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PROJECT FINANCE
NewsWire

April 2014

Outlook for Utility-Scale Renewables in California

by Laura Norin, Julia Getchell and Heather Mehta with MRW & Associates, LLC, in Oakland

Near-term surpluses of renewable energy, a sharper focus on costs and heightened concerns over environmental impacts are the new realities in the California market for utility-scale renewable power.

California's largest investor-owned utilities are expected to slow the rate at which they procure renewable energy in the near term as they meet or draw near to meeting their regulatory mandates under the state's renewable portfolio standard.

As the cost of renewable resources has fallen, regulators and utilities have both sharpened their pencils when it comes to new projects, and only projects that are competitive with the new market realities are winning in utility solicitations.

Finally, regulators are more rigorously evaluating the environmental impacts of large-scale solar and wind projects, and projects with significant environmental impacts face an uphill battle to win regulatory approval.

California is not turning away from renewable energy, but developers are likely to find a more competitive marketplace in the near term. Projects that can offer a cost or technology advantage will fare better in this tight market. Looking farther out, demand could rebound once regulators and legislators define the post-2020 renewable portfolio standards. / continued page 2

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CONSTRUCTION-START ISSUES are proving too factual for the Internal Revenue Service to address in private rulings.

Most renewable energy projects in the United States — other than solar and fuel cell projects — had to be under construction by December 2013 to qualify for federal tax credits. Production tax credits of 2.3¢ or 1.1¢ a kilowatt hour — depending on the type of project — can be claimed on the electricity output for 10 years, or else an investment tax credit for 30% of the project cost can be claimed in the year the project is put in service.

The Internal Revenue issued two notices in 2013 explaining when a project will be considered under construction in time.

IRS officials suggested last fall that they may / continued page 3

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Meeting the 33% RPS Mandate

California's renewable portfolio standard of 33% renewable power by 2020 has led to a decade-long boom in renewable energy project development. However, the state's largest utilities — Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric — have over-procured renewable power for the near term and claim to have enough projects under contract to meet most or all of the 2020 RPS mandate.

Presently, the utilities are exceeding annual renewable energy targets and are banking or selling off their surpluses to draw upon in later years. PG&E anticipates that it will not need to draw on its banked RPS credits until 2019 and will have enough banked credits to meet a 33% RPS requirement through late 2023. To continue meeting a 33% annual RPS target beyond 2023, PG&E forecasts that it will need an average of 9,500 additional GWh per year from 2024 through 2030 (see Figure 1 on page 4).

SDG&E similarly anticipates that it will continue to contribute surplus RPS credits to the bank through 2019 and that, between ongoing contracts and banked RPS credits, it has enough contracted resources to meet a 33% RPS requirement through 2025. SDG&E estimates that it will need an average of 2,000 GWh of incremental renewable power each year from 2026 through 2030 (see Figure 2 on page 4).

Southern California Edison's surplus is not as large as PG&E's or SDG&E's. SCE anticipates tapping into its banked reserves by 2017, exhausting its balance in 2020, and needing an additional 7,300 GWh of renewable energy in 2020 to meet the 33% RPS requirement for that year. SCE forecasts an increasing procurement deficit post-2020, with a need, on average, for an additional 13,000 GWh of renewable procurement per year to meet a 33% RPS requirement from 2021 through 2030 (see Figure 3 on page 4).

The utilities' assessments suggest limited contracting opportunities for renewable projects coming on line before 2020. However, these numbers do not tell the whole story because uncertainty associated with the utilities' forecasts may increase or decrease the forecasted need for additional renewable procurement. These uncertainties affect both the demand and supply sides of the equation.

On the demand side, the primary uncertainty is the level of future electricity sales. If sales (i.e., consumption) are higher than anticipated in the RPS assessments, then RPS requirements will be correspondingly higher and the utilities will draw down banked credits more quickly. The need for new procurement would occur earlier than currently anticipated. This is a symmetrical risk, as lower electricity sales would reduce the RPS requirement and delay the need for new procurement.

The three main California utilities may not need more renewable electricity before 2020.

In addition to the utilities' preferred RPS procurement forecasts presented above, the utilities also developed alternate forecasts that use sales assumptions from the California Public Utilities Commission. Under the alternate sales forecasts, PG&E would have less need for incremental renewable procurement than in its preferred forecast (with PG&E's RPS procurement deficit delayed from late 2023 to 2025), and SCE would have greater need for incremental renewable procurement than in its preferred forecast (with SCE's RPS procurement deficit starting in 2019 instead of 2020).

On the supply side, there is the risk that some contracted projects will fail to achieve commercial operation or will be delayed. Projects under development face any number of hurdles in financing, permitting, interconnection and completion of construction. Delays and cancellations are not uncommon. Historical project failure rates have been as high as 30%

to 40%. While failure rates appear to have fallen significantly in recent years, project delays and failures remain a concern.

Many of the projects included as existing contracts in the utilities' procurement plans remain under development. For example, as of December 2013, only about half of the 74 renewable energy projects included in SDG&E's plan to meet its 2020 RPS were operational, with nine projects under construction and 27 projects in the pre-construction phase. SDG&E has acknowledged that some of these projects are experiencing project development-related issues that may affect their ability to meet commercial operation deadlines or even to come on line.

Development risk is accounted for in the utilities' procurement plans to varying extents. SDG&E assigns a probability of success to each individual project, with an average success rate of 75% for approved projects that have not yet begun delivering energy. SCE uses project-specific, risk-adjusted success rates for large, near-term projects that are not yet on line and a success rate of 50% for projects with commercial operation dates more than three years out. PG&E assigns a success rate of 0% to high-risk projects and assigns a success rate of 100% to all other projects. PG&E defines high-risk projects as those that have failed to meet contractual deadlines or have certain known issues that place them at risk for doing so, as well as projects that were operating in the past but have ceased operation. Accordingly, it appears that PG&E would assign a success rate of 100% to a newly-contracted project that had not yet received CPUC approval as long as that project had no known financing, permitting or interconnection issues. To the extent that this assessment or the other utilities' risk assessments underestimate project failures and delays, there may be a need for additional renewable procurement to replace contracts that do not deliver as planned.

There is a possibility, as well, that the CPUC will modify the risk assessment approach that is used in the calculation of need for new renewable procurement. The CPUC is concerned that the utilities' assumptions of project risk are insufficient. The utilities' confidential assessments have not been benchmarked against actual project success, and the utilities have been unwilling to provide data publicly that would allow such benchmarking.

In February 2014, the CPUC staff proposed formal benchmarking of utility risk assessments through an independent analysis of projects under development using a public methodology that assesses a project's risk / continued page 4

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be willing to issue private rulings about individual projects, as long as the rulings ask purely legal questions about how to interpret the rules rather than how then to apply them to particular fact patterns.

However, after considering at least four ruling requests, the agency appears to have decided that questions in this area are inherently too factual. The IRS returned the fee that it charges for processing ruling requests in all four cases.

Meanwhile, the Senate tax-writing committee voted April 3 to extend the construction-start deadline by another two years through December 2015. The extension is part of a larger "tax extenders" bill that would extend more than 50 tax benefits.

The bill goes next to the full Senate, where it is expected to pass. The outlook in the House is uncertain. The House tax-writing committee chairman, Dave Camp (R-Michigan), has wanted to keep the focus on major corporate tax reform. However, Camp decided in March to retire at year end. The House tax-writing committee voted on April 29 to extend six expiring tax benefits. Camp said the vote is the start of a more drawn-out process of considering extenders.

Any extenders bill the House passes is not expected to allow more time for renewable energy developers to start construction. Any additional time will have to be settled in negotiations between the House and Senate.

Solar companies had hoped to persuade the Senate to convert a December 2016 deadline to place solar projects in service to qualify for a 30% investment tax credit into a deadline merely to have started construction of such projects. Senators Maria Cantwell (D-Washington) and Michael Bennett (D-Colorado) offered an amendment to do this during the tax committee mark up on April 3. However, the amendment had to be withdrawn because it was not considered germane. The underlying bill only addresses tax breaks that expire in 2013 and 2014.

Senator John Thune (R-South Dakota) tried to persuade the committee to phase out production tax credits for wind. / continued page 5

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Figure 1: PG&E RPS Procurement Forecast

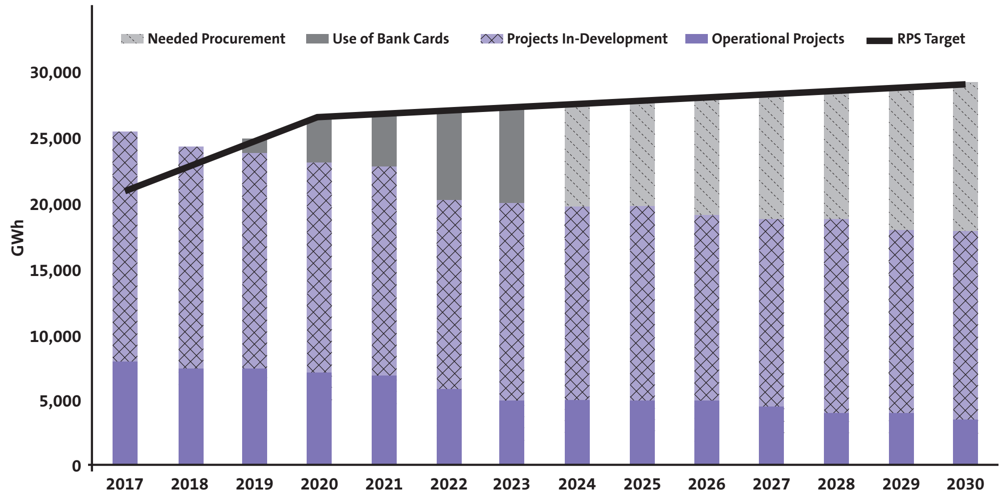


Figure 2: SDG&E RPS Procurement Forecast

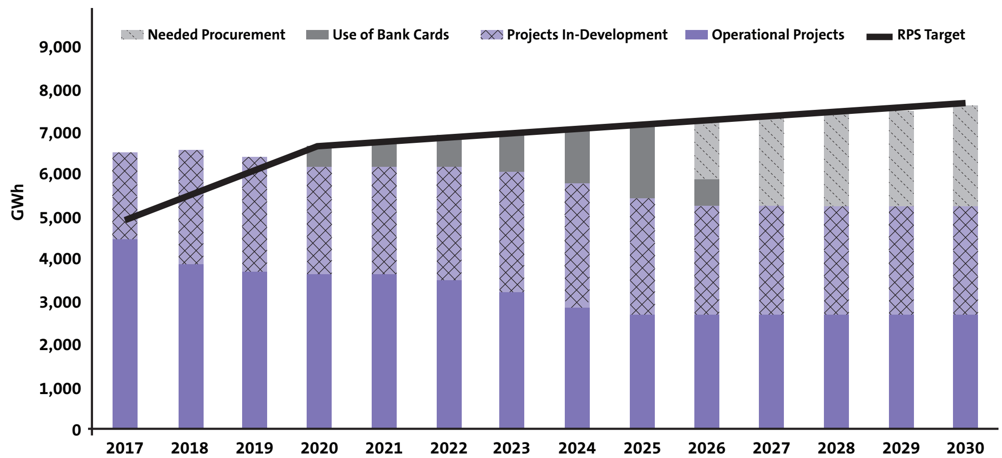
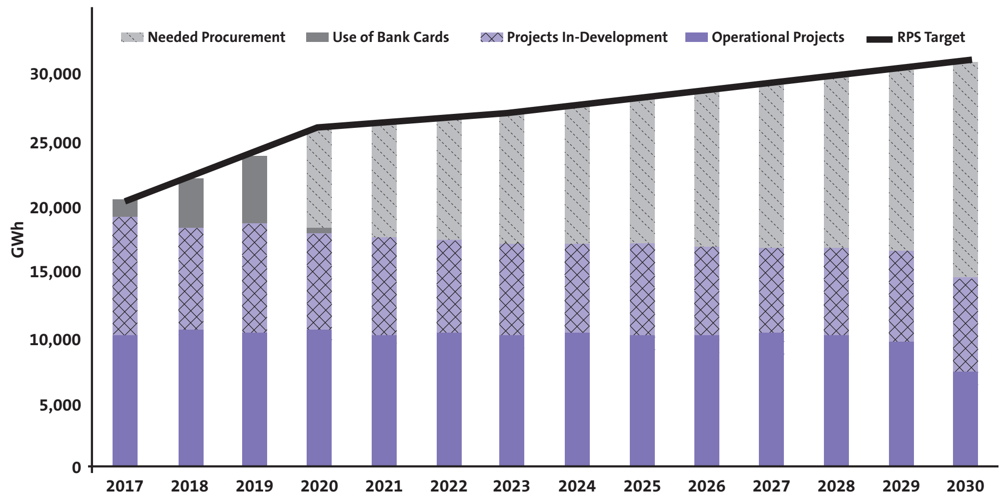


Figure 3: SCE RPS Procurement Forecast



based on the following weighted project viability categories: project technology (10%), the developer's experience (15%), site control status (25%), permitting status (25%) and interconnection progress (25%).

Under the proposal, the CPUC staff would assign each project a viability score based on a standard rubric that assesses each of these elements using pre-determined metrics. (This rubric would be a simplified version of the existing "project viability calculator.") For example, the score for developer's experience would be assessed as follows: 50 points for no demonstrated experience developing renewable energy projects, 75 points for any demonstrated experience developing renewable energy projects, 90 points for demonstrated experience developing renewable energy projects of similar size and technology, and 100 points for demonstrated experience developing renewable energy projects of similar size and technology in the utility's service territory. The CPUC staff would use the project viability score to adjust a utility's entire portfolio of RPS projects under development for risk. Staff would then benchmark the staff's risk adjustment scores against each utility's own risk adjustment to determine if there are any outliers that the utility would be required to justify in its annual RPS plan.

The CPUC is expected to issue a decision on this matter in the second quarter of 2014. It is too early to predict whether the decision will increase contracting opportunities.

Additional contracting opportunities could also emerge if the utilities sell some of their surplus renewable power to third parties with near-term need for renewable energy credits. For example, if an entity with the need for RECs in 2015 purchases some of PG&E's banked RECs, PG&E's need for new power contracts could advance by several months or more in the early 2020s when it currently anticipates relying on banked credits to meet its RPS requirements. This situation would open up new opportunities for competitively-priced renewable energy projects that are not already operational (i.e., projects that could not meet the near-term REC need directly but could meet the replacement power need in the early 2020s). The utilities have said that they will sell banked credits only if the sales price is higher than the replacement power cost. This is possible given the steep decline in renewable prices in recent years; however, opportunities are likely to be limited.

Focus on Price

The cost of the renewable energy contracts that make up the current RPS portfolio has prompted both / continued page 6

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Thune offered an amendment to limit tax credits on wind projects put in service after 2014 to only a fraction of the normal rate. The fraction would have been 90% for projects put in service in 2015, 80% in 2016, 70% in 2017 and 60% in 2016. Projects put in service after 2016 would not qualify for any production tax credits. The amendment was not included in the final bill.

The Senate extenders bill would also extend a number of other tax breaks of interest to power and other infrastructure companies. Only a few of these are expected to be included in any House bill.

The bill would extend a 50% depreciation bonus for assets placed in service through 2015. (A bonus could also be claimed on longer-lived assets put in service in 2016, but only on the costs incurred through 2015.) A 50% bonus is the ability to deduct 50% of the "basis" in the project immediately in the year a project is completed. The remaining 50% is deducted over the normal depreciation period — for example, five years for a wind or solar project.

Companies engaged in domestic manufacturing in the United States pay taxes currently on only 91% of income from such manufacturing. Generating electricity is considered manufacturing. This provision also applies to income from manufacturing in Puerto Rico, but only through 2013 and only if all of the company's income earned in Puerto Rico is subject to federal income taxes in the United States. The bill would extend the ability to pay a reduced tax on Puerto Rican manufacturing income through 2015.

Projects on Indian reservations qualify for faster depreciation — for example, accelerated depreciation over three years rather than five years for wind and solar projects and nine years for gas-fired power plants. Projects had to be completed by 2013 to qualify. The bill would extend the deadline through 2015. It would also extend a wage credit for employing enrolled members of Indian tribes who live on or near reservations. The credit is 20% of wages and the cost of health insurance / continued page 7

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concern and optimism in California.

The concern is that expensive renewable energy will lead to higher retail electricity rates for consumers at the same time that other factors are already driving up power costs. For example, Energy and Environmental Economics, Inc. forecasted in 2012 that rates in 2020 will be 8% higher than they would be under an all-gas scenario due to the 33% RPS, while prices will be more than another 11% above 2011 rates in real terms for non-RPS reasons such as the need to replace aging transmission and distribution infrastructure, pay for Smart Meter projects, and repower or replace generators to comply with once-through cooling requirements.

Projects that include storage may have an advantage in upcoming solicitations.

On the other hand, there is room for optimism due to the decline in renewable energy prices over the last few years. While the weighted average price of bundled renewable contracts approved from 2003 through 2011 was 12.2¢ per KWh for PG&E, 10.1¢ per KWh for SCE and 11.6¢ per KWh for SDG&E (in nominal dollars), bundled renewable contracts approved in 2013 had declined on average to 6.7¢ per KWh for PG&E, 8.9¢ per KWh for SCE and 7.5¢ per KWh for SDG&E. This decline reflects lower bid prices in the 2010 to 2012 RPS solicitations, consistent with industry-wide cost reductions.

Given these cost reductions, regulators are now able to exercise some cost discipline and greater selectivity in approving modifications to existing contracts, knowing that modifications to contracts from past solicitations that are denied are likely to be replaced by lower-cost contracts in future solicitations. So far, however, the CPUC has been very selective in exercising this option, with the rejection in October 2012 of three of BrightSource's proposed solar thermal projects being the notable exception.

Despite the downward trend in prices, legislators have expressed concerns with the upward pressure on retail electricity rates resulting from RPS procurement. As part of the 2011 legislation that increased the RPS from 20% to 33%, the CPUC is required to implement a "procurement expenditure limitation" in order to impose some cost discipline on the RPS procurement process. The CPUC is currently considering methods for establishing such a limitation. The CPUC staff has proposed a method that would establish a ratio of RPS procurement expenditures to a utility's total revenue requirement over a 10-year period. The ratio would provide a benchmark to indicate whether the forecasted RPS procurement is likely to put upward pressure on retail electricity rates. Other parties have proposed alternative methods.

According to an illustrative example provided by CPUC staff, SCE's annual "procurement expenditure limitation" ratios under the staff's proposed methodology would range from 14.6% to 21.2% over the 10-year period from 2014 through 2023. The ratio would essentially set an overall budget for SCE of $26.9 billion to spend on procuring RPS-eligible energy in that time frame. In 2013, SCE spent $1.4 billion, or 11.9% of total revenue requirement, to achieve an RPS level of 23.2%. Adjusted to account for the higher 2014 to 2023 RPS requirement, this level of expenditure — $17.4 billion over the 10-year period — would still remain well within this illustrative budget. While these results are merely illustrative since a final methodology has not yet been adopted, given this outcome, it remains to be seen whether the procurement expenditure limitation methodology will impose real price discipline or will serve only as a high ceiling price.

Regardless, price discipline will continue through competition among renewable energy developers. Market competition and reduced project costs have driven down the cost of newly-approved renewable contracts by more than 25% since 2011 and are likely to continue putting downward pressure on prices, particularly if new contracting opportunities remain limited in the near term.

Minimizing Environmental Impacts

Environmental concerns over the impacts of large-scale renewable energy projects are moving to the foreground as well. This reflects to some degree the knowledge and experience gained as the initial wave of renewable projects complete construction and begin operations.

In December 2013, a California Energy Commission siting committee released a proposed decision recommending that the CEC deny BrightSource Energy's application to convert the proposed 500-MW Palen project from a solar thermal parabolic trough project to a project that uses BrightSource's solar thermal power tower technology, in large part due to concerns over avian mortality.

The Palen project's power tower system would create steam by using a field of 85,000 elevated mirrors known as heliostats to focus the sun's rays onto a steam generator that sits atop a 750-foot tower near the center of the heliostat field. As proposed, Palen would consist of two adjacent 250-MW fields.

The CEC previously approved a different BrightSource power tower project, the 377-MW Ivanpah project, which consists of three 459-foot power towers and 173,500 heliostats. The CEC approved the Ivanpah project in September 2010 and concluded that the clean energy benefits of the project outweighed its significant impacts on cultural, visual and environmental resources, and that no feasible site or generation technology alternatives to the project existed that would reduce or eliminate the project's significant environmental impacts.

Concerns about the impact of power tower technology on avian mortality began to surface during construction of Ivanpah, when BrightSource's monthly compliance reports filed with the CEC listing avian deaths indicated possible increased mortality, particularly during the migratory months. BrightSource reported 23 avian deaths at Ivanpah in January 2014, up from the 13 deaths recorded in December 2013 and 11 reported in November 2013, but still less than the 52 reported in October 2013.

In the proposed decision denying Palen, the CEC siting committee, consisting of Commissioners Douglas and Hochschild, concluded that, as proposed, Palen would / *continued page 8*

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for such employees. However, the credit does not apply to any worker who is paid more than $45,000 a year (the 2013 figure before adjusting for inflation).

The bill would allow companies producing coal from reserves owned by or held in trust for Indian tribes to claim another two years of tax credits on the coal produced. The credit was $2.308 a ton. It is adjusted each year for inflation. The mine producing the coal had to be in service by December 2008. The placed-in-service deadline was not extended.

Contractors building new homes get a tax credit of $1,000 to $2,000 for making them energy efficient. The credit is $1,000 if the energy usage is reduced by at least 30% compared to a 2006 baseline and $2,000 if the energy usage is reduced by at least 50%. The bill would allow the credit to be claimed on new homes sold through 2015.

The bill would authorize another $3.5 billion in new markets tax credits in each of 2014 and 2015. The new markets tax credit is a 39% tax credit taken over seven years on investments in "community development entities" that make loans or equity investments in projects in low-income areas. The credit has sometimes been claimed on investments in power projects in rural areas.

Finally, the bill would extend various tax credits for making or mixing cellulosic biofuel, biodiesel, renewable diesel and other alternative fuels. However, ethanol credits were not extended. There was also no extension in the ability of paper companies to claim refundable tax credits for mixing black liquor with other fuels.

A technical corrections bill also approved by the committee on April 3 makes clear that section 1603 Treasury cash grants for renewable energy projects do not have to be reported as income under the alternative minimum tax. The American Recovery and Reinvestment Tax Act in 2009 already made clear that they do not have to be reported as income for regular income tax purposes.

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result in significant, unmitigable impacts on local environmental, visual and cultural resources, and that the solar flux generated from the project's solar towers would probably harm birds. The committee said the original solar trough project or a conversion to photovoltaic technology would be the preferred options for the project site. In an effort to avoid a CEC decision denying the project, BrightSource requested that the commission postpone voting on the proposed decision until at least the spring of 2014, to allow the company more time to present additional data on avian mortality being gathered at Ivanpah and from other projects employing alternative solar technologies.

The difficulties faced by BrightSource are, to a certain extent, technology specific and are not indicative of a wholesale change in sentiment against large-scale solar. At a January 2014 conference on the proposed decision regarding Palen, the CEC noted that BrightSource still has the option to build Palen as the solar thermal parabolic trough project that has already been approved or to propose a different project on the site. Commissioner Hochschild specifically asked concerned parties not to read the proposed decision as a strike against solar thermal and emphasized the benefits of the technology, stating that he believed it has a role to play as California expands its clean energy portfolio.

That same month, the CEC also demonstrated that significant environmental impacts will not necessarily undermine a renewable project, as it unanimously approved an amendment to modify the proposed Blythe project from a 600-MW solar parabolic trough project to a 485-MW solar PV plant, even though significant environmental impacts were identified. The CEC concluded that the project would result in benefits that outweighed these impacts and that there were no feasible alternatives to the project that would reduce or eliminate any of the impacts.

Environmental impacts are also a concern with wind projects, and avian mortality issues in particular have come to the fore in this context as well. The US Department of the Interior recently began granting wind developers eagle "take" permits lasting up to 30 years that, under the Bald and Gold Eagle Protection Act, shield projects from liability for unavoidable bird deaths at wind plants. (In the past, the Interior Department only issued take permits that lasted for up to five years.) To be eligible for these extended permits that will be subject to review every five years, wind plant operators must agree to regular monitoring and adaptive conservation measures. This approach provides greater certainty for renewable energy developers while offering some measure of protection to threatened species.

The state may announce a higher renewable portfolio standard for 2030 in 2016 to allow ample time to build.

These decisions, both at the CEC and the Department of the Interior, show how government agencies are trying to find a balance between renewable energy development and environmental protection. The agencies are still trying to find the right balance, and this creates risk for developers. While most projects that are thoughtfully sited are not likely to be rejected on environmental grounds, as BrightSource found, the risk of rejection is all too real, particularly for less-tested technologies.

Potential New Opportunities

Despite the slowing growth in demand for renewable energy projects, downward price trends and more stringent reviews of environmental impacts, opportunities for new utility-scale renewable projects still exist in California.

The utilities' assessments of when they will need to ramp up procurement of renewables and how much to procure are based on a 33% RPS mandate. The likelihood is quite high that there will be a need for a greater level of renewable resources after 2020 as California continues to pursue its goal of reducing greenhouse gas emissions to 80% below 1990 levels by 2050. As part of that effort, the California Air Resources Board has recommended that the RPS target for 2030, expected to be above 33%, be set in 2016 to allow enough time for contracting and development.

In addition, the state legislature recently granted the CPUC the authority to require utilities to buy more renewable energy than required under the RPS requirement. While the CPUC has not indicated its intention to do so on a universal basis, this could open up opportunities in specific circumstances. For example, a March 2014 decision that directs Southern California Edison and SDG&E to procure 40% (600 megawatts) of the power needed to replace the closed San Onofre nuclear power plant from preferred resources may lead in the near term to opportunities for new renewable power development above the RPS-driven requirements.

A similar opportunity would likely emerge in the event that the PG&E Diablo Canyon nuclear power plant licenses are not extended beyond their current expirations in 2024 and 2025. The CPUC has already put PG&E on notice that the utility will need to justify the economic costs and benefits of the large nuclear plant before the CPUC authorizes any ratepayer funding for a federal relicensing application. Should the plant not be relicensed, the carbon-free power that Diablo Canyon currently generates is likely to be replaced to a large degree from renewable resources and other preferred resources.

Additional opportunities could also open up in the near term due to utility load growth (which triggers the need for additional RPS procurement since the RPS target is a percentage of load), unanticipated contract failures, a change in the methodology for predicting contract failure rates, or utility sales of banked RPS credits to third parties. These opportunities are likely to be limited.

Renewable projects that incorporate energy storage technologies may have an advantage in upcoming solicitations. California faces a significant challenge in balancing the increasing share of variable energy resources on the grid, and the CEC and the CPUC have both made it clear that they are looking to storage as part of the solution. For example, CEC Commissioner Douglas indicated that the addition of thermal storage capability would greatly strengthen BrightSource's application for the Palen project. Similarly, when the CPUC rejected three BrightSource solar thermal contracts in / continued page 10

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THE CAMP TAX REFORM BILL has many provisions that would affect independent power and other infrastructure projects in the United States.

The bill was released as a discussion draft by the Republican chairman of the House tax-writing committee, Dave Camp (Michigan), in February. It is not expected to be enacted this year, and Camp is retiring at the end of the year. However, it may serve as a marker for future efforts in Congress to reduce corporate income tax rates.

Both major political parties want to reduce the corporate income tax rate. Republicans want to take the rate from the current 35% to 25%. The Obama administration said it would support a 25% rate for income from domestic manufacturing and 28% for other income. The current Congress has been unable to reach agreement on much of anything. Elections are scheduled for November. Republicans control the House and, based on current polls, have a good chance of also having a majority in the Senate after November.

The corporate tax rate cannot be reduced without eliminating tax breaks or imposing new taxes to make up the lost revenue.

The Camp bill is the first serious effort to show how this might be done.

The bill would reduce the corporate tax rate to 25%, but not until 2019. The rate would be reduced by 2% a year over five years from 2015 through 2019. The bill includes more than 200 revenue raisers.

Production tax credits would revert to their original uninflated value of 1.5¢ a KWh for electricity sold after 2014. Production tax credits for refined coal would revert to $4.375 a ton for refined coal sold after 2014.

Wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects built in the future qualify for production tax credits on the electricity output under current law if the projects were under construction by December 2013. There is no hard deadline in current law to complete projects that were under construction in time. However, the developer must show he worked / continued page 11

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part on economic grounds, the CPUC at the same time accepted an uneconomic BrightSource contract for a solar thermal project with accompanying storage and even accepted a second uneconomic BrightSource contract for a solar thermal project on the grounds that the project was needed to lay the groundwork for a more advanced project with storage to be financed and built.

Renewable projects with storage may be eligible to bid in the solicitations that the utilities are preparing to issue by December 2014 to procure additional storage capacity toward meeting a CPUC-mandated target of 1,325 MW of storage by the end of 2024.

Thoughtful project siting will also remain key. The US Department of Energy and the US Bureau of Land Management jointly established the solar energy zones program in 2012, which identified 17 solar energy zones in the western US, defined as areas with few impediments to utility-scale production of solar energy where BLM would prioritize solar energy and associated transmission infrastructure development. In addition to the 285,000 acres in the 17 solar zones, BLM identified roughly 20 million acres outside of the zones that are available for right-of-way or lease applications if developers apply for a "variance." Projects in these zones will have permitting advantages over projects located outside of these preferred areas. ◎

DOE Reopens For Renewable Energy Loan Guarantees

by Kenneth W. Hansen, in Washington

The US Department of Energy loan guarantee program has come back to life.

The loan program office released a new loan guarantee solicitation on April 16 seeking applications for up to roughly $4 billion in financing for innovative renewable energy and energy efficiency projects in the United States that "reduce, avoid, or sequester greenhouse gases." The Department of Energy wants projects that are "catalytic, replicable, and market ready."

The solicitation does not set a date when part I applications will be due. It suggests that there will be multiple deadlines, with part I deadlines commencing in 2014 and extending into 2015 and with part II application deadlines lasting into 2016.

Percolating Along

As the latest solicitation demonstrates, not only is the DOE loan guarantee program alive, in fact it never died, notwithstanding the best efforts of some corners of Congress.

The agency has not accepted new applications for renewable energy projects for nearly four years since August 24, 2010, and all renewable energy projects qualifying for loan guarantees under the so-called section 1705 program for renewable energy projects were required to reach financial closure by September 30, 2011. Congress authorized section 1705 loan guarantees in 2009 as an economic stimulus measure. The program attracted a lot of unwelcome attention after loan guarantee recipient Solyndra went bankrupt.

However, the loan guarantee program has always been about more than just economic stimulus. The section 1703 part of the program for projects using innovative technologies predates the stimulus and has continued forward, albeit haltingly during the Solyndra hearings.

To be sure, there has not been a lot to show from the original section 1703 applications save one, but it was an important one. DOE closed a $6.5 billion loan guarantee to finance the Vogtle nuclear power station in Georgia on February 20, 2014 based on an $8.3 billion conditional commitment issued in

February 2010, following the nuclear solicitation issued on June 30, 2008. This was the first, and so far sole, financing to close under the original section 1703 program.

An important difference between loan guarantees issued under section 1703 and those issued under section 1705 is that the section 1703 program has historically required the borrower to pay all credit subsidy costs at financial close from non-federal funds. Credit subsidy costs are the equivalent of paying a premium to buy credit insurance, and they fund a loan loss reserve held by the Treasury Department.

The latest solicitation is the second call for applications since Solyndra. DOE issued another solicitation on December 12, 2013 for $8 billion of potential financing for "advanced fossil projects." This was effectively a renewal of a solicitation that was originally offered in September 2008 but that has led to no conditional commitments, much less closed financings.

So, notwithstanding political cheap shots, the loan guarantee program has demonstrated substantial staying power. Indeed, part of the discussions when Peter Davidson succeeded to the role of executive director of the program in May 2013 was that he was being recruited, not as an undertaker to preside over the burial of the program, but to manage its post-Solyndra re-invigoration. That re-invigoration took a step forward with the closing of Vogtle and issuance of the advanced fossil solicitation. It has taken another big step now that the window is about to reopen for renewable energy project financing.

Eligibility

A developer must show three things about his project to qualify potentially for a loan guarantee under the latest solicitation.

First, the project must use a renewable energy system, an efficient electrical generation, transmission or distribution technology, or an efficient end-use energy technology. Second, it must meet section 1703 statutory requirements of avoiding, reducing or sequestering anthropogenic emission of greenhouse gases. Third, it must employ a new or significantly-improved technology as compared to technologies that are already operating commercially in the United States as of the date on which a conditional commitment is issued.

DOE identified five categories to illustrate the sorts of projects that could be eligible.

One is projects that involve advanced grid integration and storage. Examples are solar rooftop systems that incorporate storage smart grid systems / continued page 12

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continuously on the project after 2013. The IRS has said it will not challenge whether the work was continuous for projects that are completed by the end of 2015. The Camp bill would reverse this IRS decision and require developers of all projects completed after 2013 to show that the projects were under continuous construction.

The bill would also repeal production tax credits for electricity and refined coal altogether after 2024. The credits normally run 10 years after a facility is completed. The repeal would mean projects completed after 2014 would not qualify for a full 10 years of credits.

The bill would repeal investment tax credits for solar and geothermal projects that are put in service after 2016. Such projects qualify currently for a 30% investment tax credit if completed by December 2016 and a 10% credit after 2016. The 10% credit would be repealed.

The bill would also repeal a 30% residential tax credit for homeowners who install solar systems after 2014. The credit had been scheduled to run through 2016. Any such move would provide a stronger incentive than exists currently for homeowners to buy electricity or lease systems from solar rooftop companies that retain ownership of the systems.

The federal government provides tax subsidies currently for renewable energy that are worth at least 56¢ per dollar of capital cost for the typical renewable energy project. Roughly 26¢ of the 56¢ is the value of the tax savings from depreciation. The Camp bill would slow down the depreciation on assets placed in service after 2016. Such assets would have to be depreciated on a straight-line basis over the "class life," which is 12 years for wind and solar projects and 20 years for gas-fired power plants. The unrecovered basis would be adjusted each year for inflation before applying the depreciation percentage.

Independent power companies must connect their power plants to the utility grid in order to get their electricity to market. The utility pays the / continued page 13

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incorporating demand response, micro-grid projects that reduce CO2 emissions and stand-alone storage projects that facilitate the use of renewable electricity.

Another category is "drop-in biofuels." Examples of projects in this category are new bio-refineries that produce gasoline, diesel or jet fuel and modifications to existing ethanol facilities to produce gasoline, diesel or jet fuel.

Waste-to-energy projects qualify. These include projects to produce methane from landfills or ranches via bio-digesters with the gas then used to generate heat and power, and power plants that use municipal solid waste, crop waste or forestry waste as fuel, including potentially by co-firing with fossil fuels.

The US Department of Energy will write up to another $4 billion in loan guarantees on innovative renewable energy projects.

Another category of potentially-eligible projects is enhancements to existing facilities. Examples are adding generating equipment to existing dams or variable-speed pump turbines to existing hydroelectric facilities and retrofitting existing wind turbines.

The last category is energy efficiency improvements. Examples run the gamut from installing equipment in homes, office buildings and factories to reduce energy usage or to tap waste energy to more ambitious undertakings to stabilize intermittent power to large transmission lines and build smart grids and micro grids.

It is unclear whether these five categories merely illustrate the wider set of technically-eligible projects or rather suggest that technically-eligible applications that fall within these categories can expect to be more favorably received. The solicitation says the examples are merely illustrative, but some language suggests that applications within the areas identified might be more welcome than those that are not.

Credit Subsidy Costs

The Credit Reform Act of 1990 requires that a loan loss reserve be funded at the United States Treasury for every federal loan or guarantee. The amount of the required reserve is the so-called credit subsidy cost of that loan or guarantee. The amount could be paid by a federal appropriation or by the applicant or potentially by a combination of the two. As long-term fans of the DOE loan guarantee program will remember, the credit subsidy costs for all 28 section 1705 loan guarantees that closed between 2009 and September 30, 2011 were covered by appropriations, so the borrowers did not have to pay them.

The latest solicitation indicates that the credit subsidy costs for the latest round will be covered in part by appropriations. The borrowers will have to pay the rest.

The solicitation announces the availability of $4 billion in financing. The text clarifies that this number has two components, the first consisting of $2,500,000,000 drawn from authorizations under the 2007 Appropriations Act ($1,000,000,000), the 2009 Appropriations Act ($317,000,000) and the 2011 Appropriations Act ($1,183,000,000), and the second derived from a $169,660,000 appropriation in the 2011 Appropriations Act to cover credit subsidy costs. The $4 billion aggregate estimate suggests an expectation that the 2011 credit subsidy appropriation will support $1.5 billion in guarantees, implying an average credit subsidy cost rate of 11.3%.

However, there are good grounds to expect a lower average credit subsidy cost per project, which would stretch that appropriation further. Given an inevitable inclination to avoid another Congressional uproar over a failed large loan as was triggered by the Solyndra debacle and the statutory mandate always to find a "reasonable prospect of repayment," a likely sweet spot for the program will be projects that are innovative, but just barely. Indeed, the program director said that the program is searching for projects on the "cusp of commercialization." All that, plus the fact that DOE now has a track record of solid performance that did not exist during the early stimulus phase of the program and the existing loan guarantee portfolio overall is performing well, suggests that, going forward, the actual credit subsidy rate could end up well less than the implied 11.3%. If it were 5%, for instance, which all considered does not seem unreasonable, then the volume of guaranteed financing supportable by the 2011 appropriation would rise to roughly $3.4 billion. The amount of financing available under the latest solicitation could end up as much as $5.9 billion when the pay-as-you go authorizations are taken into account.

This tees up a question with which no prior solicitation has had to deal. Previously, all credit subsidy costs for successful applications were either fully paid by the federal government, which was the case for stimulus projects, or had to be fully paid by the applicants. Here, some applicants will qualify for credit subsidy coverage by appropriated funds, and others will be on their own to pay it. Even those that qualify will have to pay their own way if the appropriation is depleted before they reach financial closure.

The solicitation says that additional information on how DOE will allocate appropriated credit subsidy among qualifying projects will be posted to the loan guarantee program website before the first deadline for part I applications.

Fees

The passage of time has brought fee inflation. The program fees include application fees, a facility fee at closing and an ongoing maintenance fee.

The proposed application fees under the latest solicitation include a $50,000 application fee to submit a part I application. If the proposal is deemed worthy to proceed to the next round, then the part II application fee will be $100,000 for projects seeking up to $150 million in DOE-guaranteed financing and $350,000 for applicants who hope to close more than that.

These application fees are up substantially from the stimulus round of renewable energy project loan guarantees. Then the total application fee ranged from $75,000 to $125,000 depending on the amount of the proposed financing, with 25% of that payable with the part I application. Thus, for instance, the cost to submit an initial application for up to $150 million in financing has increased from $18,750 to $50,000. DOE presumably raised the fees to discourage smaller, / continued page 14

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cost of the intertie, but requires the independent generator to reimburse it for the cost. The cost reimbursements do not usually have to be reported by the utilities as income based on a position the IRS took starting in 1988 that the cost reimbursements are effectively capital contributions to the utilities, even through they are made by persons who are not shareholders. The Camp bill would require all capital contributions to be reported as income by any corporation or partnership receiving them in the future, unless the capital contribution is made in exchange for shares or a partnership interest. This would make interconnection more expensive since any utility would want to be reimbursed not only for the cost of the intertie, but also for the taxes it would have to pay on the cost reimbursement.

Developers who receive grants of property from local governments as an inducement to build projects would have to pay taxes on the grants.

A number of wind and solar developers have signed so-called prepaid power contracts with utilities. The utilities prepay the developer for a share of the electricity that will be delivered over time. The developer treats the prepayment as an "advance payment." IRS rules allow the payment to be reported as income over time as the electricity is delivered. The Camp bill would override the IRS regulation that allows for this deferral after 2014. It is not clear whether all remaining deferred payments under existing contracts would have to be reported in 2015.

The bill would slow down tax amortization of amounts spent to put contracts and other intangible assets in place. Such amounts would have to be amortized on a straight-line basis over 20 years rather than 15 years.

Various changes would be made that would make it harder to use REITs, or real estate investment trusts, other than for pure holdings of land and buildings. These are described later in this column in a separate news item about REITs.

The bill would tax master limited partnerships, except for minerals / continued page 15

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less capable applicants. A lot of those showed up in the stimulus round and took substantial amounts of DOE staff time away from processing applications that were more likely to succeed. The smaller applicants ultimately fared poorly in that process, and none reached financial closure. If that is the goal, then requiring substantial sponsor technical and financial capacity might be a better way forward than making the program unnecessarily expensive.

If the application reaches financial close, then a facility fee will come due. That is proposed to be 1.0% of the DOE guaranteed loan commitment for financings of up to $150 million. For larger financings, the facility fee would be the same for the first $150 million, plus 0.6% for the portion of the financing commitment above $150 million.

The third, and final, DOE fee is the maintenance fee, which the solicitation "expects" to be $500,000 per year. This fee is up substantially from the $50,000 to $100,000 annual fee for the last round of loan guarantees for renewable energy projects. In the closed section 1705 financings, maintenance fees at the $50,000 end of that range were negotiated, but DOE's requirements seemed generally to float upwards toward the $100,000 ceiling as the September 30, 2011 deadline approached. The currently proposed maintenance fee is a multiple of anything previously sought by DOE. This fee would add 100 basis points of carrying cost to a $50 million loan, a spread that will rise as a loan is repaid. The fee might be a good target in the current public comment period and at the related public meetings about the solicitation, as it is enough to cover the wages of several DOE employees to monitor a single project.

Each applicant will also be required to cover any fees incurred by DOE for advice from legal counsel, financial advisors, market consultants and independent engineers.

Poison Pill

Some of the appropriations acts supporting the latest solicitation contain a restriction against "double dipping," such that DOE is not to provide guaranteed financing for any project that, quoting from the solicitation, "will benefit directly or indirectly from certain other forms of federal support, such as grants or other loan guarantees from federal agencies or entities, including DOE, federal agencies or entities as a customer or offtaker of the [p]roject's products or services, or other federal contracts, including acquisitions, leases and other arrangements, that support the [p]roject."

The statutory bar prohibiting projects that receive loan guarantee from also benefiting from other federal funds, property or personnel was somewhat ameliorated by the following proviso: The prohibition against double dipping

> shall not be interpreted as precluding the use of the loan guarantee authority . . . for commitments to guarantee loans for projects as a result of such projects benefiting from (a) otherwise allowable Federal income tax benefits; (b) being located on Federal land pursuant to a lease or right-of-way agreement [subject to certain enumerated requirements] (c) Federal insurance programs, including Price-Anderson; or (d) for electric generation projects, use of transmission facilities owned or operated by a Federal Power Marketing Administration or the Tennessee Valley Authority that have been authorized, approved, and financed independent of the project receiving the guarantee.

Thus, with the proviso, a DOE-supported project is not precluded from benefiting from tax credits or Treasury cash grants. However, as the solicitation points out, any power project with a federal offtaker need not apply.

Additionality

The solicitation bows to the traditional federal financing concept of "additionality" -— which is the thought that federal financing should make a difference and not just support an enterprise with cheaper funds than are commercially available. In the words of the solicitation: "Applications for loan guarantees for projects that could be fully financed on a long-term basis by commercial banks or others without a federal loan guarantee will be viewed unfavorably."

One interesting change from the stimulus era is that DOE promises in the latest solicitation not to penalize potentially highly profitable projects. In the stimulus era, the Treasury staff took the position that DOE should not support projects with too high a projected rate of return. Treasury never quite embraced the concepts that technology risk is a risk for the equity as much as or even more than for the debt and elevated projected returns are appropriate to compensate investors for the elevated risk that those returns would never be realized.

Projects with high rates of return that were supported by DOE staff found themselves challenged by Treasury as inappropriate for federal financing because, in effect, they were too good. On this point, the solicitation quietly notes:

> While DOE will gather information regarding the expected rates of return for investors and developers, given the significant importance of motivated equity sponsors in a transaction, DOE does not anticipate establishing requirements regarding such metrics.

Assuming Treasury is on board with this, this is a welcome step forward.

Applicants will need to comply with a number of federal statutes. They include the National Environmental Policy Act (which requires environmental reviews and clearances of projects before DOE financing can be provided), the Davis-Bacon Act (which requires on-site laborers and mechanics to be paid at least prevailing wages, being a rough equivalent to the compensation received by similarly-situated unionized workers), the Cargo Preference Act (requiring at least 50% of imported cargoes for DOE-financed projects to be carried on US-flagged vessels unless a waiver is given) and the Federal Credit Reform Act of 1990 (which guides the determination and payment of credit subsidy costs). Information provided to DOE will be afforded the protections under the Freedom of Information Act, but also subjected to the related risks of public disclosure.

The solicitation is still a draft. There are 30 days of public comment scheduled, including at a series of public meetings to be held in Austin, Texas (April 21), Denver, Colorado (April 24), Arlington, Virginia (April 28) and the Minneapolis and St. Paul, Minnesota (May 6). Details are available on the loan program office website at http://lpo.energy.gov. ◎

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and natural resources businesses, like corporations effective after 2016. There is no provision to "grandfather" existing MLPs.

The Camp bill would repeal the authority for state and local governments to issue "private activity bonds" after 2014. These are bonds that are sold in the tax-exempt bond market, but whose proceeds are used for projects that are owned or leased by private companies or, in some cases, operated by private companies.

State and local pension funds would have to pay taxes on any unrelated business taxable income (like other non-profit entities). An example of unrelated business taxable income is earnings from a partnership that owns a power plant. The change would force state and local pension funds to hold equity positions in such projects through blocker corporations to the extent they do not do so already or to limit their participation in such projects to the role of lenders.

An especially controversial provision in the Camp bill would require large financial institutions with more than $500 billion in total consolidated assets to pay a quarterly excise tax of 0.035% of asset value above $500 billion starting in 2015. The excise tax is expected to raise $86 billion over 10 years. The $500 billion threshold would be indexed to GDP growth. JPMorgan Chase, Bank of America, Citigroup, Wells Fargo, Goldman Sachs, Morgan Stanley, AIG, GE Capital, Prudential Financial and MetLife all have more than $500 billion in assets.

STATE-MANDATED POWER CONTRACTS remain under a cloud.

The Federal Energy Regulatory Commission told a US appeals court in late March that certain long-term power purchase agreements that New Jersey required New Jersey utilities to sign went beyond the state's power to require such contracts.

Last fall, US district courts in New Jersey and Maryland found, using / continued page 17

New York Green Bank Opens for Business

by Paul Weber and Christine Brozynski, in New York

The New York Green Bank that opened for business in February could broaden the potential rooftop solar market in New York through the use of credit enhancement to allow systems put on the roofs of homeowners with FICO scores slightly below 650 to be financed.

The bank could also be a source of equity, loans or guarantees for other types of clean energy projects. It is expected eventually to have up to $1 billion with which to work. Financing terms are expected to be at market rates, but the bank is authorized to offer below-market terms in certain cases.

The bank is in discussions about potential deals, but no transactions have been announced.

It is a New York government entity and the largest institution of its kind in the United States. Clean energy advocates in New York hope it will have an equally large impact on the energy market.

The Green Bank could help broaden the solar rooftop market in New York through the use of credit enhancements.

Its goal is to reduce both actual and perceived risk in the clean energy market. It hopes to spur capital markets for the clean energy sector by using public funds to leverage private sector capital, ultimately reducing the cost of capital for these projects and increasing investor confidence.

The bank officially opened for business on February 11, 2014. The New York State Energy Research and Development Authority — "NYSERDA" for short — issued a request for proposals through its NY Green Bank division outlining the project application process.

Eligible Projects

Any project seeking support from the Green Bank must fulfill two basic requirements. First, it must be a "clean energy project." Second, it must use commercially-proven technologies. Examples of proven technologies provided by the Green Bank include "solar, wind and other renewable energy generation technologies; residential and commercial/industrial energy efficiency measures; electricity load reduction; and on-site clean generation." This list is not exhaustive, and the request for proposals indicates that the Green Bank will entertain a variety of proposals.

Industry participants as well as financial institutions and third party capital providers are encouraged to submit proposals, either alone or as part of a team. Proposers must have experience in similar energy transactions.

Projects with structures that are likely to be replicated will be favored in the selection process. This is an integral part of the Green Bank's goal to increase activity in the clean energy market. Further selection criteria include the following: transaction credit, financing and risk-to-return considerations, the potential contribution to financial market transformation and the expected clean energy outcomes.

The Green Bank has been capitalized with an initial $210 million, and its eventual capitalization is expected to be $1 billion. Its goal is to become self-sustaining, primarily by re-investing its returns.

Private financing is a required component of any project seeking Green Bank support. The Green Bank is flexible about how that financing is structured and the role that the Green Bank itself plays. For example, it could serve as a co-investor with the private sector or provide direct loans or credit enhancements. It could also provide assistance to entities funding loans or PPAs related to the project. However, it will not provide funding for project development or the general business operations of entities.

For the most part, credit risk taken on by the Green Bank will be compensated according to market standards. However, in some circumstances the bank will consider accepting a lower-than-market liquidity premium if the project and its support of the project would "provide material benefits to market expansion and future liquidity." Although examples of these benefits are not provided, the Green Bank has continually affirmed its dedication to removing financing barriers for green energy projects.

Some of the current financing barriers identified by NYSERDA include underdeveloped secondary markets, high upfront costs and de-prioritization. These and other financing barriers have led to financing gaps, such as in the financing of projects with medium credit quality. A Booz & Company study commissioned by NYSERDA suggests that the Green Bank has the financing and informational tools to reduce these financing gaps and expand the market.

Potential Benefits

One part of the renewable energy market that may benefit from Green Bank lending and credit enhancement programs is distributed generation. Energy efficiency projects may similarly benefit. For example, distributed solar deals typically require residential participants to have a minimum FICO score in the high 600s. Through methods such as credit enhancement, providing warehouse financing and direct lending and investing, the Green Bank could potentially lower that minimum to slightly below 650, expanding the number of eligible New York households by approximately 880,000.

Similar market expansion could be possible for the commercial sector. The Booz & Company study notes that the Green Bank could potentially cover an additional 4% to 8% of businesses by incorporating more of those within class 3 of the Dun and Bradstreet commercial credit score. The study also notes that a goal of providing Green Bank credit enhancements for clean energy projects across a broader tier of creditworthiness will help build a track record that will lead the private sector to expand its current coverage.

Besides the reduction of financing gaps, other potential benefits from the Green Bank include increasing standardization of deal terms, growth across multiple market segments and an increase in distributed generation, such as distributed solar, due to more flexible financing options. Energy efficiency should also experience a boost if the Green Bank is able to reach segments of the market that the private sector has not yet been able to address. ◎

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nearly identical reasoning, that bidding programs both states used to direct regulated utilities to buy power from gas-fired independent generators under long-term contracts and pay prices that differed from the prices in the regional competitive market (the PJM market) violated the federal supremacy clause of the US Constitution. The supremacy clause bars states from doing things that conflict with federal rules in the same area. The US Congress has given the Federal Energy Regulatory Commission exclusive power to set wholesale electricity rates for most independent generators.

The public utility regulatory commissions and the affected generators in the two states appealed the US district court decisions to US appeals courts for the 3d and 4th circuits.

The 3d circuit appeal is moving faster than the 4th circuit appeal. All of the briefs have been filed in the 3d circuit. The court asked FERC its view of whether the New Jersey program violated the supremacy clause. FERC said in a brief filed on March 20 that it agrees with the US district court that the New Jersey program "effectively sets the wholesale rate for capacity" in conflict with federal law. FERC said the state directive to independent generators to bid in a capacity auction "directly affects wholesale rates [in PJM], and, to that extent, is a preempted intrusion upon the Commission's exclusive jurisdiction to regulate wholesales rates and practices affecting rates." The court heard oral arguments in the case on March 27. A decision is expected within the next few months.

The 4th circuit appeals court is still collecting briefs in the Maryland case. If the two appeals courts decide the cases differently, then chances are greater than the issue will end up before the US Supreme Court.

The cases are being watched closely by other states that have comparable or similar programs to direct utilities to sign long-term wholesale power contracts based on specific state preferences or mandates.

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Korea Expected to Sell Overseas Assets

by Samuel R. Kwon and Kyunghoon Lee, in Washington

South Korean state-owned enterprises will sell some of their energy assets both inside and outside Korea to shore up their balance sheets under pressure from the South Korean government.

The assets for sale include coal and uranium exploration projects by Korea Electric Power Corporation as well as oil field and liquefied natural gas development projects by Korea Gas Corporation. Offshore energy assets owned by other Korean SOEs, such as Korea National Oil Corporation and Korea Resources Corporation, may also be put up for sale.

Why Now?

In late 2011, the International Monetary Fund advised that countries must include the debt held by SOEs in their national debt statistics. In South Korea, this caused a spotlight to be put on the growing debt incurred by SOEs. SOEs were accused of handing out excessively-generous bonuses and other perks to their employees. In 2013, the new president of South Korea promised rapidly to reduce employee benefits and borrowing by SOEs.

By the end of 2013, South Korea's public sector debt was approximately US$990 billion, consisting of roughly US$500 billion in national and local government debt and US$490 billion in SOE debt. The South Korean government originally targeted the 18 SOEs with the largest share of the debt by asking them to reduce their debts to around US$85 billion by 2017. This was viewed as reasonably achievable via sales of certain underperforming assets in combination with other cost-cutting measures.

However, the government recently revised its target substantially, and is now requiring the 18 SOEs to cut their debts to approximately US$43 billion by 2017. These 18 SOEs, including Korea Electric Power Corporation, Korea Gas Corporation and Korea National Oil Corporation, are now under greater pressure to unload assets quickly. In March 2014, the South Korean government approved the debt reduction plans submitted by a number of SOEs including KEPCO, KOGAS and KNOC while asking for additional cuts from others such as Korea Coal Corporation and Korea Water Resources Corporation.

While there are slightly conflicting reports out of Korea on precisely which assets are up for sale, some clarity is emerging.

What's For Sale?

Currently, KEPCO's debt-to-equity ratio is set to rise from 200% by 2017. Under the debt reduction plan it submitted, KEPCO pledged it would achieve a debt-to-equity ratio of no more than 150% by 2015 by slowing the growth of its debt and by selling some of its assets. Its CEO pledged to deleverage faster than the other South Korean SOEs, though he also insisted that KEPCO would continue to expand its overseas business, especially in the Middle East.

KEPCO has hired Barclays PLC to assist with the sale of certain offshore energy assets. The sale reportedly will include KEPCO's stakes in two Indonesian coal mines. The first is a 20% stake in PT Bayan Resources Tbk, an Indonesian coal miner, valued at US$500 million that it acquired in 2010, along with agreements to buy two million metric tons of coal per year starting in 2012 and another seven million metric tons of coal a year starting in 2015. KEPCO may be looking to transfer these offtake agreements along with its stake in the company. The second is a 1.2% stake in PT Adaro Energy Tbk valued at around US$31 million. KEPCO had originally paid US$51 million in 2009 for a 1.5% stake along with three million metric tons of coal per year. Also for sale is KEPCO's 40% interest in a Canadian

State-owned companies in South Korea plan to sell energy assets to pay down debt.

uranium mining project known as the Waterbury Lake property in Canada's Athabasca Basin. KEPCO co-owns this project with Denison Mines Corp.

KEPCO has other interests in Canadian mines that may end up for sale. It owns a 12.3% stake in Denison Mines following its purchase of a 19.9% stake in 2007 for C$75 million that included an offtake arrangement for a portion of the mine's triuranium octoxide. It also owns an interest in the Cree East mine in Canada for uranium exploration. It may also sell up to 49% of its interest in the Bylong coal mine in Australia that it had acquired from Anglo American PLC in 2010.

KOGAS is the world's top corporate buyer of liquefied natural gas or LNG. KOGAS is majority owned by the South Korean government, with the Ministry of Strategy and Finance holding 26.86%, KEPCO holding 24.46% and the National Pension Service holding 6.56%. According to the latest reports, the goal is to bring its debt-to-equity ratio down to 249% by the end of 2017. That ratio stood at around 400% in 2012.

The centerpiece of the KOGAS asset sale is a stake in the Akkas gas field in the western province of Anbar, Iraq, after the field begins commercial production in September 2015. The field is estimated to hold in reserve approximately 5.6 trillion cubic feet of gas, and is set to produce about 400,000 Mcf a day of gas for more than 13 years. KOGAS had signed this development deal in 2011 with the Iraqi government. KOGAS has not yet disclosed how much of its stake is for sale. According to sources within South Korea's Ministry of Strategy and Finance, KOGAS is considering selling up to 49% of its interest. In addition, KOGAS has been looking to sell some or all of its 15% stake in Australia's Gladstone LNG project for some time as well as a part of its 20% stake in Shell-led LNG Canada.

KOGAS currently holds interest in three other oil and gas fields in Iraq: a 20% interest in the Mansuriya gas field in the north, a 30% interest in the Badra oil and gas field in the west, and a 25% interest in the Aubair oil and gas field in the south. It also holds a 10% stake in the Area 4 gas block in Mozambique. So far, KOGAS has not indicated whether or not these interests are for sale.

Unlike KEPCO and KOGAS, KNOC indicated it had no intention of selling its offshore energy assets with the exception of "non-core" oil refineries in Canada. KNOC owns Harvest Operations, a Canadian oil and natural gas producer, which it bought in December 2009 for US$1.8 billion. In 2012, Harvest Operations reported a net loss of US$720 */ continued page 20*

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SAUDI ARABIA recedes as a potential market for solar developers.

Hashem Yamani, head of the Saudi renewable energy procurement agency, the King Abdullah City for Atomic and Renewable Energy or K.A.CARE, arrived at the end of his four-year term without being reappointed or replaced. Dr. Khalid Al-Sulaiman, the vice president for renewable energy, is reported to have requested an early retirement.

K.A.Care had an ambitious plan to procure 54,000 megawatts of renewable energy capacity over the next two decades. The departures after a year of delays and uncertainty suggest the procurement plan may be in jeopardy. They follow a recent decision by the Saudi government to put the rollout of the K.A.Care nuclear power program on a fast track.

The continuing indecision of the Saudi leadership about the K.A.CARE renewable energy program suggests major differences in opinion at the highest echelons of the Saudi political establishment.

Sources say that Saudi Aramco's increasingly apparent lack of buy in on the program caused friction and led eventually to deep political division.

Many developers have flocked to the Middle East in the past year and positioned themselves for the expected Saudi Arabian renewable energy boom. Although it would be unfair to conclude that all hope is lost for renewable energy in Saudi Arabia, the country's leadership will have to work to regain the confidence of the development community if and when it decides to revive any renewable energy plan.

PRODUCTION TAX CREDITS for generating electricity will remain at 2013 levels in 2014, the IRS said in April.

The credits in 2014 will be 2.3¢ a KWh for generating electricity from wind, geothermal energy and "closed-loop" biomass and 1.1¢ a KWh for electricity from */ continued page 21*

Korea

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million. KNOC has also been developing offshore oil fields in Ankor in the US and in the Caspian Sea off Kazakhstan.

Additional asset sale plans may emerge from Korea Coal Corporation, Korea Water Resources Corporation and Korea Resources Corporation.

What Next?

Foreign companies potentially interested in these South Korean SOE assets will need to observe carefully the back and forth between the SOEs and the South Korean government.

Some SOEs are resisting the pressure to deleverage quickly. They fear that committing to a massive asset sale over a short period would take away their bargaining power and force them to sell the assets at below-market prices. The senior management of the SOEs may also fear the scrutiny that will inevitably come once they achieve these debt reduction goals by 2017 since a new president (and possibly a new party) will come into power in early 2018. For example, a former official of the Ministry of Finance and Strategy came under fire politically and legally for having approved the sale of the Korean Exchange Bank in 2003 to Dallas-based Lone Star Fund, especially when the bank's shares recovered in 2005.

The South Korean media is beginning to pick up on the danger of selling valuable assets too quickly as an outflow of national wealth, citing the sale of Korean car manufacturers and commercial banks to foreign buyers during the 1997 Asian financial crisis.

To address the fear that this would be a repeat of 1997, certain South Korean government officials have said the sales will favor South Korean buyers. It is not yet clear how this would be achieved. Korean law does not currently allow such preference with one possible exception: the Overseas Resources Development Business Act provides certain tax benefits and credit enhancements, such as loan guarantees, to Korean developers of offshore resource development projects. However, it is unclear whether these benefits will be available to Korean buyers of such projects since their primary purpose may be construed as simply seeking financial gain rather than developing offshore natural resources.

For now, interested foreign buyers should begin evaluating whether partnering with a Korean investor to bid jointly for the assets may provide them with an advantage, or at least with an opportunity to mitigate any potential disadvantage.

There will be ripple effects on all types of overseas activities by South Korean SOEs that are not directly related to reducing debt. For instance, their overseas staffs are likely to be reduced in the short run, handicapping their ability to develop and execute foreign deals. They may focus on overseas investments that do not require a lot of capital up front such as operation and maintenance of projects rather than outright development that may require greater upfront capital. Some SOEs may scrap altogether offshore projects that are in the early stages of development.

The Ministry of Finance and Strategy plans on reviewing whether the large SOEs are satisfactorily carrying out their debt reduction plans sometime in September 2014. At that point, the interested buyers are likely to get additional signals as to what assets are up for sale and how much pressure there is on the SOEs to unload these assets even at depressed prices. ◎

Jordan Embraces Renewables

by Sohail Barkatali, in Dubai, and Magnus Rodrigues, in London

Jordan issued a third round of requests for proposals from renewable energy developers in February while it continues to collect proposals from the second round and negotiate with developers whose projects were accepted in the first round. The deadline to submit proposals in the second round is May 15.

Most of the focus is on wind and solar projects, but a new law also encourages independently-owned geothermal, waste-to-energy and bio-gas projects.

The 117-megawatt Tafila wind farm, on which the financing closed recently, will serve as a template for risk allocation and financing other renewable energy projects in Jordan.

At least for the near term, agency lenders are likely to be the main source of financing.

Overview of Energy Sector

Unlike its neighbors, Jordan is not blessed with significant oil and gas resources. Until recently Jordan was heavily dependent on the Arab gas pipeline from Egypt for natural gas, importing as much as 80% of the gas it uses from Egypt. Egyptian gas supplies have proven unreliable due to political unrest in Egypt and attacks on the pipeline. This has forced Jordan to switch to heavy fuel oil and diesel to generate power, increasing the financial burden on the country.

Jordan is looking at medium and long-term initiatives across a wide range of energy sectors to diversify its energy sources. These include importing LNG, exploring for oil and gas, implementing an energy efficiency program, importing electricity from neighboring countries and diversifying the types of fuel it uses for power generation.

Jordan has gas reserves, but little oil. Its oil reserves were estimated in 2012 to be around one million barrels. It has around 200 billion cubic feet in gas reserves. The country is divided into a number of exploration blocks, and additional discoveries may be made along the border with Iraq and in the Dead Sea as oil and gas exploration continues. In the meantime, it remains a net importer of hydrocarbons; up to 20% of its gross domestic product goes towards payment for imported energy. Jordan imports 97% of its energy needs.

Installed electric generating capacity is approximately 3,100 megawatts with peak demand of around 2,900 megawatts. Electricity demand is growing at a rate of approximately 8% a year.

The country also has significant deposits of oil shale, but it is not in a position currently to recover the oil.

Jordan's main exports are non-metallic natural resources, mainly potash and phosphates. It also has a pharmaceutical industry that is geared toward the export market; 75% of the pharmaceutical output is sold abroad.

The World Bank rates Jordan at 119 of 189 countries in terms of ease of doing business.

Jordan has been slower than neighboring countries like Oman and Abu Dhabi to embrace private sector participation in electricity generation. The others embraced it starting in the late 1990s. Jordan did not see an independent power project signed until February 2007 when a power purchase agreement with a 25-year term was signed with a project company established by AES Corporation and Mitsui & Co. for a 370-megawatt project known as Amman East.

This was followed in short order with PPAs for three more large independent power projects: Qatrana, IPP3 and IPP4. These were all successful projects. Projects in the renewables sector were not progressing so well.

Jordan's first attempt to enter the renewable energy sector was the launch of the 30 to / continued page 22

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"open-loop" biomass, landfill gas, incremental hydroelectric projects and ocean energy.

The credits are adjusted each year for inflation as measured by the GDP price deflator. They run for 10 years after a project is originally placed in service. The IRS said inflation was so low in 2013 that there was no change in the credit amount.

The credits phase out if contracted electricity prices from the particular resource reach a certain level. That level in 2014 is 12.06¢ a kilowatt hour. The IRS said there will not be any phase out in 2014 because contracted wind electricity prices are 4.85¢ a KWh going into the year. It said it lacks data on contracted prices for electricity from the other energy sources.

Production tax credits for producing refined coal are $6.601 a ton in 2014, the IRS said, up 1¢ from 2013.

> *The IRS said there will not be any phase out of refined coal credits in 2014. The refined coal credit phases out as the reference price for raw coal moves above 1.7 times the 2002 price of raw coal. The 2014 reference price is $56.88 a ton. A phase out would have started at $81.83 a ton and would have been total if the reference price had been $90.58 a ton or higher.*

STATE TAX CREDITS were sold, and the sponsor should have reported income from the sale rather than treated the state credits merely as allocated by a partnership to a tax equity partner, the US Tax Court said in February.

Two individuals formed a partnership in 2005 to acquire two tracts of land near Albemarle, Virginia. The properties were Castle Hill, which was 1,203 acres and had a manor house dating to 1764, and Walnut Mountain, which was 345 acres. The two individuals formed a partnership and contributed $2 million each. The partnership, called Route 231, bought both properties in June 2005 for $24 million after borrowing the rest of the purchase price from a bank.

Virginia allowed a tax credit for 50% of the value of any conservation easements donated by property owners to / continued page 23

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40-megawatt Al Kamsha wind farm. However, no project agreements have been signed with the developers. The 90 to 250-megawatt Fujeij wind farm was next out of the gate. No project agreements have been signed with the developers.

Notwithstanding this, recent legal developments are making renewable energy developers optimistic.

New Renewable Energy Law

The country enacted a renewable energy and efficiency law in 2012 — Law No. 13 of 2012 – that goes some way toward providing a framework for renewable energy. It should be read in conjunction with the General Electricity Law of 2003.

The Ministry of Energy and Mineral Resources is charged under the 2012 statute with identifying areas within Jordan that have a high potential for solar, wind, bio-energy, geothermal and hydropower. The Ministry is supposed to create a priority list for developing these resources in the areas identified as part of an energy sector master plan. The Ministry has authority to issue tenders to attract proposals on a competitive basis for the development of one or more sites and for projects exceeding 500 megawatts. The utility, NEPCO, may also issue such tenders.

Jordan is actively soliciting renewable energy projects.

Apart from large projects that must be bid by competitive tender, any person now has the right to submit a proposal to the Ministry directly to develop any site for renewable energy.

A direct proposal must satisfy certain conditions. A development plan must be submitted with the preliminary design, initial financing plan and contribution of local content to the facility, supplies, construction and operation. The applicant must be experienced with the type of project. A fixed price tariff must be proposed, and it must fall within a set of guidelines, called the "reference price list," that has been established by the Electricity Regulatory Commission.

The law requires that applicants be notified of a decision on their projects within six months. If a project is accepted, then negotiations of the project agreements follow. The Electricity Regulatory Commission issue a generating licence after the project agreements have been signed. Electricity generated can be sold to the national utility, NEPCO, or to holders of retail supply licences (for example, Irbid District Electricity Company). Practically speaking, NEPCO has greater experience with PPAs and related project agreements, although that does not preclude the possibility of doing a deal with the holder of a retail supply licence.

Equipment for renewable energy projects is exempted from all customs duties and sales taxes.

Tafila

The Tafila wind farm was the first of the round 1 projects accepted by the government under the unsolicited proposals scheme.

The project agreements were signed in November 2013. The sponsors are Cyprus-based renewable energy developer EP Global Energy, Masdar and InfraMed Investments. The government received proposals from developers indicating the maximum tariffs that the government would pay. In the first round, only facilities with a capacity greater than 10 megawatts were accepted.

EP Global Energy signed a memorandum of understanding with the Ministry of Energy & Mineral Resources in June 2011, giving the developer exclusive rights for 24 months.

Projects such as Amman East, Qatrana, IPP3 and IPP4 produced a set of bankable project agreements. The Tafila developers used the same risk allocation as a starting point for negotiations. The project was undertaken on a build-own-operate basis.

The final risk allocation for Tafila is broadly consistent with precedent projects in Jordan. The Ministry and NEPCO revisited issues at the margin. For example, the developer is responsible for procuring the site and, as a result, must accept some of the site risk associated with the parcels of land that form part of the site. There is an increased burden of investigation of title. Lenders will insist on mechanisms to ensure that leases with multiple owners of land are managed effectively to avoid defaults.

Conventional thermal projects in Jordan have benefited from the government entering into an implementation agreement. Such an agreement provides a form of government guarantee and offers "soft" but direct government support to the project company on a number of matters. Tafila has the benefit of sovereign support for payment obligations of NEPCO, but the other, softer support from the government is less evident.

The Middle East has one of the most long-established templates for financing independent power projects among emerging markets. However, the record varies from one country to the next within the Middle East.

Jordan has a more recent and less developed track record of financing such projects. The first IPP project in Jordan was the 370-megawatt gas-fired Amman East power project in 2007. The first independent power project in the Persian Gulf region closed in 1994. Jordan is regarded as a more difficult market from a risk perspective than others, like Abu Dhabi, within the Middle East.

The debt for Tafila is being provided by the International Finance Corporation, European Investment Bank and the OPEC Fund for International Development. Part of the IFC loan is being indirectly provided by FMO and the Europe Arab Bank. Repayment of the loan by the European Investment Bank has been guaranteed by Eksport Kredit Fonden, the Danish export credit agency.

The reliance on these sources of financing for Tafila is a reflection of the more challenging nature of financing projects in Jordan. For the time being, the main sources of financing for Jordanian renewable energy projects will probably be multilaterals, export credit agencies and other agency lenders. Financings led by international commercial lenders without any form of government credit support would seem challenging, and capacity constraints on long-term debt financings restrict reliance on local commercial lenders.

These other lenders may still participate in such financings.

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conservation agencies. On December 30, 2005, the partnership contributed a conservation easement in Castle Hill to the Nature Conservancy that an appraiser said was worth $8.8 million. It contributed a conservation easement in Walnut Mountain to the Albemarle County Public Recreational Facilities Authority and contributed its remaining ownership position in Walnut Mountain to the Nature Conservancy (after selling about a sixth of the property a month earlier to an individual). The appraiser said these two contributions were worth $7.3 million.

Under Virginia law, any partner allocated conservation credits by a partnership can sell the unused tax credits to a Virginia taxpayer.

Another partnership called Virginia Conservation was interested in the credits. It became a partner in Route 231 in late December 2005. Route 231 allocated it 1% of income and loss and most of the Virginia conservation credits. The two individuals who originally formed Route 231 became 49.5% partners. The amended Route 231 partnership agreement required Virginia Conservation to contribute 53¢ to Route 231 for each dollar of Virginia tax credits allocated to it. The agreement said the credits were expected to be in the range of $6.7 to $7.7 million. It allocated the first $300,000 to one of the two individuals and the rest to Virginia Conservation. The two individuals agreed to indemnify Virginia Conservation if the tax authorities disallowed any of the tax credits allocated to Virginia Conservation.

The two individuals also had an option to purchase Virginia Conservation's interest at any time after January 1, 2010. The option had not been exercised at the time of trial.

A lawyer for Virginia Conservation sent the two individuals a letter on December 31, 2005 to say that the credits were $84,000 short of what Virginia Conservation expected in view of its capital contribution. The individuals promised to replace the shortfall in credits in 2006, but there were no more charitable donations in 2006.

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Any commercial lenders will want their loan participations covered by a guarantee, insurance or otherwise from an agency lender (a structure that is commonly adopted by export credit agencies) or else there must be "A/B facilities" or an analogous structure. In A/B facilities, the agency lender is the lender of record, but part of the loan is indirectly provided by a third party lender. Tafila used an A/B structure for the IFC loan.

Special Issues in Agency Financings

The heavy reliance on agency lenders has other implications.

International commercial banks lending to finance projects in the Middle East usually also undertake the hedging for their proportion (and sometimes more) of the debt financing. Although such a bank might provide the hedging in concept for a project even if it is not also lending, for commercial reasons it is unlikely to do so. Hedging banks have limited rights. International commercial banks acting as hedging banks accept the limited rights on the basis that they have much more substantial rights in their separate capacities as lenders. Therefore, if a financing is dominated by agency lenders, a key issue will be who will provide the hedging: certain agency lenders, such as IFC and the European Bank for Reconstruction and Development, have the ability to provide hedging.

It is also typical in a commercial bank financing for one or more of the lead commercial lenders to undertake the agent and account bank roles. These roles are generally regarded by these commercial lenders as ancillary services to their participation in the lending and hedging. Although, in theory, the relevant parts of a commercial lender could undertake such roles even if they are not lending and providing hedging, they may for commercial reasons be reluctant to do so. Thus, to the extent the agency lenders are not able to undertake one or more of these roles (IFC has an administrative agent unit), these will have to be undertaken by independent agents. The number of such independent agents and account banks is limited, but certain of those independents have developed considerable experience in the area (for instance, Law Debenture acting as an English law security trustee). These independents generally have more requirements than agents and account banks that form part of the lender syndicate. This means that the agents and account banks should be identified and negotiations with them commenced at an early stage: the negotiations can be time consuming.

As the Jordanian government is developing the renewable projects in different rounds and some of the projects may be relatively small, the same agency lenders may end up financing a number of projects. Therefore as each project basically needs the same set of financing agreements, there may be a chance for cost and time savings by using a common set of documents.

The internal approval processes for agency lenders can vary considerably. For instance, larger Sinosure transactions require the approval of the State Council, which is the executive arm of the Chinese government: this can take months.

Agency lenders may also impose conditions on the financing. It is important to find out what they are early in the

Type of Technology	Old Reference Price List (Fils/KWh)	New Reference Price List (Fils/KWh)	Old Reference Price List (US$/KWh)	New Reference Price List (US$/KWh)
Wind	85	80	0.119	0.112
Solar (thermal)	135	135	0.190	0.190
Solar (photovoltaic)	120	100	0.168	0.140
Waste	90	90	0.126	0.126
Bio-gas	60	60	0.084	0.084

process. For instance, the European Investment Bank imposes certain obligations on projects it finances outside the European Union for how the projects procure their equipment.

The ability of commercial lenders to finance any project is primarily determined by commercial considerations. Agency lenders are equally subject to policy considerations. It is good always to check early whether the particular agencies on which the project will rely are open for the proposed financing. Each agency lender has its own criteria that determine the basis on which it would be able to lend. The ability of export credit agencies to finance projects is linked to the sale of goods, services and supplies from their home countries. Multilateral or bilateral agencies focus on development issues. For instance, the EBRD's funding criteria include that the project should benefit the local economy, develop the private sector and be located in an EBRD country of operations.

Even if agency lenders are available, there may be limitations. For instance, export credit agencies have different rules as to their ability to finance any local content: whereas the US Export-Import Bank is able to finance a certain level of local content (as well as US content), the Chinese export credit agency is restricted to financing content from China. The various restrictions mean that the project may have to be financed by a syndicate of agency lenders to cover the gaps.

The use of agency lenders will affect other terms of the financing.

Agency lenders will be particularly focused on environmental, social and other policy issues in their due diligence. It would be a good idea to agree the parameters early in the financing process.

International commercial banks use financing agreements developed by the Loan Market Association in London (to the extent the financing will be governed by English law). In contrast, some agency lenders have their own templates for certain financing agreements that will need to be followed: for instance, the EIB has its own well-developed loan agreement. The IFC has been developing a series of template financing agreements with a view to saving time and cost on agency financings and has been seeking the agreement of other agency lenders to use them on projects where the IFC co-lends.

Different agency lenders have their own requirements as to particular terms. For instance, export credit agencies commonly require that certain terms be included to reflect the justification for their involvement in the financing. The EBRD has certain requirements as to dispute / continued page 26

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Route 231 filed a partnership return for 2005 that allocated $215,983 in credits to one of the two individuals and $7.2 million in credits to Virginia Conservation.

The IRS asserted in March 2010 that Route 231 failed to report ordinary income of $3.8 million in 2005 from the "sale" of tax credits. It said the $3.8 million that Route 231 received from Virginia Conservation was income to the partnership. IRS regulations presume that where one partner contributes cash and is distributed property by the partnership within two years, the partner really bought the property from the partnership.

Route 231 argued that there was an allocation of tax credits and not a "distribution" of "property," but the US Tax Court disagreed. It said the evidence points to a purchase of tax credits. The amount contributed was tied to the amount of tax credits. What Virginia Conservation received in exchange for its capital contribution was not dependent on the entrepreneurial risk of a business. There was no indication that Virginia Conservation even considered Route 231's business operations before it agreed to contribute a substantial sum of money.

The case is called *Route 231, LLC v. Commissioner.*

The IRS complained about similar transactions in an internal legal memo in 2007. It said that entities like Virginia Conservation dress up transactions that are essentially bare purchases of tax credits to look like partnership allocations in order to claim a capital loss for the capital contributions of X¢ per dollar of tax credit when the sponsor repurchases the tax equity investor's partnership interest. The internal IRS memo is AM 2007-002.

If Virginia Conservation bought tax credits, then it would have a gain for federal income taxes equal to the difference between the full credit and the 53¢ it paid when it used each credit to offset Virginia income taxes, since it would be treated as using "property" — the credits — to pay its / continued page 27

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resolution clauses to reflect its multilateral status.

Intercreditor arrangements can be complicated. Certain agency lenders will require specific rights to reflect their policy considerations or to preserve separate rights they may have. If an agency lender is providing a guarantee or insurance for certain lenders, then these will be excluded from the general sharing provisions.

Rounds Two and Three

Jordan launched a second procurement round in August 2013. The deadline to submit an expression of interest has been extended to May 15, 2014.

This round is restricted to solar photovoltaic and wind projects. The project size for solar photovoltaic projects is 50 megawatts. A range of 50 to 100 megawatts applies for wind farms.

Twenty-three companies have made the cut as qualified companies and another 24 have been found conditionally qualified for the photovoltaic portion. A list of four qualified companies and two conditionally qualified companies has been released for wind.

Jordan launched a third procurement round in February 2014. This round is restricted to solar photovoltaic projects. The project size is 100 megawatts.

The launch of the second and third round prior to the completion of the first round has surprised the market, but it shows the sense of urgency Jordan feels to reduce energy imports.

All qualified applicants must enter into a memorandum of understanding with the Ministry of Energy & Mineral Resources agreeing on the electricity tariff for any project the applicant builds. The electricity tariff included in the proposal must be a fixed tariff expressed as an amount per kilowatt hour and be within an acceptable range consistent with reference price list. The Electricity Regulatory Commission issued a new reference price list in January 2014. The old and new prices in Jordanian dinars and US dollars are on page 24. The figures are caps on what may be charged.

The old reference price list continues to apply to all first round projects, subject to a production cap. The tariff caps in the new reference price list will apply to both second and third round projects. ◎

Powering Africa

The US government set a goal in June 2013 to double access to electricity in sub-Saharan Africa within five years. More than nine months have passed. A panel of seven industry experts assessed how the effort is going at the 3rd annual Chadbourne emerging markets conference in Washington in late March.

The panelists are Megan Rapp, an investment officer with the Development Credit Authority, a bank within the US Agency for International Development, the coordinating agency for the Obama Power Africa Initiative, Astri Kimball, a senior advisor to the president and CEO of the Overseas Private Investment Corporation, John Schuster, vice president for project and structured finance at the US Export-Import Bank, Justin DeAngelis, a director of Denham Capital, a private equity fund and owner of three power development companies that are active in Africa — Endeavor Energy, which focuses on large thermal and hydro power, BioTherm Energy, which focuses on wind and solar, and Fotowatio Renewable Ventures, a solar company with Africa as one of its target regions — Lida Fitts, acting regional director for Africa for the US Trade and Development Agency, Jamie Fergusson, principal investment officer and global sector lead for renewable energy at the International Finance Corporation, and Paul Hinks, CEO of Symbion Power, an independent power developer focused on Africa, and chairman of the Corporate Council on Africa. The moderator is Ken Hansen with Chadbourne in Washington.

MR. HANSEN: I am guessing some of you have seen the TV show Revolution. There is a massive deterioration of the quality of modern life thanks to blockage of access to power. I expect all of you have had the pleasure of power outages of substantial length and, notwithstanding the fond memories of romantic candlelit dinners until the lights came back on, I suspect mostly it disrupted the quality of your life, professionally and personally.

World Bank data tells us that two thirds of the population of sub-Saharan Africa does not have access to reliable, affordable electricity. Most people with access live in urban areas. As you move out to the rural areas, the same database suggests that the percentage without access rises to 85%.

On the other hand, International Monetary Fund data from

2012 says that of the 10 fastest growing economies on the planet, seven are in sub-Saharan Africa. One could ask the question, if there was not such a broad-based power shortage in the continent, what would the growth rates be?

Roughly that question was being asked a little less than a year ago by the National Security Council staff in the White House, I understand by Mike Froman, then the relevant international economic person on the National Security Council staff. What came out of it was the announcement last June 30 by the president during his tour of sub-Saharan Africa of the Power Africa Initiative.

The initiative declared a number of things. As is the want of this administration, the targets are all to be met in five years, or the remaining term of this administration plus one. Within five years, we are to double the percentage of the population that has access to power in sub-Saharan Africa. We are going to do that initially with a focus on six countries: Ethiopia, Ghana, Kenya, Liberia, Nigeria and Tanzania. Two more countries, Uganda and Mozambique, are pulled in by a footnote of sorts for purposes of developing their recently-discovered natural gas resources.

The tool to reach that goal is a partnering of $7 billion of US government money with $9 billion of private sector money to develop power projects: generation, transmission, distribution, whatever it is that is the bottleneck in sub-Saharan Africa to achieve the goal of doubling access in five years.

We are nine months in today, or about 15% of the way through the five years, so how are we doing?

That's the question I want this panel to answer ultimately, but tell us first how each of you is involved in Africa, Megan Rapp, starting with you. Each of you represents an agency or company engaged in the region.

US Efforts

MS. RAPP: USAID is playing the role of the secretariat in the Power Africa Initiative. Our lead coordinator is based in Nairobi, Kenya. USAID has a plethora of tools and programs that can be deployed.

There are five main tools that we are using for Power Africa, one of which is my shop, the Development Credit Authority.

First, we have Power Africa transaction advisors who are out in the field in all six Power Africa focus countries. Their job is to try to close transactions. They are people with significant power sector backgrounds. They are the boots on the ground for us.

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Virginia income taxes. It would be able to deduct the full taxes on its federal income taxes, notwithstanding that it did not actually pay the taxes due to the credits.

LOANS with interest rates that step up over time create tax complications.

Many project finance loans have such a feature as a way to encourage the borrower to repay the loan before the interest rate increases.

The lender may have to report the potential increases in the interest rate as income over the full life of the loan. They are considered contingent interest for tax purposes since the loan may be repaid before the interest rate increases. Contingent interest must be reported by the lender as "original issue discount," meaning the lender is considered to start earning the stepped-up portion of the interest rate from the start of the loan. Determining how the contingent interest accrues requires complicated calculations.

The lender can avoid reporting the contingent interest as original issue discount only if the odds are remote that the loan will remain outstanding beyond when the interest rate increases.

The borrower deducts the additional interest at the same time the lender reports it as income.

TREASURY CASH GRANT litigation mounts.

Four more suits were filed against the US Treasury in March, bringing the total number of pending suits to 20. All four of the latest suits involved payments the Treasury made under the section 1603 program to wind farms.

In April, the government filed a counterclaim against one of the litigants in the 20 lawsuits, LCM Energy Solutions, accusing the company of fraud and asking for $482,504 that the company was already paid in grants on 18 rooftop solar systems back plus denial of its additional claim, civil penalties of up to $220,000 and treble damages of three times the amount the company was already paid, or $1.4 million.

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Second, USAID has also been contributing money to various funds in Africa. Some are focused on geothermal, some are focused on legal support and some are focused on clean energy. These are Pan-African funds.

The third piece of support is we have ramped up our technical assistance in the six target countries. Technical assistance can range from embedding lawyers in the bulk trading company in Nigeria to providing technical staff to Tanesco in Tanzania.

The fourth piece is we have been making grants to help pay for clean energy projects for agriculture, which is a way to merge some of our development priorities in agriculture with the new priorities of power and energy.

The fifth piece is loan guarantees that are provided through my office. Loan guarantees are provided by a number of US government agencies, including by some of my colleagues here at the table, and USAID loan guarantees are handled by the Development Credit Authority or DCA.

The DCA portfolio is a little over $3 billion globally and about $300 million of that to date is in energy, so energy is currently a small part of what we typically do. Most existing loan guarantees are in aid of agriculture, health and general small and medium enterprise development. We are trying with the Power Africa Initiative to expand our portfolio in the power sector.

MR. HANSEN: Astri Kimball, what is OPIC's role in the Africa effort?

MS. KIMBALL: The Overseas Private Investment Corporation is the US government's development finance institution. OPIC has committed $1.5 billion in support for energy projects across sub-Saharan Africa as part of President Obama's Power Africa Initiative. The OPIC commitment is not limited to the six countries you mentioned at the start. The commitment is across our three business lines which are investment funds, political risk insurance and long-term loans or loan guarantees. The loans can go up to $250 million.

We expect to meet and possibly to exceed the $1.5 billion commitment. We have about $1.7 billion in projects in our pipeline currently at OPIC. Our biggest portfolio is in Ghana followed by Nigeria. OPIC has been active in Africa for more than 40 years. Our African portfolio there has grown five fold since 2007.

What is new about Power Africa is the interagency coordination to support US investors in the region.

Let me give four examples of the increasing level of activity we see, and how Power Africa has helped US investors in sub-Saharan Africa. First, we are seeing new investors go to Africa with whom we have worked with in other places, like Denham Capital and SunEdison. Another example is the growing number of transaction advisors that the US has embedded with African governments. In Tanzania, for example, the USAID transaction advisor worked very closely with the energy regulator to standardize power purchase agreements. We had a solar deal in Tanzania and were able to work with the transaction advisor and the Tanzanian government on behalf of our borrower to extend the term of the power purchase agreement to 25 years. This is exactly the kind of transaction driven-policy change that Power Africa envisions. This policy change will benefit all investors in Tanzania, and one specific OPIC deal helped get that change over the finish line.

Third, Ethiopia is a place where OPIC has not been doing business for a variety of reasons, but we are seeing it open to business. We are looking at two projects in Ethiopia, geothermal and energy efficiency, and USAID and the African Development Bank are both providing legal support to the government to help advance the projects. Finally, the projects cover an enormous range of activity: big, small, off-grid, mini-grid, on the grid.

The capital needs are immense. Our CEO and president, Elizabeth Littlefield, was just in Rwanda and Malawi where the combined grid capacity is 350 megawatts, which is a fifth of the normalized capacity of Rhode Island, the smallest US state. The needs are incredible, and we are here to work with US capital to meet them.

MR. HANSEN: John Schuster, has OPIC left US Export-Import Bank anything to do?

MR. SCHUSTER: When I raised my hand at the beginning, it was not to say hi, but to signal that we have $5 billion under the Power Africa Initiative. The reason why the president could dedicate so many Ex-Im resources to Power Africa is the bank has no country or project limits on how much that we can lend.

We have one project as large as $5 billion. We have one country in our portfolio where I think our outstanding exposure is approximately $10 billion. Indeed, there is the potential for Ex-Im Bank to do a lot. We are open for business in about 75% of the African continent.

We make direct loans and also provide 100% guarantees. We can offer stable, low-interest debt because the money can come directly from the US Treasury. The ability to offer full loan guarantees means we have the lowest spreads on our interest rates of any export credit agency in the world.

We have a total loan and guarantee portfolio in Africa of $60 billion. About two thirds of that is within the last four years. Obviously, we are lending lots of money. About $1 billion of that is in sub-Saharan Africa and most of that is in South Africa. We are keen to do more south of the Sahara.

MR. HANSEN: The fourth leg of the table of the US Trade and Development Agency. Lida Fitts, why are you here?

MS. FITTS: The US Trade Development Agency has worked in Africa for more than three decades and it has always worked in energy. As a consequence of Power Africa, we have really ramped up our activity.

TDA operates at a very early level of project planning. We prep projects so that they can be eligible for Ex-Im and OPIC financing. We help with feasibility studies and pilot projects, and then move projects to implementation through bankable documents. We look at potential regulatory reforms. We host reverse trade missions and conferences that bring people together to introduce the players and try to make deals happen.

Since Power Africa started, we went from about a third of our portfolio in energy to over two thirds in the first year, and the percentage may increase further. Our overall budget has increased 60% with the entire increase being devoted to energy projects across the subcontinent. We have expanded the number of countries where we work. We had prioritized Kenya, Nigeria, Ghana and South Africa, but under this initiative, we are looking not only at the focus countries under Power Africa, but also at interesting opportunities in places like Malawi, Angola and Namibia. We are looking in a lot of places where we had not really been open before.

Multilteral Lending Agencies

MR. HANSEN: Jamie Fergusson from the IFC, what is your role?

MR. FERGUSSON: Africa is our traditional stomping ground, and all elements of the World Bank Group are active in the power sector. Two parts of the World Bank called the IBRD and IDA make direct loans to governments for public sector projects, provide technical assistance to governments, promote regulatory reforms and offer political risk guarantees. The Multilateral Investment Guaranty Agency, or MIGA, is our insurance arm for political risk coverage. The IFC, for which I work, is focused purely on the private sector, providing direct loans, mezzanine debt and equity. Our business in the power sector has been growing rapidly. Last year, / continued page 28

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LCM filed suit in May 2012 asking the Treasury for the difference between the $482,504 it was paid and the $889,638 for which it originally applied on the 18 systems. Treasury valued the 18 systems at $5.70 a watt for purposes of paying grants. The company wanted roughly $10.50 a watt.

The government found the legal arrangements around the 18 systems were a mess when digging more carefully into the facts after the company filed suit.

Two individuals set up a solar installer called RCIAC in February 2010. RCIAC sold the 18 systems to customers in 2010. An affiliated company, LCM, that the same two individuals formed in October 2010 then applied for rebates from ONCOR, the local utility, and for section 1603 payments from the US Treasury for almost half the purported sales prices of the systems to the customers. Each customer paid RCIAC only $1,500 for its system in fact, according to the government. RCIAC excused the rest of the purchase price.

LCM said on its Treasury cash grant applications that it purchased the systems from RCIAC using the ONCOR rebates and expected section 1603 payments and was leasing the systems to the customers under leases with terms of five years and rent of $25 a month.

The rebate applications filed with ONCOR said that each customer was the system owner and that the systems would remain in place for their entire useful lives.

The Treasury asked LCM for documents demonstrating that the customer leases were true leases before it paid the original grants. LCM produced a legal opinion that said LCM purchased the systems for the amount of the rebates, and RCAIC's cost to install was $4.79 a watt. When the Treasury paid the original grants, it took the $4.79 cost to install and added 20% to arrive at $5.70.

LCM sued for more. During depositions, one of the two owners of LCM said the company arrived at the purchase price it used to calculate grants by assuming a set number of hours to install each system / continued page 31

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we committed $1.2 billion to power in Africa.

Although we are not part of the US government, we participate in regular coordination meetings with Power Africa, both at the program level and at the country level in the six selected countries that are the initial targets for Power Africa.

Working in Africa involves coordination at multiple levels: in addition to the US government and the World Bank Group, there is the African Development Bank, there are donors, there are other development finance institutions, and there are the recipient governments. The countries we are helping have limited ability to coordinate such efforts on their own.

MR. HANSEN: Let's move to the private sector. Justin DeAngelis, what are you doing in Africa, why are you doing it and is this flurry of public sector support relevant?

MR. DEANGELIS: Yes. Denham is a global private equity fund focused on mining, oil and gas and power generation. I focus on power generation.

We have three companies in Africa with a partial to exclusive focus on developing power generation assets in wind, solar, hydro, coal, gas — really all the different generation technologies except geothermal and nuclear.

There is a dire need for power in Africa. The cost of power is also quite high, so many different types of power generation can help relieve the need.

There are pluses and minuses to each form of generation. I can build a solar project in six months. It does not require 100 or 200 kilometers of transmission lines. I can build it close to load. But solar is a relatively intermittent resource that will not provide electricity steadily through the day and night. It is part of the solution but not the whole solution.

Africa is the region where we probably have the most focus. We are there to stay. It is a region with great opportunity. Our capital is going into the development of power projects, not just projects that are ready for financial close. We are taking early-stage risk to bring real projects together.

We are an $8 billion private equity fund. We have the capital to support both development and construction of power projects. When we go talk to agencies like OPIC, OPIC knows us and knows that we can actually deliver.

Developer Feedback

MR. HANSEN: Paul Hinks, what is your view of Power Africa as a private developer?

MR. HINKS: Power Africa is the public and private sectors combining resources to work together.

It is good not only for Africa, but also for America. There are projects with which we are involved where we are making the whole project come out of the United States, from the selection of consultants to do feasibility studies to engineering and procurement. We are buying steel for the first time for transmission towers for a project in Tanzania from US suppliers rather than India, China or Turkey where we would normally get our steel because there is the possibility of getting Ex-Im Bank support.

Power Africa is a fantastic initiative. It will take time to see results. The public and private sectors are strange bedfellows. People have had to get used to working together.

The governments in Africa are getting used to it as well. It takes time to ramp up. I spent almost the entire last three months in Africa. People at utilities ask me: what is Power Africa? How do we participate in it? Africa is used to the World Bank model where the bank lends $500 million to build a hydroelectric dam. The dam is put out for bid, and the job is won by a Chinese company.

The notion that the private sector will develop a project from a grassroots idea or from a utility master plan is alien to them.

Andy Herscowitz, who is the Power Africa coordinator in Nairobi and who everybody who is interested in Power Africa should get to know, is doing a fantastic job. All of the

US government transaction advisers in six African countries are helping clear red tape.

agencies are doing a fantastic job. There are six Power Africa transaction advisors, all high-quality men and women.

Power Africa is much more than a big wad of money. It is also about facilitating projects. Power Africa transaction advisors are working on the government side helping utilities deal with things like power purchase agreements. They have moved the Ethiopian utility from being anti-independent power producer to signing the first power purchase agreement.

It will take a few more months before we start to see tangible results coming out, but they are there. I know many of the projects that are underway. I think within this year you will see Power Africa become something really valuable.

MR. HANSEN: You are optimistic.

MR HINKS: Yes, but I am also realistic. It is not easy working in Africa, and it is not for the faint hearted, but given the amount of support that Power Africa is bringing to the table, if you know how to make that work and how to navigate your way around it, there are so many opportunities. Power Africa is literally creating the land of opportunity for the private sector.

US Ex-Im Reach

MR. HANSEN: That is a terrific transition. I want to ask everybody to identify a favorite challenge or two standing in the way of success.

John Schuster, let's start with you. Some of the challenges can be internal. The Ex-Im Bank by its statute can only do transactions with a reasonable assurance of repayment. There needs to be adequate credit quality. Unless you get a call from the Secretary of State, you are supposed to think about just commercial things. If you had projects in Africa that met the reasonable-assurance-of-repayment standard, you would have more than a $1 billion portfolio in sub-Saharan Africa. How will Power Africa change things?

MR. SCHUSTER: One thing I left out in terms of what the Ex-Im Bank does is that as an export credit agency, our financing is tied to US content. You need to have US turbines, steel or other equipment from the US.

It is pretty rare to get a call from the Secretary of State.

The biggest issue by far is underlying credit quality within Africa. There are many countries where, in spite of our being open for business, there are huge credit, debt and other types of issues. Only 8% of Africa is investment grade or a little below investment grade.

We follow the private sector. We will have the best chance of success where companies have sales and / continued page 32

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at $75 an hour, regardless of actual installation costs, according to the government.

MASTER LIMITED PARTNERSHIPS are subject to a pause at the IRS.

The IRS has temporarily stopped issuing private letter rulings about whether income that sponsors propose to put in MLPs is "good" income. The pause started in March. There are rumors that it may lift in May, but a similar pause last year affecting rulings about real estate investment trusts lasted roughly six months.

Master limited partnerships are partnerships whose units are traded on a stock exchange or an over-the-counter market. Partnerships that are publicly traded are normally taxed like corporations. However, Congress made an exception in 1987 for partnerships whose gross income each year is at least 90% from passive sources like interest, dividends and rents from real property or from the exploration, processing, transportation or marketing of minerals or natural resources. A master limited partnership can raise equity more cheaply than a corporation because its earnings are subject to only one level of tax at the shareholder level. Investors also pay a premium for liquidity.

The IRS has issued a series of private letter rulings in recent years that stretch what it had previously ruled is income from minerals and natural resources. Nearly 70 MLPs have gone public in the last five years. Of those, 20 were formed in 2013. The IRS released 30 MLP rulings in 2013.

Clifford Warren, an adviser to the IRS associate chief counsel who handles partnership issues, acknowledged the pause on further rulings at a conference in late March. "We're regrouping," he said. "We're speaking with our counterparts at Treasury. We're trying to decide what the rules should be."

SandRidge Energy Inc. said in April that an MLP it is considering setting up for its salt water disposal business has been affected by the IRS action. / continued page 33

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business opportunities that are supporting our exporters and where there are good developers looking at projects in some of those better-off countries. I hope people forgive us for cherry picking.

The other thing that must be done in countries like Nigeria, which has enormous wealth but also enormous problems, is the government must be very, very serious about reform to make things more creditworthy. The commitment must be from the country and not from us.

MR. HANSEN: I want to give you a little extra credit on one point. I had occasion to work at the Ex-Im Bank a few years ago for a few years, and I was fascinated when I arrived looking at the country limitation schedule, which is the chart of where Ex-Im is and is not open. There was not much doing in Africa. If you look at it today, there has been significant progress.

But I was confused that some of the biggest projects the bank was doing were in countries where the bank was closed. How is this possible? Well, if John Schuster's group, the project finance group, can structure a transaction in a way that meets the credit standards, then that deal gets done. There is a wonderful little footnote in the country limitations schedule that basically says for well-structured transactions that somehow overcome the otherwise unsatisfactory domestic environment, those deals can be done.

A power project with credit enhancement behind the power purchase agreement — I am just guessing — is the kind of thing where your division will be able to make some things happen.

MR. SCHUSTER: I really don't want to say that the moderator who used to be the general counsel of the bank has misinterpreted footnote 13.

MR. HANSEN: Which he drafted.

MR. SCHUSTER: And it actually used to state more of what you just said about a well-structured transaction —

MR. HANSEN: My God, they changed it?

MR. SCHUSTER: That is the way it was drafted. The way that it is drafted now is the project needs to externalize the risk from the country. For example, the project needs to sell something to another market with the cash going into another bank account so that we can rely on the credit of that other area. Oil and gas projects in a number of countries use this approach.

Power is hard. You can take projects if the electricity can be wheeled to another area that is a good market, so wheeling power into South Africa or Botswana would be a way of using footnote 13. It is challenging to do.

Biggest Challenges

MR. HANSEN: Astri Kimball, what do you see as the big challenges for OPIC?

MS. KIMBALL: There are two, one of which is externalized and the other has to do with our own tools.

The first is the country capacity. It is important to have a good solid energy strategy covering everything from cost-reflective tariffs to power purchase agreements, proper risk allocation, a strong independent regulator, consumers who can pay and a commitment from the government.

For example, we financed and provided insurance to a tri-fuel power plant in Togo, along with the IFC, that tripled that country's electric generating capacity. The president was personally involved in convening meetings and pushing the deal through.

We worked with the staff of an energy minister in one country who held onto the PPA for months and finally said they did not know what to do with it.

The internal challenge is that OPIC's products are ideal for power projects in Africa. We provide long-term debt. These are long-term projects. But we lack some tools as a lender: the ability to make grants and put

Two thirds of sub-Saharan Africa remains without access to reliable power.

in the earlier-stage capital. We are now collaborating closely with other agencies. There is a particular facility called ACEF, for African Clean Energy Facility, that combines our debt with USTDA's grant and early-stage project preparation support. With the help of this new partnership, we are supporting all kinds of projects that we could not have helped before.

One more point: like the Ex-Im bank, we are demand driven. Finding investors who plan to be in the investment for the long term is what we need. I think that is a constraint.

MR. HANSEN: Lida Fitts, you were just mentioned. What are your biggest challenges?

MS. FITTS: The excitement of this new initiative brings a lot of new players to the table. Those new players take time to ramp up, familiarize themselves with the politics, technologies that are available and the requirements for getting financing. Things have been a little slower than we would like.

This initiative is trying to address that in a couple ways. One is by having the transaction advisors on the ground. Having someone knowledgeable in the country to help project sponsors speeds things up. We have also tried to put some of our early investment into reverse trade missions that bring people to the US to look at best practices and how things are done here.

MR. HANSEN: Megan Rapp, what stands in the way of success?

MS. RAPP: I focus mostly on debt, so let me focus on constraints I have seen to raising debt for power projects. There are too few project finance specialty shops locally in African banks, so often they end up pulling in their experts from London or New York or the Middle East.

Local currency debt is extremely expensive. You have high collateral requirements across the board. The large banks in Nigeria and South Africa have power sector exposure limits and single borrower limits. These add up to a serious constraint on the supply side of debt. Then on the demand side, you have a project pipeline that is often opaque, fragmented and unpredictable. You often have an uncreditworthy offtaker. We could go on and on with the challenges.

However, the Power Africa Initiative is focused on problem solving. We can write reports and talk about all the problems, but the real impetus of doing this differently is using transactions as the driver in problem solving, and we are seeing that approach put to the test in most of the countries already.

MR. HANSEN: Jamie Fergusson, what do you see as the big challenges? / continued page 34

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REITs may be given more guidance.

The IRS is working on proposed regulations about what qualifies as "real property" for REIT purposes.

REITs, or real estate investment trusts, are corporations or trusts that are not taxed at the entity level on the earnings they distribute to investors. There are both private REITs and publicly-traded REITs. The assets held in a REIT must be at least 75% "real property," although a REIT can also hold some assets through a taxable subsidiary that do not qualify to be held by the REIT directly.

Several REITs have been formed to hold transmission and similar infrastructure assets after the IRS ruled privately that transmission lines and towers are real property for REIT purposes. There was a flurry of interest in REITs among solar and wind companies in 2012, but the interest diminished after the IRS rulings branches that handle REITs made clear they are not prepared to rule that solar panels and wind turbines are real property. Machines are not considered real property. Some solar advocates argue that solar panels are closer to transmission lines in that they are essentially a conduit for electricity.

Any new definition of "real property" that the IRS develops will have a prospective effective date.

It is possible any decision to expand what qualifies as real property for REITs could make European and other foreign companies invested in the US renewable energy sector more likely to pay US capital gains taxes when they exit US investments. The IRS uses the same definition of real property for taxing foreigners on capital gains from US investments. A foreign parent selling a US holding company for US investments is generally not taxed on the gain as long as less than 50% of the asset value in the holding company is in US real property.

The IRS had a hold on private letter rulings about REIT classification from May to November 2013 while it studied / continued page 35

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MR. FERGUSSON: As mentioned by others, creditworthy off-takers and suitable regulation are essential. There must be regulation to open up these markets to private capital. If there is no room or legal capacity for independent power producers, then the deal will be hard to structure

However, one issue not yet addressed by other speakers is the small scale of some of these markets, which is a serious challenge in itself. Go to West Africa: these countries are tiny, which means that the right incremental addition of generation for the expected growth in the demand is small. It is painful, but perhaps okay, to spend five years on negotiating a bankable structure for a 300-megawatt hydroelectric project that takes six years to build. Doing the same thing for a 10-megawatt PV project that takes three months to build does not make sense at all. So complexity and transaction costs are another challenge and regional interconnection and creation of larger markets is important.

The small scale of some African markets remains a challenge for developers.

What is really changing now in Africa is that, unlike a decade ago, there are a lot of developers. The developers need standardization, scale and a suitable regulatory environment.

Success Rate

MR. DEANGELIS: Our pipeline is huge, but probably only 5% of that pipeline can actually get done.

I think Power Africa can be helpful in two ways. One is by relieving some of the bureaucratic logjams in countries. For example, the energy minister wants to get a project done, but the incumbent utility disagrees and it has enough power to stop things from happening. It is a country where the lights are flickering, but the institutions have competing interests.

Two, these are emerging markets. The projects need help to become bankable. I will put my private capital into developing the projects, but there will have to be credit enhancements for projects to be bankable. It is a short-term need. It has to happen to get eventually to a functioning market.

There is a tremendous amount of capital ready to invest in good projects. There is an immense need. The key is the execution in the middle, and that is where we think our companies can help get things done and where Power Africa can help the most.

MR. HANSEN: That is a good segue to Paul Hinks, who is a bridge builder. You were present at the beginning of this initiative. You get the last word.

MR. HINKS: President Obama said, when he spoke in Tanzania about Power Africa, that there is a need for speed.

What I see as the biggest challenge to the success of Power Africa is getting the governments and the utilities to understand that concept of speed. People get fed up when they spend extended periods on the ground in Africa trying to develop a project that makes lots of sense and that the president says is fantastic, but then the permanent secretary or the commissioner of energy just cannot seem to get the various government agencies to sign the necessary pieces of paper.

The biggest challenge is making host governments react. Power Africa is already making a difference because of the transaction advisors who are on the ground and are getting to know the government officials.

I can only speak from my own experience working with the transaction advisers. We are in contact often. They go out of their way to help us. We could not ask for more.

MR. HANSEN: Are there questions from the audience?

MR. HOYT: Edward Hoyt with Nexant. What criteria were used for selecting the six countries that are the initial targets, and what is the process for adding new countries?

MS. RAPP: The selection of the countries was a long process. USAID is working in the power and energy sectors outside of those six countries. In addition to the six countries, we have a focus on Uganda and Mozambique. Outside of Power Africa, I see efforts in the energy sector in Zambia and South Africa. The six countries are not limited to USAID's work in the energy space per se. We set an initial goal under the Power Africa Initiative of adding 10,000 megawatts and bringing electricity to 20 million households in those six countries, but that does not prevent us as USAID from working in other places.

What is the process for adding new countries? The focus is on trying to do things well in these six before we try to bring others on board, but if there are countries where you are interested in working, come talk to us.

MR. SCHUSTER: From the Ex-Im Bank's perspective, the six countries are not really our focus. Our focus is sub-Saharan Africa.

MS. KIMBALL: Same for OPIC.

Currency Risk

MR. HUFFAKER: John Huffaker with OCI Solar Power. These countries have repatriation issues, political risk, expropriation risk and foreign currency risk. As a group of experts covering some of the riskiest countries in the world, do you have any suggestions for how to address these exposures?

MR. DEANGELIS: Focusing on currency, we are invested in South Africa whose currency is the rand. We put on hedges to mitigate the currency risk when we invested in some of the first renewable energy projects there a couple years ago. Those hedges are in the money right now, so it was a good move.

Outside of South Africa, many of the power contracts are in dollars, so there is convertibility risk from local currency to dollars, but explicit currency risk does not exist. There is implicit risk, and we have to watch that very carefully.

MR. SCHUSTER: The Ex-Im Bank has a foreign currency guarantee program. In South Africa where you could have rand lenders go out to a reasonable term, you can do a rand guarantee and that is something that I strongly recommend. Otherwise you can look at currency hedges in some of the markets. Currency exposure is one of the biggest single risks.

MR. HINKS: Word to the wise — do not take currency risk on any project in Africa. You do it dollar-based and the most you do is link the local currency to the dollar so that you are taking no financial exposure because you could wake up in the morning in any of these places and their currencies / continued page 36

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whether the rulings it has been issuing go too far. David Silber, a deputy IRS associate chief counsel, said in April that the agency decided it was comfortable with what it had done and is now working through a rulings backlog.

CBS, the US television company, said in April that it received a favorable tax ruling that will allow it to spin off its outdoor billboard advertising subsidiary into a REIT. The subsidiary, CBS Outdoor Americas Inc., raised $560 million in late March in an initial public offering of 19% of the shares. CBS plans to do a tax-free spinoff of the other 81% of the shares later this year and then convert the subsidiary into a REIT. One analyst estimated that the conversion would reduce the CBS tax bill by $145 million in 2014 if it had occurred at the start of the year.

Meanwhile, the IRS is under conflicting pressures on REITs. Some segments of the Obama administration have been keen to see REITs authorized for use in the renewable energy sector because they believe it will help bring down the cost of capital for the sector. At the same time, some in Congress are concerned about the erosion in the corporate tax base that has been occurring as billboard companies, cell phone and electric transmission companies, data centers, casinos and prisons get favorable private rulings from the IRS allowing them to convert to REITs.

The draft corporate tax reform bill that the House tax-writing committee chairman, Dave Camp (R-Michigan), released in February would define "real property" for REIT purposes to exclude assets with shorter depreciable lives than 27.5 years. That would rule out cell towers and billboards. It is not clear to what extent existing REITs or companies that are in the process of converting would be affected.

The Camp bill would also require any company converting into a REIT to pay tax on the untaxed appreciation in value in the company's assets through the conversion date. The bill would also bar corporations from electing REIT status for 10 years after being spun off in a tax-free transaction after February 26, 2014.

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have been devalued and you are in deep trouble.

MR. HANSEN: As we all learned in Indonesia during the Asian financial crisis, the mere fact that you have revenues that are pegged to dollars means with devaluation, the deal the local government thought it struck just became radically more expensive and the likelihood that it will perform goes down. Pegging to the dollar does not really totally hedge your risk.

MR. HINKS: No, no. We actually do everything in dollars. We don't even take the local currency. Don't peg it to the dollar. We have a fixed exchange rate.

MR. HANSEN: My point is that if they promise to pay you in dollars —

MR. HINKS: No, they have to promise to pay the dollar amount.

MR. HANSEN: Correct, but the more expensive that becomes for them as the local currency depreciates, the greater the likelihood that they will welch on that deal.

MR. HINKS: Agreed.

MR. SCHUSTER: It is a sustainability issue. There is no real running away from foreign currency risk. I would definitely say that in almost all of these markets, you have to put the contracts in dollars. You cannot take foreign currency and expect to be able to exchange that currency elsewhere. We are not going to do that. But even if you have done what is required, you will still have the issue that Ken Hansen identified.

MR. BESTANI: I'm Bob Bestani from the Department of Energy. Mine is not so much a question as a comment. The president has asked Secretary Moniz of the Department of Energy to make his own trip to Africa this year. We are having a Pan-African energy ministerial meeting on June 3 and 4. We are inviting most if not all of the countries of Africa to come. We certainly want the private sector to come and be an integral part of the meetings as well. We are doing as much outreach as we can. ◎

Ensuring That Loan Documents Address Equator Principles and Trade Sanctions

by Yasser Yaqub, in Dubai, and Gaurav Sharma and Richard Oliver, in London

New Equator Principles need to be reflected in loan agreements. Lenders and project sponsors should also protect themselves against increasing use of trade sanctions by governments to enforce foreign policy goals.

The Equator Principles are a set of rules to which development financing institutions, export credit agencies and many large banks have committed to follow when deciding whether to lend. The lenders have agreed not to lend to projects that damage the environment or cause social turmoil. The principles have been recently updated.

Equator Principles

The Equator Principles Association launched the third version of the Equator Principles — called EPIII — in June 2013. While EPIII became effective on June 4, 2013, a transition period was introduced covering the remainder of the year.

Therefore, EPIII became mandatory for projects financed by financial institutions where the mandates were signed on or after January 1, 2014.

It is timely to consider how to incorporate the requirements of EPIII into loan documentation as the finance documentation for the first projects that are subject to EPIII is currently under negotiation. The Equator Principles Association updated its guidance in March on how to implement the Equator Principles in loan documentation.

EPIII has brought within the scope of the Equator Principles, project-related corporate loans and bridge loans in addition to project finance advisory services and project finance that were already covered. The project capital costs have to be more than US$10 million to be covered. EPIII has also put new emphasis on climate change, increased emphasis on human rights, expanded the reporting requirements of the financial institutions making covered loans and enhanced the covenants that are required in loan documentation.

When considering incorporating the Equator Principles into loan documentation, it is not usually enough merely to require the borrower to comply with, or not violate, the Equator Principles. This is because the Equator Principles are not a charter specifically directed at borrowers or sponsors but rather are a set of principles directed at lenders.

Therefore, the key is to take the Equator Principles and convert them into environmental and social compliance provisions that can then be incorporated into the loan documentation.

A project will first need to be categorized by the lender during its due diligence process according to the degree of environmental and social risk the project presents.

Project Categorization

The categories are:

Category A: Projects with potentially significant adverse environmental and social risks or effects that are diverse, irreversible or unprecedented.

Category B: Projects with potentially limited adverse environmental and social risks or effects that are few in number, generally site-specific, largely reversible and readily addressed through mitigation measures.

Category C: Projects with minimal or no adverse environmental and social risks or effects.

This categorization of the project will determine the requirements that the lender is likely to impose on the project. These will depend on the category.

Thus, lenders will have to assess the environmental and social risks and require the sponsor to put in place a system for managing such risks for category A and B projects. The sponsor will have to prepare an environmental and social management plan and also have a plan to address any environmental and social issues that do not comply with the relevant standards. An independent consultant will have to be hired to assess the adequacy of these plans. This is compulsory for category A projects and may also be requested for some B projects. The lenders will have to set up complaint and grievance procedures for local communities affected by the project. They must also consult with affected local communities. This / continued page 38

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CAPTIVE INSURANCE won a round in court. The IRS is still deciding whether to appeal.

The IRS denied a company called Rent-A-Center deductions for premiums the company paid from 2002 through 2007 to an offshore subsidiary in Bermuda that the company formed to insure its other subsidiaries.

The US Tax Court said in January that the premiums were deductible.

The result would have been different if the subsidiary were insuring its parent company. This is the second time the US courts have upheld captive insurance arrangements between sister companies. The case is *Rent-A-Center, Inc. v. Commissioner.*

Rent-A-Center rents furniture and electronic appliances with a right to keep the furniture or appliances if the customer makes the full rent payments. It is about 35% of the US rent-to-own market based on store count. During 2002 through 2007, the company had roughly 3,000 stores in the United States, 19,000 employees and 8,000 vehicles. It operates in all 50 states, Canada, Puerto Rico and Mexico.

It had been buying general liability, workers compensation and auto insurance from Travelers. It started exploring other options after receiving an invoice in 2001 for $3 million in claims handling fees. The company hired Aon Risk Consultants to advise it on options.

With Aon's help, it bought insurance in 2002 from Discover Re, but Aon suggested it could save even more money by forming a captive insurance subsidiary, which it did in Bermuda in December 2002.

The captive wrote insurance for 15 Rent-A-Center subsidiaries. A third party was hired to administer claims. The policies had a cap on exposure. The company continued to buy excess coverage for losses above the cap from Discover Re. Rent-A-Center was listed as the policyholder on the insurance, and it paid the annual premiums, but the subsidiaries reimbursed it for the premiums through monthly payments. The premiums were set based on loss / continued page 39

Equator Principles

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is compulsory for category A projects and may also be requested for some B projects. Finally, the sponsor must turn in regular compliance reports to the lenders.

In order for a lender to ensure that the project to which it will be lending will comply with the Equator Principles, the above requirements will need to be tailored to the specific project based on the activity being undertaken by the project.

Financial institutions and sponsors can at times be ambivalent about the details of implementation of the Equator Principles after the loan has been funded, and such ambivalence can translate into provisions in the loan documentation that do not serve their intended purpose.

For instance, having representations and covenants simply to the effect that the borrower must comply with the Equator Principles betrays a lack of understanding of the regime set up by the Equator Principles Association.

Implementation of Equator Principles in loan documentation should typically be structured in the following manner.

New loan agreements need to be revised to reflect the latest Equator Principles.

The borrower should represent that there are no environmental or social claims or potential such claims against the project that might have a material adverse effect on the implementation or operation of the project.

There should be several standard "conditions precedent" to the initial disbursement of debt. No draw should be allowed until the borrower has obtained all necessary environmental and social permits (and provided opinions as to the completion of this requirement). The borrower should have appointed the necessary technical consultants to undertake an agreed scope of work. The borrower should also have delivered all reports, assessments and plans relating to the environmental and social impact of the project.

Conditions precedent may also be required for each future disbursement. Such conditions would typically require confirmation that the project continues to be in compliance with any applicable (at that stage) environmental and social requirements and that all actions required by any environmental and social management plan have been completed as required.

The borrower should be required to report to the lenders on environmental and social matters at regular intervals (usually on an annual basis during the operation phase and more frequently during construction). These reports will include pre-closing reports, progress reports during construction and operational reports.

Any environmental and social claims, environmental contamination, health and safety violations, protests or grievances by the local community and project employees and any other environmental and social issues should also be reported to the lenders as they occur.

The borrower may also be required to make public reports on certain issues (for example, emissions reports where the project emits more than 100,000 tons of CO_2 equivalent annually).

The borrower should be required to covenant to comply with the environmental and social requirements (including the environmental and social management plan), deliver progress reports documenting and certifying compliance with these requirements, allow access to the lenders and their representatives to assess compliance, conduct any decommissioning in accordance with a predetermined decommissioning plan and respond to complaints about construction, permitting and operation of the project. The borrower may also be required to agree not to amend the environmental and social management plan materially without lender consent.

While some lenders may insist on including events of default specific to environmental and Equator Principle compliance, such inclusions should not be required if the conditions precedent, representations and covenants outlined above have already been included. The loan documentation will already provide for lender rights of termination, subject to varying periods of remedy allowed to the borrower, upon the breach of such representations and covenants.

Trade Sanctions

Trade sanctions can be imposed by various intergovernmental organizations and states. The United Nations Security Council can impose sanctions that are binding on all UN members while the European Union issues sanctions directly effective in all member states. Individual countries such as the United Kingdom and United States also impose sanctions that are usually tougher in terms of scope and restriction than sanctions imposed by the UN and EU.

While trade sanctions can take a number of forms, the most relevant types of sanctions for parties in project financing are financial sanctions. Under certain sanctions regulations, financial institutions are prohibited from making available any funds, other financial assets or economic resources to sanctioned entities or sanctioned countries. This could include the release of money in a bank account to an account-holder or extending a loan or guarantee to a client who is linked to a sanctioned party.

Breach of financial sanctions may be considered a criminal offense punishable by imprisonment, a fine or both. A number of financial institutions have been subject to multi-million dollar fines and settlements with the US and UK regulators for sanctions breaches.

In the US, the Office of Foreign Assets Control or "OFAC," which is part of the US Department of the Treasury, administers and enforces financial sanctions. The US Treasury maintains jurisdiction over all US dollar transactions, and its aims are to ensure no sanctioned countries, entities or individuals engage improperly in US dollar-denominated transactions.

OFAC is extremely proactive and diligent in enforcing US policy and has implemented regulations that have extraterritorial reach to the activities of foreign financial institutions. In 2009, a UK bank agreed to pay a US$350 million penalty in lieu of US criminal prosecution for processing payment transactions made by its clients through unaffiliated US banks.

Although the bank was technically not a US entity and none of its process payment transactions */ continued page 40*

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forecasts by Aon. They were $3 million a year less than Discover Re quoted for the same coverage. During 2002 through 2007, the captive earned net underwriting income of $28.8 million.

The Rent-A-Center parent company guaranteed the captive's obligation to pay out on the policies, but only to the extent needed to satisfy a minimum solvency margin in Bermuda. The guarantee was cancelled once the captive reached the margin on its own.

The IRS called the arrangements a sham and denied the deductions the parent claimed for the insurance premiums. The deductions had the effect of shifting income from the US to Bermuda. The US Tax Court disagreed. It said there was a real business motivation, the insurance contracts had arm's-length terms, the premiums were actuarially determined, and the captive was subject to regulatory supervision by the Bermuda insurance commissioner, met Bermuda's minimum statutory requirements and paid claims from a separately-managed account.

The court said to have real insurance, there must be both risk shifting and risk distribution.

A contract between a parent and subsidiary does not shift risk. However, two courts have now used a balance-sheet analysis to conclude that risk does shift when a captive insures a sister company drawing solely on the resources of the captive plus, in this case, a limited parent guarantee to pay claims. The other case was a decision by a US appeals court in *Humana v. Commissioner* in 1989.

In order to have risk distribution, the insurer needs to insure a large enough pool of unrelated risks. The Tax Court said a captive may achieve adequate risk distribution by insuring only subsidiaries within its own affiliated group. There were a sufficient number of statistically independent risks in the Rent-A-Center case given the large number of stores, employees and vehicles.

The betting within the captives market is that the IRS will continue to deny deductions for premiums paid to captives, but will not appeal the Rent-A-Center */ continued page 41*

Equator Principles

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took place within the US, its actions caused its unaffiliated US correspondent banks to breach OFAC regulations and, therefore, its actions were caught by the US sanctions regime. More recently, in 2012, another UK bank paid approximately a US$300 million fine for concealing transactions through the US financial system primarily on behalf of Iranian and Sudanese clients by removing information that would have revealed the payments and otherwise would have been rejected, blocked or stopped for investigation under OFAC regulations.

Given the challenges of complying with overlapping sanctions regimes, and the potentially significant penalties and personal liability for breaches of regulations, financial institutions need to be conscious of the complexities of sanctions laws.

It is important in any project financing that lenders are aware and protected from their funds being used for any sanctioned activities. Borrowers also need to manage risk to ensure they are not inadvertently prejudiced should another party to the project finance agreements breach the relevant sanctions regulations.

Representations

As a matter of policy, lenders will include a series of sanctions-related representations coupled with undertakings in the loan documents so that in the event their funds are used in any type of sanctioned activity, the lenders will have recourse against the borrower.

Trade sanctions may be imposed for use of funds directly or indirectly in a sanctioned activity. This includes dealing with persons or entities designated on a particular sanctions list or carrying out transactions in sanctioned countries.

Therefore, when negotiating a sanctions representation, lenders should insist on not only capturing the borrower under the scope of any representation, but also any party to whom the facilities can potentially reach.

For this reason, it is not uncommon to see sponsors, shareholders, the EPC contractor, the O&M contractor and guarantors covered by the sanctions representation. While the borrower will obviously want to limit the inclusion of other parties, the borrower may be more receptive to having the scope cover the additional parties if it is able to obtain the same level of protection from the additional parties under its contractual documentation with such parties.

Lenders will want the borrower to covenant that the sanctions representation will remain true at all times until the loan is fully repaid.

Typical representations in relation to trade sanctions include that the borrower and other related parties have not made the proceeds of the facility available directly or indirectly to any person or entity that is sanctioned or affiliated with a sanctioned entity and have not made any proceeds of the facility available for use in a sanctioned country. The borrower may have to represent that neither it nor any related party is a sanctioned entity or has violated any sanctions and it is not aware of any claim or investigation against the borrower or an affiliate by a sanctioning authority.

The lenders should also require negative covenants relating to sanctions where the borrower and related parties undertake to refrain from certain actions. There should usually be a prohibition on the borrower and related parties from making any proceeds of the facility available to any sanctioned person or for use in a sanctioned country for the purpose of financing activities in breach of the sanctions.

If the borrower breaches a representation or covenant in the loan agreement, then it should be entitled to a certain number of days within which to remedy the sanctions breach before the lenders are able to call an event of default. Conversely, if the borrower breaches a negative covenant,

Lenders should make sure their funds are not used to violate trade sanctions.

then the lenders may insist on no remedy period so that the lenders have the right to call an immediate event of default.

Should a party other than the borrower breach a sanctions provision in the loan agreement, then apart from any remedy period available, the borrower's only recourse should the lender call an event of default is to claim against the other party in breach of the sanctions provision under its contractual framework with that party. This highlights the importance of the borrower properly allocating its risk and ensuring that it is covered directly for breaches of parties outside its control.

Remedies available to the lenders should the borrower or a related party breach a sanctions representation or covenant include calling an event of a default, allowing the lenders to cancel the loan agreement and facilities under it and claiming immediate payment of any funds drawn down by the borrower.

Against the backdrop of existing anti-money laundering and anti-terrorist financing laws, financial institutions must not overlook the growing area of sanctions law and how to protect themselves in project financing agreements. From a borrower's perspective, the project and finance documentation should include coverage for breach of the sanctions provisions by other project parties. ◎

The New Massachusetts SREC Market

Solar developers, tax equity investors and lenders are trying to figure out what value to assign to renewable energy credits that solar projects receive in Massachusetts for generating electricity. The state is in the final stages of implementing its new SREC II program. Three experts talked about the new program during a webinar that Chadbourne hosted in late March. The following is an edited transcript.

The panelists are Michael Judge, associate manager of the Massachusetts Department of Energy Resources renewable portfolio standards programs, Noah Pollak, a lawyer with Chadbourne in Washington, and Alex Anich, director of research at Karbone Inc. The moderator is Todd Alexander with Chadbourne in New York.

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decision, preferring to wait for other cases with better facts.

TARGETED PARTNERSHIP ALLOCATIONS may be the subject of future IRS guidance.

The AICPA, the trade group for the US accounting industry, sent the IRS and Treasury in February a draft revenue ruling that it would like the IRS to issue about targeted allocations.

IRS regulations require partnerships to keep a capital account for each partner that tracks what the partner contributed and what he got out of the partnership. When the partnership liquidates, the capital accounts are supposed to be used by partners to divide up what remains.

With targeted allocations, the partnership simply divides up what remains according to a business deal. It tries during the life of the partnership to share economic returns in a manner that causes the capital accounts to remain in the ratio the business deal requires any assets remaining at liquidation to be shared, but there is no guarantee the capital accounts will be in this ratio.

The AICPA said that there is a widespread misconception that the IRS approves of targeted allocations because it has not challenged partnerships that use them.

The ruling the AICPA wants the IRS to issue would say that targeted allocations work as long as they are economically equivalent to using capital accounts to distribute assets at liquidation. This would have to be true not only for the particular tax year in which the allocations are tested but also for all future years.

The allocations lead to the same result as using capital accounts to distribute assets at liquidation in the first two of three examples the AICPA asked the IRS to address.

In the examples, a 50-50 partnership is formed between partners A and B. A contributes $100 in cash and B contributes assets worth $100 in which B has a basis of $100. The business deal is that A and B are distributed cash in a 50-50 ratio until each gets / continued page 43

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Market Insights

MR. ANICH: It helps to have an understanding first of how prices for solar renewable energy credits have moved in the past in Massachusetts and also to understand the binary nature of markets with fixed targets under renewable portfolio standards.

Most markets have tended to trade initially as undersupplied markets. In an undersupplied market, prices gravitate toward the alternative compliance payment, or the amount a utility must pay as a penalty if it fails to turn in enough renewable energy credits to meet the RPS target. In Massachusetts, credits traded initially well above $300 a MWh and right up to $500 a MWh, which is the alternative compliance payment, because there were not enough SRECs available in the market. Buyers either had to buy SRECs, bidding up the price, or pay the alternative compliance payment, called the SACP. Obviously, the SREC price will not go above the SACP since buyers will pay the SACP rather than buy more expensive SRECs.

Like many markets, Massachusetts went from a period of undersupply to a period of oversupply as more and more solar projects were built in the state. Prices dropped rapidly and eventually fell below $285 a MWh, which was supposed to be a floor of sorts under a clearinghouse price support mechanism. The solar credit clearinghouse price support mechanism in Massachusetts is unique. Where other markets also went from periods of undersupply to periods of oversupply, SRECs in Massachusetts — notwithstanding the fall in prices — managed to maintain a premium above the value in other markets.

The New Jersey market is similar to Massachusetts in that it has free market entry. Developers can build projects with few limitations, and there is a relatively smooth approval process. However, Massachusetts SRECs maintained a $100 a MWh price premium over New Jersey SRECs when each market moved into oversupply.

Pennsylvania is distinct from these other two markets in that SRECs can be sold in that market from projects in other states within the PJM grid. That meant that when other markets moved into oversupply, the Pennsylvania market was flooded with SRECs from neighboring states. This caused SREC prices in Pennsylvania to drop below $50 a MWh. There was a very large price premium for Massachusetts SRECs compared to Pennsylvania SRECs.

As we look ahead to the new Massachusetts SREC II program, the key challenges that the program faces are price stability and maintaining the SREC prices in the range of something called the solar credit clearinghouse auction price support value. The solar credit clearinghouse auction price support value will start at $300. The Massachusetts SREC price support mechanism functions based on supply and demand, so it does not guarantee a minimum floor price. If the market is oversupplied, then prices could fall below the solar credit clearinghouse auction price support value. Therefore, the first challenge facing the SREC II market is to limit the oversupply. The SREC I market went into oversupply because of rapid development of a number of large solar projects in the commercial sector.

We are looking at two potential scenarios for the SREC II market. In an undersupplied market, we expect the prices to track above the solar credit clearinghouse auction price support value, but below the alternative compliance payment. If the market is oversupplied, then prices could fall below the solar credit clearinghouse auction price support value. These markets tend over time to become oversupplied.

> Massachusetts has a net metering cap of 663.4 MWs, and 672 MWs of projects have already been declared eligible if built.

Another challenge facing the Massachusetts SREC II market is the net metering cap. This is the amount of capacity that can be signed up to supply electricity to the grid through net metering. The current net metering cap is 663.4 megawatts, and there are already 672 megawatts of projects that effectively received a statement of qualification and have the potential to get built. Therefore, the Massachusetts legislature is considering two bills to increase the net metering cap. Net metering essentially allows projects to sell power at retail rates and is essential for establishing a strong SREC II market.

How the Program Works

MR. JUDGE: Let me give a quick overview of how the renewable portfolio standard programs work in Massachusetts.

We have three classes within the renewable portfolio standard programs. Class I, which has been in effect since 2003, is for new renewables. Class II includes both new renewables and waste-to-energy facilities. Finally, we have the alternative portfolio standard for combined heat and power facilities and other generating systems.

Within class I is a subclass that we call the solar carve out, which is a specific target for the amount of solar electricity utilities are required to supply each year. It is a carve out from the larger class I obligation. We are in the process of implementing a new carve out from class I, which will be the solar carve out II program. When everything has been fully implemented, utilities will have an overall class I target for 2014 of 9% renewable energy, which includes the two separate carve outs for SREC I resources and SREC II resources.

Solar has received special treatment in Massachusetts since 2010 when the solar carve out program was first implemented. New solar construction was a little slow at first, but then really picked up in 2011, and a lot was built last spring and summer. Unlike other states, Massachusetts has an adjustable RPS target — called a minimum standard — that is supposed to keep SREC supply and demand in reasonable balance and prevent prolonged periods of oversupply or undersupply that have been issues in other SREC markets.

Often when an SREC market is created, the targets are set by statute many years in advance. When the market moves into an oversupply, the regulators administering those programs have no ability to make adjustments. In Massachusetts, our regulations include a formula that adjusts demand based on market oversupply. We also have a forward alternative compliance payment schedule. This allows market participants to see the alternative compliance payment up to 10 years in advance.

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its $100 back, then A gets cash to give it a 5% return on its $100 in invested capital and remaining cash is distributed 50-50. The partnership allocates net income and loss so as to try to keep the capital accounts in a ratio that matches the business deal.

In example 1, the partnership has net income. The AICPA says that A and B will receive the same amount at liquidation as if the partnership kept proper capital accounts and used them to distribute remaining assets.

In example 2, the partnership as no net income. Each partner will get back $100 at liquidation.

In example 3, the business deal is different. A gets its capital and return first, then B gets its capital back and then everything else is shared 50-50. The AICPA says targeted allocations using this formula do not work because these allocations will leave B with less than B would receive if proper capital accounts were used at liquidation unless the partnership will have enough net income each year to give A its preferred return. There is no guarantee the partnership will have enough net income in future years.

It is unclear whether the AICPA believes that the IRS should allow the targeted allocations in the third example on audit as long as the partnership had enough net income in fact through the tax year being audited to cover the A preferred return.

BITCOINS are taxed as property rather than currency, the IRS said in late March.

This means that anyone holding bitcoins risks having to pay a tax on gain when the bitcoins are used in the same manner as if the holder sold property and used the cash to buy goods or services. This will make it impractical for individuals and businesses to use bitcoins as currency for ordinary course transactions because of the need to track gains and losses.

The IRS analysis is in Notice 2014-21.
The notice explains the tax treatment of virtual currencies and does not focus solely on bitcoins.

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We also have a solar credit clearinghouse auction account that provides a soft floor price. It is not necessarily a hard or guaranteed floor price. It helps maintain pricing in the market, and I think you can make a strong argument that, because of it, pricing in Massachusetts has been more stable than in some other SREC markets that have experienced oversupplies.

Deadlines

So here is an update on the market. In May and June 2013, we received about 800 megawatts of applications for about 200 megawatts of remaining capacity in the solar set aside program. Given the wide variety of projects that were in front of us, some of which had made serious investments and had serious sunk costs, and others that were not at as an advanced stage of development, we announced our intention to issue emergency regulations that were filed on June 28 and extended eligibility to projects that had met certain development milestones. Namely, any project over 100 kilowatts could qualify if it had signed an interconnection agreement with the local utility by June 7, 2013. Those projects were given through December 31 to be completed. If they were not completed by that date, then they had to demonstrate that 50% or more of their construction costs had been incurred.

We have now passed the deadline. Some projects dropped out. The majority of projects remain in the program. As of right now, we have about 675 megawatts qualified, of which about 420 megawatts are operating. So we still have a little over another 250 megawatts that are not operating, but they have until June 30 to interconnect.

We are also still qualifying projects under 100 kilowatts until the SREC II program goes into effect. Any such project that is interconnected and submits an application to us by the time the SREC II regulations go into effect will be eligible under SREC I. Otherwise, no new projects will qualify for SREC I as of the effective date of SREC II.

If any project over 100 kilowatts is currently qualified under SREC I, it cannot be qualified for SREC II until it has withdrawn its statement of qualification under SREC I and then reapplies under SREC II. No project can be qualified for both programs.

Differences Between SREC I and II

There are a few key differences between the SREC I and SREC II programs. SREC II is a much larger program. The program cap will ultimately be 1,600 megawatts minus the final SREC I cap. For example, if the SREC I final cap is 600 megawatts, then there will be 1,000 megawatts of capacity available under SREC II.

There are no more opt-in terms. The opt-in term is the number of quarters a project has the right to deposit SRECs into the clearinghouse auction account. Instead, all projects receive SREC IIs for 40 quarters from either the quarter in which they qualify or the following quarter. Also, both the alternative compliance payment and auction price have declining forward schedules. In SREC I, we had a declining alternative compliance payment schedule, but a fixed auction price for the duration of the program. In SREC II, that auction price begins to decline in the fourth year of the program. Perhaps the biggest change between SREC I and SREC II, is the introduction of "SREC factors." SREC factors offer different incentive levels to different types of projects. These were added to meet certain public policy goals as well as to differentiate the incentives based on differing economic needs of different sectors. Finally, the compliance formula has changed because, instead of growing a market from scratch, we are now trying to maintain steady, stable market growth. We are not trying to grow a market from essentially zero to 10 megawatts a year to 150 megawatts a year. We are trying to maintain it at about a 150-megawatt or so range per year.

The alternative compliance payment rate begins at $375 a MWh, which is substantially lower than the $523 rate that is currently in the SREC I program. So there has been a significant reduction in the alternative compliance payment rate, which will provide significant cost savings for ratepayers, but also less upside to project developers. The auction price stays at the same price level for the first three years as it is under SREC I, and then begins to decline.

With the introduction of the "SREC factors," the amount of marketable SREC IIs produced by a project will be a function of whether the project is in market sector A, B, C or "managed growth." Projects in market sector A receive an SREC factor of 1.0x. Projects in market sectors B and C receive SREC factors of 0.9x and 0.8x, respectively. Projects in the "managed growth" sector receive an SREC factor of 0.7x.

Market sector A includes projects of up to 25 kilowatts in size, solar canopies located on parking structures or pedestrian walkways, emergency power generation units that provide power to critical infrastructure in the event of an emergency or power outage, community-shared solar generation units, and units that provide power or metering credits for low-to-moderate income housing.

Units mounted on buildings and ground-mounted units that are larger than 25 kilowatts, but less than 650 kilowatts, and that use 67% of their output on site are all in market sector B. If these units use less than two thirds of their output on site, then they fall within market sector C. Market sector C also includes projects located on landfills and brownfields.

Finally, the managed growth sector is anything that does not qualify in one of the other sectors. Therefore, managed growth is primarily comprised of projects larger than 650 kilowatts that are virtually net metered and are not located on a landfill or brownfield. These are the very large-scale developments that make up most of the megawatts that were installed under SREC I. By giving these projects a lower SREC factor, we are trying to limit the rate at which those projects come into the market.

We revised the SREC II regulations in January. We held a public hearing and collected comments in late January. An updated draft of the regulations, based on review of those comments, was filed with the legislature on February 11. We received comments from the legislature in mid-March. We are now reviewing the comments and making final revisions. We expect to file the final regulations with the Secretary of State on April 11, and we expect it to go into effect on April 25.

I should mention a couple other things quickly. In addition to the SREC II program, we have an alternative compliance payment-funded support program for direct ownership of solar systems from homeowners. We are setting aside $30 million of alternative compliance payment funds to support direct ownership of residential solar. We see that it can be hard to get loans for homeowners who want to buy solar systems, and we are looking into designing a program. We are still in the early stages, but have done some outreach and selected a consultant. The goal of the program would be to encourage banks and other financial institutions to provide loans directly to homeowners. The state would offer credit enhancement, probably either by buying down interest rates or establishing a loan loss reserve. The final design has not been settled.

There is a lot going on with net metering in Massachusetts. We are aware that many projects depend / continued page 46

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Unsurprisingly, someone being paid in bitcoins must report the fair market value as income, and he takes that value as his "basis" in the bitcoins to measure his gain or loss when he spends the bitcoins later.

A person holding bitcoins as an investment has a capital gain or loss when the bitcoins are sold, unless he is a dealer. Dealers and anyone using bitcoins as a regular currency has ordinary income or loss.

The supply of bitcoins is controlled through a complicated algorithm. The supply increases by 25 bitcoins every 10 minutes currently. Math whizzes using computers race to solve puzzles in order to reap some of the new bitcoins. The race has been described as a cross between a math quiz and a lottery that is held six times an hour. The math whizzes are called "miners." Anyone receiving bitcoins this way must report the market value of the bitcoins he receives as income.

Bitcoin miners need cheap electricity to run their computers and are moving to places like Minot, North Dakota and Lake Moses, Washington, where the retail rate for electricity is less than 2¢ a KWh compared to a US national average of around 10¢. High electricity prices in places like New York, Tokyo and London mean any miner operating from those cities would lose money.

NO ECONOMIC SUBSTANCE was a problem in two recent transactions.

A US district court in Florida held in March that a transaction that KPMG and Bricolage, a consultancy, marketed to wealthy individuals to help shelter capital gains from taxes lacked economic substance. The transaction was called FOCus for family office customized partnership.

KPMG identified the founder of a computer company called American Megatrends that had sold a division at a gain of approximately $80.9 million, creating a tax obligation of about $16 million. KPMG brought in Bricolage. The two pitched the idea of using a FOCus partnership to the client. / continued page 47

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on net metering credits along with the SREC revenue. The Massachusetts market is not uniform in the availability of net-metering credits from one utility territory to the next. Some utility territories have more capacity available. Others have less. It is a function of how great the load is in each utility territory. Any change in the net-metering caps or aspects of the program must be made by the legislature. There are currently two bills under consideration by the legislature. It is unclear what direction the legislature will take ultimately, but there is a lot of dialogue taking place among the interested parties.

Finally, I want to highlight how successful some of the programs have been here in Massachusetts.

The new solar set-aside program effectively places a cap of $375 a MWh on SRECs, down from $523 a MWh under the old program.

The governor's goal of 250 megawatts of solar capacity by 2017 was met four years early in 2013. A new goal was set of 1,600 megawatts by 2020. Solar is widespread throughout the state: 348 of the 351 cities and towns have at least one solar installation, and more than 130 municipalities are hosting a project on town facilities or town land. Last year, more solar was installed than in all prior years combined. That is the fourth or fifth year in a row in which this has happened in Massachusetts. We are ranked very well nationally: we were fourth in solar capacity installed in 2013. We are sixth in total cumulative installed capacity. We are third in commercial installations. We are fifth in residential. We are fourth in total solar jobs, and sixth in per capita jobs.

More Differences

MR. POLLAK: Let me focus on distributed solar projects briefly. Massachusetts SRECs are only awarded to solar projects that are smaller than six megawatts and, thus, by definition most SRECs go to distributed solar facilities. Cash flow from distributed solar projects in Massachusetts comes from two sources. First, the solar company receives payments from homeowners, commercial and utility customers. These payments may be under a power contract, lease of the solar equipment or net metering credit purchase agreement. Second, the solar company receives SRECs that can be sold in the market.

It may be possible to make a forward sale of the SRECs. Investors and lenders will take the contracted SREC revenue into account in a financing of a solar project, but the allocation of regulatory risks, the creditworthiness of the SREC buyer and any credit support behind a purchase obligation will affect the value they assign. Alternatively, project owners may choose to play the spot market and rely on the stability that the solar clearinghouse auction is designed to provide. However, it is unclear how well the clearinghouse price support mechanism will function to keep prices at or above the target price and what credit, if any, tax equity investors and lenders will assign to contracted revenue when deciding how much to invest or lend.

A key difference between SREC I and SREC II is the weighting of SRECs through the "SREC factors." This mechanism is an effort by the Massachusetts regulators to promote smaller solar installations and to achieve other public policy goals by giving those projects a higher SREC factor. Thus, for example, projects under 25 kilowatts receive one SREC for every 1 MWh of output. Brownfield and landfill units have a 0.8 SREC factor. This means that brownfield and landfill units receive 0.8 SRECs for each 1 MWh of output. The large projects are in the "managed growth" category have a 0.7 SREC factor and receive 0.7 SRECs for each 1 MWh of output.

Another difference between the SREC I and SREC II programs is in the process for qualifying under the programs. Under SREC I, you needed an authorization to interconnect in order to obtain a statement of qualification. Under SREC II, a statement of qualification can be received merely upon submission of an executed interconnection agreement and demonstration that you have the real estate rights and governmental approvals to move forward with the project.

MR. ALEXANDER: Let's turn to audience questions. Mike Judge, why is the state giving the most encouragement to small solar installations rather than utility-scale projects?

Why Only Small Projects?

MR. JUDGE: We would rather see development take place on rooftops, landfills, brownfields and parking lots before other types of open space.

The intent of the original program was to encourage distributed generation. It did not have to be solar. Distributed generation tends to mean smaller projects that are on the customer side of the meter. So the program was aligned initially with the net metering rules, and it still is aligned in many respects with those rules.

You can build up to six megawatts per parcel of land. There is no intention to allow projects larger than that to qualify unless you can find multiple parcels of lands that are next to one another. Furthermore, virtual net metering rules in Massachusetts prohibit projects, unless they are under a so-called public cap, from being larger than two megawatts, and the rules actually discourage projects from being larger than one megawatt. It is possible to build larger projects; you just may be doing it without SRECs or net metering.

Floor Price?

MR. ALEXANDER: Given that SREC prices can fall below the compliance auction price, can you explain how this functions as floor? How can a tax equity investor or lender get comfortable with the potential revenue from SREC sales given such a mechanism?

MR. JUDGE: There is no floor in a sense of a guaranteed minimum price, but the auction mechanism helps. For every SREC that gets deposited into the auction, the demand for the following year is increased by one MWh. For every round that does not clear, if you go to the third round of the auction, say, then the amount of demand that is added as a result of the auction doubles. So this coming year, under SREC I, there will be about a 100,000 MWh oversupply in the market. If 100,000 SRECs are deposited into the auction, the demand for 2015 — the next compliance year for which we are calculating the demand — would be increased by 100,000 MWh. If that auction doesn't clear and it goes to the / *continued page 48*

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Bricolage set up three tiers of partnerships. The lowest-tier partnership entered into a foreign currency straddle. In a straddle, an investor goes long and short in the same currency. One leg will show a gain and the other leg will show a roughly equivalent loss. The partnership closed out the gain leg of the straddle and realized the gain, but left the loss leg outstanding.

The client then bought 99% of the top two partnerships in the chain for $6.1 million in December 2001 and agreed to pay Bricolage a separate "strategic consulting fee" of $4.3 million. The fee was calculated as a function of the loss that the client wanted to generate. Bricolage retained a 1% interest in each of the partnerships in the chain.

Still in December but 15 days later, the middle partnership sold the third-tier partnership to another Bricolage entity causing the client to realize the loss on the loss leg of the straddle. Shortly before the sale, the middle partnership borrowed money from a bank and entered into a yen carry trade structured as a deep-in-the-money call spread on which it earned $200,000, but the court said a collar in place on the trade "severely limited both risk and reward."

The client continued to have a relationship with Bricolage through 2005 and eventually made money off other transactions conducted through the partnerships. This was a pre-planned step in the FOCus shelter: slides KPMG used to pitch the transaction to the client said participation in the transaction had to last at least three years.

In early 2002, the IRS said in Announcement 2002-2 that it would waive some penalties for anyone who disclosed his involvement in a tax shelter. The client disclosed the transaction. The IRS began looking into the transaction in 2008.

A US district court denied the tax loss from the straddle on grounds that the transaction lacked economic substance. The court applied a two-prong test. It said the transaction had to have an economic effect on the taxpayer other than producing tax benefits, and the taxpayer had to have a real business / *continued page 49*

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third round, demand is increased by 200,000 MWh.

The auction functions through a series of carrots and sticks. The carrot is the SRECs are available and eligible to be used in multiple years. The stick is if a retail supplier does not buy in the early rounds, then it will face a potentially much higher compliance obligation and demand in future years and will probably end up paying higher prices. The auction has been designed to accelerate demand for SRECs. The auction is an opportunity for retail suppliers to hedge against future demand increases and future price increases.

MR. ALEXANDER: Noah Pollak, from your experience working with investors and lenders on these projects, are they willing to take future SREC revenues into account? What do they view as the biggest risk to try to mitigate?

MR. POLLAK: They will invest or lend against contracted revenue. Otherwise, they are left trying to understand how the floor mechanism will work going forward.

MR. ALEXANDER: Are they giving much credit to uncontracted SRECs?

MR. POLLAK: It is a negotiation.

Forward Sales

MR. ALEXANDER: Alex Anich, when developers come to you looking for help getting value for their SRECs, are you able to find them long-term contracts or what other types of strategies do you offer them?

MR. ANICH: We have had a huge interest from third parties who are looking to get 10-year deals, not only in the SREC I program but also in SREC II. The SREC price in a 10-year deal is a discounted price because the buyer is being asked to take price volatility risk. The longer the period he is asked to assume this risk, the higher the discount. We are also seeing a 20% discount in SREC II prices compared to SREC I prices under 10-year contracts. The reason is the SREC II rules are still going through a rulemaking process.

MR. ALEXANDER: I know from having worked on a bunch of projects in New Jersey that the discount for longer term contracts is steep. Anybody who is going to contract for SRECs for more than a year or two in advance demands a very steep discount.

MR. ANICH: We cannot really talk about a set market price or anything along those lines yet in Massachusetts. New Jersey functions through an auction for retail electricity supply that runs on three-year cycles. Most of the liquidity there is bounded by that three-year cycle, and the retailers only have to hedge their compliance for SRECs for three years.

Massachusetts is very different. Massachusetts has a 10-year opt-in term and other factors that create a different term structure of liquidity for the bid side for SRECs.

> Massachusetts reached its goal of 250 MWs of solar four years early in 2013. The new goal is 1,600 MWs by 2020.

MR. ALEXANDER: Mike Judge, if the SREC factors are adjusted in the future, would the adjustments apply to all projects, including retroactively to projects that are already in operation? Or would they only apply to the incremental capacity installed after the change in SREC factors?

MR. JUDGE: They would only apply prospectively. If there were an incremental capacity addition, the new factors would apply to the addition. The regulations say we will review the SREC factors no later than March 2016. Any changes to the SREC factors that come from that review would be implemented starting in 2017.

MR. ALEXANDER: Do solar canopy installations of any size fit into market sector A?

MR. JUDGE: Yes, as long as 75% of the modules being used are on a parking surface or pedestrian walkway. The installation could be up to six megawatts.

MR. ALEXANDER: What happens to the residual percentage of the SREC where your SREC factor is less than one?

MR. JUDGE: Let's say you are managed growth and you get a 0.7 factor, so you receive SREC IIs for 70% of your output. The other 30% would result in creation of certificates at NEPOOL that would be automatically retired. The NEPOOL certificate can't be used by anyone. They are accounted for the purpose of tracking solar generation, but they have no RPS eligibility associated with them, they are automatically retired in the NEPOOL GIS trading system.

Net Metering

MR. ALEXANDER: Can you address how the net metering caps are calculated by utility territory?

MR. JUDGE: Net metering is a statewide program, but it is implemented by the investor-owned utilities, and each utility has a cap. The overall state cap is just over 660 megawatts — about 330 for private and 330 for public — but the amount that is available in any particular utility's service territory is different. National Grid and NSTAR have similar amounts of capacity available in their service territories. Western Massachusetts Electric has much less capacity because it has a smaller electric load. So there is a lot less space available under the net metering caps in the Western Massachusetts Electric territory, even though there is a lot more space to develop projects in the western part of the state.

The public caps have been reached in terms of applications received and approved in the National Grid service territory and Western Massachusetts Electric service territory. There still is space in NSTAR's service territory.

So there are different amounts of capacity available in each utility territory and that information is available on the Mass ACA website at www.massaca.org. Even within utility service territories, the net metering rate varies depending on the type of meter that you are connecting to. If you are connecting to an industrial meter, you get the net metering credit for the industrial rate in that utility service territory. If you are connecting to a residential meter, you get the residential rate. There is also a small commercial rate. The variation in net metering credits across utilities is due to different rates in different utility service territories.

MR. ALEXANDER: Will the state consider allowing older projects that are pre-2012 into the SREC II program?

MR. JUDGE: The cutoff date in the most recent version of the regulations is January 1, 2013. So, no, we do not have any intention to allow older projects that were either eligible to participate in the SREC I program or receive / continued page 50

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purpose, other than reducing his federal income taxes, for entering into the transaction. It could find neither in this case.

It focused on the effort to push the loss leg of the straddle to the client while ignoring other trades in which the partnerships engaged.

The case is *Kearney Partners Fund, LLC v. United States*.

The US Tax Court held another transaction lacked economic substance in March in a case called *Humboldt Shelby Holding Corporation v. Commissioner*.

The promoter of the second transaction, James Haber, is a tax professional in New York who marketed tax shelters to third parties. He formed a corporation and had it pay $86 million in 2003 to acquire two other corporations with combined assets of $90 million, but the target companies had appreciated assets on which they would have to pay about $25 million in taxes eventually. Thus, the net asset value of the companies was only about $65 million after taxes. Haber overpaid figuring he could enter into a separate transaction to shelter the gains on the appreciated assets.

He had each of the target companies both buy and sell digital options and contribute the options to a partnership. The long and short positions were largely offsetting. For example, a company buying a digital option might receive $20 if the S&P 500 index is above 450 on X date. If the index is below 450 on that date, then the company would receive nothing. A company *selling* such an option would pay $20 if the index is below 450 on X date, but pay nothing if the index is above 450. No one buys and sells exactly at the same strike price. There is a slight spread, such as buying an option with a strike price of 450 and selling one with a strike price of 450.03.

One of the two target companies bought an option for $70 million and sold a largely offsetting one for $69.7 million. When it contributed the options to the partnership, it took an "outside basis" in its partnership interest of $70 million (for the long option and / continued page 51

Massachusetts SRECs

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substantial rebates or grants prior to the SREC II program being in effect to qualify. However, those projects would remain eligible to quality for general class 1 certificates.

MR. ALEXANDER: Can projects that interconnected before April 25 apply under SREC II if they do not apply under SREC I?

MR. JUDGE: Yes. The cutoff date for SREC II is January 1, 2013. Any project that came on line January 1, 2013 or later that did not qualify under SREC I and meets the other program eligibility criteria would be eligible to participate in SREC II. We do not expect a lot of that. We expect most such projects to come on line and apply for SREC I. ◎

New USDA Loan Guarantees

by Todd Alexander and David Lamb, in New York

A new farm bill enacted in February expands an existing federal loan guarantee program, called the Biorefinery Assistance Program, that was originally designed to incentivize development of second generation advanced biofuel projects, by providing new mandatory funding levels for the program and by extending eligibility for loan guarantees to producers of renewable chemicals and manufacturers of biobased products.

The bill allocates $881 million in mandatory funding to renewable energy and biofuel initiatives.

It broadens the scope of the existing section 9003 Biorefinery Assistance Program, called BAP for short. The program is run through the US Department of Agriculture.

The expansion is a potential boost for the renewable chemicals industry in the United States. Renewable chemicals are chemicals that can be produced from renewable feedstocks such as butadiene, levoglucosan, and tetrahydrofuran. According to USDA estimates, more than 3,000 companies in the United States manufacture or distribute biobased products. The most visible biobased product is soft drink bottles made from bioplastics. Major bottling companies, such as PepsiCo and Coca-Cola, have invested heavily in finding a way to produce polyethylene terephthalate (PET) plastic, a traditionally petroleum-based plastic, with entirely biobased inputs. Other large manufacturers and distributors of packaging, cosmetics, and cleaning products have also invested in the use of biobased inputs in their products. However, to date most have found that the initial costs of commercial production are too high to be passed along to consumers. Federal loan guarantees have the potential to lower the capital costs of the first few facilities and help the industry drive more quickly to economies of scale.

BAP

Loan guarantees are available under BAP for both development of commercial-scale biorefinery projects and retrofitting existing commercial facilities. The program was originally funded under the 2008 farm bill. Before this year, the program only provided loan guarantees to biorefineries producing advanced biofuels, defined as “fuel derived from renewable biomass other than corn kernel starch.” The regulations required that at least a majority of the production of the biorefineries be advanced biofuels, measured in Btu content, or volume if no established Btu values exist.

The program requires the lender, rather than the borrower, to apply for the loan guarantee from the USDA. As such, it is essential for a potential producer seeking to benefit from the program to identify a lender up front.

The program provides loan guarantees on a percentage basis, with the maximum percentage allowable determined by the size of the loan. Chart 1 identifies the maximum percentage guarantees available:

Chart 1

Loan Amount	Maximum Percentage Guarantee
0 - $125 million	90%
$125 - $150 million	80%
$150 - $200 million	70%
$200 - 250 million	60%

The maximum loan amount under the program is $250 million, and there is no minimum amount. However, loans are not allowed to exceed 80% of the total eligible project costs. Eligible project costs include the costs to purchase most of the equipment, construct or retrofit the project, pay permit and license fees, acquire land and, cover financing charges, excluding guarantee and renewal fees, and set aside an amount for working capital. A guarantee fee must be paid to USDA when applying for the guarantee; the fee is calculated as a percentage of the guarantee. Chart 2 shows the percentage fee for each level of guarantee:

Chart 2

Guaranteed Percentage of Loan	Guarantee Fee Percentage
90 % guarantee	3%
90% - 75% guarantee	2%
75% - 65% guarantee	1.5%
65% or less guarantee	1%

The USDA regulations allow for loan terms for the shorter of 20 years or the entire useful life of the project. The regulations require that the guaranteed and unguaranteed portions of the loan must be secured by a first lien; however, the USDA has considered subordinate positions on inventory and accounts payable under certain circumstances.

Expansion

Eligibility under the program is being extended for the first time to producers of renewable chemicals and manufacturers of biobased products. The expansion means potentially more competition for scarce dollars under the program.

The 2014 farm bill marks the first time that Congress has recognized and defined "renewable chemicals."

A renewable chemical is "a monomer, polymer, plastic, formulated product, or chemical substance produced from renewable biomass." Renewable biomass differs from other biomass in that it is organic material that Congress has decided is available on a regular and recurring basis. Renewable biomass under the farm bill includes renewable plant material, plant waste material and animal waste byproducts.

Biobased product manufacturing is defined in the bill as the "development, construction, and retrofitting of technologically new commercial-scale processing and manufacturing equipment and required facilities that will be used to convert renewable chemicals and other biobased outputs of biorefineries into end-user products on a commercial scale."

The BAP program has been used to date mainly to help producers of advanced biofuels.

In addition to expanding eligibility, the farm bill authorizes $100 million in mandatory funding for BAP / continued page 52

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nothing for the sold option). The other company bought an option for $4.4 million and sold a largely offsetting one for $4.38 million.

One set of options was linked to the S&P 500 index. The other was linked to the NASDAQ 100 index.

All of the options expired three months later with no payment on either side. The two corporations then liquidated their partnership interests and claimed their outside bases as capital losses.

The companies would have had large gains in theory if the options had expired while the stock indexes were within the sweet spot, but the Tax Court said the most that could have been earned in practice was between $320,000 and $510,000. The Tax Court said this amount of potential profit was inconsequential compared to the $25 million in capital losses that the options were guaranteed to generate. The existence of some potential for profit does not foreclose a finding of no economic substance. The only way Haber could have paid $86 million for two companies worth $65 million after taxes was by figuring out a way to eliminate the taxes.

The Tax Court said any appeal of its decision would go to the US appeals court for the 2d circuit. That appeals court has no rigid formulation of the economic substance test but would look more broadly at whether the digital options trades and use of the partnership had any purpose other than the creation of tax losses.

The court upheld the IRS assessments of back taxes of $25.6 million and a penalty of $10.2 million. IRS regulations allow penalties of up to 40% in the case of a gross valuation misstatement.

US MULTINATIONAL COMPANIES continue to accumulate more earnings in offshore holding companies.

A Bloomberg survey of securities filings by 307 of S&P 500 companies found the companies have $1.95 trillion parked offshore. The earnings would be taxed if repatriated to the United States. The 307 / continued page 51

USDA Loan Guarantees

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in fiscal year 2014 and $50 million in mandatory funding for each of fiscal years 2015 and 2016. The bill also authorizes discretionary funding of $75 million for each fiscal year from 2014 through 2018. In the statute, the only limitation on the funding is that the Department of Agriculture is only authorized to allocate up to 15% of the mandatory funding to biobased product manufacturing for fiscal years 2014 and 2015.

Lenders to biorefinery projects may qualify for federal loan guarantees from the US Department of Agriculture.

Record To Date

The BAP program has had mixed results to date.

Since the program was first funded in 2008, four projects have achieved financial close as a result of the program, while 12 conditional commitments have been issued. Two of the conditional commitments have since been withdrawn.

The loan guarantees reduce the cost of debt by allowing borrowers to raise money on the guaranteed portion of their loans at close to the cost of similarly-maturing US government obligations, such as US Treasury bonds, rather than borrowing based on the underlying creditworthiness of the borrower. A typical borrower could easily benefit from a 4% to 5% reduction in the overall interest rate on its debt.

The program requires that the lender of record, not the borrower, submit an application for a loan guarantee. Thus, an initial step for any borrower attempting to take advantage of the program is to find a lender of record willing to go through the application process.

The USDA opens the applications window with a "notice of funding availability." The most recent NOFA occurred in October 2013, and the window was open through January 31, 2014. The October 2013 NOFA was for a total of $180 million, including mandatory funding and uncommitted amounts from previous fiscal years.

Once the NOFA is issued, the applications window is opened. While the application must be submitted by the lender of record, the lender and the borrower must work together to prepare the application for submission. An application under the USDA guidelines must address the following areas: feasibility studies, technical assessments, economic analysis, business plan, environmental information, a lender's analysis and financing information.

The application can be time consuming to prepare for more complex projects. Companies hoping to avail themselves of the program should begin discussions with potential lenders of record and begin preparing the necessary information before the next NOFA is issued so that the application can be submitted within the given time frame of the NOFA.

The USDA is likely to issue a new NOFA in the coming months in line with the mandatory funding amounts provided under the bill. This means that there may soon be opportunities for renewable chemicals producers and manufacturers of equipment for making biobased products to take advantage of federal loan guarantees. ◎

PPP Update: US Infrastructure Legislation

by Jacob Falk, in Washington, and Christine Brozynski, in New York

The US Congress is considering multiple infrastructure funding bills. Will these bills facilitate broader use of public-private partnerships in the United States?

Some of the bills under consideration include new or expanded infrastructure financing programs and would encourage greater private-sector involvement in public projects. Congress is still debating the specifics. It appears somewhat more willing to set aside partisan wrangling in this area, but infrastructure spending bills remain challenging even in the best of times and will be particularly so in advance of the mid-term elections this November.

President Obama asked Congress to pass two infrastructure bills in his State of the Union message to Congress in late January. He asked Congress to reauthorize the federal government's surface transportation programs, which most recently passed Congress in 2012 as the Moving Ahead for Progress in the 21st Century Act or "MAP-21." He also asked Congress to reauthorize the federal government's water resources programs under the Water Resources Development Act. The President followed up the State of the Union with a budget proposal in early March to authorize up to $302 billion in spending on MAP-21 over the next four years, although specific legislative language was not provided.

Congress is still talking about whether to create a new "national infrastructure fund." A Partnership to Build America Act has been introduced in the House and Senate. There are several more proposals that various members of Congress have introduced that focus on specific issues related to infrastructure investment.

The House Transportation and Infrastructure Committee recently created a special panel to focus on public-private partnerships across various types of infrastructure, including all modes of transportation, water and public buildings. The panel's recommendations may lead Congress to encourage project financing, private-sector investment and PPPs as part of the reauthorization of the surface transportation and water resources programs. / continued page 54

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companies added another $206 billion in 2013, up 11.8% from the year before. The increase in profits held outside the United States is particularly noticeable among technology companies, which put their intellectual property offshore.

The Congressional Research Service, an arm of the US Library of Congress, reported in 2013 that US multinationals attributed 43% of their 2008 overseas profits to just five countries: Bermuda, Ireland, Luxembourg, the Netherlands and Switzerland.

Switzerland is under pressure from the European Union to revise the corporate income taxes charged by Swiss cantons. Favorable rates for foreign companies act as an inducement to locate in Switzerland. The European Commission declared in 2007 that the current tax regime violates a 1972 free trade agreement between the European Economic Community and Switzerland.

Some companies are leaving Switzerland without waiting for higher rates to hit. Yahoo announced plans in February to move its European website services from Switzerland to Ireland. Ireland has a 12.5% corporate tax rate. Other internet companies like Google and Facebook are already there. Noble Corp., an offshore drilling contractor, announced plans to move its headquarters from Switzerland to the United Kingdom, which also has a favorable headquarters regime.

Meanwhile, some US states are trying to tax corporate income parked in offshore havens. The states have grown impatient with stalled efforts in the US Congress to rewrite the rules for taxing income that US companies earn in other countries.

Oregon enacted a bill for the 2014 tax year identifying 39 countries and territories as tax havens. Montana has had a similar law for a decade. The Maine legislature voted for a similar bill on April 4. Minnesota and Rhode Island are studying similar measures. None of the states that has passed such bills to date is home to many large multinational corporations. / continued page 55

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Surface Transportation

Congress has until September 30, 2014 to reauthorize the federal surface transportation programs under MAP-21 before the programs expire. A key concern for this bill is the level of funding that the federal government can provide from the increasingly strapped Highway Trust Fund. The US Department of Transportation is maintaining a Highway Trust Fund ticker at http://www.dot.gov/highway-trust-fund-ticker to show that the surface transportation programs continue to spend money faster than receipts are coming into the trust fund that funds these programs. Congress has not raised excise taxes on motor fuels, the primary source of revenue for transportation funding, since 1993 and few alternatives have been seriously considered. The funding issue was the topic of the first MAP-21 reauthorization hearing by the Senate Environment and Public Works Committee in February this year.

Several bills before Congress would encourage broader use of public-private partnerships to build public infrastructure projects.

The President's budget proposal includes $302 billion over four years for reauthorization of MAP-21, which is more spending than the Highway Trust Fund can support and an increase from the annual spending levels under the current MAP-21. The Obama administration is proposing to make up the funding gap through corporate tax reform. A Republican discussion draft of a corporate tax reform bill that Congressman Dave Camp (R-Michigan), the House tax-writing committee chairman, released in March would also dedicate some revenue raised through corporate tax reform to support the Highway Trust Fund. However, no action on corporate tax reform is expected this year.

The reality of federal shortfalls over the last several years has helped push state and local governments to consider new approaches for funding infrastructure. Several bills in Congress propose programs to encourage broader project financing and private investment through PPPs as an alternative to traditional funding mechanisms. Two of these financing programs that are relevant for PPPs in the context of the MAP-21 reauthorization are private activity bonds and the Transportation Infrastructure Finance and Innovation Act or "TIFIA" for short.

Private activity bonds allow tax-exempt borrowing to finance projects that serve a public purpose but that are owned, leased or in some cases operated by private companies. Expanding the capacity of the private activity bond program for surface transportation projects would facilitate the use of PPPs by ensuring that tax-exempt debt remains available for PPPs. Congress authorized the use of private activity bonds for surface transportation projects in 2005. The US Department of Transportation can allocate up to $15 billion in total in such tax-exempt financing authority for eligible projects. Private activity bonds are seeing more use for transportation PPPs. In 2013, such bonds were issued for the $763 million East End Crossing PPP between Indiana and Kentucky, the $1.35 billion North Tarrant Express PPP in Texas and the $1.5 billion Goethals Bridge PPP connecting New York and New Jersey.

Recognizing that the $15 billion cap could soon be exhausted, President Obama called for the cap to be increased to $19 billion in March last year. The use of private activity bonds and the pace of PPP activity has accelerated since then. Approximately $9.3 billion of the $15 billion cap had been allocated by the end of February 2014. Industry estimates are that the cap will be fully allocated as early as 2015. Accordingly, PPP proponents are hoping Congress will authorize a substantially higher cap or remove the cap altogether. Senator Mark Kirk (R-Illinois) introduced a bill in late February to increase the cap to $19 billion.

However, these efforts may be swimming upstream as the tax-writing committees that have jurisdiction over tax-exempt bonds are no fans of such bonds. The Camp tax reform bill would eliminate all uses of private activity bonds.

TIFIA provides low-cost, flexible loans for part of the cost of major transportation projects. A multi-year commitment in a reauthorization bill to maintain TIFIA's current lending capacity would be important for PPPs, as a number of PPPs are working through competitive procurement processes and may not be ready for financing until 2015 or beyond. The President's budget proposal includes an extension of TIFIA at current funding levels through fiscal year 2018.

Under MAP-21, TIFIA was expanded significantly from a program that could make approximately $1 billion of loans each year to a program with approximately $17 billion to lend over two years. While TIFIA has not used these funds as quickly as some may have hoped or expected, the pace of TIFIA lending has accelerated significantly. In fiscal 2013, TIFIA made two loans using MAP-21 funds for a total of $388 million. So far in fiscal 2014 TIFIA has made six loans using MAP-21 funds for more than $4 billion (and two loans for $534 million using pre-MAP-21 funds). More TIFIA loans using MAP-21 funds are expected before the end of fiscal 2014, and the expanded program is managing a growing pipeline of future projects.

Renewing existing financing options is one thing, but Congress could also consider programmatic reforms and other initiatives as part of a surface transportation reauthorization bill to make it easier for public officials to consider other ways to deliver basic infrastructure. Reforms could build on efforts initiated in MAP-21 to loosen restrictions, cut red tape, focus on performance and develop best practices. For example, Congress could consider further loosening restrictions on tolling and pricing that would facilitate broader use of project financing mechanisms.

Senator Kirk and Senator Mark Warner (D-Virginia) introduced a bill in late February to expand the number of states that can participate in federal programs that allow broader use of tolling and pricing on highways. The bill, called the "Highway Innovative Financing Act of 2014," would eliminate an existing cap on the number of states that could participate in a "value pricing pilot program" that encourages testing of congestion pricing strategies. The bill would also increase from three to 10 the number of states that could participate in an "interstate system reconstruction and rehabilitation pilot program" that allows tolling on certain existing */ continued page 55*

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MINOR MEMOS. The United States added 50% less new generating capacity in 2013 than the year before, according to Platts. The figures were 15,078 megawatts in 2013 compared to 31,652 megawatts in 2012. Gas accounted for close to half the new capacity additions with 7,086 megawatts. Solar had a 142% gain in installations to 3,983 megawatts. Wind was down 94%, with just 789 megawatts of new wind farms installed in 2013 after a rush in 2012 to build projects before a deadline — since extended — to complete projects in order to qualify for federal tax credits. New capacity additions in the US as a whole are expected to dip further in 2014. Platts reports that only 12,795 megawatts of new capacity are under construction for completion in 2014 . . . The US Energy Information Administration reported in early April that 47% of new capacity added in 2013 was in California. The EIA data focuses solely on utility-scale projects . . . . Renewable energy accounted for 91.9% of the 568 megawatts in new capacity additions in the first two months of 2014.

— contributed by Keith Martin and Bob Shapiro in Washington, Richard Leder in New York and Marc Norman in Dubai

PPP Update

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interstate highways that require repair. All three of the current slots are reserved.

The Obama administration could also continue to streamline federal review and approval processes. The latest budget request to Congress builds on previous efforts in this area by establishing a new Interagency Infrastructure Permitting Improvement Center that will be administratively housed within the US Department of Transportation along with a new "permitting dashboard" on the department's website. Congress and the administration could also try to coordinate PPP efforts across federal agencies and provide higher-level support and visibility for PPPs.

Bills reauthorizing federal transportation and water programs need to pass by September.

Water Resources

Congress is in position to pass a water resources bill this spring for the first time since 2007, but progress has slowed in recent months. The existing Water Resources Development Act provides federal support for ports and waterways and targeted flood protection and environmental restoration. The Act does not currently facilitate project financing or PPPs, but new programs under consideration could encourage private investment. The Senate and House passed different versions of the bill — the House added an extra "R" to the title of its bill for "Reform" — and a conference committee was appointed in late 2013 to reconcile differences.

The Senate version includes a new Water Infrastructure Finance and Innovation Act program called "WIFIA" that would be modeled after TIFIA. This program would provide $50 million annually to each of the US Army Corps of Engineers and the US Environmental Protection Agency to make low-interest loans for water infrastructure projects, including PPPs. Water and wastewater projects would be eligible, as would projects for flood control, hurricane and storm damage reduction, enhanced energy efficiency, improvements to treatment works, community water systems, aging water distribution and waste collection facilities, desalination, managed aquifer recharge and water recycling.

Like TIFIA, WIFIA would be able to provide loans for no more than 49% of project costs to encourage co-investment. The financing would be flexible, with a repayment schedule based on projected project cash flows, final maturity up to 35 years after substantial completion, and repayment of principal or interest commencing up to five years after substantial completion. Project costs from development through construction, including certain refinancing costs, would be eligible for assistance. The threshold for minimum project costs would be $20 million (or $5 million for rural projects).

The House version of the water bill does not include WIFIA, but it includes a pilot program authorizing PPPs for water projects. Under this program, the US Army Corps of Engineers would be authorized to allocate $25 million each year from 2014 through 2018 for projects to be managed by private entities. Fifteen total projects would be chosen, covering the areas of flood risk management, hurricane and storm damage reduction, coastal harbor and channel improvements, inland navigation and aquatic ecosystem restoration.

A National Infrastructure Fund

The idea of a national infrastructure bank or fund has been proposed multiple times over the last several years in Congress and by the Obama administration. It has not had much traction and suffered from, among other things, House Republican efforts to shine a spotlight on the US Department of Energy loan guarantees given to companies like Solyndra that went bankrupt after receiving federal support.

Nevertheless, the Obama administration reiterated its support for "establishing an independent National Infrastructure Bank to leverage private and public capital to support infrastructure projects" in its latest budget proposal to Congress. The budget message did not provide any details for how the National Infrastructure Bank would be structured or operate.

A "Partnership to Build America Act" introduced by Congressman John Delaney (D-Maryland) in May last year would capitalize a new American Infrastructure Fund through the sale of $50 billion of infrastructure bonds. The corporations that purchase the bonds would be allowed to repatriate overseas earnings tax free in an amount to be determined. While the bill is supported by a bipartisan group in Congress, it has not been referred to a committee, which is the first step in the legislative process. Meanwhile, the tax-writing committees are not keen to write earmarks like this into the tax code.

Delaney would require the infrastructure fund to put a minimum of 25% of its funding into infrastructure projects that use PPPs with at least 20% of the financing for such projects consisting of private capital. The fund would be designed to be self-sustaining and would not be backed by the full faith and credit of the federal government. No federal appropriations would be required.

To ensure accountability, the bill proposes an 11-member board to manage investment decisions. Seven spots on the board would be appointed by the seven entities purchasing the most bonds, and the other four spots would be appointed by the President and would require Senate confirmation. The mission of the board would be to operate the fund as "a low-cost provider of bond guarantees, loans, and equity investments to State and local governments and non-profit infrastructure providers for both urban and rural non-profit infrastructure projects that provide a positive economic impact and to meet such other standards as the [b]oard may develop." The fund would only assist with state and local projects.

The independence of the fund may alleviate some concerns about federal accountability for investment decisions, but giving control of the board to the bondholders could raise questions about the criteria that will be used for making investment decisions and the alignment of investment decisions with public policy considerations. ◎

Environmental Update

The US Environmental Protection Agency clarified in late January how and when air permit deadlines for commencing construction of new facilities may be extended. The standard prevention of significant deterioration air permit requires the holder to start construction of his project within 18 months after the permit is received. New EPA guidelines allow the permitting authority to extend the deadline without extensive re-analysis.

Air permits require developers to start construction within 18 months.
They can usually get at least one extension.

PSD air permits are required to construct new, or make major modifications to, projects in areas that comply with ambient air quality standards if the project qualifies as "major" under the regulations. Power plants are prime examples of projects required to have such a permit. In such cases, the PSD permit program also requires the project to use the best available control technology, or "BACT," to control air emissions.

The Clean Air Act does not set a deadline by which a project must commence construction once it receives its PSD permit, but agency regulations require that permittees must begin within 18 months or get an extension. The need to get an extension is often cause for significant uncertainty for developers and potential lenders, particularly at complex or controversial projects.

Any request for an extension in the future should include a detailed justification of why the project cannot commence construction by the deadline. Among the factors that could justify an extension are ongoing litigation over the project or the PSD permit itself, impediments to obtaining other necessary permits, trouble securing financing or other economic impediments to commencing operations, and direct impacts from natural disasters. Permittees should apply for an extension before the deadline expires.

The first request for an initial 18-month extension appears likely to be granted under the new EPA guidance absent unusual circumstances. While any extension allows the agency to take a fresh look at the emissions analyses on which the permit was originally granted, and extensions are granted on a case-by-case basis, the guidance suggests that a substantive re-evaluation should generally not be required for the agency to grant a first permit extension. This is an acknowledgement that what qualifies as best available control technology does not tend to change rapidly.

Additional extensions beyond the first may be harder to get. Project managers should take special care to demonstrate that the failure to commence construction was beyond their control and be prepared to provide an updated substantive analysis of the project and its emissions technology. EPA believes that it is more likely that technology and air quality considerations will become outdated when construction does not begin for 36 or more months after the initial permit was issued.

While construction-start deadlines are usually extended in 18 month increments, the agency has discretion to make the period shorter or longer if the permittee demonstrates the necessary justification. The agency also continues to have discretion to grant subsequent extensions without technical re-review, but we expect new reviews to be required in most

California will have to decide on rules for disposing of used solar panels before widespread replacements start over the next 10 years.

cases for additional extensions beyond the first one.

Other factors that can complicate the extension process include cases where construction has yet to commence, but a regulatory change relating to relevant emissions has occurred. For example, EPA may take a harder look where permittees have been "grandfathered" from having to demonstrate compliance with new or revised PSD requirements that took effect after the original permit was issued. Similarly, if a PSD permit was issued in an area that changed from attainment to nonattainment for one or more ambient air quality standards, additional regulatory review is more likely. Permit holders asking for extensions should address any special circumstances in their extension applications.

Importantly, the guidance states that a new public notice and comment period will not be necessary for permit extensions that do not involve reconsideration or amendment of the substantive conditions of the permit.

Natural Gas

EPA is seeking input on how best to incorporate new data from recent studies of methane emissions from natural gas fields, pipelines, storage facilities and distribution lines into its annual calculations of such emissions. The new data suggests that methane gas emissions occur at significantly lower levels than previously estimated by EPA. The finding is particularly noteworthy because methane is thought to be a significantly more potent greenhouse gas compared to the same amount of carbon dioxide.

The studies are ongoing. The Environmental Defense Fund, oil and gas companies, and the University of Texas at Austin are jointly conducting some of the key studies.

EPA made the announcement in February as part of its release of its latest draft estimates of greenhouse gas emissions from a variety of emissions sources. EPA will review upcoming data from the studies for potential updates to next year's 1990 to 2013 inventory report.

Some have used EPA's existing estimated methane emissions data to claim that total carbon emissions from gas-fired power plants are as great or greater than from coal-fired power plants.

The new data, which focuses more on direct emissions testing, are welcome news to the natural gas industry as some groups continue to press for specific regulatory controls on emissions of methane from natural gas production. EPA opted against imposing direct methane controls in its recent final new source performance standards for the power sector.

The draft inventory report says emissions of methane from the natural gas sector dropped by nearly 17% since 1990 as a result of voluntary industry efforts and regulatory controls, including increased use of technologies such as plunger lifts and more efficient pipeline materials.

NOx and SO2

A US court of appeals unanimously upheld EPA's new source performance standards, or "NSPS," in March that set emissions limits on conventional air pollutants from power plants.

At issue was a 2012 rule that sets emission limits, testing and monitoring requirements for nitrogen oxides, sulfur dioxide and particulate matter from coal and oil-fired power plants that commenced construction after May 3, 2011.

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The disputed rule had replaced an earlier utility NSPS for conventional pollutants released in 2009. The case is called *Utility Air Regulatory Group v. EPA*.

The court is expected to rule soon on a separate industry challenge to a related 2012 EPA rule imposing maximum achievable control technology standards to curb mercury and other air toxics from utilities.

Solar Panels

The California Department of Toxic Substances Control abandoned as flawed a pending proposal to establish new regulations for disposing of solar photovoltaic panels that are considered hazardous waste. The department made the announcement in February.

Instead, state regulators will ask EPA for approval to implement federal "universal waste" regulations in California under the federal Resource Conservation and Recovery Act. Once granted, California will be able to develop a state-specific program for disposing of PV panels that contain toxic compounds.

While some environmentalists suggest the state legislature is better positioned to determine how toxic waste from PV panels should be recycled or disposed of safely and bills may be introduced in the legislature to address this, a number in industry support the new regulatory plan so long as it does not bring undue costs and burdens to the industry.

California expects the first large-scale replacement of existing panels will occur over the next 10 years as older solar panels are swapped out for newer technology.

— contributed by Drew Skroback in Washington

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