted on rooftops or on the ground near houses, big box stores, commercial office buildings and schools are best financed by setting up a "master financing facility" and using it to fund construction of a series of installations rather than trying to finance one at a time. There are three basic structures in use in the US market for doing this. Three solar developers and two bankers whose banks are active both as lenders and as tax equity investors participated in a roundtable discussion on financing distributed solar projects at an Infocast conference in San Diego in December. The following is an edited transcript.

The panelists are Matt Cheney, chief executive officer of Clean Path Ventures, Phil Henson, senior vice president and chief financial officer of Solar Power Partners, Michael Streams, general counsel of Perpetual Energy Systems, Daniel Siegel, a senior representative from US Bank, and Gregory Rosen, vice president of solar finance with Union Bank. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Matt Cheney, an interesting article in the business section of *The New York Times* a week ago talked about the business model that Clean Path Ventures is using. You are offering homeowners plots in "solar gardens." Explain how that works.

Solar Business Models

MR. CHENEY: The concept is to build distributed wholesale generation in small increments in and around suburban and urban areas. The power is sold to the grid, but each power plant is owned by a group of local businesses and homeowners.

The idea is to find a way for people who live in older neighborhoods with tree canopies who would like to own and control their power plants, but without having to put them on their rooftops, can participate in solar. An example is in Davis, California where the city has spent the last five decades diligently growing a canopy over the community. The city is hard pressed to look at programs that promote individual installation of systems on rooftops to the extent that it would lead to cutting down trees. The temperature reaches 110 degrees in the summer, but it is 70 degrees in the shade. It is a dry heat.

MR. MARTIN: You grew up in Davis, if I read correctly in *The New York Times*. There were lots of trees. It's not an appropriate place to put panels on roofs, so you build a 20-megawatt solar power plant outside the tree canopy, and what does each participating homeowner or business owner get? He buys an interest in the power plant?

MR. CHENEY: That's right. He buys the equivalent of a garden plot in a family farm.

MR. MARTIN: Does he receive the electricity directly from your company or does he buy it from the local utility, PG&E?

MR. CHENEY: He owns that garden plot in the family solar farm and can visit his panels. However, the linkage is through a legislative remedy. In this case, there is a bill credit arrangement in California that allows solar "farmers" to sell power to PG&E and have that power show up as a generation credit to a municipal meter. The legislation in the public utilities code needs to be expanded to include other customers. We think it can be, and we are working to promote that.

MR. MARTIN: The homeowner pays you money for a section of the solar array. You sell the electricity to PG&E. The homeowner receives a credit from PG&E for its share of the electricity?

MR. CHENEY: That's right. The homeowner would pay us in the case of the Davis project. He would pay us through the city because the city sells services to its commercial and residential customers. The city acts as a central collection agent. There is no separate bill from us to the homeowner.

MR. MARTIN: I imagine such a project could be a challenge to finance. You have lots of individual owners each owning a small piece of a large solar array. Have you tried yet to secure bank financing for such a project?

MR. CHENEY: This gets into the dirty little underbelly of solar finance. The idea is that a single entity through which homeowners and business owners have an interest in the project controls the plant. The plant is repossessible. It can be refurbished. Interests can be sold at the entity level to another customer. That sidesteps the issue of credit. / *continued page 20*

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The statute dates back to 1977 and makes it a crime for US companies and individuals to offer anything of value to foreign government officials in an effort to win or retain business or secure any improper advantage.

The World Bank estimates that more than a trillion dollars in bribes are paid each year, or about 3% of the world economy.

Senator Arlen Specter (R.-Pennsylvania) used the hearing to urge the government to try to send more individuals to jail. He said that fines become simply a cost of business and end up being borne by the shareholders. (Specter was defeated for reelection in November.)

One of the other two Senators at the hearing—Amy Klobuchar (D.-Minnesota)—expressed concerns that it is not always clear to US companies where lines are drawn. The other Senator, Chris Coons (D.-Delaware), said more needs to be done to get other countries to prosecute bribes so that American companies are not at a disadvantage.

Two former US prosecutors, one representing the US Chamber of Commerce, said the statute should be clearer about who is considered a foreign government official. The Justice Department treats employees of state-owned enterprises as such officials. The witnesses said Congress did not intend for them to be covered.

The Chamber of Commerce also urged Congress to amend the law to allow companies that turn themselves in to avoid prosecution. Currently, companies that turn themselves in after finding wrongdoing by employees have no guarantee this will not lead to prosecution. The Justice witness said the government does not believe a bank robber who confesses should be let off. The Chamber witness urged that there be a distinction between companies whose culture encourages or turns a blind eye to bribery and those that actively discourage it, but discover rogue employees and inform the government.

CHINESE WIND SUBSIDIES are being challenged by the United States **/ *continued page 21***

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You have the ability to make these assets more mobile to new customers.

MR. MARTIN: We would need a lot more time than we have this morning to dig into this properly, but it is an interesting concept. Michael Streams, Perpetual Energy Systems has installed solar systems for wineries, schools and some cities. How would you describe your business model? You retain ownership of the systems? Do you contract to sell the electricity to customers or do you lease customers the equipment? For how long a term do you contract with customers?

Three main types of master financing facilities are in use currently in the distributed solar market.

MR. STREAMS: Perpetual has been focused in the past primarily on distributed-scale solar projects, but it is moving to do more utility-scale projects. We develop, own and operate the projects. We enter into power contracts with customers.

The company's roots are in the low-income housing market. The principals are experienced with use of tax credits to generate capital. The company started in the solar business in July 2008. We currently have 10 megawatts of installed solar capacity. All of the projects were financed using a master financing facility.

MR. MARTIN: How long a term is your typical power contract?

MR. STREAMS: Our typical contract is 25 years, although they have been as short as 15 years and as long as 30 years.

MR. MARTIN: What happens at the end of the term? Do you take back the equipment?

MR. STREAMS: The customer has an option to purchase the system at the end of the term. The exercise price is greater than what it would cost to relocate the system.

MR. MARTIN: You don't have a choice of customer arrangements when dealing with cities and schools. You must sell them electricity rather than lease them the equipment or you will forfeit the ability to claim an investment tax credit and accelerated depreciation on the systems. However, you do have a choice with wineries. Why use power contracts with wineries?

MR. STREAMS: It works. Our power contract meets the underwriting criteria of banks and tax equity investors. It is a familiar instrument. It produces a predictable revenue stream over time.

MR. MARTIN: Phil Henson, Solar Power Partners is heavily focused on schools, but it also installs systems on grocery stores. What is your business model? Do you use power contracts or leases with customers? How long a term?

MR. HENSON: We use power contracts mostly. We have a mix of distributed systems with commercial and municipal customers and some utility-scale projects. Our strategy has been evolving over time. The earlier projects in our portfolio were more heavily weighted towards the smaller commercial customers like grocery stores. We have been moving toward larger offtakers like universities, schools, water districts, airports and utilities.

In terms of a power contract versus a lease, we offer both forms. We are fairly indifferent. We do not see much difference from either an accounting or a legal point of view. The contract terms are typically 20 years, but with some longer and some shorter.

MR. MARTIN: Going back to Matt Cheney, you told me before our session that the solar garden is a small part of your business plan. What is your main business model?

MR. CHENEY: The main business model is pretty simple. We come in at some point in the development cycle to put everything together, work out all the details and the elements of a successful project, boost it up into construction, and get the thing built. In this case, instead of doing what we have had to do in the past, and that is to operate as an independent power producer to own and operate assets over a term, we use the strong asset management skills that we developed going back

10 years and that we used to build well over 50 projects for MMA Renewable Ventures and then Fotowatio Renewable Ventures.

Clean Path is focusing on representing buyers in the market place to look for assets and act on their behalves to organize projects, derisk them, get them built and then transfer them over. We have a significant amount of obvious expertise but also development capital—we call it shock development cash—pretty much to do every job.

MR. MARTIN: Phil Henson, you said Solar Power Partners is moving toward doing more deals with municipalities. What's the attraction? I know as a lawyer it can be hard to work through all of the local regulations to get hired, and I imagine it is the same thing for a solar developer.

MR. HENSON: It is. Nevertheless, there are two attractions. One is the system sizes tend to be larger. We end up building a one-megawatt system for a water district as opposed to a 200-kilowatt system for a grocery store. The other attraction is it is a better story for senior lenders from a credit point of view. Most of them can get their arms around a rated municipal entity more easily than a corporate entity particularly if it is a smaller, unrated corporate entity.

MR. MARTIN: Are you worried about the declining credit quality of municipalities?

MR. HENSON: It is certainly a long-term credit issue from a financing point of view, but on the whole, municipalities have stood the test of time, so fundamentally no.

Master Financing Facilities

MR. MARTIN: Michael Streams, you said that you use a master financing facility to finance your projects. What type of arrangement is it?

MR. STREAMS: We group our smaller systems into a portfolio. The financing facility assumes there will be a series of projects with staggered commercial operation dates. Bundling projects together in this fashion reduces the overall risk profile.

MR. MARTIN: Do you raise debt and tax equity in the same facility?

MR. STREAMS: Yes. In fact, Dan Siegel of US Bank and I are in such a facility now. We closed the first few projects of that facility on the tax equity side.

MR. MARTIN: And US Bank is both the lender and the tax equity investor?

MR. STREAMS: In this instance, it is both the tax equity investor and the lender. We've done it before / continued page 22

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in a complaint to the World Trade Organization.

The US trade representative filed a formal complaint on December 22 against China for requiring manufacturers of wind turbines in China to use Chinese-made parts and components as a condition to receiving government grants. The grant program has been in effect since 2008.

The US requested consultations with China under the WTO dispute settlement procedure, and discussions are expected to take place this month. If consultations do not resolve the dispute, then the US can request a WTO panel of judges to rule on the issue.

The complaint followed an investigation into China's renewable energy trade practices at the urging of the US steelworkers' union. The WTO complaint addresses only part of the steelworkers' allegations. Others were addressed during the investigation. In December, China agreed no longer to require foreign companies to have prior experience supplying large Chinese wind power projects in order to obtain approval for new wind projects. It now will recognize companies' experience outside of China. Other subsidy programs were found to have been discontinued.

Some parts of the steelworkers' petition remain under investigation, including China's practices regarding "rare earths"—- metals that are key for manufacturing many clean energy technologies. In a December 23 report to Congress regarding China's WTO compliance, the US trade representative expressed disapproval of China's export restraints on rare earths and said that it could take further action, including filing another complaint with the WTO.

The wind turbine proceeding could lead to US duties on Chinese products. The US trade representative is accepting public comments during the course of the settlement talks. To be considered, comments should be received by January 31.

SOLAR PANELS and batteries that a utility plans to install in some customer / continued page 23

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where we have used a different term debt lender.

MR. MARTIN: To help the audience follow the discussion, a master financing facility is a financing facility where the financiers agree to finance every project that the developer puts in service between now and some date in the future up to some dollar amount as long as the developer can check off a list of 10 or 12 items on a checklist. Each project is acquired by the master financing entity either at the start of construction or closer to when it goes into service.

MR. STREAMS: Yes, that's the plan.

MR. MARTIN: There are three different versions of such facilities in use in the distributed solar market. There are master sale leasebacks, master partnership flips and master inverted leases. Which of those three are you using?

MR. STREAMS: We use the inverted lease structure to raise tax equity. We lease the systems to the tax equity investor. The term debt is a distinct and separate facility. We borrow from the lender.

MR. MARTIN: Describe for the audience how an inverted lease works.

MR. STREAMS: Without going into too much detail because the structure has a lot of moving parts, you basically have a lessee and a lessor, and there is a master lease agreement between those two entities. The lessor owns the projects for tax purposes. It elects to pass through to the lessee all the tax credits. The lessee sells electricity to customers, collects revenue and pays most of it to the lessor as rent for use of the solar equipment. The depreciation on the equipment remains with the lessor.

MR. MARTIN: An inverted lease is like a yo-yo. The developer puts the equipment out on a string to US Bank. It leases the equipment from the developer. When the lease ends, the developer pulls the equipment back.

MR. STREAMS: The structure has been used for at least 13 or 14 years. It is the old sandwich lease structure that has seen heavy use in renovations of historic buildings where the federal government provides tax credits. Actually, your firm represented us in our first three transactions, although I don't believe you gave a tax opinion.

MR. MARTIN: Of the three structures—sale leaseback, inverted lease, partnership flip—why have you gravitated toward the inverted lease?

MR. STREAMS: It allows us to keep some of the depreciation and shed just the investment tax credits.

MR. MARTIN: Phil Henson, which type of master financing facility has Solar Power Partners used?

MR. HENSON: We have used both the partnership flip and inverted lease structures, and we are currently evaluating whether to do a sale leaseback for our next portfolio. We look for whichever approach will give us the best return.

MR. MARTIN: Let's fill in the rest of the pieces for the audience. In a partnership flip, the developer brings in a tax equity investor as a partner and the two of them own all the projects and deal directly with the customers. In a sale leaseback, the developer sells the assets to the tax equity investor and leases them back. The developer deals with the customers directly.

MR. HENSON: That's right.

Sale leasebacks raise 100% of the project cost in theory, but less in practice because a portion of the rent must be prepaid.

How to Choose

MR. MARTIN: How do you choose among the three structures?

MR. HENSON: It boils down to the numbers.

MR. MARTIN: Is there a difference in the percentage of capital cost that you are able to raise with each structure? For example, a sale leaseback raises 100% of the cost of the systems. A partnership flip raises something less.

MR. HENSON: The sponsor has to put in some equity with the partnership flip and inverted lease, but that is also true these days of a sale leaseback where the sponsor, as lessee, must usually prepay part of the rent.

MR. MARTIN: The return you get as a developer is the key to which structure you choose. Is there another factor that is a close second?

MR. HENSON: We want a structure that is easy to execute and administer. Transactional friction is a huge issue in all three structures. They all are complex structures, and particularly when you are trying to bring senior debt into the structure together with tax equity, the interplay between those two often leads to additional transaction time and cost. The cost to get the deal executed is the other critical factor.

MR. MARTIN: Matt Cheney, you tried a number of strategies while you were heading MMA Renewable Ventures.

MR. CHENEY: The partnership flip structure is more efficient in a general sense; it produces more value out of a deal for us. However, if you try to combine tax equity with debt in such a structure, the tension between the lender and the tax equity investor strips out a lot of the value and, as a result, anyone toying with using a leveraged flip would do well to try to have the leverage come from the same tax equity investor as that will provide a much more efficient solution. I think that's where pretty much everything is headed.

MR. MARTIN: Why do you feel a developer gets more value out of a partnership flip?

MR. CHENEY: First and foremost, the asset remains controlled and largely owned by us. It is not on the customer's balance sheet, so there is no friction there. We are in a reasonably good position at some point to cash out the tax equity, restructure the deal around our own ownership and, if necessary, bring in lower-cost capital. With leasing solutions, set payments are harvested every month for the term of the lease period. More of the value remains with the tax equity investor. We don't completely control the project.

Current Yields

MR. MARTIN: Michael Streams, we have been talking about using both debt and tax equity. What debt and tax equity rates are you seeing today in the market?

MR. STREAMS: They are all over the place. In earlier days, we benefitted from debt rates that were maybe 200 or 250 basis points above LIBOR. Now I think we are in the 350 to 375 -basis-point range. / continued page 24

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homes as part of an experiment to test different approaches to energy conservation do not have to be reported by the homeowners as income, the IRS said.

The customers will be given the equipment to own.

The utility will also install smart meters to help customers monitor how they are running up charges for electricity.

Normally when someone is given something of value by someone else, he must report it as income. However, a special provision in section 136 of the US tax code spares homeowners from having to report utility rebates to reduce electricity or natural gas usage in a home. The IRS said in a private ruling released in late November that the solar equipment in this case is covered by that section.

The ruling is Private Letter Ruling 201046013.

GRANTS normally must be reported by grant recipients as income, but not grants paid by the US Department of Energy to manufacturers of electricity storage devices and related components, the IRS said.

The IRS made the announcement in Revenue Procedure 2010-45 in November. The Department of Energy was given $2 billion for such grants as part of a series of economic stimulus measures authorized by Congress in early 2009.

GERMANY took steps in late November to shut down the use of Maltese holding companies to make outbound investments.

A large majority of German blue chip companies have such holding companies.

The new rules took effect on January 1.

Basically, Germany modified how it determines whether passive income received by an offshore holding company is subject to tax in the country where the holding company is located at less than a 25% rate. Tax at less than that rate would cause Germany to look through the holding company and tax the German owners of the holding company / continued page 25

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MR. MARTIN: Is there an additional up-front fee and, if so, how much?

MR. STREAMS: Up-front fees range from 1% for construction financing and up to 3% for term debt. It depends on whom you are dealing with. We have been dealing a lot lately with US Bank and find its terms attractive, but we have also been speaking with several European banks who are interested and have experience with this type of portfolio financing and may be a little more aggressive, especially with regard to tenor.

MR. MARTIN: What tenor are you getting?

MR. STREAMS: The US-based banks have been offering loans mainly of seven to 10 years in length, but we are starting to see tenors going out to as far as 25 years or the length of the power purchase agreement.

MR. MARTIN: In the institutional debt market but not in the bank market, correct?

MR. STREAMS: Correct. Bank tenors are going out as far as 17 years in the case of a couple European banks.

MR. MARTIN: Turning to tax equity yields, do you know how much you are paying for tax equity?

MR. STREAMS: Yes, we know how much we're paying.

MR. MARTIN: You don't want to share it with the group? [Laughter] Is it above or below 9% after tax?

MR. STREAMS: Above.

MR. MARTIN: Phil Henson, do those rates sound similar to what you are seeing currently in the market?

MR. HENSON: Yes. We are seeing between 7% and 7 1/2% for debt, which would swap back to LIBOR plus 250 to 350 basis points, and we are seeing some banks willing to go longer tenors as they try to break into this market. It is not just the institutional guys who are willing to go 15 to 20 years.

MR. MARTIN: And the cost of tax equity is?

MR. HENSON: I would say also just above 9%.

MR. MARTIN: Matt Cheney, what are developer yields? John Eber with JPMorgan Capital Corporation was on a panel at the Solar Power International convention that I moderated in October, and he said it is hard for the financiers to see where the developers are earning their returns. That has been a common comment from financiers in this market.

MR. CHENEY: Developers have one essential source of revenue. In the old days you might have had firms gunning for north of 20%, maybe north of 30% as a developer fee. Developer fees of that size are harder these days to get. At the end of the day, there is only so much left.

The Treasury Department has weighed in lately with what it is prepared to accept as the tax basis for calculating Treasury cash grants and, indirectly, how much of a developer fee is acceptable. This is pushing developer fees to a lower level than they might have been historically. We also have heard a lot about "zombie" deals being done in the market at levels strictly to capture market share, and those projects tend to be very lean.

MR. MARTIN: Are developer returns in the current market in the high single digits?

MR. CHENEY: They are probably a little lower than that.

MR. MARTIN: Michael Streams or Phil Henson, any comment?

MR. HENSON: I would say unlevered returns for distributed generation projects in the commercial and municipal sectors are in the 9% to 12% range and much lower for distributed utility projects, perhaps 6% unlevered, which probably translates on a levered basis to 10% and 15%.

MR. MARTIN: Michael Streams, same numbers?

MR. STREAMS: Yes. We attempt to structure our projects in such a way that the sponsor equity requirement is as minimal as possible, and sometimes we are able to achieve that by

Developers of solar photovoltaic projects are paying 7% to 7.5% for debt and more than 9% for tax equity.

pulling down developer fees at closing, but it not always possible with capital-intensive projects.

Tax Equity Investors

MR. MARTIN: Let me pull in the bankers, starting with Dan Siegel from US Bank. US Bank pioneered the use of the inverted lease in the distributed solar market. There are rumors that US Bank is running out of capacity to use capital losses, which are part of that structure, and that it is now moving to another structure, perhaps a partnership flip. Is there any truth to those rumors? What is your preferred structure at this point?

MR. SIEGEL: We typically let our customer determine what type of structure is used. It is no coincidence that the inverted leases that we are using also have US Bank as a lender. Intercreditor terms between third parties tend to be very difficult in inverted leases.

We are still closing inverted leases. Our appetite for capital losses is not really an issue. The issues are who the other parties are in the deal, what are they looking for, and how much are they willing to spend on transaction costs standpoint to get it done?

MR. MARTIN: Why do you put in part of your investment as debt and part as equity, and what percentage is each?

MR. SIEGEL: We typically put in tax equity of anywhere from 38% to 44% of total project cost and the debt makes up the remainder. We do not necessarily need to see sponsor equity. Sometimes depending on the size of the project and the experience of the sponsor, it gives us additional comfort to know the sponsor has some skin in the game.

MR. MARTIN: So as much as 44% of the cost of the assets goes in as tax equity, and that's really your payment for the Treasury cash grant or the investment tax credit and a 49% share of depreciation on the assets, and then the debt is a loan at a lower rate against the project cash flows, correct?

MR. SIEGEL: Yes, that's correct from the standpoint of our equity investment. US Bank Community Development Corporation does not provide debt, although we do have lending groups in other parts of the bank with whom we work and good relationships with other industry lenders.

MR. MARTIN: Greg Rosen, does Union Bank have preferred structure?

MR. ROSEN: We are a big believer in the KISS method, which is keep it simple, especially for smaller, distributed solar projects.

MR. MARTIN: Keep it simple—there is a word missing, no? [Laughter]

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on dividends, interest or other passive income received in Malta without waiting for the income to be repatriated to Germany.

German companies had been using a two-tier structure in Malta. The lower-tier holding company was subject to tax in Malta on its income at a 35% rate. However, the upper-tier company was then allowed a tax refund of 5/7ths or 6/7th of the tax paid by its subsidiary, reducing the effective tax rate in Malta to 5% or 10%.

Germany will now look at the combined effective rate of the two companies.

MINOR MEMOS: Owners of biomass projects were given a reprieve by the US Environmental Protection Agency. The agency announced on January 12 that it will wait at least three years before subjecting such projects to new permitting requirements under greenhouse gas regulations that take effect this year while it studies whether such projects should be subject to the new rules . . . . The IRS said in regulations in December that it has six years to pursue taxpayers who overstate the basis in property they sell, with the result that they report too little gain, if, as a consequence, the taxpayer ends up understating its income for the year by more than 25%. The normal statute of limitations for the govenrment to pursue tax claims is only three years. The regulations are at section 301.6229(c)(2) . . . . US companies cannot credit any "exceptional profits taxes" they pay in Algeria against US taxes on the same income. The US allows a foreign tax credit for taxes paid to other countries, but only for net income taxes. The Algerian tax is calculated on gross income. The IRS explained its position in CCA 201052017, an internal legal memorandum that the agency released on December 30.

— contributed by Keith Martin and Amanda Forsythe, in Washington.

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MR. ROSEN: There is no question that a single project that costs $100 million can add leverage and can get more value than the pain and headache of combining debt and tax equity and working out inter-creditor issues. I was on the sell side for 10 years before joining Union Bank. I set up a tax equity flip partnership at my last job for very small projects that were 200 kilowatts each. It is very hard, unless you have lived through it, to have a realistic sense of the transaction costs for attorneys, accountants and so forth. They can easily overwhelm any return for the developer. The fewer entities involved, the shorter the negotiations, and there will very likely be fewer sticking points.

I think the distributed solar market really lends itself to a single-investor lease, meaning a sale leaseback without any leverage. We have done a number of such transactions. If you can find a lender who will provide construction debt as well as the lease equity to take out the construction debt, it makes the financing a lot easier.

MR. MARTIN: In a single-investor lease, the tax equity investor buys the project at full fair market value from the developer and leases it back to him. The investor pays all equity for the project. Dan Siegel at US Bank is putting in as much as 44% as tax equity in his inverted lease plus the balance as debt. He is offering 100% financing, or close to it, at a blended tax equity and debt rate.

Greg Rosen, your rate is entirely tax equity. It would seem that funding entirely tax equity would be more expensive.

MR. ROSEN: Each institution has a slightly different flavor but fundamentally a lot of these structures end up being somewhat the same. The "equity" return for which we are looking is really a blend of the debt of our back leverage plus our equity. Union Bank is also active in the providing debt financing.

At the end of the day, if I were a developer, I would concentrate first on getting as much contracted cash flow as possible. You know what your power purchase agreement will yield. Try to make a forward sale of SRECs.

Then, in addition to looking at the money, you have to look at the bandwidth, the amount of time that you will have to spend personally, because if you are small shop with just one person or a few people, it is a heck of a lot easier to close a sale leaseback than it is to close a leveraged partnership flip.

Also, look at transaction costs because they can cut severely into the return for the developer.

I want to clarify one thing about the sale leaseback, because typically we look for "skin in the game." Technically, we are providing 100% financing for a project, but the sponsor prepays part of the rent that is on the order of 10% to 20% of the project cost. It is a form of equity contribution.

MR. MARTIN: As prepaid rent?

MR. ROSEN: It is prepaid rent, and there is a mechanism that's called a "section 467 loan" that is also employed that allows for uneven rent payments.

Really the big difference between a lease and a partnership flip is that, with a lease, the tax equity investor is looking for basically 80% of the estimated cash flows, and a developer will get 100% of the upside and have to deal with 100% of the downside. Thus, for example, if the cash flow is $100 a month coming in to the developer, the tax equity investor will get $80 a month and the developer keeps $20. If the cash flow increases to $105 a month, the tax equity investor still gets $80 but the developer gets $25. If the cash flow is $90, the developer gets $10. The structure provides a more stable payment stream for the tax equity investor.

Risk Allocation

MR. MARTIN: There is also different risk allocation in a lease versus a partnership flip. In a sale leaseback, the developer has a hell-or-high water obligation to pay rent. If he is having trouble collecting from customers, the tax equity investor doesn't want to hear about it. He just wants his rent.

In a partnership flip, the developer and the tax equity investor are like two passengers in a car together. They are both on the front line with customers. In an inverted lease, who knows?

Let's move to another issue. You heard from the developers on the panel that they are doing more deals with municipalities. How do you deal with non-appropriation risk, or the clause that the municipality puts in the power purchase agreement that says the current city or county council cannot bind a future one? It can really only commit to pay rent for the remaining term of the current government.

MR. SIEGEL: We don't see it as great risk. First, the tenor of our investment is only about five years. From an appropriation standpoint, we see it as keeping-the-lights-on type of risk. We really don't see it as a critical problem for municipalities, and we actually like them. It is nice to have a publicly-rated offtaker.

MR. ROSEN: I second that. I have done municipal financing for solar projects. The municipalities are petrified that their credit ratings or reputations will suffer if they stop making payments and this will drive up their costs of funds in general.

MR. MARTIN: Dan Siegel, coming back to you, one of the risks dealing with homeowners and big box stores is vacancy risk. The average homeowner in California stays in his house six or seven years. How do you as financiers deal with that risk?

MR. SIEGEL: We deal with it through diversification. Residential solar deals will have certain FICO requirements for homeowners. These are well-diversified portfolios. When you move to commercial systems, you are talking about maybe eight, nine or 10 big-box retailers, so we have to do deeper diligence. We like to see investment-grade offtakers.

MR. MARTIN: So diversification gives you comfort. You are not as concerned about vacancy risks. It all comes out in the wash. Greg Rosen, what do you do about vacancy risks?

MR. ROSEN: Commercial solar is sort of this middle ticket. It is not small-ticket residential, and it is not big-ticket utility. It is the worst of all worlds in a lot of ways, so it is challenging. We look for the sponsor to take those kinds of risks.

MR. MARTIN: The sponsor will keep paying rent?

MR. ROSEN: Some kind of a mechanism. If the sponsor is going to do that, it better have a balance sheet that shows it could be around 17 years from now. That's how long the tax equity capital is at risk.

MR. SIEGEL: Other considerations are whether the transaction is levered, what the debt terms are, how much debt-service coverage there is and how the particular portfolio is weighted. For example, if one offtaker is providing 75% of the cash flow and that offtaker goes under, then that is a problem for the whole fund. If there are 10 different offtakers with each accounting for about 10% of the cash flow, it is possible for the economics to work even if one or two go under.

MR. MARTIN: Are there special issues in master financing structures that vary by state and if so, what is an example? Are there special obstacles to use of structure X, for example, in Arizona or Massachusetts?

MR. HENSON: The primary differences are the state incentive structures. It doesn't really affect the choice of an inverted lease versus a sale leaseback versus a partnership flip, but there are peculiarities from state to state that affect how much capital can be raised. For instance, revenues from the sale of solar renewable energy credits or SRECs account potentially for a large share of the projected cash flow for projects in New Jersey.

MR. MARTIN: I read somewhere that the revenue from renewable energy credits could be as much as four or five times the revenue from electricity sales in some states. Does that sound right?

MR. HENSON: That depends on the bidder, but it is potentially a significant portion of cash flow.

MR. MARTIN: Is anyone getting value in these financing structures for future REC revenue or for state tax benefits?

MR. HENSON: Yes. In California, obviously, there are the CSI PBI performance-based incentive programs from which developers benefit. On the east coast, there are equivalent incentive programs that are done through renewable energy credits, but the challenge in those markets is to find a creditworthy utility willing to enter into a contact to purchase a number of years' worth of credits. Without a contract, tax equity investors and lenders will not take the potential cash flow into account in sizing how much they are willing to invest or lend.

It is hard to get value for state tax credits. For example, we are looking at projects in New Mexico where there is a state tax credit, but there are not many potential tax equity investors with enough tax liability in New Mexico to use them.

Treasury Cash Grants

MR. MARTIN: If the Treasury cash grant is not extended by Congress, what effect do you foresee on cost of capital in this market?

MR. SIEGEL: I can only speak for US Bank. Last year, we closed about $300 million of tax equity in renewable energy projects. This year we'll probably close about $500 million. Most of that has been solar. Next year, we plan only to invest in projects that qualify for Treasury cash grants and then only in projects that are considered to have started construction in time to qualify for a grant because they incurred more than 5% of the total project cost by the end of 2010. We think we can hit somewhere between $300 and $500 million even with those projects that are just within the 5% safe harbor. Unfortunately for the people in this room, competing areas of our business are growing. Low-income housing is growing. We have targets as a bank under the Community Reinvestment Act that we need to hit and have decided that is where we should redirect sources to the extent the cash grant sunsets. It is a resource allocation issue.

MR. MARTIN: So it will be hard for solar companies to get financing from you except for cash grant deals next year. Greg Rosen, what do you see happening?

MR. ROSEN: Without a cash grant, the demands on the tax equity market will be twice as large. The cash grant is roughly half the tax subsidy on these projects. Take it away and you will need twice the tax base in the tax equity / continued page 28

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market to monetize what will now be pure tax subsidies.

MR. MARTIN: So it should push up the cost of capital. It is a simple matter of demand and supply.

MR. ROSEN: Yes, unless a number of new tax equity investors enter the market. We have all heard rumors about some Fortune 500 companies thinking about entering the market, but it is usually a lot of tire kicking without leading to an investment. Without the cash grant, what will make or break solar is how many of those tire kickers actually take the plunge next year. If they don't, the situation will be pretty ugly.

MR. MARTIN: How well has the cash grant program been working? Have any of you had trouble getting the cash grants for which you applied?

After the Treasury cash grant expires, the tax equity market will need to double in size in order to finance the same number of projects as today.

MR. SIEGEL: The program has been a success. That said, cash grants are sometimes taking a little longer than we expected to be paid, especially on the residential side. It has been a bit of an education process with the Treasury to explain why the costs per watt are so much higher for a rooftop project than a utility-scale solar project, getting Treasury comfortable frankly that the developers aren't loading up the tax basis with phantom costs and that it is truly more expensive to build residential systems. The grant program allowed us to do more in this market than we have done otherwise. We hope it continues.

MR. MARTIN: US Bank has applied for a large number of grants on rooftop solar installations. I am assuming that some of the grants you received were less than the amounts for which you applied?

MR. SIEGEL: There have been a few here and there, but by a large margin, most of them have been approved without haircuts.

MR. MARTIN: How long does it take to get the grant?

MR. SIEGEL: We are seeing a faster turnaround of somewhere between three and four months. There were times in the past where we had to wait as long as eight months.

MR. MARTIN: Actually, I think the turnaround time is now down to about two weeks. Has anyone else had trouble getting the cash grants for which he or she applied? Phil Henson?

MR. HENSON: We have not. There was some back and forth on questions the reviewer asked and it has taken a little longer than advertised to get the grants.

MR. MARTIN: What value are you claiming per watt?

MR. HENSON: That depends on the individual project.

MR. MARTIN: What is the range? Is it six to eight dollars a watt? Nine? Higher? Lower?

MR. HENSON: It is probably lower than that, approximately \$5 to \$7 a watt.

MR. STREAMS: We have applied for a number of grants, maybe eight now. Our big consternation is timing. Grants are supposed to be paid within 60 days after the application is filed, but Treasury resets the clock if it has questions to which the developer has to respond. Also, the amount of the grant that gets paid ultimately seems to be determined in a black box.

MR. MARTIN: Who takes the risk that the grant will come in less than expected?

MR. STREAMS: At least in deals with US Bank, the developer takes the risk.

Biggest Challenge

MR. MARTIN: My last question, and I want each of you to answer, is what is your biggest challenge in trying to finance distributed solar projects?

MR. ROSEN: Transaction costs and trying to standardize the documentation so that it is the same across a portfolio of projects.

MR. MARTIN: So keep it simple, stupid. Matt Cheney?

MR. CHENEY: I think it's the lack of an organized plan, a strategy, a tactic to help us transition into the future inclusive of transmission, making sense out of how we convey electrons around this country and how our different states organize themselves in the absence of a federal policy.

MR. SIEGEL: For us, it is legislative uncertainty. These deals are complicated, but we can work through those complications.

MR. MARTIN: We took a survey at a Chadbourne energy conference years ago about which country had the biggest political risks. It was when the independent power industry was doing deals worldwide. We expected the answer to be a country in Africa, Asia or Latin America. The audience response was New York. [Laughter] Phil Henson?

MR. HENSON: The biggest challenge is transactional friction, and by that I mean not just transaction costs, which are substantial, but also just the time and the internal effort that is needed to get these deals closed and to balance the needs of your offtakers, construction contractors, equipment vendors and financing parties.

MR. STREAMS: I agree with Phil Henson and Greg Rosen about transaction costs. Managing those costs is a challenge, as costs for an independent engineer, outside counsel for the lender, tax equity investor and sponsor and other consultants can get out of control quickly.

MR. MARTIN: One developer said at the Solar Power International conference recently, quoting Forrest Gump but changing the quote slightly, "Life is like a piece of taffy." He feels like he is in the middle, and everyone from the banker to the tax equity investor to the construction contractor to the utility is pulling in a different direction. He is hoping to have some little piece left to chew on at the end.

MR. STREAMS: Welcome to our world. ◎

Turkey Moves to Boost Renewable Energy

by Ayşe Yüksel and Turgut Cankorel, in New York

Turkey put in place new feed-in tariffs and other incentives for renewable energy in a new law enacted December 29 by the Turkish parliament.

Demand for electricity in the country has been growing at a rate of more than 6% a year for the past decade. Turkey imports around 70% of its electricity to meet this growing demand.

Turkey has no large oil and gas reserves, but it has ample renewable energy resources, especially geothermal, hydraulic, wind and solar.

Given these market realities, as well as concerns about pollution and energy security, the Turkish government has been liberalizing the energy market and encouraging investors to undertake renewable energy projects. The new law—called Law No. 6094 for short or the "Amendment of the Law on Utilization of Renewable Energy Resources for the Purpose of Generating Electrical Energy"—is the latest in a series of policy measures aimed at encouraging renewable energy.

Existing Incentives

Two key statutes and one regulation contain the core rules that govern the renewable electricity sector in Turkey. They are commonly referred to as the "Electricity Market Law No. 4628," the "Renewable Energy Law No. 5346" and the "electricity market licensing regulation."

The regulatory body with responsibility for the sector is the Energy Market Regulatory Authority, or "EMRA." The government ministry with jurisdiction is the Ministry of Energy and Natural Resources.

Independent generators already enjoyed a number of incentives to use renewable energy before the latest action by parliament in late December to give more encouragement.

The following types of renewables already enjoy favored status under Turkish law: "wind, solar, geothermal, biomass, biogas, wave, current and tidal energy resources together with hydraulic generation plants either canal or run of river type or with a reservoir area of less than fifteen square kilometers."

Independent generators must pay a one-time licensing fee when applying for permission to build that can run as high as the Turkish lira equivalent of approximately €120,000, or about $160,000, and additional annual fees of nominal amounts. However, generators proposing to build power plants that use renewables are exempted from the application fee except for 1% of application fees otherwise payable. Once they obtain a license, they remain exempted from paying annual license fees for the first eight years of commercial operation.

Effective as of December 2010, renewable generators with an installed capacity of less than 500 kilowatts are exempted from both the initial and annual licensing fees altogether. This new incentive also permits facilities generating electricity for their own use to sell their excess electricity to the market under certain conditions.

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Licensed electric utilities must give priority to purchases from renewable generators, but only if the price is no higher than the sale price of the state-owned wholesale supplier, TEİAŞ, and there is no cheaper source of supply. The purchase price is determined by the regulatory body, EMRA, and is calculated as the average Turkish wholesale price for the previous year. However, it cannot be less than the Turkish lira equivalent €50 a mWh. (This purchase priority applies under existing law, but will no longer apply under the new law enacted in late December.)

In addition, the state-owned electricity transmission company, TEİAŞ, and privately-owned transmission companies must provide priority to renewable generators in interconnecting them to the grid.

The permitting costs, rent and other costs of gaining rights of access and usage of state-owned land are subject to an 85% reduction where the property is used for a renewable energy project. This incentive is available only to projects that are in operation before December 31, 2012. The break on rent or easement fees runs for 10 years after a project commences operation.

What is Changing?

The new law that parliament enacted in late December provides additional incentives for projects that commence operations between May 18, 2005—the effective date of the original renewable energy incentives—and December 31, 2015.

Renewable generators have the choice of opting into the new incentives, but they do not have to do so. The new incentive package is called the "renewable energy support mechanism." Certain existing renewable energy incentives will remain in place for those who choose not to opt in.

The new incentive package covers the same renewable energy sources as the existing incentives, but with the clarifying replacement of "biogas" by "gas obtained from biomass, including landfill gas." The definition of "biogas" has been expanded to clarify coverage of energy sources derived from biomass by-products.

The new law provides the following feed-in tariffs for licensed renewable generators that apply to the electricity regulatory body, EMRA, by October 31 of the year before they desire to start benefiting from these feed-in tariffs.

Power source of generating facility	Feed-in tariff (dollars/mWh) for first 10 years of operation
Hydraulic	73
Wind	73
Geothermal	105
Solar	133
Biomass (including landfill gas)	133

These feed-in tariffs are generally less favorable than what was proposed in the draft legislation that was initially considered by parliament. For example, the magnitudes of the tariff rates are measured in dollars instead of euros, and they are significantly lower—for example, the draft had proposed feed-in tariffs as high as €250 a mWh for photovoltaic solar projects. In addition, while the draft included feed-in tariffs for wave, current and tidal energy sources, the new law as enacted does not. Moreover, the new law provides a single feed-in tariff for all forms of solar energy (while the draft had provided higher tariffs for photovoltaic solar projects) and all forms of wind energy (while the draft had provided higher tariffs for offshore wind projects). Finally, the draft had provided for 20-year feed-in tariffs in certain instances, with a higher tariff rate during the first 10 years than the second 10 years. The new law, as enacted, does not have this distinction.

The tariffs in the schedule are available only to facilities commencing operations before December 31, 2015. The Council of Ministers is expected to publish a schedule of feed-in tariffs for facilities that are built after 2015. The tariffs in the new schedule cannot exceed the tariffs in the existing schedule. There is no deadline for the Council of Ministers to publish the post-2015 schedule.

In addition to the high feed-in tariffs, the new law provides incremental price incentives for renewable generators that use certain domestically-manufactured components in their projects. These incremental incentives are available only to facilities that commence operations before December 31, 2015 and only for five years after they go into service. The incremental incentives range from the Turkish lira equivalent of $4 to $35 a mWh, depending on the type of project. For example, it is $6 a mWh for reflective surface panels used in solar thermal projects, $13 a mWh for turbines used in hydroelectric projects and $35 a mWh for using photovoltaic modules in solar projects.

The new law also provides a pooling mechanism for making payments to renewable generators. According to the new mechanism, utilities buying renewable power from a project that has opted into the “renewable energy support mechanism” must make their payments directly to a pool that is managed by the state-run Market Financial Settlement Center, or “PMUM.” Funds are then distributed from the pool to the renewable generators according to the amount of electricity they have sold. While the new law specifies that payments to the pool shall be made for each billing cycle in Turkish liras (based on the currency exchange rate of the day on which power is provided to the grid), it generally delegates to the the energy regulator, EPDK, the authority to implement the pooling mechanism. In essence the pooling mechanism functions as a limited government purchase guarantee, since failure to make a payment into the pool would be in direct violation of the law in addition to a breach of contract.

The total capacity of solar projects that can be connected to the grid is limited. In the event that multiple solar developers apply for licenses in the same geographic area, then TEİAŞ will use a reverse bidding process to award slots starting with projects demanding the lowest feed-in tariffs. The total installed capacity of licensed solar plants that will be connected to the grid before December 31, 2013 cannot exceed 600 megawatts. These limits were not part of the draft legislation originally debated by parliament.

The new law authorizes the Ministry of Energy and Natural Resources to identify areas of the country that have good renewable energy resources and notify the local zoning authorities so that the areas are protected for renewable energy projects. It also extends to December 31, 2015 the 85% break on the costs of using state-owned land.

All existing licenses for independent power projects are expected to be amended within three months after the new law takes effect upon publication sometime in January in the Official Gazette to specify the installed capacity of the licensed project and maximum permitted annual power production. The new law permits renewable generators to install additional capacity at already licensed projects as long as the additional capacity does not expand a project outside the geographical area specified in the license or provide more electricity into the system than the amount of installed power specified in the license.

Analysis

The new law is probably not sufficient to make Turkey a more attractive sector for renewable energy than other major renewable markets. Turkey has the largest geothermal energy potential in Europe, more solar energy potential than California, and compelling potential in wind and hydraulic energy. However its renewable energy sector is in its infancy.

While the new law provides an improvement over the current regulatory regime, historically regulators elsewhere have provided more generous incentives to boost this industry into growth stages. For example, feed-in tariffs last 20 to 25 years after a project commences operation in the European Union, as opposed to the 10 years being in the new law. In addition, solar feed-in tariffs range between €300 to €540 a mWh and wind feed-in tariffs range between €80 to €200 a mWh, which are significantly higher than those put in place by the new law. ◎

Cellulosic Biofuels: The Future Is When?

The US government has been encouraging production of ethanol from cellulosic materials, but the incentives are temporary in duration. Six Washington insiders and biofuel industry experts talked during a roundtable discussion, at an Infocast cellulosic biofuels summit in Washington in mid-November, about the outlook and what else the industry is asking the government to do to help it get off the ground. The following is an edited transcript.

The panelists are Jim Nussle, a former Congressman, chairman of the House Budget Committee and head of the Office of Management and Budget under President George W. Bush and currently president and chief operating officer of Growth Energy, Bob Dinneen, chief executive officer of the Renewable Fuel Association, Douglas Durante, executive director of the Clean Fuels Development Coalition, Dr. Matthew Carr, managing director of policy and industry in the environmental section of the Biotechnology Industry Organization, Dr. Candace Wheeler, biofuels lead in the global energy systems center at General Motors, and Wesley Bolsen, chief marketing officer and vice president for government affairs of Coskata. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: Cellulosic biofuels plants have been built in the United States on a pilot scale, but we really / continued page 32

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have not seen commercial-scale projects yet. Brazil has quite a number of them. What is the hang up in the United States?

MR. BOLSEN: The capital markets. We have demonstrated that the technology works. The technology has moved out of the laboratory and pilot facilities into full demonstration scale, and the Department of Energy has funded several companies to do fully-integrated biorefineries as well.

What we are missing is movement from the US Department of Energy to issue loan guarantees. It has had the authority since 2005. The US Department of Agriculture is now stepping into that role.

The challenge is to get the first plant built on a commercial scale. This is first-of-kind technology, and there is risk. Banks are not willing to take technology risk. That is a role that the government needs to play and, to date, the government has not been out on the playing field.

MR. MARTIN: So the main challenge is to prove the technology works. Why have the Brazilians been able to do it, but we have not?

MR. BOLSEN: The Brazilians have not built full cellulosic commercial-scale facilities. There are exactly zero commercial-scale cellulosic ethanol facilities in the world. The Brazilians have produced ethanol from sugar cane, and they know how to do that extremely well.

MR. DINNEEN: If Brazil had in fact cracked the code to processing cellulosic materials commercially, we would not be having the difficulties we are having financing projects. They have not done it. Nobody in the world has done it. Nature put cellulose together so as not to break down very easily. I have seen ethanol being produced today from cellulose on a demonstration scale, but scaling up is the challenge.

In the economic environment today, it is difficult to get a loan for a car, never mind a couple hundred million dollars to build a new facility using a new technology relying upon a new infrastructure in markets that are not yet secure.

We need to get the loan guarantees up and running as intended by Congress. We also need to make some changes in tax policy to encourage investment. It is going to require a real commitment from Congress and the administration to make it happen, but I think that we can do it. We need to.

MR. MARTIN: There are a number of federal policy supports currently for cellulosic biofuels. They include the renewable fuel standard, or RFS2, loan guarantees, a producer tax credit, a tariff on imported fuels, a 50% depreciation bonus [*Ed.—Congress increased the bonus to 100% in late December on equipment placed in service after September 8, 2010 through December 31, 2011.*], sales to the Department of Defense and the ability to use master limited partnerships to own ethanol pipelines. Are there other important federal policy supports for this industry?

MR. DINNEEN: The RFS2 is not really a mandate as long as the Environmental Protection Agency is allowed to continue to adjust the levels downward. That particular support isn't working as intended. The loan guarantee program has been broken and is not working as intended. The producer tax credit isn't going to be useful to developers until they are actually producing, so the list that you just gave largely demonstrates the problem.

MR. MARTIN: Are there any other federal policy supports that should be added to the list?

MR. BOLSEN: The Department of Energy is looking at a reverse auction program under which the US government would buy cellulosic biofuel. The program was authorized in 2005, but has never been implemented. DOE was still hoping that it can get the program running and funded with more than $5 million.

MR. DURANTE: There is also a biomass crop assistance program that is run by the Department of Agriculture.

I agree with Bob Dinneen. If you look at that list, we just keep going back and trying to fix what is not working and throwing more stuff on top of it. Congress keeps asking, "Will this help?" It keeps throwing stuff at us with different definitions, requirements, stipulations and carve-outs and, by the time the regulations are done, it is clear that however well intentioned the effort was, it does not work.

MR. MARTIN: So we need to make what is already there work. Are there any meaningful programs or incentives at the state level?

MR. BOLSEN: The low carbon fuel standard in California. By requiring that fuels used for transportation in California have low carbon content, the state may do more to stimulate biofuels than the renewable fuel standard at the federal level because the California standard has teeth.

DR. CARR: California is not the only state looking at this. Several northeastern states and others are doing so, as well. The key will be how these programs are implemented. They could drive investment in cellulose or biofuels or they could scare away such investment. For example, if the programs impose a huge indirect land use change penalty, then the scales are tipped against biofuels but not against biomass power, with the result that biomass gets diverted into electricity generation.

Renewable Fuel Standard

MR. MARTIN: Let's drill down further into the current incentives. Bob Dinneen, what is RFS2? Is it working? Is the industry seeking any changes in it?

MR. DINNEEN: In 2005, we worked with the oil companies to create the first ever requirement for them to blend a certain percentage of their fuel as renewable. It was a 7 1/2 billion gallon requirement and, at the time, a lot of folks said, "Oh my goodness, 7 1/2 billion gallons of fuel. How in the world can that small industry in the Midwest satisfy that demand?" We not only satisfied it, but we also blew past the targets in 2006. It was clear that the program had been an extraordinary success, and that there was far more that could be done.

In 2007, with a new Congress and new stakeholders at the table, we worked with the environmental community greatly to expand the first renewable fuel standard, and we were able to create a 36 billion gallon requirement that capped grain ethanol at 15 billion gallons and created this tremendous new market opportunity for 21 billion gallons of advanced biofuels.

The problem is that the 21 billion gallon requirement for advanced biofuels has several off ramps to it down which the Environmental Protection Agency has been too willing to exit. This makes it awfully hard to go to a bank and say, "I have this market," when the size of the market keeps being reduced. It is hard to blame EPA if the production is not there, but it is a question of which comes first. You are not going to get the production until the mandates really mean something.

MR. NUSSLE: When policy makers are faced with a problem, they invent a program. Members of Congress can then go home and explain to their constituents that they did something. The result is that we end up with a patchwork of things, among them RFS2, but each of these programs requires tremendous follow through to make it work properly, and the policy has to remain in place long enough to achieve the objective.

A renewable fuel standard is important. This industry needs demand for its product and it needs infrastructure, whether it is flex-fuel vehicles, blender pumps or the ability to move product around the country. At the end of the day, that's what has to be there—in addition to the interesting programs, loan guarantees, tax credits, mandates, standards and everything else that can be woven together—for the industry to work. The reason Brazil has done so well is it picked a strategy, stuck with it and is not deviating from the strategy until the mission is accomplished.

We, on the other hand, have various temporary measures that must be renewed periodically by Congress. We sit here now eleven months after the biodiesel tax credit has expired. We are on the precipice of watching the ethanol credit expire if both political parties don't get their acts together in the next three weeks. This sort of repeated uncertainty undermines the effectiveness of the programs. [*Ed.—Congress extended tax credits in late December for ethanol and biodiesel blenders and small producers through December 2011.*]

MR. MARTIN: Candy Wheeler, does the auto industry view RFS2 as an effective stimulus for cars to move to ethanol and other biofuels?

DR. WHEELER: We are producing flex-fuel vehicles regardless of the RFS2. However, it would be very helpful to General Motors to have RFS2 hold and not have EPA take the off ramps as freely as it has done. The standard has teeth if we let it work. If we keep reducing it, then the bankers lose confidence, and we end up in a vicious cycle.

The Environmental Protection Agency does not want to set a standard that is impossible to reach, so it polls everyone in an effort to estimate likely cellulosic production each year, but if the target were set just a little higher than what producers say they plan to produce, there is a safety valve that is already built into the program under which parties can meet their obligations using RINs. You could take the money generated from the sale of RINs and invest it back into getting the pumps and other the infrastructure in place, so that the RFS2 could actually start to build the industry.

The existing program does not really have teeth on the vehicle side. We have made a commitment to have 50% of our portfolio using flex fuel by 2012. That was contingent upon having the infrastructure in place. We have not seen the infrastructure develop, but we continue to try to meet that goal anyway.

MR. MARTIN: Matt Carr, is the industry working for any changes in RFS2, other than to try to prevent further back sliding?

DR. CARR: There have been a lot of calls to reopen RFS2 to make sure that the program is running the way it should.

If you look at the cellulosic mandate—and I really do say that it is a mandate because the EPA is required to set its volume at least at the level of projected production—if the volumes are produced, they must be blended. There is / *continued page 34*

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also a waiver provision within the cellulosic bucket that says there will be a price support provided to cellulosic biofuels in the event of a waiver. Thus, within that cellulosic bucket, there are two mechanisms that are supposed to provide support to cellulosic biofuels.

I don't think the Department of Energy understands this. The Environmental Protection Agency doesn't understand it. We have to make sure that the agencies understand how this program is intended to work, so as to ensure consumption of cellulosic biofuels.

MR. DINNEEN: I just want to go back briefly to something Candace said because it is really important. General Motors has done a phenomenal job working with the industry, and the company's commitment to have 50% of its vehicles be flex fuel by 2012 is really important. I wish other companies would follow its lead.

She mentioned the need for infrastructure. We brag in the industry about the fact that we have 3,085 pumps, and there are more blender pumps coming every day, but we have only had a UL-certified E85 or a UL-certified blender pump now for about three months.

I hope that the infrastructure follows much more quickly. One of the tax incentives on which the industry has focused besides the volumetric ethanol excise tax credit is the infrastructure credit that is also set to expire at the end of this year, but if we get that incentive extended with UL-certified pumps, Candace, do you think that infrastructure is going to be deployed a bit more rapidly now? [*Ed.—Congress extended a tax credit for installing blender pumps in late December through the end of 2011, but at a lower dollar level than applied in 2009 and 2010.*]

DR. WHEELER: The UL holdup was a significant issue, and now that has been resolved, we should see things start to move forward. Blender pumps are a good option because they allow us to have a whole wide range of concentrations.

MR. MARTIN: What is UL?

MR. BOLSEN: Underwriters Laboratory. They stamp the pumps to say, "This pump has been certified." Another significant action was the announcement by US Agriculture Secretary Tom Vilsack that the government will fund 10,000 blender pumps in the next five years. There is room for it in the existing budget. These are really meaningful measures. You hear the automakers saying they need such measures. You hear the Coskatas of the world saying they need something past E15. We need to get to E30, E40, E85 both in blender pumps and flex-fuel vehicles. Let's not expect General Motors to stand up alone and make flex-fuel vehicles without the infrastructure to allow demand for such vehicles to grow.

There are at least seven public policy supports for cellulosic ethanol plants.

Federal Loan Guarantees

MR. MARTIN: Let's move next to what seems from your descriptions like a vast reservoir of disappointment —- the federal loan guarantee program. What is the Department of Energy program? What is the Department of Agriculture program? What are these agencies authorized to do?

MR. BOLSEN: DOE has authority to guarantee repayment of up to 80% of the debt on certain energy projects. There are two different DOE programs: a section 1703 program guarantees debt on projects that use innovative technologies. Borrowing under it is through an arm of the US Treasury called the Federal Financing Bank. There is also a section 1705 program that guarantees debt on projects that use commercially-proven technologies. Under that program, you arrange a loan from a private lender, and the government guarantees the lender that it will be repaid.

MR. MARTIN: Are there separate loan guarantees through the Department of Agriculture?

MR. BOLSEN: Yes. The department was given authority under the 2008 farm bill to guarantee loans of up to $250 million per project for, among things, cellulosic biofuels projects. You negotiate the loan from a bank, and then the department applies a guarantee to it. However, at most 60% of the loan is guaranteed for loans above $125 million.

MR. MARTIN: This industry has a problem getting to commercial scale and proving the technology. Until it does so, no banks will lend. The DOE loan guarantee program seems exactly the ticket because the federal government will lend until the projects have proven themselves. Why has this program been such a disappointment?

MR. NUSSLE: The technology is just part of the story. Many people in this room have been at this a long time. They can make ethanol and alcohol out of anything. They can take your old tie and eventually break it down. The bigger piece of the story is the market. If you have a market for the output, then the economics will work. The challenge for all of us is to get that message out. We need the basic infrastructure so that there can be a market for the output. Until that happens, the loan guarantees are helpful, but they are only part of the story.

MR. BOLSEN: I would love to have Jim Nussle back in charge of the Office of Management and Budget. We do not have a commitment as a country to remove our dependence on oil. Every one of us in this room is responsible for not telling the story. Job growth, economic growth and rural development come from biofuels. You can put up windmills and solar facilities that help reduce our dependence on coal and natural gas. It is fantastic to have China making these wonderful solar cells and wind turbines and shipping them back into our country. Biomass is local. Biofuels are local. They are rural industries. They create jobs that cannot be exported. You don't ship your corn stores to China and have them ship back fuel. This is about long-term economic growth and jobs for this country. We have missed this story.

MR. MARTIN: I think we got the message.

MR. BOLSEN: This town has not gotten that message.

MR. MARTIN: Let me give you some statistics about loan guarantees. To date, the Department of Energy has written four loan guarantees and issued 16 commitments. Projects have to start construction by September 2011 to qualify for guarantees. Is the program in danger of running out before anything significant is done for biofuels?

MR. DINNEEN: Earlier this week, Jonathan Silver indicated that three biofuels projects are in the pipeline. Part of the problem is structural. Companies are competing for a pot of money. Among the competitors are wind, geothermal, solar and other renewable technologies that have been proven and do not carry the technology risk that cellulosic producers do. DOE has tended to focus on power generation. The program was also intended to provide some risk management for the fuels industry.

The memo that leaked from the White House in October that was critical of the program focused on power generation. There was not a single reference in it about the impact of this program on fuels. We are constantly having to remind DOE that, "Hey, we are out here, too." Look, I'm an optimistic person. I have been in this industry for 23 years. You can't be anything but an optimist if you have stuck with it for so long a period of time. I remain optimistic that at some point, DOE will do a loan guarantee for a biofuels project.

Cellulosic Producers Credit

MR. MARTIN: Let's move next to the tax credit for cellulosic biofuels. Matt Carr, how much is the credit and when does it expire?

DR. CARR: The 2008 farm bill provided a tax credit of $1.01 per gallon of cellulosic biofuels produced minus the ethanol blender tax credit and small producer ethanol tax credit. The big challenge with this program is that it is expiring in 2012, and we are not likely to see many commercial projects completed by that time. Therefore, the credit is not of much value when talking to investors in an effort to raise money for projects.

There is a complementary accelerated depreciation benefit that was authorized in the same bill.

The industry is trying to extend both incentives for at least four years to provide greater certainty for investors. It is also asking for flexibility to be paid the credit value by the Treasury in cash, like the refundable section 1603 grants for which other renewables like wind and geothermal qualify. The grant program has been tremendously effective. It is another example where the focus has been on the power sector but not on other emerging technologies that are part of the larger renewables picture. We need parity for fuels.

MR. MARTIN: Jim Nussle, how likely are these tax credits to be extended and, if so, how long? The Republicans have taken over the House. They have a mandate to cut spending and reduce the deficit.

MR. NUSSLE: My crystal ball worked / continued page 36

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until 1997 and then it broke. It is hard to predict what will happen in the next three days let alone the next three months or two years. There is no question that the deficit and the pressures of the debt will come to bear, but exactly where things will settle is unknowable at this point. The House of Representatives is only part of a matrix of the House, Senate and President.

MR. MARTIN: Do you think the odds of an extension are lower in the next Congress that will take office in January 2011 than they are this year?

MR. NUSSLE: Yes, and I worry about that. Anyone who wants to know what the playing field may look like should consider the challenges the biodiesel tax credit has faced since 2009, and you will have a glimpse of what the future may look like. These credits used to be routinely extended. They are now routinely debated and controversial and not extended, and that's a very troubling prospect if you are looking for enough certainty to attract long-term investment.

MR. DINNEEN: If the tax credits for biofuels are not extended in late 2010, then you will begin to see a crumbling of the foundation and that will not bode well for any of us. These tax credits are an incentive that marketers and refiners depend on today in order to make ethanol a cost-competitive component of their motor fuels. The tax credits will be critically important when cellulosic ethanol enters the marketplace.

Tariff

MR. MARTIN: Bob Dinneen, another public policy support is the tariff at the US border that must be paid on imported ethanol. How much is the tariff? How long does it remain in place?

MR. DINNEEN: It is 54¢ a gallon. It was intended to offset the tax benefit that refiners and marketers get when they use ethanol, whether that ethanol is imported or domestic. The notion of having an offsetting tariff is so that the United States does not end up subsidizing already highly-subsidized ethanol produced someplace else. It is there to protect the taxpayer and not the industry. We import a fair amount of ethanol when the market conditions are right. Right now, we are exporting a fair amount of ethanol because of market conditions, so the tariff does not really have an impact on world trade. It does have an impact on making sure the US taxpayer is not subsidizing a foreign product. I believe as long as there is a market-based incentive available to refiners and marketers to use ethanol, there will be an offsetting tariff. Do you need to coordinate those so that they match up more directly? Sure. We have supported that. But I don't believe you will see the tariff go away as long as the market-based incentive exists.

MR. MARTIN: What would happen if the tariff were lifted? Do you think we would see a flood of Brazilian ethanol, for example?

MR. DINNEEN: Not in today's marketplace because of where the world price is for sugar. Brazil is having a difficult time meeting internal demand.

MR. DURANTE: There is also nowhere to put the ethanol whether it is cellulosic ethanol, corn ethanol or Brazilian ethanol. Ethanol prices are down, and no one is getting rich off ethanol. Bob Dinneen is right. Complaints from foreign producers about the tariff are the single biggest red herring I have seen in my more than 20 years here. The idea that if it was not for the tariff, foreign producers would be coming in to save the day is preposterous. Without the tariff, they would receive the benefit of a federal tax break plus whatever other incentives they get in their own countries.

Government Sales

MR. MARTIN: The next public policy support is potential long-term sales to the Department of Energy, the Army, Navy and Air Force. How important are such sales? What type of contract is it possible to get and at what price?

MR. BOLSEN: Contracts do not run longer than five years currently. We need to see the government signing contracts that run longer. There is also some confusion about a rule that one government agency cannot guarantee another agency's obligations.

DR. CARR: There is a growing appreciation at the Defense Department that oil dependence is a national security issue. Several branches of the military have expressed a desire to test or buy advanced biofuels. We need to get authority for the Defense Department to enter into long-term contracts. I hope that the department will also play a role in helping to get these commercial biorefineries constructed because it is in the national interest to do so.

MR. MARTIN: This seems pretty important. Once the industry gets past the challenge of demonstrating the technology works, it will still face the challenge of signing up long-term offtake contracts. It is hard to finance a project unless you can show a long-term offtake contract that banks can evaluate.

Candy Wheeler, let me come back to you. We talked about a number of federal policy supports. We talked about the RFS2 loan guarantees, producer tax credit, the tariff, the 50% depreciation bonus and the possibility of long-term contracts with the Defense Department. You mentioned that building out infrastructure is probably the most important thing from the standpoint of General Motors. Of these other items, how do you rank them? Which is most important?

Wish List

DR. WHEELER: It is hard to rank them. They are all pieces of the puzzle that need to fit together. That said, getting those first plants built is critical, so the loan guarantees need to be in place. Having the RFS2 target hold and be consistent is also critical to helping to get those first plants built. Those are the two real keys to moving things forward.

MR. MARTIN: Wes Bolsen, some of the panelists suggested there is something of a confusing patchwork of programs, and the government might do better to focus on getting the existing programs to work rather than to add more. Sander Levin, who is chairman of the House tax committee this year and who will be replaced as chairman in 2011 by Dave Camp, also from Michigan, proposed, as part of an extenders bill he released in late July, to allow a 30% investment tax credit for cellulosic biofuels projects and to direct the Treasury to pay the value in cash. Is this an industry priority?

MR. BOLSEN: Absolutely. Each of us is in a different spot. Chairman Levin proposed extending the production tax credit past 2012 and allowing it to be traded for an investment tax credit that would be payable in cash.

When we talk about how to get facilities financed, how about taking the decisions out of the hands of DOE and USDA and letting the market decide which technologies to support and having tax parity between fuels and other types of renewable energy?

MR. MARTIN: Bob Dinneen, we heard Candy Wheeler say one thing the government should do is build more infrastructure. We only have so many gasoline pumps that can pump gas with ethanol blends. Is this a place where the federal government can help and, if so, how?

MR. DINNEEN: Certainly it can and in a couple ways. One is to extend the tax incentive that I talked about earlier for installing new pumps. The other is to tap some existing federal funds that the states could use to create programs to encourage installation of more pumps capable of pumping E85.

DR. WHEELER: The UL certificate that we discussed earlier is a big step. It was hard to get service station owners to put something in that wasn't certified for use. However, a lot more will have to be done to get to higher levels of ethanol usage. We are never going to get to 36 billion gallons by doing things incrementally. We need to go to higher-level blends like E85. In order to get a large number of flex-fuel vehicles into the market, the pumps must be available so that people can get the fuel they need for those vehicles. There are more than eight million flex-fuel vehicles on the road in the United States today, but 90% of those do not have an E85 pump anywhere in their zip codes.

MR. MARTIN: And the way to get more pumps is through tax credits?

DR. WHEELER: That's one way to do it. Another way is to have the states partner in the effort. Brazil is an interesting example in that all of its service stations have an E85 pump if not an E100 pump. Sweden has fully distributed pumps. It is not important to have every station have an E85 pump. Just getting pumps evenly distributed at 10,000 or 20,000 stations would be enough to get traction.

MR. MARTIN: Jim Nussle, the Republicans will have 56% of the House and 47% of the Senate in 2011 and 2012. As we discussed earlier, they are trying to reduce the federal deficit. Are there ways to help the industry that do not require spending money? Tax credits, as you said earlier, may be a tough sell.

MR. NUSSLE: What this industry needs most is certainty. There have been too many fits and starts. Regardless of what the policy is—and we all have our own ideas of what that policy ought to be—the government needs to stick with it to provide some certainty in the marketplace. Part of the reason why there is so much more capital sitting on the sidelines today is we don't know what will happen in the next number of days to several weeks, let alone the next year or two. What Washington should do is settle on a plan and then make it clear that the plan will remain in place for a number of years.

MR. DINNEEN: Keith, you suggested a couple times that because the Republicans will have more power in the next Congress, the policy is likely to change. Ethanol biofuels and energy security have never been partisan issues. We have strong friends on both sides of the aisle.

Will there be new pressures on all of Congress to address fiscal responsibility? Absolutely. We welcome that debate because the investment that the taxpayers have made in the federal ethanol program has been an / continued page 38

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extraordinary success in terms of creating jobs. Every $1 invested by the federal government has returned $7 to the taxpayer through reduced farm program costs and increased in corporate tax collections. We welcome the debate and don't see any issue with the changes in Congress.

MR. MARTIN: Bob Dinneen made an important point. These issues divide not along partisan lines but more along geographic lines. That is also true of the renewable energy debate generally. Also, the Senate has been the battleground for almost everything in the last two years. That dynamic will not change in the new Congress. Whether the House is controlled by Democrats or Republicans, it has had to swallow hard and accept whatever can get through the Senate.

Are there any significant issues in play at the administrative level in the federal government that the industry is watching closely?

MR. DURANTE: There were problems at DOE. We have seen some helpful changes there in attitude. Let me give you an example. A year and a half ago, there was absolutely zero, no interest whatsoever by anyone at DOE to put federal money toward blender pumps. The idea was that ethanol is a mature market that does not require such support. Then there was an acknowledgement that government support may be needed to get service stations to deploy pumps that can dispense E85. The industry said E85 is great, but there may be other grades we want use in the middle that would require a blender pump. About a month and a half ago, an assistant secretary at DOE said in a letter to block grant recipients that such grants funded with Recovery Act money can be used for blender pumps.

Another important regulatory development at the agency level is the effort by the Environmental Protection Agency to reduce greenhouse gas emissions. It could be a big help depending on how it is done. The key is to give credit for the greenhouse gas reduction in higher-level blends like E85.

MR. NUSSLE: I may have sounded a little pessimistic at times today, so let me tell you where I am optimistic. If you look back in recent history when there has been positive progress on policy at the federal level, it has often been during periods when Congress and the president were from different political parties.

The most recent example was the Clinton administration after the 1994 elections that put the House back in Republican hands. The parties had no choice but to work together, and they discovered that they shared a lot of common ground—for example, on such things as welfare reform. The Clinton library touts welfare reform as one of Bill Clinton's top accomplishments. Newt Gingrich lists it as one of his proudest accomplishments.

There may be the same opportunity in the next two years for President Obama and the Republicans in the divided Senate to work together. We are seeing it in the tax cut debate where the President cut a deal with Senate Republicans. There may be the same potential to act on a national energy policy; both parties agree it is something that should be done. Make no mistake, there will be a lot of disagreement and argument over budgets and taxes in short order leading up to and probably following a debt limit vote in the spring, but there will be an opportunity after that for the administration and Congress to figure out where they can work together. The welfare reform debate provides a model that energy policy might follow. ◎

PPPs in the Middle East

by Richard Keenan, in Dubai

There is currently a lot of focus across the Middle East on the public-private partnership as a viable means of procuring public infrastructure such as power plants, water desalination and wastewater, roads, transports, school and hospitals.

The PPP model undoubtedly has its pros and cons and its supporters and detractors. However, if a PPP project is effectively managed, the participation of the private sector should increase the likelihood that a project will be completed on time and on budget.

Use in the Middle East So Far

PPP projects have been done in the Middle East since the early 1990s. The Al Manah project in Oman was the first independent power project to be developed in the Persian Gulf using the PPP model. However, until recently, most PPPs have been done on an *ad hoc* basis without there being a PPP law or government policy underpinning the project.

In some sectors, this approach has proven to be very successful, particularly in the power and water sectors.

Some of the stand-out PPP models in the Middle East are the Abu Dhabi Water and Electricity Authority's power and water model, the Oman Power and Water Procurement Company's power and water model, the Bahrain power and water model and the Saudi power and water model.

Each of these authorities has implemented tremendously-successful PPP programs. These models have been tried and tested with the international banking market numerous times.

Why have the models used by these authorities been so successful?

There are a number of reasons. The economics of these projects are sound. Equity investors typically achieve an internal rate of return of at least 13%. The essential nature of the service contributes to the success. Electricity and water are basic necessities for which demand has skyrocketed over the last 20 years.

The level of government support behind these projects has also been very important. The support has taken various forms, but has included ministry of finance guarantees, although there has been a push back on these from certain tendering authorities over the last year or so. The sponsors of the Rabigh and PP11 independent power projects in Saudi Arabia did not benefit from a ministry of finance guarantee and neither will the sponsors of the Muharraq sewage treatment project in Bahrain.

Another form of support has been contractual assurances built into offtake agreements as to both fuel supply and power and water offtake—in effect the equivalent of a tolling arrangement. These structures ensure that the project is not exposed to market risk with respect to the offtake.

Payment regimes typically include guaranteed capacity payments in the event operation of the plant is affected by political force majeure. The project documents also provide for termination compensation that ensures the government is required to buy the project at a price sufficient to pay all outstanding senior debt in most termination cases, except where the project company defaults. There have also been tax and custom duty concessions and sovereign immunity waivers.

Well-structured project agreements with bankable risk allocation also have been a key to success. Mark ups of project documentation on bids for these projects have become lighter and lighter. It has become increasingly difficult for bidders of these projects to take the position that a particular provision is not bankable when it has been banked 10 times before. Mark ups of project documentation for these projects are now more or less confined to deal-specific content.

Another key factor has been very well-managed tendering processes. This has undoubtedly helped foster market confidence.

However, the track record in other sectors in the Middle East has not been so impressive.

There have been very few PPP projects in the transport sector. Abu Dhabi has recently tendered the Mafraq to Ghweifat highway project. There have also been very few projects in the health and education sectors. Abu Dhabi is probably again leading the way in the education sector having recently financed two university PPP projects—the Zayed and Paris-Sorbonne University PPPs.

Impediments to PPPs

Despite the success in some cases, significant impediments remain to broader use of PPPs in the region. The reasons for this are many and varied.

They include lack of political will to reduce public sector control over the provision of basic services, political and country risk (perceived or actual), lack of international investor and lender confidence with respect to PPPs in certain sectors, lack of PPP experience by some regional government departments and the absence of comprehensive PPP-enabling legislation or policy frameworks.

Some of these problems have led, in turn, to a difficulty in attracting the number and type of private sector participants needed to achieve the appropriate level of private sector competition that is so important for the successful implementation of PPP projects.

One may legitimately question whether a PPP law is necessary when there are a number of examples of very successful PPP programs in place in the Middle East that have been implemented in the absence of an enabling PPP law.

While most governments tend to have procurement rules, the rules are often not customised for PPP and can impede efficient procurement. In order for the private sector to invest in a PPP, the public sector should have the legal ability or basis to enter into long-term contracts and agreements with lenders and investors. The advantages of having a PPP law and framework are many.

A PPP law would provide a clear legal basis for a project by eliminating the potential for conflicting laws and legislation. This would help instill confidence in the private sector.

The implementation of PPP projects is often hindered by a lack of clarity in terms of how procurement rules are applied to a project. This sometimes delays projects resulting in increased costs for bidders and can even result in the cancellation of projects. One of the primary benefits from a PPP law is the establishment of clear procurement rules */ continued page 40*

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and procedures. Having transparent eligibility criteria makes potential bidders more confident they have a reasonable chance of winning the bid and attracting more bidders.

PPP laws often require the relevant authority, prior to tendering a project, to carry out an analysis of the economic benefits of the project and whether it is technically and commercially feasible.

This instills confidence in the market that the government has given due consideration to the need for the project prior to tendering the project and is not going to pull the plug on the project half way through the tendering process.

Most PPP laws embody a value-for-money requirement. The principle behind the value for money and a whole-life costing approach is that the government should seek the best value and not necessarily the lowest initial price. Bid comparison is carried out on whole-life costs (including maintenance costs). The bidders must ensure that their costs are the lowest for the whole life of the concession and not just the initial construction costs.

The way in which disputes are dealt with is often an area of concern for participants in PPP projects.

One area of particular concern to private investors is the enforceability of contracts against the government and the finality of judgements handed down by courts or arbitral tribunals outside the host country. Investors will usually desire some degree of certainty in this respect, seeking waivers of sovereign immunity and assurances that foreign judgements and arbitral awards rendered in accordance with a PPP project agreement cannot be litigated again in the courts of the host country.

One of the advantages of a PPP law is that they often regulate how disputes under project agreements are settled and allow for waivers of sovereign immunity.

PPP Legislation in the Middle East

Of the six Gulf Cooperative Council nations, Oman, Bahrain and Kuwait have gone the furthest in terms of implementing enabling legislation.

In 2002, the government of Bahrain enacted legislative decree No. 41, "With Respect to Policies and Guidelines of Privatization." In 2004, the government of Oman enacted a royal decree known as the "privatization law." Both the Bahraini and Omani laws are fairly broad in scope and essentially establish a platform for the privatization of industry sectors. The Bahraini law makes specific reference to the tourism, communications, transport, electricity, water, ports and airports, oil and gas and postal sectors.

The Omani privatization law is more prescriptive in terms of regulatory rules.

In contrast, the government of Kuwait in 2008 enacted what is commonly referred to in Kuwait as the PPP law. The legislation is comprehensive and establishes a framework for implementation of PPP projects in Kuwait. One of the things this law does is establish a partnerships technical bureau that is the central government agency for the PPP program. The bureau is in charge of the financial and technical evaluation of PPP projects and is involved in all phases of a project, from inception through to financial close.

With respect to the remainder of the GCC countries, Qatar, the United Arab Emirates and Saudi Arabia, the legislative framework is less developed.

That is not to say that these countries are trailing behind the others in terms of numbers of PPP projects. Abu Dhabi is probably leading the way when it comes to the development of PPP projects, and Saudi Arabia is not far behind.

Outside of the GCC, probably the country in the Middle East with the most advanced enabling legislation is Egypt. Last year, the Egyptian government adopted a "Law on Regulating the Participation of the Private Sector in Infrastructure and Public Utilities Projects."

The deal flow coming out of the PPP central unit in Cairo is impressive. The New Cairo wastewater project reached financial close last year. Requests for proposals are expected soon for the Abu Rawash wastewater treatment plant and the 6 October wastewater treatment plant. Two or three additional wastewater treatment plants are scheduled to hit the market within the next year.

Projects in the transportation, health, university and schools sectors have either recently hit the market in the form of requests for qualifications or requests for proposals or will do so shortly.

In terms of the power sector, the Egyptian government has recently adopted a five-year plan for new power generation. The Egyptian Electricity Holding Company is proposing to procure between 2,000 and 3,000 megawatts of new power plants each year for the next five years. The Dairut independent power project will be the first. This project is expected to be tendered in the first quarter of 2011. EEHC reported earlier this year that it received 19 separate applications in response to its request for qualifications in connection with the Dairut IPP.

There is an obvious correlation between the implementation of Egypt's new PPP law and the significant increase in the number of PPPs either currently in the market or very soon to come to the market in Egypt.

Egypt's PPP Law

Egypt's PPP law establishes a PPP central unit within the Ministry of Finance. The PPP central unit has overall responsibility for the development of the PPP program in Egypt.

The PPP law also establishes a "supreme committee for partnership affairs." Members of this body include the prime minister, various ministers and the head of the PPP central unit. PPP projects cannot be tendered without the approval of the committee.

Article 2 of the PPP law prescribes what must be in a PPP or "partnership contract." The duration of the partnership contract must be at least five years and cannot exceed 30 years from the date of completion of construction, provided that cabinet may, based on the recommendation of the supreme committee for partnership affairs, agree to enter into a partnership contract for more than 30 years if the project is essential to the public interest. The entire value of a partnership contract cannot be less than one hundred million Egyptian pounds. The project company is not permitted to start receiving any payments until an acceptance certificate in relation to the relevant works or plant has been issued by the relevant authority.

There a number of provisions supporting the financing of PPP projects that allow for the creation of share pledges in favor of project financiers or the creation of security interests in favor of lenders with respect to the project company's assets and for the relevant government authorities to enter into direct agreements with project lenders.

The relevant government ministries or agencies are entitled to amend the terms of a partnership contract. Such modification may include changes to the prices of products or the charges for the services, provided that the project company is compensated in accordance with the terms of the partnership contract.

There is an express prohibition on confiscation or compulsory acquisition of project assets by the government.

Each ministry or department of government that procures a PPP project is required to establish a prequalification committee for the purposes of determining whether a potential investor satisfies the eligibility criteria. Investors not included in the qualified investors list may file an objection against the qualification committee.

For each project, a project feasibility study must be carried out by a special committee set up for this purpose. Once this assessment is completed, the PPP central unit reviews the findings of this committee.

The procuring authority may, with the permission of the PPP central unit, elect to tender a project in two phases. The first phase will be a non-binding bid that includes the broad terms of the bidder's technical and financial offer followed by a "competitive dialogue" with the qualified investors. In the second phase, final bids will be submitted upon which the final evaluation is based.

Like many of the GCC tendering procedures, offers are submitted in two closed envelopes, one for the technical offer and the other for the financial offer.

Offers that are incompatible with the RFP conditions and specifications must be disqualified. Negotiations with a successful bidder may take place with respect to certain technical and financial aspects of an investor's bid. However, these negotiations must not tackle any contractual terms of the RFP that are stipulated as being non-negotiable or any terms that are not subject to reservations raised by the bidder in its offer.

A tender may be cancelled in the event only one offer is submitted or if there is only one offer left after the disqualification process, if all or most of the bids contain reservations that are incompatible with the RFP requirements, if assumptions or reservations made by the bidders are difficult to evaluate, or if the value of the lowest priced offer is unjustifiably more than the government price endorsed by the supreme committee for partnership affairs.

The PPP law establishes a grievance committee composed of various government officials. The grievance committee has the power to consider all grievances and complaints submitted by the investors or consumers during the bidding, awarding and execution phases of partnership contracts. Any decision it renders is final and binding. ◎

ENVIRONMENTAL UPDATE

Environmental Update

A federal "tailoring rule" took effect on January 2, 2011 in all states except Texas. The tailoring rule sets thresholds for when emissions of greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons and sulfur hexafluoride) will trigger the need to get so-called title V permits and to undergo a separate review process under a "prevention of significant deterioration" or "PSD" program.

During the first six months of 2011, a review will be required under the PSD program for existing facilities that are already covered by the program and that increase their greenhouse gas emissions by more than 75,000 tons per year of CO_2-equivalent (a measure of global warming potential). During this time, existing major greenhouse gas emitters and new major sources obtaining title V permits for non-greenhouse gas pollutants will also be required to have permits covering their greenhouse gas emissions. However, no one will be required to get a title V permit solely on account of its greenhouse gas emissions.

During the last six months of 2011, the PSD program will be triggered for new facilities emitting more than 100,000 tons per year of CO_2-equivalent or modified existing facilities emitting more than 75,000 tons per year of CO_2-equivalent, regardless of whether these facilities trigger the need for a title V permit under the PSD program for other regulated pollutants. New and existing facilities not already subject to the title V program that emit or have the potential to emit more than 100,000 tons per year of CO_2-equivalent will be required to obtain title V permits for their greenhouse gas emissions.

With the exception of Texas, all other states either have revised their respective state implementation plans that explain how states will implement the PSD program, or have ceded authority to EPA to issue permits under the tailoring rule to avoid any permitting delays. Texas takes the position that EPA does not have the authority to regulate greenhouse gas emissions from facilities in Texas and refused to cede permitting authority for greenhouse gases to EPA.

On December 30, 2010, EPA issued an "interim final rule" revoking approval it had given earlier to part of the Texas state implementation plan for air pollutants because the plan failed to address how new pollutants like greenhouse gases would be handled.

Power plants and factories may need permits starting this year to increase their greenhouse gas emissions.

In the absence of an approved state plan for greenhouse gases, EPA would have assumed permitting authority for such gases on January 2, 2011. Texas would retain authority to issue permits for other regulated pollutants like nitrogen oxides.

The same day as EPA revoked its approval, Texas convinced a US appeals court in Washington to issue an emergency "stay" to block the EPA action. Until the dispute is resolved, facilities that are major sources of greenhouse gas emissions in Texas will probably have to postpone any planned new construction or major modifications to existing facilities that may trigger the tailoring rule since any permits that might be issued by Texas without limiting greenhouse gas emissions would almost certainly be challenged by citizen groups.

BACT

Permits issued under the PSD program must set emissions limits for a range of pollutants based on best available control technology or "BACT." Now that greenhouse gases are regulated under the PSD program, the question becomes what is BACT for such emissions?

Section 169(3) of the Clean Air Act provides the following definition of BACT:

> *an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation … emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such facility through the application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, treatment or innovative fuel combustion techniques for control of each such pollutant. Any proposed major stationary source or major modification which the [US Environmental Protection Agency], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.*

EPA released guidance in November to assist permitting authorities and permit applicants to determine BACT for greenhouse gases.

In this guidance, EPA suggests using the same five-step process that is already used to determine BACT for other pollutants regulated under the PSD program like nitrogen oxides.

Step 1 Identify all available control technologies. In this initial step, all available emissions control technologies for the greenhouse gas should be identified and ranked from most to least effective for emissions control.

Step 2 Eliminate technically infeasible options.

Step 3 Evaluate and rank the remaining emissions control technologies.

Step 4 Evaluate the most effective controls and document the results.

Step 5 Select the BACT. The highest ranked emissions control technology that has not been eliminated is selected.

Under the guidance, identified control technologies that are not considered "achievable" are eliminated from consideration. EPA explains that BACT is not achievable if the "permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental or economic impacts justify a conclusion that the top-ranked technology is not 'achievable' in that case."

EPA released two white papers discussing greenhouse gas emissions control technologies for coal-fired power plants and cement production facilities and set up a greenhouse gas mitigation strategies data base. The agency expects to continue adding information to the data base, including performance and cost information for greenhouse gas mitigation measures. EPA also expects to release additional white papers for other sectors of industry.

EPA recommended including carbon capture and sequestration, modification of production process or even fuel switching in the list of possible best available control technologies, but acknowledges that technologies like carbon capture and sequestration may be cost prohibitive and will ultimately be eliminated from consideration during the BACT analysis process.

The agency emphasized the role of increased energy efficiency as a best available control technology.

The biomass industry is awaiting additional guidance in January that EPA indicates will provide the framework to assess the environmental, energy and economic benefits of biomass for purposes of the BACT analysis.

In addition, EPA indicated that it expects to determine whether carbon emissions from bioenergy or biogenic sources should be counted for purposes of triggering the PSD program for greenhouse gases and, if so, how such emissions should be quantified. This guidance is expected in May. Many expect investment in biomass projects to cool until it is issued.

BACT for greenhouse gases will also be shaped by settlements to which EPA agreed to settle lawsuits requiring it to set "new source performance standards" for greenhouse gases from power plants and petroleum refineries under section 111 of the Clean Air Act. Section 111 requires the agency to establish federal emission standards for industrial facilities that cause or contribute significantly to air pollution. These standards act as the floor for determining BACT for specific industries. Under the power plant settlement decree, EPA must propose new source performance standards for new facilities and propose emission guide-

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Environmental Update

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lines for existing facilities by July 26, 2011 and finalize the standards by May 26, 2012. EPA has said that it is unlikely that existing facilities would need to reduce greenhouse gas under any such new source performance standards until 2015 or 2016. Owners of many existing power plants may determine that it is not economical to comply with the new standards.

Clean Air Act New Source Review

Setting aside possible closures resulting from implementation of any new source performance standards, many fear that implementation of the tailoring rule and BACT for controlling greenhouse gas emissions will accelerate closures of coal-fired power plants across the country.

Even if such plants are not planning any modifications that would trigger the need to get a new permit under the tailoring rule, EPA and citizens groups may force shutdowns by pursuing new source review program violations.

Certain plant modifications that are considered major trigger review under the new source review program and may require adoption of new pollution control measures. Even though these modifications may have been made years ago, EPA can require facilities to comply with current BACT even if the modifications that were made many years ago would have triggered a less stringent BACT.

If new source review violations are found, it may make economic sense to close a plant rather than install a new BACT. For example, in May 2010, American Municipal Power announced that it would permanently retire its coal-fired power plant near Marietta, Ohio under a settlement to resolve violations of the new source review program. As part of the settlement, American Municipal Power must pay a civil penalty of $850,000 and spend $15 million on an environmental mitigation project. The settlement resolved allegations that certain work performed at the facility during the period 1981 to 1986 (before American Municipal Power even had an interest in the facility) and during the period 1988 to 1991 (after American Municipal Power had an interest in the facility) triggered the new source review program.

Although EPA will continue targeting investor-owned utilities for new source review violations, it now appears to be moving on to state- and municipally-owned utilities. It has been reported that dozens of Clean Air Act section 114 letters were sent to state- and municipally-owned utilities in Wisconsin and Ohio in December. Section 114 letters ask for information about past modifications at a facility and are considered by many to represent the start of an enforcement action.

— contributed by Andrew Giaccia, in New York, and Sue Cowell, in Washington.

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