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Islamic Bonds Go Mainstream

by Simon Stevens, in Dubai

Sukuk or Islamic bond financing still has the reputation of being a niche product. Despite this, it is showing signs of becoming a mainstream option to finance infrastructure projects.

The origin of the niche product comes from the fact that *sukuk* are inherently an alternative. *Sukuk* permit bond-like financings to be structured in a way that is compliant with *shari'a* law. (The singular form is *sakk*, meaning certificate.) With the growth of Islamic finance generally, *sukuk* generated a significant amount of interest in the early to mid-2000s, but suffered a decline after the twin blows of the worldwide financial crisis and the influence of Islamic scholarship that criticized the structures used at that time for their lack of adherence to Islamic principles. As markets have slowly recovered, interest in *sukuk* is once again growing.

This article describes what *sukuk* are, who is interested in them, how typical *sukuk* that might be used in project finance are structured, some inherent risks and mitigation mechanisms and key trends to watch.

Among recent developments of note, a consortium of two Australian solar companies announced that it will fund the first 50 megawatts of a planned 250-megawatt solar project in Indonesia entirely through *sukuk* issued in Malaysia that will include construction financing. Also of interest to the market is the joint venture between Saudi Aramco and Total that successfully launched *sukuk* financing with a 14-year tenor for the greenfield development of the Jubail oil refinery in Saudi Arabia. In April this year, */ continued page 2*

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SEVERAL CONSTRUCTION-START ISSUES remain unsettled. Meanwhile, the market is feeling its way.

New wind, geothermal, biomass, landfill gas, small hydroelectric and ocean energy projects must be under construction by December 2013 to qualify for federal tax credits. Such projects qualify for a 30% investment tax credit or for production tax credits for 10 years on the electricity output. There are two ways to start construction this year: by starting "significant" physical work on the project or by "incurring" at least 5% of the project cost.

However, the developer must also show that work on the project after this year is "continuous."

The Internal Revenue Service said on September */ continued page 3*

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Sadara Basic Services Company issued 15.75-year *sukuk* that were equivalent to US$2 billion in size to finance part of the development of a chemical and plastics production complex in Saudi Arabia.

These changes come at an opportune time. The Gulf Cooperation Council (GCC) nations have a large pool of underutilized sovereign capital. Islamic finance structures are an obvious fit for the region. There is a confluence of a generally-acknowledged need for infrastructure development and increasing political support for the development of Islamic finance as an alternative to conventional finance. The Emirate of Dubai in the United Arab Emirates has recently launched an effort to develop a vibrant *sukuk* market to rival those of financial centers with a longer track record of *sukuk* — particularly Malaysia and fellow GCC member Bahrain.

To date the absolute number of *sukuk* issuances remains a small proportion of bond issuances. But with some peaks and troughs, the trend is generally upwards. Issuers claim that recent *sukuk* issuances have been heavily oversubscribed — in some cases by as much as three and a half times — and that it is a lack of offerings that is holding up the market, not lack of demand.

Interest in *Sukuk*

Islamic investors with a mandate to invest in investment opportunities that comply with Islamic principles are the most obvious market for any Islamic product. But Islamic investors are by no means the only market for *sukuk* issuances. Issuers report that conventional investors have shown an appetite for *sukuk*. The most cited reason is that *sukuk* offer a means of diversification. Some conventional holders report being comforted by the fact that the Islamic banks who invest alongside them tend to hold their investments until maturity, creating a more stable investment for everybody else.

So-called ethical investors are an additional pool of liquidity that may be attracted by *sukuk*. Because of *shari'a* compliance requirements, *sukuk* can only be issued for projects that meet ethical standards including for purposes that include some degree of public good. While those standards are grounded in Islam, there is often a coincidence with the goals of more secular ethical investors. Another group who may become comfortable with *sukuk* are traditional project financers and developers.

Sukuk are an asset-based financing structure, so they share a risk profile that in certain respects is reminiscent of equity investments, including "tax equity" finance widely used in the United States. International investors will find them more familiar than might be expected.

A final point worth emphasizing is that there is nothing inherent in a *sukuk* structure that limits its application to countries with large Muslim populations or that have a tradition of Islamic law. These structures can be implemented for projects located anywhere.

What *Sukuk* Are

Like a bond issuance, *sukuk* are a way to securitize lending. In fact, the *sukuk* are only part of the overall structure. They are the part of a transaction that is used to securitize underlying Islamic finance structures. This is why *sukuk* come in a variety of flavors such as the *ijara sukuk* or *musharaka sukuk* described below. However, while it is common to call *sukuk* Islamic bonds, doing so can be misleading. There are similarities, but also a number of important differences between the two types of instruments.

In its simplest terms, a bond is a form of debt and represents a sophisticated IOU. In exchange for advancing a share of the principal, the bondholder is entitled to interest (the coupon) and also the repayment in full of the principal amount of the bond. Both the fact that a bond represents a debt and there is a payment of the coupon offend key principles in Islamic finance. Islam forbids treating money as a commodity with inherent value that can be traded at a profit. Rather, Islam regards money as no more than an exchange mechanism for other goods and services. Because of this, the payment of interest (the Arabic term is *riba*) and the selling of debt for interest are not permitted.

In contrast, instead of representing a debt, a *sakk* represents an undivided beneficial ownership interest in a physical asset being financed. Because a *sakk* is an undivided share of an asset, the holder of the *sakk* can receive a portion of the income generated by the *sukuk* asset as his return. This, rather than an interest payment, is the incentive to invest. This ownership should also be distinguished from equity financing. The *sukuk* holder does not own any part of a company, and neither are the sukuk assets available to be sold in the event of non-payment.

Other basic similarities between *sukuk* financing and conventional bond financing include the payment of principal at maturity (even though in a *sukuk* this may be achieved in a somewhat roundabout manner). *Sukuk* also feature issuing mechanics that are based on and in many cases are identical to conventional bond issuances.

A sukuk issuance will include a rating of the issuer, usually by a conventional bond rating agency using completely conventional bond financing methodologies. Like some bonds, overall rating of a *sakk* is generally the same as the ultimate sponsor since the *sukuk* are generally issued by a special-purpose vehicle that will not have an extensive operating history.

There will also be a prospectus that is little different from a conventional bond prospectus. Like a conventional bond issuance, there will usually be a roadshow by the issuer. *Sukuk* are typically listed in well-established bond markets such as London, Dublin or Luxembourg, although other jurisdictions such as Dubai would very much like to change this. Because of the strength of the Malaysian market in *sukuk*, it is common to see *sukuk* issued in Malaysian ringgits. Dollars are also common, but the currency used is deal specific and not critical. To the extent that *sukuk* can be traded on a secondary market, those trades will occur in a conventional manner. Finally, *sukuk* are subject to the same securities regulations that apply to conventional instruments issued in the same markets.

Although *riba* is not permitted, it is permitted for the *sukuk* holders to receive a return deriving from their beneficial ownership of the *sukuk* assets. The return paid to the *sukuk* holders does not have to be the entire income generated by the asset. The issuer and the holder can agree to send some of the income to the holder of the *sakk*, and some to the issuer. They can even agree to benchmark the return to some widely-known index such as LIBOR.

Permitting a benchmark is subject to some restrictions. The *sukuk* issuer may not promise to pay the entire benchmarked amount regardless of actual performance of the *sukuk* assets. If the income from the asset is insufficient, then the payment to the *sukuk* holder will not be the amount that might have been predicted. This may seem like a severe restriction that significantly increases risk to the holders. However, the restrictions placed on the certainty of a return have an inherently mitigated impact where the income of the project can be predicted with accuracy — for example, because the project is a power project with a long-term offtake agreement. In addition, many *shari'a* boards will permit mechanisms to a degree to enhance the credit of the issuance. These may include debt service reserve accounts that can be drawn upon in the event of insufficient cash from the *sukuk* assets to pay the return and sometimes also a payment guarantee, provided that the guarantor is a third party.

Perhaps surprisingly, *sukuk* usually provide for the payment of default interest just as would a / continued page 4

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20 that work on any project that is placed in service by December 2015 will automatically be considered to have been continuous. The IRS made the announcement in Notice 2013-60. Developers had been worried they will have trouble financing projects because lenders will be unable to tell at closing on the financing whether the project will qualify for tax credits.

Continuous work will remain an issue for projects that are not completed until 2016 or later.

The notice has caused developers to take another look at the physical work test rather than try to incur at least 5% of the project cost this year for projects that are expected to be completed in 2014 or 2015. It is not as expensive to start physical work at the project site or a factory, but many developers are asking how much work this year is enough.

According to the IRS national office, it is the start of significant physical work to put down a single turbine foundation or build a road around one or more turbine pads (as opposed to an access road to the main highway) or to have a factory start assembly of custom-made components for the project.

Rep. James Lankford (R.-Okla.) asked Curtis Wilson, the IRS associate chief counsel who handles energy tax credits, at a House subcommittee hearing in early October whether it is enough to put down turbine foundations for two turbines and put in a road this year to enable a 100-turbine wind farm to qualify for tax credits. Wilson suggested the entire project would qualify as long as the project functions as a single, integrated facility.

However, some developers remain uneasy. The IRS included an example of significant physical work in guidance it issued last spring on starting construction. That guidance had an example of a developer excavating foundations and pouring concrete for pads for 10 of 50 turbines, or 20% of foundations. IRS sources say the reference to 10 turbines was an error, and the intention was to refer to one turbine foundation like a similar example used in the Treasury cash grant program.

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conventional bond. The apparent contradiction is reconciled by provisions requiring that default interest that is charged will not actually be paid to the *sukuk* holders. Rather, it will be given to charity.

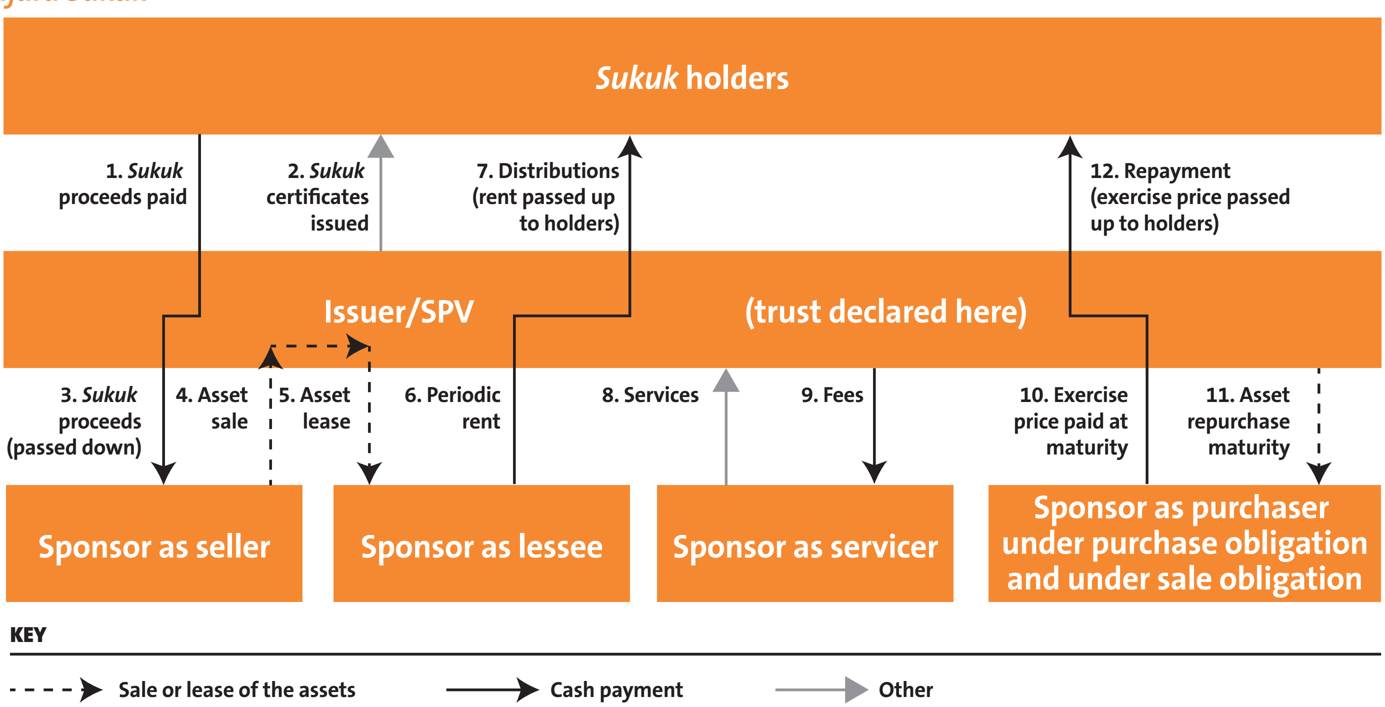
One addition to these largely conventional features is a feature unique to Islamic finance. *Sukuk* will be vetted by a *shari'a* board for compliance with *shari'a* principles. This board is appointed by the bank that is structuring the *sukuk*, and the composition of the board will be disclosed to investors. The *shari'a* board will examine the structure of the *sukuk* and opine on whether it meets that board's *shari'a* compliance standards. This will include an examination of the nature of the underlying business or project being financed. Certain endeavors such as those involving alcohol, pork, gambling and obscenity may not be financed by *sukuk* — or any Islamic finance for that matter. The ethical goals of the *sukuk* will also be examined. Infrastructure projects often have a high degree of social utility and so they can be an excellent fit in this respect.

One problem of which an investor should be aware is that *sukuk* have been subject to different opinions among Islamic jurists about what is and what is not permissible within a structure. The Malaysian market has been criticized for what some influential scholars perceived as an overly liberal approach. An investor will want to examine the reputation of a particular board, and some investors may choose to conduct their own *shari'a* review. The *shari'a* board's evaluation of an issuance does not form a part of the bond rating.

In some jurisdictions, prevailing tax treatment may make *sukuk* less tax efficient for the issuer than conventional bonds. This is because the periodic distributions under *sukuk* may be treated as non-deductable distributions whereas interest payments are generally deductible. A number of countries with vibrant financial centers have addressed this imbalance by legislation. These include the United Kingdom, Singapore and Luxembourg. A notable exception is the United States tax code, which has not been changed to accommodate *sukuk*.

There are a number of basic types of *sukuk* structures. Each of them is based on an underlying Islamic finance structure. The "*sukuk*" aspect is the element of securitization that is layered on top of one of these structures (or a hybrid of more than one). The structures are chosen depending on the nature of the activity being financed and to a large extent the preference of the issuer or the perceived appetite of the market. Within general parameters, significant degrees of innovation and customization are possible.

Ijara Sukuk



The most common *sukuk* that are readily adaptable to project finance are the *ijara* (or leasing) *sukuk* and the *musharaka* (partnership) structure. Of these, an *ijara sukuk* is the most common.

Ijara Sukuk

The basic steps and key documents for a typical *ijara sukuk* are shown in the diagram on the previous page.

A special-purpose entity or SPV is established, and each holder contributes cash to the SPV in exchange for its *sakk*.

The sponsor sells assets to the SPV and receives in return the proceeds of the cash contributed by the *sukuk* holders. The SPV declares a trust over the assets and becomes the trustee acting for the *sukuk* holders. The trust is typically granted under English law.

The SPV pays the cash to the sponsor as contribution for the purchase of the assets. The cash may be used for the purposes of the *sukuk*.

The SPV then leases the assets back to the sponsor.

The SPV enters into a separate purchase obligation agreement, a sale obligation agreement and an asset service agency agreement with the sponsor. These agreements have the following features.

The purchase obligation agreement obligates the sponsor to purchase the assets back at maturity or (at the option of the holders of the *sukuk*) on an event of default. The purchase obligation in the case of an event of default is in lieu of a direct right by the *sukuk* holders to liquidate the *sukuk* assets.

The sale obligation agreement permits the sponsor to purchase the *sukuk* assets for an agreed price equivalent to the face amount of the *sukuk* certificate plus any remaining unpaid periodic distribution amounts upon certain events, which typically are tax events.

The service agency agreement provides for the sponsor to manage the *sukuk* assets and the trust. Insurance obligations may be shifted from the SPV trustee to the sponsor (as lessor of the assets) through the service agency agreement.

In some *ijara sukuk*, there may also be a substitution undertaking agreement to allow the substitution of *sukuk* assets that must be sold or that wear out. The replacement assets must have no less than the same value and ability to generate revenues.

During the rental period, the sponsor, as lessee, makes rental payments to the SPV rather as would be done in a conventional sale-leaseback. These rental payments are intended to be sufficient to pay periodic distributions to the

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The IRS is following precedent under the section 1603 or Treasury cash grant program. The Treasury never required a minimum amount of work, but over time, it questioned whether some projects that lacked permits or other basic project contracts were truly under construction.

Many wind companies have spent the summer negotiating master turbine supply agreements with turbine vendors that require delivery of enough tower segments, blades, nacelles or other specially-made equipment to amount to at least 5% of the expected cost of their projects. The IRS has said informally that the projects at which the equipment will be used do not have to be identified this year. By extension, if the contract identifies four projects at which the equipment will be used and another project is later substituted for one of the four, components can be moved to that project and it should qualify for tax credits as long as the developer had been working steadily on it.

Some common issues are emerging in turbine contract negotiations. Costs are not considered "incurred" for purposes of the 5% test until there is delivery or transfer of title to equipment or services, with one exception. A payment in 2013 counts as a 2013 cost as long as delivery or title transfer is expected within 3 1/2 months of the payment.

Many developers are planning to pay in late 2013 for equipment to be delivered in early 2014. General milestone payments or down payments for a larger turbine order do not count for this purpose. The 2013 payment should be for the specific components. The 3 1/2-month rule appears to be a "method of accounting," meaning that if the developer has used another method in the past to determine when costs are incurred, then the IRS must give permission to change. Some developers who are unsure whether they can use the 3 1/2-month rule are turning the entity that contracts with the turbine vendor into a partnership for tax purposes so that it has a clean slate to choose an accounting method.

Developers relying on

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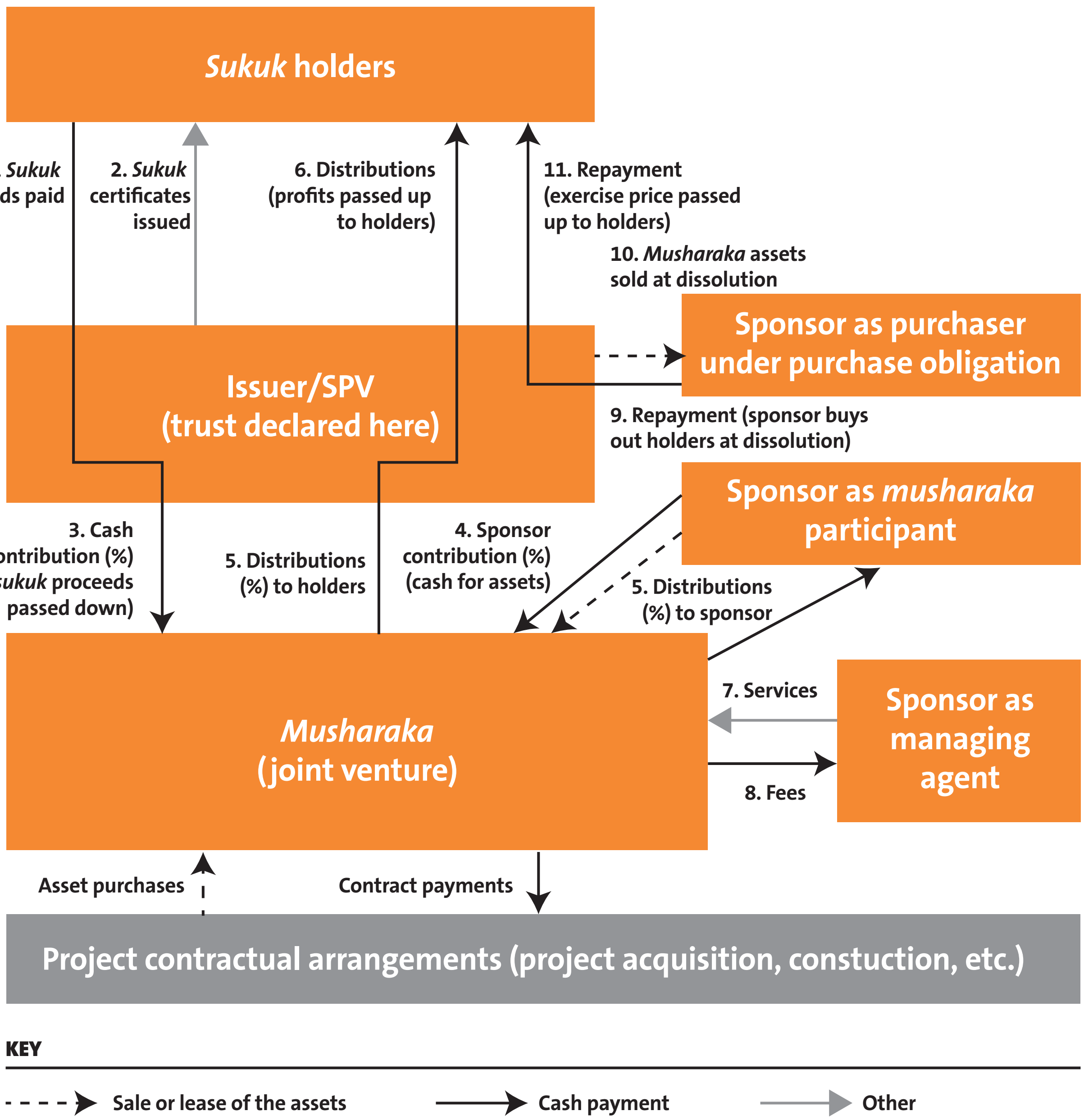
sukuk holders. The payments flow through the SPV as back-to-back payments.

The end of the lease period and dissolution of the trust coincide with the maturity of the *sukuk*. The *sukuk* assets are purchased back by the sponsor pursuant to the purchase obligation agreement. The purchase price, which is generally the face amount of the *sukuk* certificate plus any remaining unpaid periodic distribution amounts, is passed on to the *sukuk* holders, repaying their principal.

For *shari'a* compliance reasons, the assets held in trust must generally both be existing assets and ones that will not be consumed during the lease period. If the assets cannot be identified at the time they enter the trust, then the *sukuk* will not be salable on the secondary market except at par. This creates a problem in projects that are in their construction phases. Some

Musharaka Sukuk



transactions have allowed an *ijara sukuk* to be combined with an *istisna'a* contract and have permitted trading on the secondary market once the percentage of identified assets reach some threshold — generally 30%. An *istisna'a* contract is a contract whereby a supplier or construction contractor agrees to manufacture certain identified goods (such as a project) in exchange for staged payments. (For further reading on *istisna'a* project financing structures, see Keenan, Richard, "Islamic Project Finance: Structures and Challenges," in the February 2010 *Project Finance Newswire*.) *Sakk* in an *ijara sukuk* will be saleable on the secondary market for a profit once the asset becomes existent or identifiable.

With that tradability caveat, an *ijara sukuk* structure is sufficiently flexible to be used to finance a pool of assets acquired over a period of time, such as, for example, a pool of distributed solar projects where individual installations would be acquired over a period of time with periodic investments by the *sukuk* holders to finance the acquisition and installation of the projects as they enter the pool. This is done through a master *ijara* (or master lease) agreement where contribution, purchase and lease take place periodically as assets are acquired. This is very similar to master lease agreements that have been used in the United States as part of tax equity transactions for distributed solar projects.

Musharaka Sukuk

Another *sukuk* form is a *musharaka*, or partnership *sukuk*. Until a few years ago, this was a popular structure widely regarded as being particularly suitable for project finance because it closely replicated the risk profile of more conventional bond structures. Unfortunately, it so closely replicated them that it later came under severe criticism for being not *shari'a* compliant. Since that time, it has lost a great deal of the popularity it once enjoyed and is now much less likely to be used than an *ijara sukuk*. Nevertheless, certain recent transactions like the aforementioned financing of the Jubail oil refinery in Saudi Arabia have used this structure.

The basic steps and key documents of a typical *musharaka sukuk* are shown in the diagram on the previous page.

The venture is established as a *musharaka*, which is a joint venture typically between two parties — the trustee as partner and the sponsor as managing agent. A *musharaka* does not have to be (and frequently is not) a formal partnership entity. It can be established contractually. The sponsor generally manages the joint venture and can charge a management fee if there is a separate management agreement, although / continued page 8

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the 3 1/2-month rule should make sure that the purchase order for the components is a "binding contract." The contract cannot be merely an option to choose components later. Some contracts give the manufacturer the option to substitute different components in 2014 if the manufacturer is unable by the deadline to deliver exactly what was ordered. The IRS is still evaluating whether such a right for the manufacturer will prevent the contract from being considered a binding contract after indicating initially that such substitution clauses are okay.

Chadbourne has never felt comfortable relying on title transfer as opposed to delivery in 2013 (or within 3 1/2 months of a 2013 payment). Delivery can be at the factory. However, the parties must prove delivery occurred if the turbine vendor still remains in physical possession of the equipment. The developer should send a representative to inspect the equipment and sign a delivery certificate. It should have the right to remove the equipment at any time. It should pay for storage. It should have risk of loss. The equipment should be segregated from other inventory belonging to the vendor or, if the components are too large to do this, at least marked as property of the developer. Sales and other transfer taxes that are triggered by delivery should be paid. If the vendor is expected to re-deliver the equipment later to the project site, then there should not be anything in the later contract arrangements that calls into question whether the equipment was originally delivered at the factory. The equipment should not be of a kind that must be returned to the factory for further assembly.

Turbine vendors are agreeing to damages if they fail to make delivery deadlines, but the amounts vary from one contract to the next.

The ability to drop components into projects to be identified in the future gives an advantage to larger wind companies that are able to stockpile equipment. A common question is whether a company that has 2013 turbines can buy a project that a smaller devel- / continued page 9

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any such management fee is generally quite nominal.

An SPV is established to hold the *sukuk* holders' interests in the *musharaka*.

Sukuk holders' contributions come as contributions to the SPV in exchange for the *sukuk* certificates. The SPV declares a trust over the proceeds and any assets acquired with them. Like the trust in an *ijara sukuk*, the trust is conventional and is usually formed under English law.

Recent Islamic bond offerings have been oversubscribed by as much as three and half times and have run as large as US$2 billion.

The SPV contributes the proceeds from the *sukuk* to the *musharaka*. The sponsor also makes a contribution to the *musharaka*. The contribution cannot consist solely of debts. Each of the SPV and the sponsor receives a proportionate number of units of the *musharaka* in return. Their respective investments in the *musharaka* partnership are used for the purposes of the *musharaka* — for example, to construct, develop and own a project.

The *musharaka* can include contractual arrangements to construct a project. These would generally be Islamic compliant financing arrangements, such as an *istisna'a* contract arrangement.

The *musharaka* participants may make their contributions over time, for example, as phased payments to build a project.

The *musharaka* participants share profits of the *musharaka* in an agreed proportion. The agreed portion that is returned to the issuer SPV is usually calculated to be sufficient to pay the periodic distribution amount that is paid by the issuer SPV to the *sukuk* holders. The agreed proportion does not have to be the same as their contribution proportion.

In contrast to profits, losses are shared strictly in accordance with the amount contributed. However, a *musharaka* structure is like a partnership in that there can be circumstances where there is not enough profit generated to make this return guaranteed.

On maturity of the *sukuk*, or (at the option of the trustee acting on instructions of the *sukuk* holders) upon an event of default, the *musharaka* is dissolved. To provide for the return of the investment to the *sukuk* holders, the sponsor purchases the *musharaka* assets at an agreed exercise price.

Both the payment of distribution amounts and the exercise price for the repurchase option are at the heart of the controversy that has surrounded the *musharaka* structure.

A *musharaka* is explicitly a joint venture and so inherently it ought to be capable of losing money as well as earning money. This would not be the case in a conventional bond, and so structures were devised to remove this feature as much as possible. Prior to 2008, it was common for *musharaka sukuk* transactions to include a number of mechanisms that largely eliminated these risks so that the transaction behaved from the investors' point of view very much like a conventional bond. The sponsor (as managers) committed to make interest loans to the investor partners at times when the venture did not have sufficient profits to pay the periodic distributions to the *sukuk* holders, thus protecting the periodic distributions from most shortfall events. The sponsors also committed to repurchase the *sukuk* assets at maturity for the face amount rather than the prevailing market price, which, in the case of a failing project, could be less than the amount of principal advanced by the holders.

In 2008, both of these mechanisms were criticized for being inconsistent with the concept that a *musharaka* is a joint venture. Loans that guaranteed the periodic distribution regardless of profitability made a *musharaka* indistinguishable from a bond with interest payment obligations that do not depend on profitability. A binding promise by the sponsors to repurchase the *sukuk* at the face amount rather than the prevailing market value also removed functional risk of loss of principal. This criticism had an immediate practical effect because spearheading it was the chairman of the Islamic board of the Bahrain-based Accounting and Auditing Organization for Islamic Financial Institutions, which is usually abbreviated to AAOIFI and happens to be the organization that accredits many *sukuk*. With these mechanisms no longer permitted, interest in the structure plummeted.

One form of *musharaka* that is still commonly used is the diminishing *musharaka*. To date, this structure is mostly confined to the residential housing market, but it could be applied in project finance. In a diminishing *musharaka*, the sponsor party makes periodic payments to the *sukuk* holders over the life of the *sukuk*. In this way, the ownership of the *sukuk* assets by the holders diminishes steadily with each payment, rather than all at once on a maturity date as in a conventional *musharaka*. Unlike conventional lending, however, the obligations and benefits with respect to the *sukuk* assets also shift along with the shifting ownership. Thus, the return that is paid in the form of periodic distributions will diminish as the holders' stake in the assets that generate the return reduces.

Mitigating Risks

Like conventional bonds, *sukuk* holders may not be comfortable taking construction risk. Therefore, *sukuk* are sometimes created as refinancing arrangements for a project that was financed conventionally during the construction phase. On the other hand, some recent *sukuk* have financed construction using risk mitigation such as robust EPC arrangements and guarantees by third parties. However, these guarantees have been limited to those provided by governments.

The fact that the market still desires a government guarantee is perhaps more a feature of the relative immaturity of the market than anything inherent to *sukuk* as a structure. As the market develops, it can reasonably be expected that other third party guarantees will be accepted. Regardless of who gives them, these third party guarantees should be carefully distinguished from the guarantees of return by the issuer that were a problem in *musharaka sukuk*. The issuer cannot guarantee the return of the *sukuk* investors because such an undertaking would be economically identical to a promise to pay interest regardless of the performance of the project being financed. But it is possible for a bona fide third party to do so, provided that the guaranty obligation is separately documented and voluntary in nature.

Just as in conventional project bonds, a practical issue that makes construction phase *sukuk* / *continued page 10*

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oper has under development in 2014 and use the turbines to qualify for tax credits. The answer appears to be yes, provided the smaller developer has been working steadily on the project, but the IRS has yet to confirm this.

No further guidance is expected from the IRS on construction-start issues. The agency is still thinking about whether to entertain requests for private letter rulings. It does not rule on factual issues. Any rulings would have to present legal questions.

Before the IRS notice in September that dispenses with the need to show continuous work on projects that are completed by December 2015, many developers had been focusing on the 5% test. This remains the safer course for 2016 and later projects. For 2016 and later projects, physical work this year must be followed by "continuous construction," while incurring 5% of the cost this year must be followed only by "continuous efforts." The types of tasks that qualify as "continuous efforts" contemplate that a project may still be under development, while "continuous construction" seems to require a project to be farther along.

The IRS uses two principles to decide whether development efforts are continuous. First, it wants to see steady and diligent effort to finish developing the project and then build it. The development team should keep weekly logs showing what was done each week to advance the project. The team ought to ask itself every Monday what it can do that week to advance the project and then work at it. Second, interruptions in the work schedule that are outside the control of the developer are not a problem.

The IRS has said informally that it is not a problem to take the date when the utility to whose grid the project connects will have completed the substation improvements and network upgrades needed before the utility can start receiving electricity from the project and then work backwards from that date to determine when to start erecting turbines at the site. / *continued page 11*

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financing difficult is the higher likelihood that a project will need to obtain covenant waivers. Bonds and *sukuk* holders equally are traditionally reluctant to get involved in day-to-day issues, and obtaining consents can be difficult, especially when the project may need a rapid response. This can be mitigated by carefully drafting covenant packages to account for issues that may emerge during construction and providing more leeway for a single agent to make decisions without requiring the full holder group to issue the waiver or consent.

Other issues to be aware of are somewhat unique to *sukuk*. These are flagged in the prospectus just as would be done in conventional bond financing. Prospectuses will caution that the returns generated by the *sukuk* are generated by the *sukuk* assets and, therefore, if the assets do not generate income (for example, because they are destroyed), no return or periodic distribution may be forthcoming. Prospectuses also generally caution that a secondary market may not be available, so *sukuk* holders may not be able to liquidate their positions as readily as they could on the conventional bond market.

There are two issues at play here. One is mainly a function of the relatively small size and novelty of the *sukuk* market and, in time as new listing venues appear, this may diminish. The other is that, in some cases, *shari'a* compliance rules would forbid the trading of *sukuk*. Such restrictions should be disclosed in the prospectus.

A more significant market problem that has hindered the use of *sukuk* for project finance, but that will not be identified as risks in the prospectus, is that *sukuk* have typically had a maturity that has typically hovered around five to seven years. This is not a theoretical limit; it has simply been the longest maturity with which investors have previously been comfortable. However, it is usually not a good fit if the project being financed has a power purchase agreement with a typical 20-year term. Conventional loan financing has long been comfortable with tenors that more closely approximate the income generating life of the project, and so this makes *sukuk* less attractive. Happily for those interested in financing using *sukuk*, there are market indications that this barrier is increasingly being broken with some *sukuk* issuances having tenors as long as 15 years. It is not unlikely that longer tenors will emerge if perhaps initially only for the more robust projects and issuers.

Another issue that a prospectus will not mention is that *sukuk* have also been criticized for being somewhat document intensive. To some extent, this is unfair. For *shari'a* compliance purposes, some obligations of a *sukuk* structure are broken out into separate undertakings, frequently of a unilateral nature. This adds some apparent complexity, but it may not actually add significantly to the true complexity of a transaction. Nevertheless, it remains fair to say that, as a relatively new structure with complex requirements, issuers are more likely to find themselves breaking new ground in a *sukuk* than a conventional structure such as an interest-bearing loan. This can result in somewhat higher transaction costs. Over time, it is expected that documentation and *shari'a* board requirements will both become more standardized and this will inevitably bring transaction costs down.

Security issues in *sukuk* are much closer to a bond than a conventional loan, and the assets on which the *sukuk* have an undivided beneficial interest cannot be foreclosed upon. For this reason, *sukuk* are said to be asset based, but not asset backed. The holders' remedies for non-payment are limited to guarantees that may have been provided and to contractual remedies. On the other hand, the fact that *sukuk* assets are held in a trust by a special-purpose entity means that those assets are protected from bankruptcy claims against the sponsor, giving a somewhat lower risk profile than a

Islamic bonds can be used for projects anywhere and not just in countries with large Muslim populations.

conventional corporate bond issuance.

A related issue is the need for the holders to protect the assets. Without assets, the *sukuk* will generate no revenue. Insurance is therefore critical just as it is in project finance generally. This could be conventional insurance, but conventional insurance is not favored in Islam because it is considered to be a species of gambling (more technically called *gharar*, which conceptually refers to excessive risk). Therefore *takaful* Islamic insurance products may be used in preference to conventional insurance. A *takaful* insurance product is a cooperative risk allocation pool where members donate to a fund from which payments can be made when a member encounters a defined loss. It, therefore, provides a means for compensation without the speculative element that makes conventional insurance repugnant to Islamic finance principles. As in project finance, the obligation to procure insurance can be shifted first to the SPV, and then it can be further shifted to the sponsor.

In theory, if a transaction is declared to be not compliant with *shari'a* law, the transaction could be considered void from an Islamic point of view even if the closing of the transaction has occurred. However, even if this happens, the contracts that make up a *sukuk* structure will not be invalidated, and the deal itself will not be unwound. The contracts that make up a *sukuk* transaction are generally governed by a well-established body of law such as that of England or New York, and contract interpretation and enforcement are no different from any other contract under those bodies of law.

Trends to Watch

At the present time, *sukuk* are far from being the default financing mechanism in any market, but *sukuk* are already an available alternative. In any growing financing market, the volume and size of deals are trends that are important to watch as an indication of market trajectory. However, perhaps an even more important measure of the development of this market is who is doing the issuing. As the *sukuk* market matures, we would expect to see a shift from issuances almost exclusively by large governmental or quasi-governmental entities to smaller or more purely private sector issuers. We can anticipate that this will begin first with international project developers with a strong track record. There are some indications that this is beginning, and from the perspective of international developers and potential investors alike, it is a key issue to watch.

A second trend to watch is the increasing maturity of issuances. As maturities extend, *sukuk* become increasingly suited to finance projects. Until maturities routinely / *continued page 12*

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TREASURY CASH GRANTS lead to more litigation.

A partnership of NextEra and JPMorgan filed two lawsuits in September over shortfalls in so-called section 1603 payments the US Treasury paid the partnership last year on wind farms in California.

The partnership bought three wind farms from Western Wind in December 2011 for $502 million. It allocated $210 million of the purchase price, or $2.69 million an installed megawatt, to the 78.2-megawatt Vasco wind farm in Contra Costa, California, and approximately $115 million, or about $2.3 million an installed megawatt, to the 49.5-megawatt WPP 93 wind farm near Riverside, California. Both projects were put in service within days after the purchase.

The partnership applied for grants in March 2012 for 30% of what it paid for the projects. The Treasury informed the partnership in October 2012 that it was paying the grants, but the amounts were $5.86 million or 9.6% short on the Vasco project and $2.9 million or 8.8% short on the WPP 93 project.

The complaints filed in the lawsuits said Western Wind earned a 28.6% profit on the sale of the Vasco project and, in what may have been a typo, a 68.6% profit on the WPP 93 project.

The Treasury said a share of the purchase price in each case should have been allocated to the power contracts that came with the projects. Grants are paid only on equipment and not also on intangible assets like power contracts.

The partnership treated roughly 96% of the purchase price for each project as eligible basis for calculating its grants. It argues that nothing had to be allocated to the power contracts because the contracts are not separate assets. Each contract can only be performed by delivering electricity from the particular project. This makes the contracts encumbrances on ownership of the wind farms rather than separate assets in the same way that someone buying an office building with / *continued page 13*

Islamic Bonds

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approach those of conventional loans, many projects will be unable to finance using *sukuk* structures.

Another trend worth monitoring is the increase in political support for *sukuk* issuances. Some of this has already occurred. Malaysia has been the most aggressive jurisdiction in fostering a vibrant *sukuk* market, followed closely by Bahrain. The willingness of countries with influential financial centers such as the United Kingdom to adjust their laws to level the playing field between *sukuk* and conventional bonds is a significant indication that *sukuk* are taken seriously in those countries. Dubai's announced goal of becoming a global center for *sukuk* represents another significant development. Many believe that a regional market would make it easier to attract capital from other Gulf states. It is also hoped that these trends will increase standardization of *sukuk* issuance rules.

This brings us to a final trend to watch, and it is one that is maybe a little counterintuitive if you read the press releases that often follow a successful closing. Highly bespoke and difficult transactions make for good war stories, but they are a barrier to the expansion of the *sukuk* market as a whole. As *sukuk* become more common and more familiar, we can look forward to more frequent and routine transactions that break less ground and generate less fanfare.

In the meantime, *sukuk* are already a practical alternative financing technique that can attract significant pools of liquidity. Perhaps they are a niche now, but the signs are *sukuk* are going mainstream in the project finance market. ◎

Renewable Energy Opportunities in The Middle East

by Marc Norman, in Dubai

Jordan has initiated the second round of its unsolicited proposals scheme that permits developers to submit renewable energy project proposals directly to the government.

The Kingdom's Ministry of Energy and Mineral Resources, or MEMR, is seeking expressions of interest from qualified investors interested in developing renewable energy projects on a build, own and operate basis. The deadline to submit an electronic and hard copy response is October 31, 2013.

The first round of unsolicited proposals extended to an array of renewable energy sources such as wind, solar, waste and geothermal, but this round is restricted to wind and solar.

MEMR launched the first round of unsolicited proposals in May 2011. Thirty-four applications including 12 wind projects, 15 solar photovoltaic projects, two concentrating solar photovoltaic projects and five solar thermal projects initially qualified. However, only two wind projects and 12 solar photovoltaic projects were eventually approved. The aggregate capacity of the two wind projects is approximately 200 megawatts, and the aggregate capacity of the 12 solar photovoltaic projects is also around 200 megawatts. In May 2013, MEMR received proposals for each of the approved projects. Formal project awards are still pending, and MEMR is currently hosting clarification meetings with a number of bidders.

The launch of the second round prior to the completion of the first round has surprised the market, although this is consistent with Jordan's aim to reduce its dependence on imported energy — 97% of the energy it used in 2011 was imported — and increase the share of renewable energy contributions from 1% in 2011 to 10% by 2020.

The near finalization of the first round combined with the launch of the second round positions Jordan as the Middle East's most active and arguably advanced renewable energy market.

International renewable energy developers should view Jordan as a place to plant a flag in the Middle East and eventually as a stepping stone toward other high potential, but currently less active, regional markets, including Saudi Arabia with its colossal program to procure 54,000 megawatts of renewable energy facilities by 2032.

Amidst the high hopes and hype surrounding the Middle East's apparent drive towards renewable energy, and solar power particularly, the reality is that the pace of deploying commercial procurements has been sluggish. Very few renewable energy tenders have recently come to market.

At present, the key Middle Eastern renewable energy markets are Jordan, Saudi Arabia, the United Arab Emirates, Kuwait and, with some reserve, Qatar.

Jordan: Notable Points

An applicant's expression of interest to MEMR must include a description of both the applicant and the project, evidence of the applicant's technical capability and experience and a demonstration of the applicant's ability to raise debt and equity.

The applicant must provide a project description, including the location with coordinates on a map, capacity and estimated generation per year and envisaged wind or solar power technology.

In the first round, MEMR chose to focus most of its efforts on the southern region of Ma'an and, in particular, an 8.75 square kilometre zone dubbed the Ma'an Development Area, or MDA. The MDA is attractive because the applicable regulatory and administrative regime is more streamlined and flexible than would otherwise be in Jordan; the fiscal regime is also more advantageous. The MDA is also attractive from a resource standpoint. The area had been earmarked as the best location in Jordan for concentrated solar power projects by Lahmeyer International, a Germany-based technical advisor. MEMR's initial focus in the first round was on concentrated solar power.

In the second round, Jordan wants to shift the focus away from the Ma'an region towards the northern and eastern parts of Jordan. MEMR said explicitly in its expression of interest request that submissions for projects in those parts of the country will be prioritized. The key driver behind this geographic shift is to ease the pressure on the already fragile grid in the southern part of the country. The grid in the northern and eastern parts of Jordan is currently less saturated.

The northern and eastern parts of Jordan may pose a number of challenges to wind and solar developers. First, there is no MDA equivalent; although, there are rumors that the granting of development area status for a specific parcel of land is being considered. Second, the northern and eastern parts of Jordan are more industrialized than the Ma'an region, which could lead to complications, particularly in terms of land rights and permits. Third, proximity to the

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space leased out to tenants would not allocate part of the purchase price for the building to the leases. The leases are an encumbrance on the owner's unfettered use of the building.

The IRS accepted this approach in a private letter ruling involving another wind farm that the agency made public in April 2012, but then withdrew the ruling a few months later after having second thoughts about the conclusion.

The partnership says that even if the power contracts were separate assets, they had no value because the electricity prices the contracts require the utilities to pay are not above market.

The suits were filed in the US Court of Federal Claims. There are now 10 lawsuits pending against the Treasury under the section 1603 program. An 11th suit by a solar company was withdrawn "with prejudice," meaning the solar company agreed never to re-file the suit, after the US government filed a counterclaim accusing the solar company of filing fraudulent grant applications.

Not counting the suit that was withdrawn, the oldest remaining suit has been pending since July 2012. No dates have been set yet for trials. The Treasury has moved to dismiss, at least in part, four of the cases, but the government has not succeeded to date in having any of the cases dismissed. The government lawyer came poorly prepared to argue the motion to dismiss one of the suits in late September. Grant applicants who believe they were shortchanged have up to six years after a grant was paid to file suit.

Cash grants approved for payment on or after October 1 will be subject to haircuts of 7.2%, the Treasury said in a posting to its website.

ECONOMIC SUBSTANCE remains a focus in US tax cases.

A US appeals court set aside a transaction in August that the parent company of Wells Fargo Bank did in 1999 on which the parent claimed a large capital loss. The court said the transaction had no substance other than a desire to generate tax losses.

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border with war-torn Syria cannot be ignored; certain plots being targeted by developers are only around 25 kilometers from the Syrian border, and even closer to the growing refugee camps inside Jordan.

In its expression of interest request, MEMR said the applicant must contact the relevant transmission or distribution company to establish the suitability of the envisaged grid connection at the proposed location.

On the basis of round one precedent, interested parties are not expected to furnish documentation to substantiate any exchange with the transmission or distribution company. A mere mention in the expression of interest that exchanges between the developer and the transmission or distribution company have taken place and identifying the proposed location for the envisaged grid connection should suffice.

If the developer connects at a high voltage level, the interconnecting utility, and ultimately the power purchase agreement counterparty, will be Jordan's sole transmission company, NEPCO. Otherwise, the counterparty will be one of Jordan's three distribution companies: Jordanian Electric Power Company, or JEPCO, Electricity Distribution Company, or EDCO, and Irbid District Electricity Company, or IDECO. As illustrated in the map below, each of the distribution companies could be relevant in round two. JEPCO operates in the north, EDCO in the northwest and in the east, and IDECO operates both in the northern and eastern parts of the country.

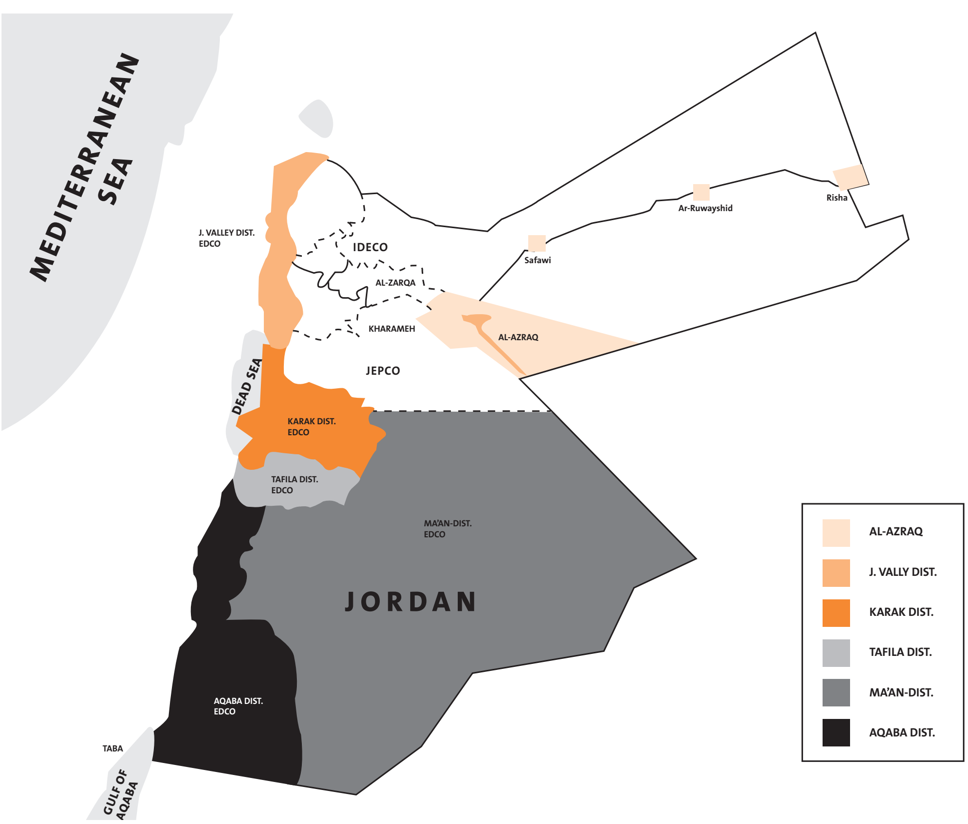
The power purchase counterparty will be an important consideration. First, there is an asymmetry of interest for each of the transmission company and the distribution companies to adopt renewable energy-based power. Second, varying experience levels mean that power purchase agreement negotiations may be more laborious with certain parties. NEPCO, for instance, has procured and successfully banked four major conventional independent power projects in the Kingdom: the 370-megawatt Amman East IPP (the first independent power project in Jordan), the 373-megawatt Al Qatrana IPP, the 573-megawatt IPP 3 and the 241-megawatt IPP 4.

Applicants that submit an expression of interest and qualify to bid will receive a memorandum of understanding from MEMR enabling each to proceed with measurement campaigns, feasibility studies and other preparatory and due diligence work such as negotiating land access and financing options. The form of memorandum of understanding in round two is likely to be substantially the same form as in round one.

Once the steps outlined in the memorandum of understanding are completed, the applicant is required to submit a full and committed proposal in compliance with the provisions of the applicable laws and regulations. All proposals must be submitted within the time period specified in the memorandum of understanding.

The Renewable Energy and Energy Efficiency Law requires any unsolicited proposal to

Map



Source: EDCO

generate electricity and connect to the grid must meet four conditions.

First, the proposal must contain a development plan including the preliminary design, initial financing plan, and the contribution of local inputs to the facility, supplies, construction and operation. Second, the bidder must demonstrate that it has experience with similar renewable energy facilities. Third, the bidder must include any documents or additional data necessary to fully appraise the proposal. Finally, the proposed electricity tariff must be a fixed tariff expressed as an amount per kilowatt hour and be within an acceptable range according to Jordan's so-called reference price list.

Electricity Prices

The reference price list prescribes the pricing mechanism for the purchase of electrical power from renewable energy sources. It is issued by Jordan's Electricity Regulatory Commission, or ERC.

The reference price list sets a separate electricity tariff cap for electricity generated by wind facilities, solar photovoltaic facilities, non-photovoltaic solar power facilities, biomass facilities and biogas facilities. The tariff cap for electricity generated by a wind power facility is JD 0.085/kWh (approximately US$0.12/kWh). For a solar photovoltaic facility, the tariff cap is JD 0.12/kWh (approximately US$0.17/kWh), whereas the tariff cap for a non-photovoltaic solar power facility is JD 0.19/kWh (approximately US$0.183/kWh).

The reference price list also includes a localization incentive. If a winning bidder installs a renewable energy facility that is of "fully Jordanian origin," then the proposed tariff will be increased by 15%. The ERC's council of commissioners may terminate the localization incentive once 500 megawatts of renewable energy facilities are connected to the grid.

The council of ministers is permitted to review the reference price list on an annual basis or whenever deemed necessary.

MEMR or any other entrusted body has six months from bid submission to notify the bidder of its decision. If initial approval is granted, then the energy minister is required to submit its recommendations to the council of ministers for it to issue a final decision.

Out of the 34 shortlisted projects in round one, only two wind projects and 12 solar photovoltaic projects were eventually approved.

In May 2013, MEMR received proposals for each of the approved projects. Since early September / continued page 16

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Wells Fargo went through two bank mergers in the 1990s and ended up with at least 21 leases for office space that it no longer needed and that were underwater in the sense that it had to pay more rent than it could get from subleasing the property.

National banks are regulated by the Office of the Comptroller of the Currency. With some exceptions, the OCC does not allow such banks to own real estate that is not needed for banking operations. Banks have five years to dispose of excess real estate, but can get extensions.

KPMG proposed a transaction to Wells Fargo in 1998 that it called an "economic liability transaction." The transaction was designed to produce a large capital loss by taking advantage of an anomaly in the US tax rules. Wells Fargo did the transaction in December 1999 after focusing internally on a suitable business purpose to justify the deal.

It made a capital contribution of government securities in which it had a basis of $426 million to a subsidiary corporation. It also contributed 21 leasehold interests in commercial properties. The subsidiary issued 4,000 shares of stock to Wells Fargo in exchange for the contributions and assumed the obligations to pay rent under the leases.

Normally an assumption of liabilities by a subsidiary is treated as if the subsidiary distributed cash equal to the liabilities assumed to the parent company: it reduces the basis the parent company has in the shares of the subsidiary. However, there is no basis reduction if the subsidiary will have a current deduction — in this case for rents — when it pays the liabilities.

Therefore, Wells Fargo had a basis in the shares of the subsidiary equal to the $426 million in government securities it contributed for the shares. Wells Fargo sold the shares to Lehman Brothers for $3.7 million and took a capital loss of $423 million.

It did not use the loss on its 1999 return as originally filed, but in 2003, / continued page 17

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2013, MEMR has been hosting clarification meetings with bidders. This is because a number of bidders proposed a tariff that deviates from the feed-in tariff and a capacity that differs from what had initially been approved.

The submission of these "alternative" proposals has caused a stir in the market. MEMR has reportedly asked the council of ministers to resolve whether it may negotiate the proposed tariff and capacity with bidders, or whether the feed-in tariff should be honored.

Despite some of the challenges experienced in the first round, round two will undoubtedly generate considerable market interest, and probably more than in the first round.

Few renewable energy tenders in the Middle East have come to market, but Jordan, Saudi Arabia, the UAE, Kuwait and Qatar are the countries to watch.

First, the drivers for Jordan to adopt wind and solar power remain very strong. Of the energy Jordan used in 2011, 97% was imported. Such acute dependence on imports also has major security implications, especially in the context of ongoing regional instabilities.

Second, the barriers to entry in the Jordanian renewable energy market are relatively low. For instance, bidders will not be required to provide a bid bond.

Saudi Arabia

Saudi Arabia is the market with the highest potential and, accordingly, the key focus of most market participants.

By 2032, the Kingdom plans to issue procurements for 25,000 megawatts of solar thermal projects and 16,000 megawatts of solar photovoltaic projects worth more than US$60 billion, plus another 13,000 megawatts of wind, geothermal and waste-to-energy plants.

The first step in the process was the release of a white paper in late February 2013 by the King Abdullah City for Atomic and Renewable Energy or K.A.CARE, Saudi Arabia's renewable energy procurement agency.

One month after the white paper was issued, K.A.CARE was due to issue both a draft request for proposals and a draft power purchase agreement marking the onset of an introductory procurement round of up to 800 megawatts of renewable energy facilities, including approximately 600 megawatts of solar and 100 megawatts of wind. To date, no such documents have been issued which means that the program is already half a year behind schedule.

The roll out of the program depends on K.A.CARE's financial empowerment. This, in turn, requires the approval of an implementing regulation by the Saudi Arabian Council of Ministers.

Arguably, the deployment of the program also hinges on garnering sufficient buy-in from Saudi Aramco. Sources say that Saudi Aramco's increasingly apparent lack of buy-in on the K.A.CARE program has caused friction and may continue to do so. A few months ago, market rumours went as far as suggesting that Saudi Aramco may take control of the program.

The need for an implementing regulation together with the need to co-opt key stakeholders such as Saudi Aramco means that the timing for the launch of K.A.CARE program procurements is uncertain and that further delays are to be expected. It is unlikely that tenders will be issued in 2013.

There are opportunities beyond K.A.CARE's program, however. Saudi Electricity Company, the state-controlled listed electric utility, is set to launch tenders for two gas-fired integrated solar combined cycle projects in Dibba City.

In 2013, Saudi Electricity Company plans to tender the Dibba 1 IPP, a 550-megawatt integrated solar combined-cycle project. The solar power component reportedly amounts to 30 megawatts. Saudi Electricity Company expects the project to be completed in 2016. Tender issuance is dependent on Saudi Electricity Company securing land which is reportedly underway.

In 2014, Saudi Electricity Company plans to tender the Dibba 2 IPP, a 1,800-megawatt integrated solar combined-cycle project. The solar portion has yet to be confirmed. Saudi Electricity Company expects this project to be completed in 2017.

For each of Dibba 1 IPP and Dibba 2 IPP, the procurement will be undertaken on a build-own-and-operate model. The solar power technology, in each case, has yet to be confirmed.

Saudi Electricity Company is the key procuring entity for conventional power in Saudi Arabia and has developed a well-oiled independent power project procurement model. In recent years, it banked the 1,200-megawatt Rabigh 1 independent power project, the 1,729-megawatt Riyadh PP11 independent power project and the gargantuan 3,927-megawatt Qurayyah independent power project, currently the largest independent power project in the world.

United Arab Emirates

The two key markets in the United Arab Emirates are the Emirates of Abu Dhabi and Dubai. Each emirate has its own utility — the Abu Dhabi Water and Electricity Authority and the Dubai Water and Electricity Authority — and each develops and issues its own independent policies and procurements, subject to federal laws.

Abu Dhabi plans to generate 7% of its electricity from renewable sources by 2020 while Dubai has a 5% target. The key focus in the United Arab Emirates is solar power.

Abu Dhabi has been at the forefront of renewable energy developments. Last year, it commissioned the Shams 1 solar power project, a 100-megawatt solar thermal project. The project was precedent setting for a number of reasons, but the key reason is that it was the first utility-scale solar power facility in the Gulf to be procured on an independent power project basis.

Shams 1 was developed largely on the basis of the Abu Dhabi Water and Electricity Authority independent power project model for conventional power. This model has been banked on numerous occasions and is arguably one of the Middle East's most advanced independent power (and water) project models.

Masdar, a wholly-owned subsidiary of the Abu Dhabi government-owned Mubadala Development Company, is procuring the 100-megawatt photovoltaic Noor-1 project, which was intended to figure as the first phase of a 200-megawatt solar park. The preferred bidder has yet to be to be selected, however, and severe delays have caused uncertainty as to whether the project will ever follow through.

Although in a regional context Abu Dhabi's track record is impressive, from a forward-looking perspective, opportunities for renewable energy developers, at least in the short-to-medium term, are somewhat limited. The only concrete and notable development is the possible launch of a solar photovoltaic rooftop program. This plan has been / *continued page 18*

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filed an amended return on which it tried to carry the loss back to 1996 and get a refund of $82.3 million for the 1996 tax year.

The IRS denied the loss on grounds that the transaction lacked economic substance, and two courts agreed.

US courts set aside transactions that are purely tax motivated. Some courts used a two-prong test in 1999 when the transaction was done to assess whether there was any substance to a transaction. Others used a single-prong test. The appeals court in this case — for the 8th circuit — said it was unclear which approach should be used, but that it did not matter because the transaction failed both prongs. (Congress has since written a two-prong test directly into the US tax code.)

Prong one is whether the transaction had the potential to earn a profit. Wells Fargo argued the profit was in being relieved of the obligation to continue paying rent. Transferring the leases to the subsidiary relieved the bank of stringent OCC rules to dispose of the leases by putting them under a separate entity that was regulated by the Federal Reserve Board, rather than the OCC, and whose rules were less strict about making a quick sale of the leases.

The court said Wells Fargo could have earned such a "profit" simply by transferring the leases without also selling the subsidiary shares to Lehman. A profit on one leg of the transaction does not impart a profit motive to the rest of the transaction.

Prong two is whether there was a business purpose for the deal. An internal tax attorney at Wells Fargo said in an email: "We are working . . . on a project to move underwater leases to a special purpose entity to trigger unrealized tax losses." The first Wells Fargo employee assigned to come up with a business purpose suggested two ideas that the new vice president for taxes described in an email as having a 99% risk of being found wanting on audit. An internal bank regulatory lawyer then suggested using the pressure from the OCC to sell the leases as the business purpose. / *continued page 19*

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in the pipeline for several years, however, and is unlikely to be launched in 2013.

Dubai plans to source 5% of its power supply from solar energy by 2030. Last year, the Dubai Water and Electricity Authority launched the Sheikh Mohammed bin Rashid Al-Maktoum Solar Park. The project is expected to reach a capacity of 1,000 megawatts by 2030 using a combination of solar thermal power and photovoltaics. The first phase, a 13-megawatt photovoltaic plant, was awarded last year and is currently under construction.

The procurement of the first phase of the Sheikh Mohammed bin Rashid Al-Maktoum Solar Park was undertaken on a publicly-financed engineering, procurement and construction basis. Surprisingly, the Emirate of Dubai does not yet have an independent power project procurement model. Last year, the Dubai Water and Electricity Authority tendered what was meant to be its first independent power project at Hassyan; however, the project was shelved just before the preferred bidder was due to be named. The Hassyan project is soon to be reincarnated, on an independent power project basis, in the form of a two-phased 1,200-megawatt clean coal project.

The Dubai Water and Electricity Authority recently divulged details on the procurement of the second phase of the Sheikh Mohammed bin Rashid Al-Maktoum Solar Park. The project will be procured on an independent power project model. Like the first phase, it will be a solar photovoltaic project. The size of the project remains uncertain, but it seems likely that it will be a large project between 100 and 200 megawatts. Regrettably, no details have been provided on the timing for tender issuance.

Separately, Dubai is also planning to launch a solar photovoltaic rooftop program. It appears to be in more advanced stages than Abu Dhabi, reports having suggested that it is finalizing legislation for the program that would include a feed-in tariff. The program launch date is uncertain, however. At the beginning of the year, market rumors went so far as to suggest that the program had been shelved. In any event, Dubai's solar rooftop program is unlikely to be launched in 2013.

Kuwait

Kuwait is one of the newest players in the Middle Eastern renewable energy sector. The country plans to generate 15% of its electricity from sustainable sources by 2030. The key focus is on solar power and wind.

In June this year, the Kuwait Institute for Scientific Research, or KISR, announced that it had invited pre-qualified contractors to submit bids for three pilot renewable energy projects. This is the first phase of a 2,000-megawatt renewable energy project known as the Shagaya renewable energy park that, as a whole, is due for completion in 2030.

The first phase of the park, which is scheduled for completion in the second half of 2016, is being procured on an engineering, procurement and construction basis. The overall capacity of this initial phase is 70 megawatts, comprising a 10-megawatt wind farm, a 10-megawatt solar photovoltaic plant and a 50-megawatt solar thermal plant. The strong emphasis on solar thermal mirrors the approach of neighboring Saudi Arabia.

Thirty-seven companies out of 107 pre-qualified to bid for the first phase projects, including 16 for the wind farm, 13 for the solar photovoltaic plant and eight for the solar thermal plant. The bid submission deadline is October 13, 2013.

The second and third phase projects will be procured on a build-own-and-transfer basis, with a 25-year power purchase agreement. KISR plans to procure 930 megawatts of solar power facilities in phase two and another 1,000 megawatts in phase three. It is not clear whether further wind power capacity will be procured in the second and third phases.

The renewable energy park will be built on a 39-square-mile area in Shagaya, a desert zone 62 miles west of Kuwait City and near the country's borders with Iraq and Saudi Arabia.

In terms of power project procurement, KISR is a new player. It is therefore likely to take some time before tenders are issued for the second and third phases of the Shagaya park.

In parallel, the State of Kuwait's Partnerships Technical Bureau is set to tender the Al Abdaliya integrated solar combined-cycle project, a 280-megawatt power project with a 60-megawatt solar power component. The solar power technology has not been confirmed. No time indication for tender issuance has been provided.

Kuwait's Partnerships Technical Bureau is responsible for the implementation of the country's public-private partnership program. The Partnerships Technical Bureau does not have quite as developed a power procurement model as, say, Saudi Arabia's Saudi Electricity Company; however, it is very close to closing the country's first independent water and power project, the 1,500-megawatt Az-Zour North project. Once that project closes, and the newly-developed Kuwaiti power procurement model emerges, then the likelihood of progress on the Al Abdaliya integrated solar combined-cycle project will be enhanced.

Qatar

Qatar plans to meet 20% of its electricity demand from renewable sources by 2030. The key emphasis is on solar power.

The only large scale solar facilities in Qatar are a 776-kilowatt solar photovoltaic rooftop system on the Qatar National Convention Center and an 800-kilowatt solar photovoltaic rooftop system on the student halls of the Qatar Foundation.

In 2012, Qatar announced plans to launch 1,800 megawatts of solar projects by 2014. A first phase of 200 megawatts was due to be tendered in the first quarter of 2013. Lack of progress has created uncertainty, however, and has led to some loss of confidence in the market.

Notwithstanding recent public spats, Qatar should be the host of the 2022 World Cup, which potentially creates a major opportunity for renewable energy players. The country has said publicly that the event would be the first carbon-neutral World Cup and explicitly said that this would be accomplished by using solar power and other renewable energy sources to power and cool stadiums. ◎

Additional Power Needed in Southern California

by William A. Monsen and David N. Howarth with MRW & Associates, LLC in Oakland

The shutdown of the 2,246-megawatt San Onofre nuclear generating station — called SONGS — and the expected shutdown during the period 2017 through 2020 of 5,068 megawatts of coastal power plants that use seawater for cooling in southern California will create opportunities for developers of both supply- and demand-side resources.

The exact magnitude of the opportunities will play out over the next several months in California Public Utilities Commission proceedings.

The region will need approximately 4,600 megawatts of new resources to maintain reliability, according to the California grid operator, CAISO. The amount of additional capacity needed will be higher if new resources are sited at less effective locations than the plants being shut down or are less effective at meeting peak demand than the gas-turbines assumed in CAISO's modeling.

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The court said between only three and 11 of the leasehold interests had to be sold. Moreover, the regulatory pressure to move the leases into a subsidiary did not explain the stock sale to Lehman, the court said.

The case is WFC Holdings Corp. v. United States.

SOME REFUNDABLE TAX CREDITS are subject to sequestration.

The IRS said in a statement posted to its website in August that a 38% haircut applied through September 30 this year to any refunds taxpayers received who choose to forego a depreciation bonus on new equipment and instead turn in unused alternative minimum tax credits that they are carrying forward for cash.

The federal government is currently subject to across-the-board cuts in spending under a "sequestration" program that took effect last March 1 after Congress failed to reach agreement on spending cuts. The automatic spending cuts were a fallback budget plan agreed to by Congress if it could not agree on how to make spending cuts. Sequestration will remain in effect for nine years. It requires spending reductions of $109 billion a year each year. The cuts are spread evenly between defense and non-defense spending. The Office of Management and Budget calculates the percentage reductions in different programs.

The IRS said the haircut in AMT tax credit refunds applies to such refunds claimed on original or amended tax returns beginning August 13, 2013. A different haircut will apply to refunds approved for payment on or after October 1 this year. The percentage haircuts must be recalculated by OMB at the start of each fiscal year. The government's fiscal year runs from October 1 to September 30.

The haircut does not reduce the AMT credit itself, only the amount of cash refund that a company can receive. It is not a permanent loss. The difference not paid in cash should remain a tax credit carryforward.

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The need for additional resources would be reduced by new transmission projects, but CAISO has not yet considered those in its modeling.

Southern California Edison and San Diego Gas & Electric estimate need to be about 1,800 to 4,300 megawatts, depending on whether they are able to site new high-voltage transmission lines in the densely-populated southern California area. As with the CAISO analysis, these estimates assume resources are located at the most effective locations.

In any event, replacement of SONGS and the coastal power plants represents a significant opportunity for developers to solve difficult local supply problems in the western Los Angeles basin and San Diego. The region's needs can be met with new or repowered gas-fired units, grid-connected and customer-located renewable resources, combined heat and power, demand response, energy efficiency, storage and new transmission.

Senior staff from the California Energy Commission, California Public Utilities Commission and CAISO presented a preliminary plan to address the situation. The plan recommends meeting about 50% of the resource need with energy efficiency, demand response, renewable energy, combined heat and power and storage. These are "preferred resources." The remaining need would be met by transmission upgrades to reduce capacity requirements and conventional generation to the extent that preferred resources and transmission development are insufficient.

This 50-50 split would require the addition of about 3,250 megawatts of preferred resources and 3,000 megawatts of conventional generation. These estimates take into account that not all of the resources will necessarily be located at the most effective locations. A large portion of this capacity has already been authorized or is being counted on under existing programs, meaning that the state would need to authorize about 2,000 megawatts of additional preferred resources and about 1,500 megawatts of gas-fired generation to meet the targets in the staff plan.

The utilities have their own procurement proposals as well. Southern California Edison wants to procure a wide variety of resources, including a minimum of 1,000 megawatts of gas-fired generation, 400 to 600 megawatts of storage and other preferred resources, and about 500 to 700 megawatts of capacity from any resource type. SDG&E proposes to procure between 500 to 550 megawatts of new capacity from all sources. Both Edison and SDG&E premise their procurement plans on the construction of major high-voltage transmission projects that would deliver power to the western LA basin and San Diego region.

This "all-of-the above" strategy is intended to maintain reliability while keeping environmental impacts, including greenhouse gas emissions, to a minimum. While such a strategy appears to provide something for everyone, resource planning and procurement in California are subject to overlapping regulatory processes, making the outcome for any particular resource type uncertain.

The Problem

Unit 3 of the San Onofre nuclear generating station experienced a radioactive leak on January 31, 2012 caused by unexpected wear in steam generator tubes that had been installed in 2010 and 2011 as part of a steam generator replacement project at the plant. When the leak was discovered in Unit 3, the plant (including Unit 2, which was already out of service for refueling) was shut down to investigate the cause and determine whether the reactors could be operated safely. Facing mounting replacement power costs and an uncertain timeline for bringing the plant back in service, Southern California Edison decided on June 7, 2013 to shut down the plant permanently and to begin decommissioning.

Southern California will need another 1,800 to 4,600 megawatts of generating capacity in the next four to seven years to replace power plants that are shutting down.

The SONGS plant was a key part of the electrical infrastructure serving southern California, accounting for 16% of the local supply and serving an average of 1.4 million homes in the service territories of three utilities: Southern California Edison, San Diego Gas & Electric and the municipal utility in Riverside. More importantly, the transmission system in the local area and the connection between the Edison and SDG&E systems was designed assuming the SONGS plant would be there to provide voltage support and reactive power. The loss of SONGS reduces the ability to import power into southern Orange County and San Diego and represents a serious threat to grid reliability.

Compounding the loss of SONGS is the impending closure of up to 5,068 megawatts of gas-fired plants in the local area that rely on once-through cooling using seawater. These plants must comply with water regulations that practically eliminate the use of seawater for cooling by 2017 to 2020.

Government Plans

The utilities, state regulators and the California grid operator have been implementing short-term contingency plans that include the conversion of retired generators at Huntington Beach to synchronous condensers to provide voltage support. However, there is a need in the longer term to replace lost generating capacity, provide voltage support and reconfigure the transmission system.

The need for new capacity presents a significant opportunity for suppliers able to develop or repower renewable and gas-fired generation projects, combined heat and power projects, energy efficiency and demand-response programs and storage projects located in the western LA basin and San Diego. There may also be an opportunity to develop transmission lines. The types and quantities of these resources that are ultimately deployed will depend on the outcome of ongoing regulatory processes that concern resource planning and procurement in California.

The preliminary plan that senior staff of the California Public Utilities Commission, California Energy Commission and California grid operator presented proposes meeting about 50% of the incremental need with energy efficiency, demand response, distributed generation, renewables and storage. The remaining need would be met through transmission upgrades and, to the extent that preferred resources and transmission development are insufficient, conventional generation.

This 50-50 split would require the addition of about 3,250 megawatts of preferred resources and 3,000 megawatts of conventional generation. A large portion of this capacity has already been authorized or is being counted on / continued page 22

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The United States has essentially two different income taxes: regular income taxes and an "alternative minimum tax" at a lower rate on a broader definition of taxable income that must be paid to the extent it exceeds the regular tax. A portion of any AMT paid may then be claimed as a credit against regular taxes in future years.

It is unclear whether the IRS intends to start reducing payments on other refundable tax credits.

INVESTMENT FUND managers remain troubled by a decision by a US appeals court this summer that suggests such funds may sometimes be engaged in the US trades or businesses of portfolio companies the funds own that are corporations. The court declined in late August to rehear the case.

The decision has led to lots of speculation at industry conferences about potentially far-reaching tax implications.

The decision had the effect in the particular case of making two investment funds potentially liable for underfunding in a union pension plan to which one of its portfolio companies had been contributing before the portfolio company went bankrupt.

Two investment funds managed by Sun Capital Advisors bought a company, Scott Brass, Inc., that made high-quality brass, copper and other metals. The funds purchased the company in 2007 for $7.8 million.

Sun Capital describes the business of the funds it manages as buying underperforming but market-leading companies at below intrinsic value with the aim of turning them around and then selling them for a profit.

Scott Brass made contributions to a Teamsters pension fund under a collective bargaining agreement. Sun Capital employees were heavily involved in the business after the acquisition. However, falling copper prices in the fall 2008 reduced the value of the Scott Brass inventory, and the company was forced into bankruptcy in November / continued page 23

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to result from existing programs. The incremental capacity to reach these targets amounts to about 2,000 megawatts of preferred resources (including 1,000 megawatts of energy efficiency included in base forecasts, but not yet authorized and funded) and 1,500 megawatts of conventional generation. Figure 1 shows how the staff sees these additions playing out over time, as well as the timing of the retirements that create these resource needs.

In the case of preferred resources, the programs designed to support new development have historically been statewide and not location-specific. Given the local reliability issues that need to be addressed, regulators will need to make a concerted effort to ensure that the resources are developed in the locations where they are needed. For example, resources located outside the western LA basin or San Diego provide no assistance in meeting local capacity requirements.

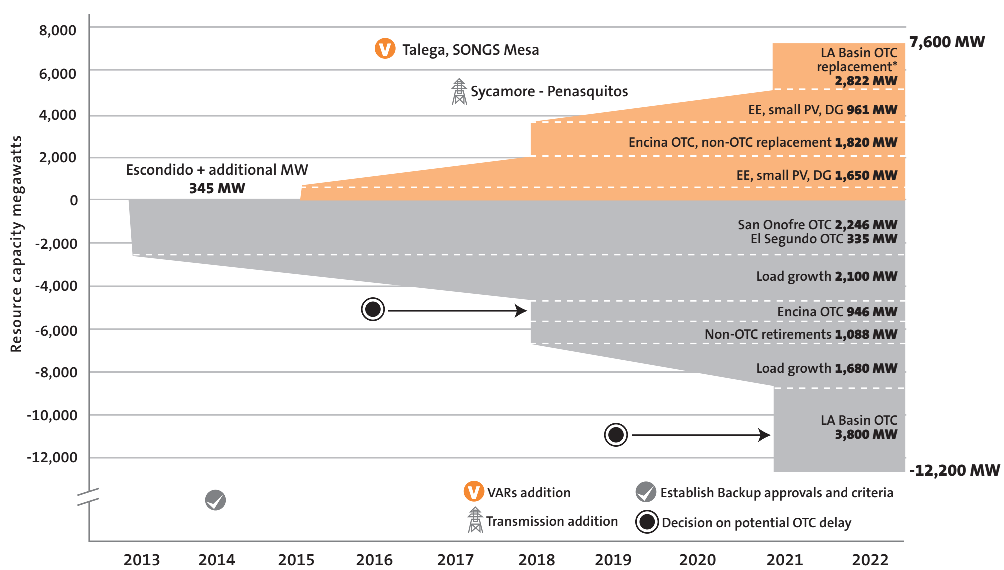
The staff also made some specific recommendations to mitigate near-term risks. These include focusing preferred resource development in the SONGS area, adding reactive power support including synchronous condensers at key points in the affected transmission system, accelerating development of CAISO-approved transmission projects, delaying retirement of existing generation and accelerating development of approved new projects, and authorizing procurement to replace the 950-megawatt Encina power plant that will have to comply by 2017 with restrictions on use of seawater for cooling.

The staff also identified some longer-term mitigation options. It wants to see alternative transmission proposals, including a project identified by Edison to loop the Mesa substation into the transmission system using existing rights of way, as well as other alternatives like a submarine DC cable delivering from the north to San Diego. Another option is to consider extending the seawater cooling compliance schedule, specifically for the Encina project, which has a compliance date at the end of 2017. Another idea is the San Diego energy park proposed by SDG&E to be located at Camp Pendleton, which is across the highway from SONGS, and offered to independent generators as a site for up to 1,000 megawatts. Another option is for Edison to offer contingent site permits to developers for peaking plants to be located at high-value sites in the southern part of the western LA basin.

Every two years, the California Public Utility Commission holds a long-term procurement planning proceeding to authorize the procurement of new resources needed to maintain system reliability. The current planning cycle for 2012 and 2013 was divided into multiple tracks including a track 1 that addressed local reliability in the LA basin and a track 4 that is addressing resource needs stemming from the SONGS shutdown.

Track 1 concluded in February 2013 with a decision authorizing Southern California Edison to procure 1,400 to 1,800 megawatts of resources in the western LA basin. At a minimum, Edison must procure 1,000 megawatts from conventional gas-fired resources, 50 megawatts from energy storage and 150 megawatts from preferred resources. No more than 1,200 megawatts may be procured from

Figure 1: Expected Resource Needs and Potential Solutions



Total load in LA Basin & San Diego:
2018 = 27,500 MW
2022 = 29,000 MW

***1,800 MW authorized**
- May include additional preferred resources
- Transmission could further reduce need

Source: Southern California Reliability: Preliminary Plan; CPUC, CEC, CAISO; September 9, 2013; p. 6.

conventional gas-fired resources, and up to an additional 600 megawatts may be procured from preferred resources and energy storage. Edison issued a request for offers on September 12. Bids are due on December 16.

Local needs for San Diego Gas & Electric were addressed in a separate proceeding. In that proceeding, SDG&E was authorized to procure 308 megawatts. SDG&E has applied to meet this authorized need by contracting with the Pio Pico gas-fired generator, which was selected in a previous solicitation and rejected by the California Public Utilities Commission.

Track 4 is ongoing. The procurement authorization anticipated in February 2014 will probably be for an amount less than the identified need to reflect the possibility that subsequent analyses that incorporate various transmission system improvements show a reduced need. It is unclear whether additional procurement beyond the interim authorization resulting from track 4 will be considered in a second phase of track 4 or delayed by two years if it is carried over into the next long-term procurement planning proceeding.

Utility Plans

The California grid operator, CAISO, is currently studying transmission options for addressing local reliability issues associated with the SONGS retirement as part of its current transmission planning process and anticipates adopting a transmission plan in March 2014, at which point it plans to update its resource needs assessment.

At this point, CAISO has not recommended any specific level of procurement authorization to address the shutdown of SONGS. However, it suggested in testimony in the CPUC long-term planning proceeding that approximately 4,600 megawatts of additional capacity will be needed in the SONGS area assuming replacement gas-fired resources are sited at the most effective locations. CAISO proposes to delay firm decisions about the need for new generation until it is able to finalize its transmission planning process. Meanwhile, CAISO has indicated that it does not oppose the CPUC authorizing Edison and SDG&E to procure about 500 megawatts of local capacity each above and beyond any prior procurement authorization by the CPUC.

Edison and SDG&E both submitted testimony in the long-term procurement planning proceeding in which they offered estimates of local capacity need as well as their preferred approaches for procurement. Both utilities relied on different reliability requirements than CAISO in their assessments, which led to lower levels of identified needs. The following tables summarize the need identified by each utility / continued page 24

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2008. Scott Brass had stopped making contributions to the pension fund shortly before the bankruptcy. There had been some underfunding of pension benefits even before the Sun funds bought the company.

After the bankruptcy, the Teamsters pension fund sent a demand for $4.5 million in withdrawal liability to Scott Brass and Sun Capital.

It claimed that the two Sun Capital investment funds and Scott Brass were under common control and, therefore, were jointly and severally liable for the withdrawal liability for the underfunding.

The Sun funds asked a court for a declaration that they were not liable.

The Multiemployer Pension Plan Amendments Act of 1980 allows the US government to recoup unfunded pension liabilities in union, multi-employer plans. Any employer withdrawing from a plan must pay its proportionate share of the plan's vested but unfunded benefits. The Act treats all trades or businesses under common control as a single employer of workers who work in any of the businesses. Two conditions have to be satisfied to impose liability on an entity for underfunding in a pension plan. The entity must be under common control with the entity employing the union workers, and the entity must be a "trade or business."

The court noted that the US taxpayers would have to pick up the underfunding through the US Pension Benefit Guaranty Corporation if the Sun funds are found not liable. It said the only authority on when investment funds are engaged in a "trade or business" for this purpose is a 2007 appeals letter, a form of PBGC ruling, in which the PBGC said it would apply a two-prong test based on a US Supreme Court decision in an income tax case. The PBGC said an investment fund is engaged in a trade or business if it is doing "investment plus," meaning more than just managing investments in shares by digging more deeply into managing the work force and assets directly of the invested / continued page 25

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and their recommended levels of procurement. ◎

Table 1 - Resource Need Estimates by Different Parties (in megawatts)

	LA Basin	SDG&E Area	Total
CAISO	3,022 - 3,722	920 - 1,485	4,507 - 4,642
SCE	1,198 - 2,802	n/a	1,818 - 4,272
SDG&E	n/a	620 - 1,470	

Table 2 – Utility Procurement Proposals (in megawatts)

Category	SCE	SDG&E
Transmission?	Yes	Yes
Gas-Fired Generation	1,000-1,200	308
Storage (minimum)	50	n/a
Preferred Resources (minimum)	150	n/a
Additional Storage or Preferred Resources	up to 600	n/a
All Source	500	500 - 550
Total	**1,900 - 2,300**	**808 - 858**

Legislative Victories Promise Further Growth for Rooftop Solar in California

by Matt Nesburn, in Los Angeles

A series of bills that cleared the California legislature in September could dramatically alter an already rapidly-growing market for distributed solar.

Chief among these is AB 327, which passed the state legislature on September 19 and is awaiting an all-but-guaranteed signature by the California governor.

Many in the industry believe that AB 327 effectively changes California's 33% renewables portfolio standard from a "ceiling" to a "floor," but it is also fraught with potential pitfalls for the solar industry.

AB 327

AB 327 makes major changes in the energy rate structure in California, with both the solar industry and investor-owned utilities declaring victory. There are potential spoils for both sides: solar advocates achieved long-awaited fixes to the net metering policy, while the three major utilities — Southern California Edison, Pacific Gas and Electric Co. and San Diego Gas & Electric Co. — secured long-sought changes in tiered customer rates and a flat monthly fee for all customers.

The retail solar industry nearly unanimously opposed AB 327 just weeks before the bill passed the legislature. The original bill addressed only the utility priorities of flattened pricing and a $10 across-the-board surcharge on customer utility bills. The solar industry managed to amend the bill toward the end of debate with instrumental support from California Governor Jerry Brown. The final bill grants a permanent reprieve from the scheduled expiration of net metering in California. Net metering refers to what happens when a homeowner or business with solar panels on its roof sells any excess electricity it generates back to the local utility. The homeowner's utility meter runs backwards. In this way, he receives credit at retail rates for the electricity he returns to the grid.

California has nearly three times more rooftop solar than the next highest state. Installed distributed solar capacity in California is 3,761 megawatts.

Net metering had been expected to end as early as late 2014. The bill extends the current program for each investor-owned utility through July 1, 2017 or, if earlier, the date when the amount of installed distributed solar capacity in the utility's service territory reaches the following level: 607 megawatts for SDG&E, 2,240 megawatts for Southern California Edison and 2,409 megawatts for PG&E.

However, the real win for the solar industry is that the bill authorizes the California Public Utilities Commission to extend net metering indefinitely via a new program set to take effect by July 1, 2017, and it lays out a procedure for how the CPUC will calculate the cost of net metering moving forward. The CPUC must also propose rules for a transition from the current net metering program to the new program by March 2014.

If the extension of net metering leads to more widespread installation of distributed solar, then it could have a dramatic effect on the utilities. A recent forecast by the CPUC suggested that net metering could cost the three main utilities $1.1 billion a year by 2020, primarily in the form of additions to transmission infrastructure, and customers using solar panels will shift nearly $359 million a year in costs to other customers.

AB 327 will also alter the rates that utilities charge customers. California will move to a simpler, two-tiered system in place of the current multi-tiered system. The current rate structure dates from 2000 and was adopted in the wake of the California energy crisis. Heavier electricity users pay higher prices. Rates range from 13¢ to 50¢ a kilowatt hour. Under the new two-tiered structure in AB 327, customers using the least amount of energy will pay higher rates per kilowatt hour, while the highest-use customers will pay decreased rates.

The simpler rate structure may help utilities retain customers in inland regions who require heavy air-conditioning use year round. This has been a prime region for solar installation. The rate reduction for such customers may blunt the rapid adoption of solar.

Under the current California net metering program, a customer is paid for the energy he sells back to the grid at the same retail rate that he pays to buy electricity from the grid. If rates are cut for this target demographic, then not only are the savings from solar power not as significant, but it will also take a homeowner a longer period to amortize his investment. According to one analysis, flattening tiers would essentially negate the federal tax incentive for rooftop solar customers by increasing the cost of solar by $2.50 per watt of installed capacity, or 30% of the total cost of a typical

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companies.

In this case, the court said, the two funds sought out potential portfolio companies in need of extensive intervention, and they were heavily involved, through their asset manager, in running the companies in which they invested.

It concluded that one of the two funds was engaged in the Scott Brass trade or business and sent the case back to a district court to look more closely into the facts surrounding the other fund and to determine whether Scott Brass and the funds were under common control.

The decision has led to considerable hand wringing over whether it will have broader tax implications.

Among the potential implications are the decision could cause income earned by fund managers to be treated as ordinary income rather than investment returns. It could lead foreign investors who hold shares in US corporations to be considered engaged in US trades or businesses and force them to file US tax returns and possibly cause them to lose protections under US tax treaties that reduce or eliminate US withholding taxes on dividends and interest the foreign investors receive from US sources. It could also require tax-exempt investors to have to pay taxes on corporate dividends received through funds as "unrelated business taxable income."

Craig Gerson, a lawyer in the tax policy section at Treasury, said at an American Bar Association tax section meeting in San Francisco in late September that the government recognizes the decision may give it the opportunity to take an expansive view of what a trade or business means, but there will not be a rush to exercise any such authority.

The case is Sun Capital Partners III, LP v. New England Teamsters & Trucking Industry Pension Fund.

SOLAR EQUIPMENT PRICES continue to fall.

A report by the Lawrence Berkeley National Laboratory in August said that the median price

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system. Another analysis suggests that it will take 30% more time to recoup energy efficiency investments due to the combined effect of the $10 fixed monthly charge and the new flattened rates.

On the other hand, when electricity rates increase for homeowners who use relatively little electricity, it could make such homeowners more likely to switch to solar.

The new rates remain to be worked out. Rulemaking in California can be an attenuated process. One potentially unsettling aspect of AB 327 for solar companies is that while the CPUC is required to fill in details of the new net metering program, AB 327 offers no guidance. It merely sets a December 2015 deadline for the rules to be completed.

The bill gives the CPUC until March 2014 to specify how customers who receive benefits under the current net metering program will transition to the new net metering program. Particularly troublesome to many solar companies and customers alike is the ability of the CPUC to revise current net metering contracts. According to the bill, "Any rules adopted by the commission shall consider a reasonable expected payback period based on the year the customer initially took service under the tariff or contract authorized by Section 2827." There is no gloss on what "reasonable expected payback" means. The bill allows for the possibility of retroactive changes to binding contracts. The concern over this uncertainty prompted Governor Brown to address the matter by vowing that the sanctity of the current contracts will be respected.

Two Other Bills

Another bill that was signed into law in September, SB 594, would establish a new version of net metering called "meter aggregation." Meter aggregation allows property owners to select the prime locations on their property to be used for solar generation, without restriction. The measure would allow an infinite number of solar energy facilities on an individual property, as long as each separate facility has a capacity of one megawatt or less. Meter aggregation would also allow individuals to use the energy generated on one property to offset their bills on a contiguous property, as long as the owner of both properties is the same.

A third bill, SB 43, was signed into law in early October and will create a 600-megawatt "green tariff shared renewables program." The program will let Californians who are unable to install solar energy generators at their places of business or homes purchase up to 100% of their energy from a community renewable energy facility. The target audience is local governments, businesses, schools, homeowners and the millions of renters and business owners who lease stores or offices. The bill also provides special treatment for communities adversely affected by pollution and for homeowners unable to finance installation of renewable energy systems. The renewables referred to in this bill would not be limited to solar energy, but also include wind, geothermal and other forms of renewable energy.

The California solar market has seen tremendous growth despite diminishing state subsidies. For the first half of 2013, 57.2 megawatts (out of 258.3 total megawatts added) of residential and commercial rooftop systems were installed in California without any government subsidy. Installations of solar energy systems were up 78% in the residential market and 26% in the non-residential market, making the second quarter of 2013 the strongest second quarter in California history.

Attention will now shift to the California Public Utilities Commission. The CPUC has been granted tremendous new power to shape the future of the California energy industry as well as the fate of both the solar industry and the regulated utilities. It remains to be seen how the CPUC will perform this balancing act, but both sides are certain to press their cases. ◎

California changed its retail electricity rate structure and extended net metering in a way that will affect the outlook for distributed solar.

UK Green Bank Update

by Julie Scotto, in London

What started out as an idea to make the UK government the "greenest government ever" could in fact be becoming a failing scheme. The target of 10,000 people to sign up to the "green deal" (a scheme supported by the green investment bank) by the end of 2013 set by the minister for energy and climate change has not been met; in fact, quite the opposite since only a mere 132 people have committed to the scheme eight months after its commencement.

The green deal promotes energy-saving measures that are intended to protect the environment by helping meet carbon emissions targets and to save on winter fuel bills. The scheme allows people to borrow money to install double glazing, draft proofing, renewable energy technologies (such as solar panels), insulation and more efficient boilers. The idea is that the knock-on effect of these works will allow people to save money on their energy bills, which ultimately should exceed the cost of repayments.

A total of around 58,000 assessments were carried out, but only 1% of the homes assessed actually signed up to the green deal. "The fact that over 99% of people who had a green deal assessment didn't want to take out a package should be a wake-up call for the government," said Luciana Berger, the shadow minister for climate change. General opinion suggests that the £16 million (US$25.6 million) already spent (with a total £125 million (US$200 million) committed to it from the green investment bank) could be better used elsewhere, for example, by city councils directly.

Reasons for Failure

The reasons behind the green deal's lack of success include high interest rates, penalty payments and hidden charges associated with this form of borrowing. The complications make taking out a regular bank loan almost a more viable option. Adding to these problems, the debt attached to the participating household means the house is likely to be more difficult to sell in the future. It is doubtful that prospective buyers would willingly take on a loan repayable at £50 (US$80) per month over a period of 10 to 15 years.

In addition, recent studies suggest that some energy-saving innovations could generate health risks during summer heat waves, particularly in London and other densely-populated areas. With global warming on the rise, / *continued page 28*

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for residential and commercial solar systems installed in 2012 was $5.30 a watt for systems of up to 10 kilowatts in size, $4.90 a watt for systems from 10 to 100 kilowatts and $4.60 a watt for larger systems. Prices fell by another 10% to 15% during the first six months of 2013. These prices are higher than in some other countries. The median prices for residential and commercial solar systems were $2.60 a watt in Germany, $3.10 in Australia and Italy and $4.80 in France.

There is a wide distribution of prices around the median. Twenty percent of US residential and commercial systems were installed in 2012 for less than $4.50 a watt, and 20% cost more than $6.50 a watt. The median prices also varied significantly from one state to the next, with the lowest prices for very small systems of up to 10 kilowatts found in Texas ($3.90 a watt) and the highest in Wisconsin ($5.90 a watt).

Meanwhile, cash rebates that some states and utilities offer as inducements to customers to install solar fell faster in some states than the decline in solar equipment prices, thereby offsetting to a large degree the potential benefit to customers from falling equipment prices. The incentives fell from 2011 to 2012 by 50% to 150% of the decline in equipment price.

Turning to utility-scale projects, the average utility-scale photovoltaic project cost $3.30 a watt for projects with crystalline modules and fixed tilt, $3.60 a watt for projects with tracking, and $3.20 a watt for thin-film projects with fixed tilt. The data sample was 106 projects put in service in 2012. However, there was a wide distribution in prices, from $2.30 to $6.80 a watt.

Larger projects (greater than 10 megawatts) generally ranged in cost from $2.50 to $4 a watt. Smaller utility-scale projects "were clustered within a similar range, but with a sizeable tail to the distribution" with 20% of projects costing more than $4 a watt and several above $5.

A separate paper by the same lab in September reported that electricity prices in a sample of 57 power purchase agreements signed recently by solar developers / *continued page 29*

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this does not make for a positive outlook for the future. “Overheating is like the little boy at the back of the class waving his hand. It is forgotten about because the other challenges are so big,” said Professor Chris Goodier of Loughborough University’s department of civil and building engineering.

These drawbacks are not as predominant in other green investments, as often larger-scale projects will by represented by companies that could mitigate potential losses more easily than individual homeowners. One of the main drawbacks for the green investment bank is finding projects of sufficient scale in the energy efficiency field.

Large Infrastructure Projects

On a more positive note, the green investment bank appears to have had more success in relation to large infrastructure projects. Such projects that have been backed include a combined heat and power plant at Addenbrooke’s Hospital in Cambridge and a local authority-managed recycling center in Wakefield (West Yorkshire). Other investments include a total of £990 million (US$1.58 billion) in the conversion of the Drax power station to burn biomass.

London-based Sustainable Development Capital has launched an energy efficiency fund with £50 million (US$80 million) from the green investment bank (and £50 million from other investors) to finance the upgrade of an insulation factory in Holywell (North Wales).

Outlook

According to the Confederation of British Industry (CBI), a quarter of businesses are not aware of the £3 billion (US$4.8 billion) green investment bank, and 41% of infrastructure providers believe the green investment bank to be ineffective. John Cridland, director general of the CBI, called the findings “alarming” and added that the government must hasten legislation to boost investment confidence.

A meeting is planned in Edinburgh on October 17 with approximately 20 influential people in international clean energy finance in an attempt to aid the bank’s development. The green investment bank’s director of operations, Rob Cormie, said, “Even after 12 months we are still learning how best we can address the market. The market we are in is relatively new, so it will be useful to talk to others from around the world about the lessons we have learned and the challenges we face”.

Hawaii: Renewables Paradise?

Hawaii has ambitious renewable energy and clean infrastructure goals, including a goal of generating at least 40% of its electricity from renewable energy and at least 70% from clean energy by 2030. This suggests plenty of opportunity for project developers, but there are unique challenges in Hawaii.

A panel of experienced developers talked about the Hawaiian market at a conference in Honolulu in September. The panelists are Hanson Wood, manager of development at EDF Renewable Energy, Joseph Rowley, vice president for power project development at Sempra US Gas & Power, Drew Bradley, Hawaii regional manager at REC Solar, William Kucharski, director of Pacific region renewable energy for AECOM, and Evelyn Lim, a Chadbourne project finance partner in Los Angeles. The moderator is Megan Strand, a Hawaii native who is with Chadbourne in Washington.

MS. STRAND: Hawaii has very ambitious goals for renewable energy. What should anyone know who is new to the Hawaii market about developing or financing a project there?

Special Challenges

MS. LIM: There are unique challenges. One is geographic isolation, which can make for challenging logistical issues to arrange for and coordinate deliveries of equipment. The high and low tides vary from one island to the next. Deliveries must be scheduled at high tide so that the ship can reach port.

Another challenge is curtailment. Utilities are responsible for maintaining a safe and reliable system. It is hard to maintain a reliable system if your electricity source disappears as soon as the wind dies. Unless there is some sort of smoothing aspect to it, it is really hard for the utilities to integrate such resources. Consequently, utilities are requiring developers of renewable energy projects to include energy storage in their proposals.

Another challenge is community relations. People here are more protective of the view, and you get into some interesting conversations with people who want to achieve energy independence but also preserve the natural beauty of the islands.

Moving to the plus side of the ledger, electricity prices are higher than on the mainland.

MR ROWLEY: On the islands, space is at a premium, and the space is valuable economically, ecologically and culturally. On the mainland, we can afford to avoid sensitive areas, but it is much more difficult to do on islands. It requires a much more intensive look at siting to reduce the impact on cultural and biological resources.

There is a strong desire to restore native habitats on the islands. We have gone to great expense to restore the native habitat even where it does not exist today. That is an additional cost to an island project that you would probably not have on the mainland.

The grid is a huge issue on the islands. When you have an island grid, you cannot lean on your neighbors. The grids are not interconnected, so each island has to manage its own frequency. To do that every moment of every day is a huge challenge. Intermittent resources present a challenge. For example, at our Auwahi wind project, we have 12 megawatts of battery storage to act as a shock absorber between the project and the grid. A project on the mainland would not have to have that.

MR. WOOD: Government policies and incentives are an important part of any renewable energy developer's life. Trying to pin down the policy in Hawaii has been a major challenge. Anyone developing projects here has to take a long view. It is not a place where you can come in and get two or three projects done six months from now.

MS. STRAND: Does project development take longer in Hawaii than on the mainland?

MR. WOOD: It is less predictable when you will have the opportunity to market your project. Permitting a wind project in Hawaii is probably the most difficult place you could imagine. Add on top of that the uncertainty of knowing that there will be a market for the output in theory, but you do not know when. Once the door opens to negotiating a power contract, you can be sure that there will be challenges and local opposition.

MR. KUCHARSKI: Another issue is the small scale of projects. Because the islands are not interconnected, you are dealing with lots of small loads.

MS. STRAND: What advice do you have for someone who is new to Hawaii about the policy process?

MR. WOOD: People are lured into the market because of the high energy rates and the abundant resources. Developers think "Oh yeah, development's difficult, but we have done it before and we can do it again." It does not */ continued page 30*

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have continued to fall "to the point where recent PPAs have been priced as aggressively as \$50-\$60/MWh levelized (in 2012 dollars)." The PPAs studied are all "bundled" PPAs, meaning the utility gets both the electricity and any renewable energy credits for the reported prices.

Solar thermal projects had an early advantage when photovoltaic projects were too expensive to compete, but the table has turned: all recent PPAs in the sample were for PV projects. Solar thermal "was seemingly competitive back in 2010," the report said, "but the lack of any new contracts since then (at least within the sample) . . . is perhaps telling in its own right."

THE MEXICAN CONGRESS is expected to vote by the end of the month on a tax reform plan that President Enrique Peña Nieto proposed on September 8.

The plan is being heavily lobbied.

It would bar tax consolidation, making it more difficult for a group of affiliated companies to make use of losses in one company to shelter income in other affiliated companies.

It introduces a 10% tax on dividends paid to a nonresident shareholder or Mexican individual. Dividends to Mexican corporations will not be subject to the new dividends tax. The 10% tax is a corporate tax imposed on the distributing corporation and not a withholding tax. Currently, corporations are taxed at a 30% rate, and there is no further tax on the remaining income when it is distributed. The government wants to collect another 10% tax on the remaining 70% of earnings. This would have the effect of increasing the corporate tax rate to 37%. Industry groups are pressing the government to hold the combined tax rate at 35%.

A 16% value-added tax would apply to real estate sales.

The new tax plan would also eliminate a current "flat tax." The flat tax serves as an alternative minimum tax. It */ continued page 31*

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work here the way it does on the mainland. You have to plan to build a presence that can be sustained over a very long period of time.

You cannot come into Hawaii thinking you are going to show results in six months or a year. Your management will have to understand that this is a longer-term play.

MS. STRAND: Is the extended development process as much a problem with distributed solar installations on the various islands?

MR. BRADLEY: The main challenge with distributed solar is uncertainty about the incentive. Every year we get the legislature together and figure out what the state incentive will be that year. The Hawaii Department of Taxation steps in and comes up with a temporary administrative rule that completely changes the returns. There are a lot of wild cards.

It is good that the deals can be fatter here. They start with what appears to be a high rate of return, but by the time you take into consideration the additional cost, the premium of doing business in Hawaii and the premiums for labor and land, the soft costs and the friction on the deals, the high return can disappear quickly. Be prepared to lose some hair.

Hawaii is making a push for 40% renewable energy and 70% clean energy by 2030.

Construction Contractors

MS. STRAND: Is the construction work contracted out locally or do you work mainly with companies on the mainland?

MR. BRADLEY: We are a contractor so we build the majority of our projects. The challenge is finding enough electrical journeymen, who are always in short supply here because of the lack of reciprocity for electricians licensed in other states. There are never enough electrical journeymen. It is easy enough to find mechanical people and workmen with low-level skills. Anybody can look on Craigslist and see that every single contractor is looking for electricians right now.

Obviously if you cannot find them here, the last ditch effort is to fly them in. Nobody wants to fly in electricians because they cost more, and you are paying not only a per diem rate, but also putting them up in hotels and paying for rental cars and all of the additional costs.

MR. WOOD: We used REC, which has one of the largest presences in the Hawaiian Islands, but it also has a large presence on the mainland. We ran an informal solicitation to look at both mainland and local companies. We had a high-profile client, Safeway, which has 19 solar facilities already in Hawaii and got into the game in 2007. One of our projects went over the delivery deadline, so it was great to have a company like REC that can expedite by pulling in reinforcements from other locations.

MS. LIM: The utility-scale developers work with both national and local companies. The lenders and tax equity investors usually want to see a large company that has done a number of projects so as to reduce the execution risk. The national companies will often hire local subcontractors to do a lot of the work.

MR. ROWLEY: An important distinction is that a utility-scale project on the islands is smaller than a utility-scale project on the mainland. For example, our 21-megawatt Auwahi wind project is a good sized project anywhere, but it is not really large enough to finance efficiently. We used our own internal capital to fund the project. Unless one has enough projects to aggregate, the threshold for where you can get project financing is not readily crossed here. Financing utility-scale projects in Hawaii is an issue because the projects are not large enough to finance efficiently.

Another factor that contributes to the small project size is that finding enough land in one place to do a large project is really not practical. In theory, if there were two or three smaller projects that were done around the same time and had similar attributes, then they might be aggregated and financed, but that is not a strategy that we are pursuing.

MS. LIM: It differs from developer to developer. A developer with a large balance sheet can afford to use its own capital. It will have a lower cost of capital than a smaller developer who might be backed by private equity or venture capital and whose cost of capital is high enough to make project financing a necessity. As long as you are developing a good project, you should be able to get it financed. Developing a good project means identifying the risks and addressing each. Risks do not have to be eliminated. If they can be quantified and mitigated, then the project should be possible to finance. You need to get your lenders or tax equity investors comfortable that you are aware of what might happen and that you have a plan in place to address issues that come up during development, during construction or during operations.

MR. ROWLEY: What I was talking about is not whether the project is financeable, because I agree that the financeability of a project is all about the quality of the project, and that is not really a function so much of size. What I was talking about was efficient financing for a project because there is a transaction cost of financing that is substantial. The larger the project, the more efficiently it can be financed.

MR. KUCHARSKI: There is also the issue of having confidence the project can be completed on the time schedule and within the budget that you agreed with the financier.

MS. LIM: That is particularly important with the deadline to have started construction of wind farms and some other projects this year to qualify for tax credits, and solar facilities need to be in operation by December 2016 to qualify. You might want a contractor who is large enough to be able to pay damages if the deadline is missed.

MS. STRAND: Do technologies that are considered proven on the mainland have to prove themselves separately in Hawaii before they can be financed?

MR. KUCHARSKI: Not usually, but there are some special technologies in Hawaii that still have a way to go before they are fully financeable. An example is ocean thermal energy conversion or OTEC. I think OTEC is a great technology. It has been proven on a pilot scale, but still needs to be proven on a large scale.

Small Loads

MS. STRAND: The state is talking about an undersea cable to link the islands. How important is the cable to meeting the 40% renewable energy target?

MR. KUCHARSKI: Having 500 megawatts of new power on various islands is not going to help anyone / *continued page 32*

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is calculated separately from the regular income tax, and, if the calculated flat tax is higher than the regular income tax, then the difference between the two is added to the regular income tax to determine the taxpayer's total tax due. The difference is taxed at a rate of 17.5%.

A special 100% depreciation rate for equipment used to generate electricity from renewable resources would also be eliminated.

A CALIFORNIA PROPERTY TAX VALUATION of a power plant has come under scrutiny.

The California Supreme Court said in August that the State Board of Equalization erred in how it valued a 550-megawatt cogeneration facility for property tax purposes.

The board used two methods to arrive at the fair market value of the power plant.

One was replacement cost. It assumed that anyone building a similar power plant today would have to buy emission reduction credits or ERCs to cover the air emissions. Therefore, it included the cost of ERCs in the calculation of what would have to be spent to reproduce the plant since the plant cannot operate by law without them.

It also used the income method to arrive at value. In that case, it deducted the cost of ERCs from the future revenue the plant is expected to earn before converting the future revenue stream into a present value.

The state tax code allows property tax assessors to "assum[e] the presence of intangible assets or rights necessary to put the taxable property to beneficial or productive use," but it does not allow direct taxation of intangibles. The prohibition against direct taxation dates to 1933.

The Elk Hills power plant is in Kern County near Tupman, California. The San Joaquin Valley Unified Air Pollution Control District requires any new pollution sources to buy emission reduction credits from existing sources to cover their emissions. Owners of existing power plants can free up ERCs for sale by reducing their own emissions. / *continued page 33*

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if it cannot be exported to Oahu. Eighty five percent of the population is on Oahu. If you cannot export power from other islands to Oahu, then it will be very difficult to reach the 40% renewable energy target.

Even more fundamentally, say 9,000 people are on an island. The power needs to be generated where it can be most inexpensively produced and exported to where there is a load so that you can get to base-load levels, even if it is a variable power source. The only way to reach scale is to have interconnections among the islands.

MR. BRADLEY: There are only 1,200 megawatts of load on Oahu, 200 megawatts on Maui, roughly 200 megawatts on the big island of Hawaii and just a few megawatts on each of the other islands. Two hundred megawatts is not insubstantial. There is a substantial grid on Maui. There is a substantial grid on the big island, and likewise on Oahu. Obviously, the bigger the grid, the more easily some of the issues that we have talked about can be managed. When you have a larger aggregation of load and a larger selection of generating resources, the bigger the pot that you mix together and the more effectively it can be done. So the question is at what point does it make sense to integrate islands in order to achieve scale? What we are seeing is a very thoughtful approach in that direction.

MS. STRAND: Is it both an issue of integrating between islands and also upgrading the existing grids on individual islands?

MR. BRADLEY: As long as the islands operate independently, then it is just that island and what degree of energy storage needs to be incorporated in order to deal with the intermittency of new wind and solar. The same issues still exist with a larger interconnected grid, but things tend to smooth out when you put more pieces together.

MS. STRAND: Will all future utility-scale solar and wind projects have to incorporate storage?

MR. ROWLEY: No, but I think it makes sense for the first projects. This is a very different world from just a few years ago where utilities had complete control over generation and could readily match generation and load for each moment of the day.

In these initial projects, it makes sense for the generation resource to bring along energy storage as a form of shock absorber. As the grid operators become more experienced with intermittent generation, then I think that we will see a transition toward the grid operator looking at it from an aggregated perspective rather than looking at individual generators. The needs for ancillary services and storage are less in the aggregate than when you look at a single project. As the utilities gain more experience, they will want to place ancillary service sources and energy storage in places that most advantage the grid from an aggregate perspective.

One of the more thoughtful approaches we see as Hawaii gains experience is a strong emphasis on economics. It is one thing to have a certain percentage of renewable energy, but it is quite another to say let's meet that objective but at a cost that makes sense. One of the benchmarks on which Hawaii is focused is to have our renewable energy be cheaper than displaced oil. Putting storage where it is most economic to place storage, rather than in smaller units at each project site, would aid in meeting that objective on economics.

Retail electricity prices are higher in Hawaii, in part because it takes longer and is more expensive to develop projects than on the mainland.

MS. LIM: I agree with Joe Rowley, but how do you see the widespread adoption of residential rooftop solar affecting decisions about storage?

MR. BRADLEY: If we are going to stick with the battery concept, it would be nice if the utility could collect the cost from ratepayers, but right now it looks like the developer is going to have to pay for the storage on a project-by-project basis. Turning to distributed generation, I see a big market for storage because we have a 100-kilowatt cap for net metering, and we have a bunch of commercial businesses that do not have a seven-day-a-week load. There is potentially a healthy market for batteries essentially to take a net metering project and overstuff it with capacity, with more modules, and then use the batteries to shift electricity into the evening hours.

We are involved in only one big utility-scale project currently with Kauai Island Utility Cooperative. It is 12 megawatts. The utility decided the project needs six megawatts worth of batteries, and it will pay for them. So in its mind, it is using a two-to-one ratio of PV to batteries. That is pretty conservative, but it wants to ensure that it can maintain grid stability and it is willing to pay whatever six megawatts worth of batteries costs for grid stability.

MR. WOOD: The economies of scale change dramatically when you go from 50 kilowatts to 100 kilowatts to five megawatts to 20 megawatts. Energy storage should be a tool for the grid to identify. The utility should identify weak places in the grid and strengthen them through ancillary services. As market penetration of distributed generation increases, there will have to be that support system even though the grid may need to be upgraded itself. It will probably end up with some form of band-aid, especially if there is rapid growth in distributed generation.

Distributed Solar

MS. STRAND: Drew Bradley, you mentioned the temporary rules the Department of Taxation issued for the state tax credit for distributed solar. Have they had a chilling effect on new distributed solar development, and do you think the state legislature will have more to say on this subject in the upcoming session?

MR. BRADLEY: I sure hope so. They do not affect distributed generation projects that cost less than $1.43 million. If you were working on projects that were bigger than that, back in the day, you would just throw more inverters at it and treat the project as multiple systems, each of which qualifies for up to a $500,000 tax credit.

Let's say you do not have any state tax liability and you are taking the 24.5% refundable tax credit and, all of a sudden, you move from a $1.43 million system up to a 1-megawatt system at $3 million. Your state tax credit as a percentage of the project cost went from 24.5% down to about 10%. You lost 14 points with that one, with the Department of Taxation essentially creating law rather than interpreting it. That's what happened on the bigger systems, so it made it much harder to get bigger projects to pencil out. It definitely chilled the market.

MS. STRAND: Did you see an effect on residential projects?

MR. BRADLEY: Just from 300 kilowatts up to one megawatt. The closer you get up to one megawatt, the lower your return because you are getting a smaller and smaller state tax credit as a percentage of project cost. Every year / continued page 32

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The Elk Hills plant uses natural gas to produce electricity and steam for oil recovery at an Occidental Petroleum Corporation field.

The owners sued for recovery of excess property taxes paid during the period 2004 through 2008.

The state Supreme Court said the board should not have added the cost of the emissions credits to the replacement cost, since that is impermissible direct taxation of the credits, but it said the board acted properly when it subtracted the cost of credits from the revenue stream from electricity sales to arrive at the net revenue that could be earned by the power plant since that revenue cannot be earned without the credits. It said in one case, the board improperly increased the property value by the credits, while in the other case, it merely "assumed the presence" of the credits.

The case is *Elk Hills Power, LLC v. Board of Equalization*. The court released its decision on August 12.

Although the court declined to remove the ERCs from the income stream in this case, it said it would have removed them if they were the type of intangibles that add directly to the revenue stream. Thus, production tax credits and renewable energy credits, or RECs, to which a project is entitled should not be added to project value under either appraisal method.

ARGENTINA changed its tax laws effective September 23.

A new 10% tax will apply to dividends paid by Argentine companies, with one exception. The tax will not be collected on dividends paid by one Argentine company to another.

Capital gains from sales of depreciable movable assets and shares, participations, bonds and other securities will be taxed. Such gains had been exempted from taxes for the last 20 years. Individuals will be taxed at a 15% rate on net gains. Foreign legal entities will be subject to a withholding tax on sales / continued page 35

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the residential market is uncertain what will happen at the turn of the calendar on January 1. That actually helps the residential solar companies because potential customers never know what they will receive the following year. Therefore, there is an incentive to act now.

The uncertainty is less helpful to commercial solar developers. They are usually trying to do a two- or three-year project, and they cannot see what the incentives will be even the following year.

MS. STRAND: To what extent are the larger commercial projects driven by the tax credit, whether state or federal?

MR. BRADLEY: As long as we have a 30% federal tax credit and something in the neighborhood of a 20% or 25% refundable state credit, then that works. The projects here are very attractive. Financiers from the mainland call us constantly looking for projects to finance.

Other Opportunities

MS. STRAND: What technologies do you believe Hawaii will have to tap to reach the 40% renewable energy target? We touched on OTEC, which is still in development phase. What else?

MR. KUCHARSKI: Biofuels. Hawaii has three crops a year, and some reasonably clean fuels can be produced to compete with refined petroleum. That is a growth area. The majority of imported fuel in Hawaii is going for transportation, not for utilities. Every plane that lands in Hawaii refuels and that fuel has to come from somewhere.

MS. STRAND: Are there any other technologies that appear promising?

MR. BRADLEY: You will not see wind farms built after this year if they have not qualified for federal tax credits by starting construction this year. Your bread-and-butter developments will more than likely come from distributed solar. Hawaii has major land use issues for greenfield development. Solar is well suited for brownfield-style development or even development in parking lots or on other land that can be put to dual use.

MR. WOOD: You can achieve scale in areas that are already developed. That is the ace up the sleeve on solar in my opinion.

MS. LIM: Offshore wind has many advantages, but one of the biggest challenges is the technology. It is hard to get banks to finance new technology, even if the technology has been proven in another country.

MS. STRAND: How about some parting advice? We all learn from our mistakes and by doing.

MR. ROWLEY: Have a long view.

MR. KUCHARSKI: My advice is similar. Don't think in months.

MR. WOOD: My advice is for mainland developers who may be thinking of entering this market. If you have been active in the renewables sector and bidding into utility solicitations, particularly in California, you have seen how aggressively people have been bidding. In Hawaii, things will cost more than you think. You don't know where your cost overruns are going to come from, but there will be cost overruns. Don't be short-sighted and try to undersell your first deal and not deliver on it. Hawaii is a small community. Your reputation will get around pretty quickly. Sell the projects that you know you can do. Make sure that those projects are high-quality projects. Don't rush in here and try to underbid because the strategy will backfire.

MS. LIM: Make sure that you are familiar with the local and state regulatory regimes. They can be a source of surprises and contribute to cost overruns.

MR. BRADLEY: Get beyond the initial upfront cost when shopping for a construction contractor. Look more at life-cycle costs and make sure that when you save a dime, it doesn't cost you a dollar. Look at a company's track record. Investigate what it has built. Actually look at it. Make sure the company has an O&M group that can take care of the project after it is built. Take that reference list and call every last customer. Find out what references are not on the reference sheet, find out why, then contact those companies, and dig a little bit deeper so that you're not bending over to pick up a dime and really missing sight of the fact that it's a 25- to 30-year project. ◎

Bridge PPAs

The California utilities are putting out requests for proposals, but they do not need the electricity until 2019 or 2020 and are asking for power purchase agreements of only 10 years. Solar, wind, geothermal and biomass projects must be in service well before then to qualify for large federal tax credits. For example, solar projects must be in service by December 2016 to qualify for a 30% investment tax credit. Is there a way to bridge the gap so that a project has enough revenue, while waiting to start sales *under the power purchase agreement, to be financed?*

A panel talked about various ideas at the Infocast utility-scale solar summit in San Diego in late September. The panelists are William Cannon, vice president of Sumitomo Corporation of America, an equity investor in projects, Arleen Spangler, a principal at The Carlyle Group, a project lender, and Arlin Travis, an independent consultant with 25 years of experience in electricity trading. The moderator is Keith Martin with Chadbourne in Washington.

MR. MARTIN: We need to have a project operating in 2016, but the utility is not ready to take the output until 2019 or 2020. Arlin Travis, you said there is a solution to this problem of how to earn some revenue in the meantime to allow the project to be financed. It is a financial hedge. It does not exist yet. Describe what the market needs to do.

Hedged Spot Sales

MR. TRAVIS: We need to think about 2014. Are there deals we can close in 2014 for a start of 2015? If we can do a 2015 start, then we can clearly do a 2016 start.

You have to connect to an ISO so that the project is in a position to sell into the day-ahead market, and then you have something that we can write a swap against. When we were writing swaps for wind farms, we were writing them on a P90 or a P95 output case. What that meant was that if we had a 90% or 95% probability that the wind farm would produce this amount or more of energy in a given month, then we could write a swap against it, and those swaps got financed. You need a liquid market for the electricity before you can write a swap.

You could write a swap today against the California ISO. It trades two years forward, which means you could probably do a stack and roll to get yourself a four-year energy hedge. Is it going to be brilliant? Are you going to love the amount of money you make? No. But it is something that will be part of your financing package along with monetizing the tax credit.

MR. MARTIN: So the key is to make spot sales. Someone will write a swap to bet on what the minimum price will be in the spot market. You think that a two-year swap is the farthest the market will go in California, but you can get to four years by doing stack and roll. What is a stack and roll?

MR. TRAVIS: A stack means that I take the amount of energy that the project is expected to generate over four years, and I hedge the front two because that is the tradable portion of the curve. Then I keep rolling my hedge */ continued page 36*

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at a 13.5% rate on the gross sales price. It is unclear whether foreigners can choose to be taxed on a net basis instead. In cases where both the buyer and seller are foreigners, the buyer must withhold the tax from the sales proceeds and pay the Argentine authorities.

WASHINGTON STATE increased a tax credit for harvesting forest biomass for use as fuel to produce electricity or steam or as a feedstock for making biofuels. The tax credit was $3 per harvested green ton. The state said in a notice on August 20 that the credit has increased as of July 1 to $5 a ton. The credit is claimed by the timber company or other person harvesting the biomass.

The state said in the same notice that a sales tax exemption on sales of "hog fuel" — bark, wood chips and similar debris left over from making lumber or paper — for use in making electricity, steam or biofuel has been extended through June 2024. The sales tax exemption has a clawback provision that requires the seller to look back two years and pay any sales taxes that were waived during that period if the taxpayer shuts down a facility in the state with a loss of jobs.

The tax changes can be found in a bill that the state legislature passed, ESSB 5882.

MINOR MEMOS: Revenue collected by IRS agents declined 9% in fiscal year 2012. A Treasury inspector general report in September attributed the decline to a 14% drop in the number of IRS agents. The IRS has had to cut 8,000 full-time positions since fiscal year 2010, with 5,000 of them specifically from enforcement of the tax laws . . . . The fact that a parent company or partner guarantees payment of rent, debt or other obligations can produce favorable tax consequences. The IRS is expected to require in regulations this fall that a partner who guarantees partnership debts or other obligations must show it has an adequate net worth to make good on a guarantee before the agency will treat the guarantee as real.

— contributed by Keith Martin and Amanda Forsythe in Washington

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forward under the theory that the third year is going to trade in relation to the second year, and the fourth year will trade in relation to the third year.

MR. MARTIN: But the price that the hedge or swap sets is effectively reset after the two-year period, correct?

MR. TRAVIS: I don't think you have to do that. When we were writing wind hedges on California projects, we did not require the wind farm owner to be exposed to that price risk.

We need some new entities in the marketplace to step forward and start writing these types of contracts. The risk exposure is part of the reason why these institutions do not exist today. The banks are in flux right now. The Federal Reserve Board is considering to what extent bank holding companies can trade commodities. The banks have their heads pulled in like turtles, and are waiting for things to clear up.

MR. CANNON: I agree that the only realistic way to go forward would be to enter into a hedge with a financial institution or some other entity that is willing to provide such a hedge. I am bullish in believing you could probably get a four-year hedge. The concern that an owner or developer will have is that the hedge will be an energy-only hedge. You will not be able to hedge your capacity or renewable energy credits, which are material parts of the revenue stream for the project.

The reason why the utilities are signing power purchase agreements to buy solar electricity at above-market prices is they need the renewable energy credits to meet renewable portfolio standards.

Gap

MR. MARTIN: So the project will earn what it can from spot sales during the four-year interim period. What are current spot prices in California?

MR. CANNON: They are $42 to $44 a megawatt hour.

MR. MARTIN: What electricity price will the winning bidders bid to win these RFPs? At what minimum price will solar developers have to bid to have an economic project?

MR. CANNON: It is easier to say what has won before. It is a price in the mid-$70-a-MWh range. That leaves a significant gap. How do you start off at around $40 for four years increasing to $70 for the next ten years, and how do you shape the repayment schedule on the project debt? Perhaps a lender could do it, but it has not been done yet, and the first one will be challenging to do.

MS. SPANGLER: You can view it as an opportunity for the marketplace. I think what we really need is the development of an unbundled REC market. That unbundled REC needs to trade at such a value that it makes it competitive for a solar project to build before having a long-term PPA. Right now, RECs are trading at around $1 to $2 a MWh in California. We will need something more like $30 a MWh, and there is no unbundled REC market today that supports that.

MR. MARTIN: So we need a policy change at the California state level, and we need the Federal Reserve Board to allow banks to continue serving as counterparties on electricity price hedges. Are there short-term PPAs available in this market?

MS. SPANGLER: There may be some municipal utilities or electric cooperatives that are looking for short-term PPAs to bridge some of the gaps they have in meeting their compliance targets under the state renewable portfolio standard. Industrial customers are another possibility, although the project would have to be on the industrial site to avoid violating a bar in California against retail sales. It is an opportunity for the solar industry to try to find those outlets and, as a financier, we will be there to help you. We are flexible enough to look at all sorts of structures and counterparties.

MR. MARTIN: Bill Cannon suggested that a developer would need a repayment schedule that probably requires payment of

California developers who win PPAs to supply renewable electricity starting in 2019 or 2020 will need "bridge" revenue from 2016 to qualify for federal tax credits.

interest only, and maybe a little bit of principal, for four years and then starts to repay principal. Does that work for a lender like Carlyle?

MS. SPANGLER: Yes. We need some current return, but we would be able to push some of the return to the back end. As a private equity fund, we do not want a long-term financing. We want to be out in five to seven years, so the loan would have to be structured so that it can be refinanced in the bank or bond market at a lower cost of capital. We would be a source of bridge debt whose loan would be taken out in the bank market or capital markets later.

Other Ideas

MR. MARTIN: What about using PURPA, the Public Utility Regulatory Policies Act, which requires utilities to buy electricity from solar projects that are less than 20 megawatts in size. Has anyone tried this?

MR. CANNON: We have seen developers try a PURPA put on wind projects in Texas. I have not seen that approach used in California. The typical commercial bank will not touch that type of structure because there is no guaranteed level of revenue for the first four years. You would have to go to a Carlyle to work with it, but you will have refinancing risk in as soon as five years.

MR. MARTIN: Under PURPA, you are only assured of the avoided cost to the utility, which is probably around the spot price, so you have not really advanced the ball. Is it possible that another developer might have spare capacity under an existing power contract that could be used by another project? Have you ever seen that work?

MR. TRAVIS: Municipal utilities, electric cooperatives and direct access providers all contract on a short-term basis. Those are your primary targets. The hedge is a way to lock in a floor price. If you can combine a hedge with selling to a muni, a coop or a direct access provider at a floating price and some premium for the RECs, then you will have a premium product.

Another strategy is to store the RECs and sell them in the future. This will not help bridge the four-year revenue gap at the front end, but it might enhance the potential revenue from the project once electricity sales start under the power purchase agreement.

Bucket-one RECs from projects that are connected to the CAISO and tied to power contracts of at least 10 years can be pushed into the future. As the law is set up today, a utility buying renewable electricity can claim only 50% of the electricity from a bucket-one project as a renewable energy credit against its state RPS target, but in the future, the percentage will drop to 25%. Over time, the utility will need to buy more and more actual RECs. This suggests that the price of RECs will increase over time. So pushing a bucket-one REC into the future is probably a good strategy.

MR. MARTIN: “Bucket one” is a state regulatory classification. Does it mean the power plant generating the electricity is inside California?

MR. TRAVIS: It refers to generating facilities that are connected to the CAISO grid. A facility does not have to be in-state, but it has to be connected to the CAISO.

MR. MARTIN: Arleen Spangler, I assume the tax benefits are valuable enough that it is worthwhile to try to finish a project by 2016. When you include accelerated depreciation as well as tax credits, they amount to at least 56% of the project cost. What about having the project owners who take the tax benefits make ongoing capital contributions to the project company for a large fraction of the value? That would provide additional cash with which to pay debt service in the short term.

MS. SPANGLER: The tax benefits are very important for the project. It behooves the developer to put the plant in service as soon as possible to get the tax benefits.

MR. CANNON: We own a fairly large solar project that comes on line over a two-year period. We are selling to the utility today even though the full project will not be on line until 2015. The utility is not paying full price for the electricity it takes today, but it is taking the power and its obligation to do so is contractually driven so that makes the lenders happy. Perhaps the way to go is to get a clear right in the contract to sell test energy at a reduced price until the contract kicks in.

MR. MARTIN: Four years of test energy sounds like a long time, but it is a good thought. You would need to compare the price that could be earned in the spot market after taking into account the cost of a hedge. You would still need a hedge unless the test energy price is fixed.

MR. TRAVIS: You are producing zero carbon energy. There is a value to that, and it is at least $5 a MWh. So you tell the utility that I am not just giving you energy, I am giving you zero carbon energy. It may not be a $30-a-MWh REC, but it is more than the $1 a MWh that is being paid for RECs in the market now.

MR. MARTIN: Are there counterparties for financial swaps besides banks?

MR. TRAVIS: Absolutely. Twin Eagle, EDF and Shell will all write a swap. BTG Pactual, a new Brazilian bank, is gearing up to write swaps and do financings for these / *continued page 38*

Bridge PPAs

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kinds of projects. There are new people moving into the space that is being vacated by the American banks.

Financeability of Merchant Projects

MR. MARTIN: Can merchant power projects in California be financed?

MS. SPANGLER: Yes, we definitely have appetite for merchant projects, but the financing structure will be project specific. Merchant projects can be financed in parts of the country where there is a deep liquid market for the offtake and where it is possible to get a long enough term hedge to set a floor under the electricity price for the debt term. California lacks the REC market that you would need for solar. In other markets, particularly in the northeast where RECs are a lot more expensive, you may be able eventually to finance something on a merchant basis. Texas is a market where merchant financing is possible today. A few gas—fired power plants have been financed on a merchant basis. They have hedges at the front end to give more predictability to the cash flows.

MR. MARTIN: ERCOT and PJM are the two markets where gas-fired power projects and some wind farms are being financed on a merchant basis. Is there something different about utility-scale solar that makes it tougher to finance that way?

MS. SPANGLER: The difference is that the markets in which they happen to be dominant do not have the same liquidity. There is no capacity market. There are some must-run contracts in California, but they are not very common.

MR. MARTIN: California is tough, but what if you have a large utility-scale solar project in Texas? Is it possible to finance a solar project on a merchant basis in Texas?

MS. SPANGLER: We would be willing to take that type of merchant risk, but we would not take 100% merchant risk; there should be a hedge. You have ultimately to get to the load. Is the load willing? The market is more deregulated in Texas than anywhere, so there are lots of retail players.

We would prefer a hedge for some period of time. In the projects in which we have invested, there is a hedge for a time after which the project is purely merchant. We are taking risk that the hedge can be replaced in time, but looking at market prices for electricity in the out years. If there is a liquid market, then we assume the hedge can be replaced.

MR. MARTIN: Bill Cannon, many people are skeptical about the ability to finance a utility-scale solar project on a merchant basis. Gas seems to work a lot better, wind maybe. What do you think?

MR. CANNON: ERCOT is obviously the easiest example to give because it is a liquid market and there are so many hedge providers. Gas is on the margin there, so you can easily do a merchant gas project and get it financed or have a hedge in place. Wind has reached grid parity in parts of Texas. With production tax credits of $23 a MWh, a project is close to grid parity in Texas if it is in an area with strong wind and can operate at capacity levels in the 40% to the lower 50% range. Such projects can be financed with just a hedge.

Solar is still materially more expensive than wind and gas. Solar qualifies for investment tax credits, but there is not enough juice between the tax credit and spot electricity prices for the developer to make the fair return.

MR. MARTIN: So banks don't like to finance an uneconomic project.

MR. CANNON: The equity tranche would be left with negative yields.

MR. MARTIN: If you put on a hedge or swap, some of the electricity revenue will have to be used to pay for it. What does a hedge or swap cost? If the project is earning $44 a MWh, how much would go to the price protection?

MR. TRAVIS: Ten percent.

MR. MARTIN: The utilities in California are offering 10-year power contracts so you not only have a problem at the front end, but you also have one potentially at the back end. The project has a long merchant tail. Arleen Spangler, you are lending for five to seven years. Do you worry about take-out risk?

MS. SPANGLER: Yes. We need to be taken out after five to seven years. Merchant risk at the back end could make a takeout harder to arrange. On the one hand, tail merchant risk is somewhat easier to address because the project will have operated for a number of years by then. On the other hand, you will have an older project competing with newer technologies, so there is obsolescence risk to take into account. That is a key risk for solar. The panels keep getting better and better.

MR. TRAVIS: Let me make some observations about the ability to hedge in different markets. PJM was liquid and the deepest electricity market, and it was a bank-driven market where the banks were in their comfort zones. ERCOT is very much an energy-company-driven market. California is a regulatory-driven market, and you have had people simply vacate

California and not trade.

What we see happening now is that the liquidity is declining in PJM. Liquidity is increasing in ERCOT because the energy companies are trading, not the banks. California is a volatile market today. The San Onofre nuclear generating station is being permanently shut. A carbon cap-and-trade system is being implemented. In 2016, the transportation sector will be invited into the carbon market. All of this is stirring the pot. Wherever there is volatility, you will find traders. We are seeing liquidity coming back into California as a result. That makes me think that you can get your projects financed in 2016.

MR. MARTIN: You see an opportunity for traders to profit. Is that also an opportunity for developers to get financing?

MR. TRAVIS: As we bring more players into the market, that is where these guys are going to have their opportunity to get financing. ◎

Chinese Solar: On The Upswing?

by Edwin Lee, in Beijing

The poet Percy Bysshe Shelley wrote in *Ode to the West Wind*, "If winter comes, can spring be far behind?" This is a good description of the current solar photovoltaic industry in China. The Chinese PV industry has suffered two long years of winter, and now the government is working overtime to make the spring winds blow in order to spare the PV industry from being frozen to death.

The China National Development and Reform Commission (NDRC) issued two notices at the end of August on "Using Price Leverage to Promote Healthy Development of the PV Industry" — called the PV notice — and on "Matters Related to Surcharges on Prices for Renewable Energy and Energy Generated by Environment-Friendly Coal-Fired Power Plants" — called the surcharge notice. The notices implement policy decisions taken earlier by the State Council, which is eager to promote solar energy.

On-Grid Prices for Solar

Investors looking for solar opportunities in China should keep in mind that there is differential pricing for solar electricity based on the project location. The PV notice establishes three categories of benchmark on-grid prices for solar power. These are prices that state-owned utilities will pay for electricity from solar power generators.

The benchmark on-grid price for category I is RMB 0.90 and covers areas like Ningxia, Haixi in Qinghai province, Jiayuguan, Dunhuang, Jiuquan in Gansu province and some cities in Xinjiang and Inner Mongolia (mostly in the northwest of China). It is RMB 0.95 for category II, which covers areas such as Beijing, Tianjin, Helongjiang, Liaoning, Jilin, Sichuan, Hebei and the areas in Qinghai, Gansu and Xinjiang excluded by category I (mostly in the northeast, southwest and northern China). It is RMB 1.00 for category III, which covers areas not covered by categories I and II. The benchmark on-grid price for solar power in Tibet, where insolation is the highest in China, will be decided separately. Currently, the on-grid price of coal-fired power is from RMB 0.40 to 0.50.

Solar power suppliers are able to sell at a profit at the benchmark prices since modules are cheap due to overcapacity among solar panel manufacturers and technological advances. The difference between the benchmark on-grid price for solar power and coal-fired power is paid by the National Renewable Energy Development Fund (NREDF).

Generally speaking, the benchmark on-grid prices are 20% more than what the industry expected and will help beleaguered solar panel manufacturers by creating additional demand for solar panels. The condition of major manufacturers should be improved by around 80% if all the provisions in the PV notice are implemented as planned. On the other hand, this may attract more investment in the manufacturing sector.

The actual prices may be lower than the benchmarks in the PV notice. The actual electricity price is set through public tender. The winning bidder's price should not exceed the benchmark prices in the PV notice; it can be lower.

Distributed Solar

The draft PV notice set a benchmark grant — as opposed to electricity price — of RMB 0.35 for distributed solar. The grant in the final PV notice is RMB 0.42 per kilowatt hour and is much more than was expected. Any shortfall between the grant amount and the market price will be paid by the NREDF through the grid companies. The grid companies enjoy a monopoly position at the intersection with the grid. It is not clear how the regulators will supervise the payment function.

The distributed PV market in China is becoming hot. The on-grid price for electricity for systems / *continued page 40*

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connected to the grid will be the same as the benchmark price of coal-fired power, which is around RMB 0.50. Therefore, the total revenue to the owner of a distributed solar facility that is connected to the grid will be slightly less than RMB 1.00 per kilowatt hour, or a grant of RMB 0.42 and a payment for electricity of RMB 0.50. Furthermore, the government has lifted the need for approval for construction of residential PV systems. Some companies and even individuals are eager to break into this market as installers of residential solar systems. Foreign companies with experience and technology in these services will have a huge opportunity in the local market.

However, the grid company still needs to do a survey and connection plan before installation commences. It has to confirm that the building can bear the system and assess the impact on the surrounding environment and neighbours. This could be time-consuming.

The period of return on investment will be cut in half from 15 to 20 years to seven to nine years. Foreign solar companies interested in the distributed PV market should assume it will take around seven years to get all the investment back for a four-kilowatt distributed PV system based on the current on-grid price and grant. The system's life will be around 25 years. This sector is becoming more attractive.

Who Qualifies?

Solar PV projects qualify for the benchmark on-grid prices in PV Notice in two situations.

An application for the project must have been filed or approved after September 1, 2013. Alternatively, the project must commence operation on and after January 1, 2014.

Interestingly, investors who obtained approval years ago for projects whose construction or operation was delayed will also benefit from the prices in the PV notice. This is probably not fair for those who struggled to complete construction in time, even though their projects may be operating at a loss.

The PV notice requires the grid company to pay the on-grid price on the project output as measured by the grid company.

The grant for distributed solar is only available to projects that do not enjoy other government grants, such as the Golden Sun and BIPV grants.

The benchmark price for PV power and grant to distributed PV will last in principle for 20 years beginning from when a project starts operation. However, the government reserves the right to decrease the price and grants based on the development volume and cost.

Due to overcapacity and the high growth rate in the PV sector in China, it would not be surprising if the prices and grant are reduced in the near future.

Electricity Surcharge

The government collects a surcharge on all retail electricity sales. The surcharge notice in August increased the rate to RMB 0.015 per kilowatt hour, 87.5% more than the past rate. The central government will not be able to afford the grants to owners of distributed solar facilities without such additional funding. The surcharge was only RMB 0.008 per kilowatt hour before the surcharge notice. Based on the old rate, the government collected around RMB 20 billion each year. By the end of 2011, the gap between what the government was collecting and grants owed to renewable energy projects was RMB 10.7 billion. That's why grants are always being paid in arrears. The average delay is around two years.

If the surcharge rate had not increased, then it was estimated that the gap would have widened to RMB 33 billon by 2015. The total power generation output in 2015 will reach 6.4 trillion kilowatt hours. The total collected surcharges at the new rate will range from RMB 80 billion to RMB 100 billion, which should be sufficient to support the development of PV sector in China.

China is changing its approach to incentives to the PV sector from the upstream to mid-downstream. For large-scale projects, the on-grid benchmark price will be paid by the grid company to the generator directly. For distributed solar facilities, the grant will be given to the homeowner who has the facility in his yard. The government is expected to use this American-style approach to foster a healthy upstream manufacturing market. The spring in 2014 should be much warmer for both local and foreign solar companies. ◎

Environmental Update

September was a tough month for developers of new coal-fired power plants. China announced that it was banning new coal-fired power plants in three regions around Beijing, Shanghai and Guangdong to help reduce air pollution and, here in the United States, the US Environmental Protection Agency proposed a new rule that would limit carbon dioxide or CO_2 emissions from new fossil fuel-fired power plants.

EPA proposed a similar rule setting CO_2 emissions limits in 2012, but reconsidered it, in part because of more than 2.5 million comments. The 2012 proposed rule would have set a limit of 1,000 pounds of CO_2 per megawatt hour emitted from new fossil-fueled power plants. EPA formally rescinded the 2012 proposal last month concurrently with its issuance of the new proposal.

EPA's new proposal applies to new affected fossil fuel-fired electric utility steam generating units (utility boilers and integrated gasification combined-cycle or IGCC units) and natural gas-fired stationary combustion turbines.

The proposal does not apply to the following fossil fuel-fired electric utility steam generating units under development that are either capable of commencing construction soon or whose developers have represented that construction is already underway: Wolverine (Michigan), Washington County (Georgia) and Holcomb (Kansas). In addition, EPA's proposal does not apply to units undergoing modifications or to reconstructed units.

Subject to these exceptions, the proposal applies to the following electric utility steam generating units and stationary combustion turbines that commence construction after the date of the publication of the proposed rule in the Federal Register.

It applies to electric utility steam generating units that burn fossil fuel for more than 10% of the heat input during any three consecutive calendar years and supply more than a third of their potential electricity output and more than 219,000 MWhs net-electric output to a utility power distribution system for sale on an annual basis.

The proposal affects stationary combustion turbines with a design heat input to the turbine engine greater than 73 megawatts (250 MMBtu/h) that burn fossil fuel for more than 10% of the heat input during any three consecutive calendar years, burn over 90% natural gas on a heat input basis on a three-year rolling average basis and were built for the purpose of supplying, and supply, a third or more of their potential electricity output and more than 219,000 MWhs net-electrical output to a utility distribution system on a three-year rolling average basis.

These sources of CO_2 emissions would be required to comply with the following limits:

Coal-fired utility boilers & IGCC units	• 1,100 pounds of CO_2 per MWh of gross energy output measured over a 12-operating-month rolling average or • 1,000 to 1,050 pounds of CO_2 per MWh gross energy output measured over a 84-operating-month rolling average
Natural gas-fired stationary combustion turbines	• 1,000 pounds of CO_2 per MWh gross energy output for larger units (> 850 mmBtu/hr) measured on 12-operating-month rolling average • 1,100 pounds of CO_2 per MWh gross energy output for smaller units (≤ 850 mmBtu/hr) measured on 12-operating-month rolling average

To help put these emissions rates into context, EPA cited government estimates that a new subcritical pulverized coal unit firing bituminous coal would emit CO_2 at a rate of about 1,800 pounds per MWh and a new IGCC unit would emit at a rate of about 1,450 pounds of CO_2 per MWh. A new natural gas-fired combined-cycle unit emits CO_2 at a rate of about 800 pounds of CO_2 per MWh.

Unlike the 2012 proposal, EPA's current proposal does not contain any specific exemptions for natural gas-fired simple-cycle units. Simple-cycle units are often used in peaking power plants because, unlike combined-cycle units, simple-cycle combustion turbines can more easily be ramped up and down. EPA acknowledged that some of these peaker units could be subject to the proposed rule, / continued page 42

but as a practical matter, most would not be since the majority of peaker projects, by their nature, do not generally sell more than one-third of their potential electric output to the grid.

Under the proposed rule, new coal-fired and IGCC power plants could meet the CO_2 limits by installing carbon capture and sequestration technology to prevent CO2 permanently from being released into the atmosphere. EPA proposes verifying that the captured CO_2 is actually sequestered by adding requirements to existing greenhouse gas reporting program rules.

The proposed rule allows for some flexibility by judging coal-fired utility boiler and IGCC compliance with the rule over a seven-year time period. Under this alternative compliance plan, new coal-fired power plants could be built and come on line without carbon capture and sequestration technology if a plant commits to an enforceable limit of 1,000 to 1,050 pounds of CO_2 per MWh gross averaged over a seven-year operating time frame.

EPA used its authority under Clean Air Act section 111 to issue the proposal. This section of the Clean Air Act requires that the EPA identify the best system of emissions reduction that has been "adequately demonstrated." Critics of the proposed rule argue that carbon capture and sequestration have not been adequately demonstrated. EPA acknowledges that there are no commercial coal-fired power plants currently operating with carbon capture and sequestration technology, and instead relied on power plants that are being constructed (notably Southern Company's Kemper facility in Mississippi that is designed to capture 65% of CO_2 emissions) or developed (like the FutureGen project in Illinois with technology designed to capture more than 90% of CO_2 emissions) to assert that this technology is "adequately demonstrated." This aspect of EPA's proposal will almost certainly be challenged in court.

The EPA does not expect a significant effect on coal-fired power plants since the low prices of natural gas have already pushed developers to favor natural gas over coal. Nevertheless, there will be significant opposition to the proposal, particularly since it is a prelude to regulating CO_2 emissions from existing power plants. EPA has been directed by President Obama to propose standards, regulations or guidelines, as appropriate, for existing and modified power plants by June 1, 2014. EPA said that the standards for existing projects that will be developed "are expected to be different from, and less stringent than, the standards" proposed for new power plants and suggested that it will not require existing power plants to install carbon capture and sequestration technology.

Comments to the EPA proposal are due 60 days after publication of the proposed rule in the *Federal Register*.

The US is expected to propose new limits on carbon dioxide emissions from existing power plants by June 2014.

All Appropriate Inquiry

The US Environmental Protection Agency is expected to withdraw a final rule issued in August that would have allowed the additional use of a new technical standard, ASTM E1527-13, as of November 13, 2013 to satisfy the requirement for performing "all appropriate inquiry" before purchasing real estate.

Briefly, prospective purchasers of commercial real estate are advised to perform appropriate inquiry into the current and past uses of a piece of property to qualify for certain defenses against liability under Superfund for environmental contamination that they did not cause or make worse.

"All appropriate inquiry" is typically performed by a qualified environmental consultant by conducting a phase I environmental site assessment pursuant to an EPA-accepted technical standard. A phase I environmental site assessment includes a physical inspection of the site and adjacent properties, interviews, and review of historical information and agency regulatory files and databases. Although a phase I environmental site assessment requires an inspection of the property, no invasive sampling is typically performed. The inspection serves to identify visual evidence of environmental contamination associated with the property and the potential risk for such contamination. Specifically, a phase I environmental site assessment provides a description of recognized environmental conditions and provides recommendations for further investigation, if warranted.

EPA proposed using a new standard (ASTM E1527-13) in addition to two previously-approved technical standards — ASTM E1527-05 and ASTM E2247-08. ASTM E1527-05 applies to commercial property and ASTM E2247-08 may be used on forest land or rural property.

The new standard revises the definition of recognized environmental conditions and requires more rigorous reviews by consultants conducting phase I environmental site assessments of agency records and an increased focus on vapor intrusion. Vapor intrusion occurs when vapors from volatile soil or groundwater pollutants migrate into indoor structures. Some suggest that the requirement to conduct more rigorous record reviews could add $400 or more to the current cost of performing a phase I environmental site assessment and potentially lengthen the time it takes to perform such an assessment.

Many believed that ASTM E1527-13 would simply replace ASTM E1527-05, but EPA proposed to allow the continued use of ASTM E1527-05. This led to concern that the new standard may not be uniformly adopted because of the increased cost and that continued use of the old standard could lead to confusion and litigation, particularly since it is possible that recognized environmental conditions identified under the new standard (ASTM E1527-13) may not be identified as such under the old standard (ASTM E1527-05).

EPA is expected to withdraw the proposal later this fall.

California Cap and Trade

In August, California sold 13,865,422 2013 vintage allowances for $12.22 a ton and 9,560,000 2016 vintage allowances for $11.10 a ton under the state's cap-and-trade program. Each allowance allows the holder to emit one metric ton of greenhouse gases.

This was the first time in the short history of the auctions that the settlement price for the 2016 vintage allowances was higher than the auction reserve price (the minimum price at which the state was prepared to sell) of $10.71. Interest in the 2016 vintage allowances more than doubled as compared to the May auction (total qualified bids divided by allowances of 0.79 for the May auction and 1.69 for the August auction).

The 2013 vintage allowances sold at a price higher than the auction reserve price, but below the $14-a-ton price in the May auction. The drop in price appears to be because California emissions are now projected to be lower than originally expected and remain below the state's cap through 2019.

Regulated utilities may also use emissions offsets to meet up to 8% of their compliance obligations each compliance period under the cap-and-trade program. Offset credits are created when projects reduce or remove greenhouse gas emissions and meet regulatory criteria set by the California Air Resources Board or CARB. Only CARB can issue offset credits for use in the cap-and-trade program. These credits represent verified reductions in greenhouse gases or removal enhancements from sources of greenhouse gas emissions that are not subject to a compliance obligation under the cap-and-trade program. The reductions must come from projects that were undertaken using a CARB-approved compliance offset protocol, issued by another jurisdiction whose credits California recognizes, or be sector-based offset credits issued by an approved sector-based crediting program. CARB has already approved four compliance offset protocols (US forest projects, urban forest projects, livestock projects and ozone-depleting substances) and is / continued page 44

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considering adding two more (rice cultivation and mine methane reduction).

CARB anticipates releasing about 600,000 offset allowances by the end of September. Currently, with the exception of offsets allowances issued pursuant to the forest compliance offset protocol, the buyer of the offset allowances issued pursuant to the other approved protocols bears the risk that CARB could invalidate the offset allowances if they were determined to be faulty or fraudulent. CARB has proposed to shift the risk of forest offset allowances to the buyer as well. Thus far, the market has adjusted to this risk by offering offset allowances that come with seller guarantees to replace the offsets should they be invalidated (these are also referred to as golden offsets) and insurance policies that specifically cover this risk.

— contributed by Sue Cowell in Washington

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