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PROJECT FINANCE

NewsWire

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The Risks of Rushing into Iran

by Ramsey Jurdi, in Dubai

The risks of rushing into investing in Iran, for Americans and non-Americans alike, are significant and underreported.

You would be hard-pressed to read any major publication today without encountering at least one story about the rush to Iran, the incomparable opportunities, or the welcoming arms of the Iranian government. The nuclear agreement with Iran does in fact provide significant opportunities for banks and financiers, if the risks can be managed or priced.

Beyond the stories of red carpets, minister-led business delegations, and bustling hotels in Tehran, Western business executives are having serious conversations about whether the potential reward of being first to market outweighs the risks of charging into a country that is, for example, ranked 137 for corruption and ranked 130 for ease of doing business. Iran's history of expropriations and reneging on nuclear deals must similarly be factored into decision making.

In this article, we step back from the hype of endless opportunities to take a stark look at the key factors that executives are, or should be, discussing.

The Legal Obstacles

The Iranian economy will remain largely closed to US businesses and US nationals for the medium term, as Chadbourne reported in a client alert in July that can be found at http://www.chadbourne.com/understanding-iran-sanctions-relief. The EU sanctions relief is fairly comprehensive, with exceptions, but the US sanctions relief */ continued page 2*

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TAX EXTENDERS are expected to move sometime between October and December.

The Senate tax-writing committee voted in July to extend more than 50 expiring tax benefits by two years. Its bill includes a two-year extension, through December 2016, of the deadline to start construction of new wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects to qualify for federal tax credits. Developers who start construction of projects in time would have the option to claim 10 years of production tax credits on the electricity output or a 30% investment tax credit.

The committee disappointed solar companies by */ continued page 3*

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provides openings currently for only export of civilian aircraft, civilian aircraft parts and related services, import of Iranian foodstuffs and carpets, and transactions by non-US companies owned or controlled by US companies or persons. Further, the sectors of the Iranian economy that are under control of the Iranian Revolutionary Guard Corps, or IRGC, will remain off limits for US and EU companies alike regardless of whether the specific business activity is permitted under the expected sanctions relief.

The risks of investing in Iran are significant and underreported.

For US companies, the loosening of sanctions for US-owned or controlled companies that are established outside of the US provides the most significant, yet little understood, opportunity. Guidance on the sanctions relief, which is expected to be issued in October ahead of its implementation in the first half of 2016, should provide much needed clarity on the extent of the relief for foreign subsidiaries of US companies. The agreement with Iran appears to contemplate the issuance of a general license for US-owned or controlled companies established abroad, but without a broader loosening of the restrictions on US nationals, this relief will be of limited value in practice. The US's prohibition on "facilitation" by US nationals of non-US transactions with Iran prohibits US nationals from taking affirmative action to allow their foreign affiliates to transact business with Iran. US nationals employed by the foreign affiliate, or by non-US companies, will similarly be prohibited from participating individually in any transaction with Iran.

Another critical obstacle, for both Americans and Europeans, will be the prohibition on conducting transactions with entities and persons subject to an asset freeze, commonly referred to as blacklisted persons. The IRGC controls large portions of the Iranian economy and will remain blacklisted by both the US and EU for approximately eight years under the deal with Iran. Transactions with the IRGC or its blacklisted officials, directly or indirectly, could subject companies to criminal or civil penalties by the US or EU.

To mitigate these risks, companies operating in any sector in Iran will need to screen business partners and beneficial owners diligently and comprehensively for blacklisted persons, as well as screen for government officials in connection with anti-corruption laws. Documented compliance programs will be necessary not only to ensure the integrity of this process, but also to ensure that agents, business partners and vendors are similarly abiding by these restrictions when applicable. Notwithstanding the due diligence, companies will inevitably encounter transactions in which participation by a blacklisted entity will be unavoidable, and thus the transaction will be prohibited without authorization.

If companies can come to terms with these obstacles and the other risks identified here, then the remaining EU sanctions should not pose significant legal obstacles for the non-US finance industry. An explicit and repeated provision in the agreement with Iran is that the Europeans will provide finance and export credit assistance to Iran. Additionally, frozen funds estimated to equal between $30 and $100 billion will be released to Iran as part of the agreement. The agreement removes the asset freezes from Iranian banks, permits the transfer of US dollars to Iran (by non-US persons), and allows the unimpeded transfer of funds between non-US banks and Iranian banks. One significant financial restriction will remain in place for the first eight years of the agreement: the EU prohibition on the provision of financial messaging services to Iran.

The Business Environment

Legal risks can usually be identified and managed, but the business risks of investing in Iran will be difficult to quantify. Red tape, corruption, violation of the nuclear accord, and vested interests are some of the obvious challenges that new entrants to the Iranian economy will immediately need to consider and factor into decision making on how fast to enter the market. These are the factors that will dominate boardroom conversations over the next few months. Most media reports address them only in passing.

The biggest business risk, by a good measure, is a violation of the nuclear accord by Iran causing a "snap back" of sanctions. Western businesses investing in Iran might price in the risk factor that the Iranian government reneges on its commitments. The US (or any party to the agreement with Iran) can cause an automatic snap back of UN sanctions on Iran by unilaterally submitting that Iran is not complying with its obligations under the agreement. The snap back would be automatic and could take place in as few as 65 days from the first submission by the complaining party. Absent an affirmative vote by the UN Security Council (which any of the permanent five members can veto) or a resolution between the parties, the UN sanctions would be automatically reimposed.

The agreement with Iran provides a safe harbor for existing investments in the event of a snap back of sanctions, which should provide some comfort to investors. However, the practical value of this safe harbor would probably be limited because further investment could be prohibited and Iran could once again become cut off from the international financial system. The snap back would only apply to UN sanctions. The US (assuming it is the complaining party) might find it difficult to convince its European allies to join the US in reinstating unilateral sanctions on Iran, but current attitudes could change in the future.

The second major business risk is the relatively opaque and underdeveloped business environment in Iran. The World Bank's Ease of Doing Business report, which ranks Iran at 130 overall, provides comparatively positive rankings for Iran in only two areas: enforcement of contracts and business set up, at 66 and 62 respectively. In the areas of construction permits and property registry, Iran is ranked near the bottom at 172 and 161, respectively. Protection of minority investors, trading across borders and paying taxes are also poorly rated.

On paper, Iran's Foreign Investment Promotion and Protection Act provides the right incentives for foreign investment, such as 100% foreign ownership, repatriation of profits and tax incentives. However, this 2002 law has not been significantly tested. Iran is not a standard-bearer for the rule of law, and as vested interests come under threat from the influx of foreign investment, pushback from these powerful */ continued page 4*

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failing to extend a 30% investment tax credit for new solar projects. Solar companies had hoped the committee would turn a December 2016 deadline to complete solar projects into a deadline merely to start construction. Solar was not included because it was not considered germane to the bill. The bill deals only with tax benefits that have already expired or are expiring this year. Solar advocates will have another chance to amend the bill when it reaches the Senate floor.

The committee also voted to allow a 50% "depreciation bonus" on new equipment put in service by December 2016 or, in the case of transportation equipment and long-lived equipment like transmission lines, by December 2017.

No date has been set yet for the full Senate to take up the bill. Attention is focused for now on the Iran nuclear deal and on a funding measure to keep the US government operating past the end of the current fiscal year on September 30. Some Republicans want to use the funding measure as a vehicle to cut off funding for Planned Parenthood. Religious holidays and a visit by the Pope to Washington mean Congress will have very few work days in September.

Paul Ryan, the House tax committee chairman, said he hopes to have his committee take up the extenders in September. However, Ryan has also talked about combining the extenders and renewed funding for the highway trust fund, whose authorization runs out on October 29, with an international tax reform bill that most lobbyists consider a long shot this year for passage.

The House is not expected to extend any tax benefits for renewable energy.

The fate of any extenders for renewable energy will come down ultimately to a negotiation between the House and Senate, probably late in the year.

The staff of the Joint Committee on Taxation estimates that extending the construction-start deadline for wind, geothermal, biomass, landfill gas, incremental hydroelectric and ocean energy projects will cost the US Treasury $10.492 billion over 10 */ continued page 5*

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interests would not be surprising. Careful consideration of these risks, an understanding of the existing industry participants (and their beneficial owners), and reliable access to legal recourse will be factors that companies should address before making major investments.

Missed Opportunities

The common sentiment among US businesses at the moment, that they will miss out on opportunities in Iran while EU companies snap up the contracts, is simplistic.

For Americans, the opportunities in Iran will remain if and when US sanctions are lifted and public opinion changes. The demand for advanced technology, quality and finance — often the American differentiator abroad — will not disappear. The Europeans, Russians, and Chinese might have their pick of the low-hanging fruit in Iran, but Iran is not rolling out the red carpet for American investors at the moment, regardless of the legal restrictions. Iranian authorities have said on several occasions since the nuclear agreement was reached that attitudes toward the US will not change.

The US government chose to keep most restrictions on US companies in place for what could be very good reasons. A charge into Iran by US business will limit the options for US foreign policy and potentially endanger US citizens in a worst-case scenario. In the event of a breach by Iran of the nuclear accord, a strong US business presence in Iran would also limit the US government's options from a domestic special-interests perspective. From an international perspective, a strong US presence in Iran will provide the Iranians with leverage vis-à-vis the investments and people in the country.

In summary, Iran is not the untapped paradise that the media reports are portraying it to be, and the Europeans are undoubtedly discussing the same issues addressed in this article. Being first to market can undoubtedly result in huge windfalls. However, as those who rushed into Iraq, Libya and South Sudan can attest — three countries that recently led the world in GDP growth — the risks attendant to being first to market can often rise to the level of 100% loss of investment. For now and for Americans in particular, the cautious choice is to wait and see. ◎

More US Loan Guarantees for Distributed Generation

by Kenneth Hansen, in Washington

Another $1 billion in federal loan guarantees will be made available for distributed energy projects, such as micro-grids and rooftop solar with batteries, President Obama said in a speech at a Clean Energy Forum in Las Vegas in late August.

The loan guarantees are being offered under the existing US Department of Energy loan guarantee program. The additional $1 billion will be added to two existing solicitations: one that was issued in July 2014 for up to approximately $4.2 billion in loan guarantees for renewable energy projects and another that was issued in December 2013 for up to $8 billion in loan guarantees for advanced fossil energy projects. The plan is to increase the authorized loan guarantees under each solicitation by $500 million. (For earlier coverage, see the July 2015 *Project Finance NewsWire* starting on page 61.)

Solar rooftop and other distributed energy companies that are interested in applying should follow the deadlines and rules for those solicitations.

The department acknowledged in a "supplement" issued in conjunction with the Obama speech (available here: http://energy.gov/lpo/downloads/distributed-energy-projects-supplements-renewable-energy-and-efficiency-energy) that distributed energy projects "require financial structures that are different from most of the financing structures that [DOE] has used in the past for financing large, centralized projects" and said it is open to new structures.

Eligibility

To qualify, a developer must offer a "distributed technology" and plan to deploy installations at multiple sites under a master business plan.

An eligible project must also still satisfy the threshold criterion for the DOE loan guarantee program, which is to employ an innovative technology, meaning one not already in commercial operation in the United States for more than five years, that reduces greenhouse gas emissions.

Loan guarantees are written for a "project."

In stating the requirement that the developer must plan to deploy installations at multiple sites under a master business plan, DOE is removing any doubts about what had been a key concern for distributed generators considering taking advantage of the loan guarantee program. The DOE loan guarantee rules say that a developer "may not submit a[n] . . . application for multiple projects using the same technology." Thus, if each installation were to be considered a "project," which is one possible reading, then financing of distributed generation by this program would not have been feasible.

DOE had already in principle cleared that regulatory hurdle when it provided conditional commitments to two distributed generation applications submitted in the first round of loan guarantees written through September 30, 2011. One application was abandoned when DOE concluded that insufficient time remained to complete structuring and documentation of the project prior to the September 30, 2011 statutory deadline. The other distributed generation project closed, but its implementation required aggregation of utility-scale power purchase agreements that proved to be in short supply. So, while that project achieved financial closure, it did not proceed to full deployment of the loan guarantee.

DOE made clear in the supplement that it considers multiple installations at multiple locations a single "project" when done under a master business plan. Thus, key to a successful application will be putting together a master business plan that ties together each installation as a component of the overall project. All systems installed under the plan will have to use the same technology or technologies. Multiple unrelated installations using unrelated technologies would not qualify.

The bigger issue may be whether rooftop solar systems can satisfy the requirement to use a technology that has not already been in commercial use in the US for more than five years.

The loan guarantee program "does not offer low-cost financing for proven commercial technology," the supplement warns. Thus, projects limited to purely commercially-established technologies need not apply.

However, the supplement opens an interesting door when it says, "For example, standard rooftop solar or energy efficiency technology is not eligible unless at least a portion of the Project meets the . . . 'innovation' requirements."

It has been well established in the development of the DOE loan guarantee program to date that a project need not be innovative in all respects. The projects on which loan guarantees have been written so far are basically single-site operations, so their qualifying innovations were present on site.

While a new type of battery or inverter would probably allow a project to qualify, would a distributed / continued page 6

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years, or roughly 12% of the net cost of the full extenders bill.

SOME ENERGY TAX CREDIT ISSUES may be revisited by the Internal Revenue Service.

The IRS hopes to issue a notice in September asking for suggestions from the public about areas where its existing regulations about investment tax credits for renewable energy projects need updating. The regulations were written the early 1980's. They address what parts of a renewable energy facility qualify for an investment credit.

The agency hopes, after collecting suggestions, to issue a set of proposed changes to the regulations by the end of June next year. This may be ambitious.

An example of an area where the IRS feels the law could use clarification is a case the US Treasury Department won in January in the Court of Federal Claims where the government allocated the cost of a biomass power plant between the parts of the plant that produce steam and electricity and paid a Treasury cash grant only on the cost allocated to electricity. Cash grants are paid on the same equipment that qualifies for an investment credit.

The Treasury is fighting a similar lawsuit that MeadWestvaco filed in April about another biomass power plant.

The Treasury lost a case in March involving two fuel cell power plants that convert methane gas from municipal wastewater treatment facilities into electricity. The Treasury paid grants on the fuel cell assemblies, but not the gas conditioning equipment. The issue was what the US tax code means by "fuel cell power plant" — the equipment on which an investment credit can be claimed and, by extension, a Treasury cash grant would be paid. (For earlier coverage, see the May 2015 *Project Finance NewsWire* starting on page 5.) The court said the gas conditioning equipment is integral to generating electricity. The fuel cell case is now before a US court of appeals.

Other areas that are ripe for clarification are in what circumstances / continued page 7

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generation application pass muster if innovative technologies were employed on some sites but not on others?

Although the answer is not clear in the supplement, some of the suggestions by way of qualifying technologies in past projects on which loan guarantees have been written were at the system management level, which suggests that each installation might not need to have an on-site innovation. There are good legal grounds and programmatic precedent for the answer that not every site needs to reflect the same, or any, innovative technology as long as the overall project does.

NEPA

Compliance with the National Environmental Policy Act (NEPA) has been another factor potentially discouraging DOE support of distributed generation projects. A time-consuming environmental impact statement must be prepared before a loan guarantee can be written.

DOE's obligation to comply with NEPA in advance of financial close was sometimes difficult to satisfy for utility-scale projects at a single project site. Where a multitude of sites is contemplated, some (or most) of which may not be known by financial close, NEPA compliance becomes all the more challenging. DOE appears to be feeling its way forward carefully on this front, but it clearly recognizes the problem and appears open to solutions.

The supplement the department released in late August opens with the easy case, suggesting "[t]he universe of sites on which the installations would occur would be identified in order to permit DOE to satisfy its obligations under the National Environmental Policy Act . . . and complete other necessary diligence." It also recognizes this may not be the typical case. The supplement goes on to say that "in some circumstances it may be sufficient to identify the proposed sites categorically," meaning to provide a general description of the types of sites that will used, "with conforming site information to be certified by" by the developer and verified or audited by DOE as there are draws on the loan guarantee after closing.

Timing and Location

Timing may prove an issue. Many solar rooftop installations are financed today in the tax equity market in order to convert tax benefits on the solar equipment into current cash that can be used to pay capital costs. Tax rules require a closing on the tax equity financing before the equipment is placed in service. The tax equity investors fund groups of systems over time as each "tranche" of systems reaches completion.

DOE would rather wait in some cases to fund the guaranteed loan after all the equipment envisioned under the master business plan has been installed and fully tested. Its supplement says, "In instances where the equipment supply and the construction process pose greater than normal risk, [DOE] would look more favorably on [projects] structured in a manner to permit loan disbursements for project costs only after the relevant installation and/or pool of installations is completed and tested in accordance with the requirements of the Engineering, Construction, and Procurement Contract ("EPC") and offtake agreements."

Perhaps DOE will not take this position for rooftop solar installations since the equipment supply and construction process do not pose "greater than normal risk."

If the position does apply, then the loan guarantees may prove more useful as a potential source of refinancing rather original coverage for installation costs. In that sense, this position by DOE evidences another step forward for the loan guarantee program.

Another $1 billion in federal loan guarantees will be available for rooftop solar and other forms of distributed generation.

In the program's initial rounds, DOE was unwilling merely to refinance projects that were already underway, since this was a failure of "additionality": its participation was not really making something possible that would have failed to occur in the private market. It is a step forward for DOE to have concluded that offering financing at completion of installations can be a critical inducement to moving a project forward and that the mere fact that physical completion may precede disbursement of DOE funding does not mean that access to DOE funding was not critical to the project happening.

Eligible projects must be in the United States or US territories. At least one site must be identified in the application, according to the supplement. This requirement seems unnecessary, since the restriction to US projects is well understood among project participants and it will no doubt be stated explicitly in the conditions precedent to disbursement of the loan guarantee that each financed site is in a qualifying location.

Based on the precedent of a proposed cross-border transmission line that was at one point under consideration for the DOE loan guarantee program financing, an offshore element should not preclude DOE financing for the US-based portion of the project.

Use of Proceeds

The supplement warns applicants that DOE will not allow "relending" of loan guarantee proceeds.

However, as long as the developer is responsible for the loan and provides adequate security, it is not clear why DOE should be troubled by a degree of on-lending of DOE loan proceeds. Some likely structures, including leasing structures specifically mentioned by DOE as examples of what might be acceptable, are arguably the equivalent of on-lending. That is, an arrangement in which the developer installs systems, leases them to building owners and is paid over time through rental payments, the arrival of which depend on the creditworthiness of the building owner, is the functional equivalent of the developer having financed, in part with DOE loan proceeds, a loan to the building owner.

One could imagine a portion of DOE loan proceeds being used to fund a revolving short-term loan facility available to distributed generation customers, where such proceeds remained a fully-secured, senior payment obligation of the developer to DOE.

In a discussion of "Example B," DOE notes that it "would also anticipate looking through a . . . lease, power purchase agreement or other revenue contract structure to ensure that the [developer] is not merely relending DOE-guaranteed loan proceeds to project hosts for unreasonable profit." This suggests that some relending might be possible if not on terms that would provide an "unreasonable profit."

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batteries and other storage facilities qualify for tax credits, when support structures for solar panels mounted over parking canopies qualify, and a series of fact patterns around community solar projects.

The IRS released a private letter ruling in early September that it issued to a Vermont homeowner who bought solar panels that are part of a larger, utility-scale "community" solar array that is some distance from his house. The array was sold panel by panel to multiple individuals. The individuals are all members in a limited liability company that handles administrative and financial tasks related to the array, but they own their panels directly.

All of the electricity from the array is sold to the local utility. Each panel owner buys the electricity he uses in his home from the local utility and receives bill credits for the electricity from his solar panels that are used as an offset against his utility bill.

The IRS told the homeowner he could claim a 30% residential solar credit on the panels he owns. The credit can be claimed on equipment used to generate solar electricity "for use in a dwelling unit [that is] used as a residence by the taxpayer."

Although not a slam dunk, it was probably the easiest of the three or four community solar fact patterns for the IRS to address. The IRS had already said in a notice in 2013 that the residential credit may be claimed for solar panels owned offsite. The ruling is Private Letter Ruling 201536017.

AN UNUSUALLY LARGE NUMBER of issues of interest to the project finance community are on the latest business plan the IRS released at the end of July.

The business plan is a list of issues the IRS hopes to address by June next year.

The IRS hopes to settle in what circumstances solar rooftop equipment can be owned by real estate investment trusts or REITs. The issue is whether such equipment qualifies as "real property." The / continued page 9

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The supplement indicates DOE's willingness to consider alternative financing structures. It could be worth exploring with the department whether some on-lending might be possible — especially if it is not provided with too great a spread and does not undermine DOE's recourse to the developer.

Another prohibition is against the "capitalization of state Green Banks." However, the program is clearly open to complementing the capital of state green banks as a co-lender and to benefiting from their creditworthiness, thereby reducing DOE's repayment risk and, with it, the "credit subsidy cost," or fee, that the developer must pay for the loan guarantee. While the DOE program "is not a vehicle to capitalize state green banks," it does offer them a way to leverage their capital. ◎

Solar Tax Equity Structures

by Keith Martin, in Washington

Solar companies use three main structures to raise tax equity to finance projects.

The volume of tax equity and the number of tax equity investors are increasing, ironically as a tax credit for investing in solar approaches expiration. How risks are allocated and the timing of when the tax equity investor must invest in relation to project completion vary by structure.

Current Market

The US government offers tax benefits on solar projects that are worth roughly 56¢ per dollar of capital cost. Most solar developers have a hard time using the tax benefits; thus, a core financing tool for most solar companies is "tax equity" where the benefits are effectively bartered for capital to build the solar project.

There are two benefits: a 30% investment tax credit and the ability to deduct 85% of the cost or fair market value of the project, depending on how the tax equity transaction is structured, over five years on an accelerated, or front-loaded, basis.

Solar tax equity deal volume was $4.5 billion in 2014. Tax equity deal volume for wind and solar combined was $10.1 billion. Deal volume is expected to be higher in 2015, and to be higher still in 2016 as solar companies rush to complete projects before a December 2016 deadline to qualify for a 30% investment tax credit on their projects. The rush is expected to strain tax equity shops. A significant number of tax equity deals in late 2014 spilled over to early 2015 due to inability of the market to complete the transactions by year end. Each tax equity shop has a limited number of people who can work on deals; however, the most significant constraint in late 2014 was a shortage of outside engineering consultants who help with diligence. Another spillover is expected in late 2015.

Projects that fail to get into service by December 2016 will still qualify for a 10% investment tax credit and the same accelerated five-year depreciation, but the depreciation will be on 95% — instead of 85% — of the capital cost or market value of the project.

There is a reasonable chance that Congress will convert the 2016 deadline to complete solar projects into a deadline merely to start construction, but it may not happen this year. The Senate tax-writing committee voted in July to extend more than 50 expiring tax benefits by two years. The measure does not include any extension of the solar investment tax credit. The tax extenders bill is expected to be taken up on the Senate floor this fall, at which time solar advocates have been promised a vote on their proposal. The problem has been that the proposal is not considered "germane" to the Senate bill, since the bill is limited currently to extensions of tax benefits that have expired or will expire by the end of this year. The House is expected to oppose extending tax benefits for renewable energy projects; thus, the fate of the current extenders bill is expected to come down to a negotiation late in the year between the two houses.

We see at least 34 tax equity investors currently in the renewable energy market. Another 11 have done some deals, but are currently out of the market. Another 11 companies are on lists of potential tax equity investors or have made the decision to invest but have not yet done their first deals. Only a subset of this number is interested in any particular market segment: for example, wind, utility-scale photovoltaic projects, solar thermal projects, residential rooftop and commercial and industrial rooftop.

Tax equity yields in the last six months have been trending down, although tax equity investors are recovering some of the decline through fees and are often pricing to a second yield 50 basis points higher at year 20. Utility-scale solar PV yields are 7.25% to 8% unleveraged for the least risky deals involving the chadbourne

The number of tax equity investors is increasing, ironically as the solar tax credit approaches expiration.

most experienced sponsors. Residential rooftop solar for brand-name developers is a little below 9%. Some tax equity investors price by quoting an amount per dollar of investment tax credit. The amounts range from $1.10 to $1.32 per dollar of tax credit, with most around $1.27 or $1.28 in the current market.

Adding debt ahead of the tax equity in the capital structure can increase the yield demanded by the tax equity market by at least 500 basis points. Project-level debt is unusual in the current market. Most debt is back-levered debt at the sponsor level that sits behind the tax equity in priority of payment. In deals where debt is ahead of the tax equity investors, the tax equity investors will insist that the lenders agree to forbear from foreclosing on the project after a default long enough to give time for the tax equity investors to reach their target yield. The market consensus on forbearance terms appeared largely to have collapsed as of mid-2014 after a number of new lenders came into the market who were unfamiliar with the existing deal terms.

There are three main tax equity structures for transferring tax benefits, with two significant variations. The three are partnership flips, sale-leasebacks and inverted leases.

Partnership Flip

A partnership flip is a simple concept. A sponsor brings in a tax equity investor as a partner to own a renewable energy project together with the sponsor. The partnership allocates taxable income and loss 99% to the tax equity investor until the investor reaches a target yield, after which its share of income and loss drops to 5% and the sponsor has an option to buy the investor's interest. In some recent deals, the post-flip sharing ratio has been 6% to 7%. Cash may be distributed in a different ratio before the flip.

Many early flip deals had a "cash drought" for the sponsor: cash went first to the sponsor to return its */ continued page 10*

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IRS issued a proposed new definition of real property for REIT purposes in May 2014. Under it, a REIT that owns a building can also own solar equipment that is used to supply electricity to the building occupants. (For earlier coverage, see the June 2014 *Project Finance NewsWire* starting on page 9.) However, it is not clear a REIT could own rooftop solar systems in other situations. Five US Senators wrote the IRS and Treasury on August 17 asking it to drop a requirement that solar panels would qualify as real property only if the REIT owns an "equivalent interest" in the solar equipment to its interest in the building.

The IRS hopes to issue guidance on the tax treatment of prepaid forward contracts. It has had such guidance in the works since 2008. The focus was originally on the tax treatment of forward contracts in the foreign exchange market, but the guidance has the potential to affect the tax treatment of prepaid power contracts.

The agency is also working on guidance about advance payments for goods and services. US tax rules let a company that is paid in advance for goods — for example, electricity or gas — spread the taxable income out in certain circumstances over the period the goods are delivered. This is a key feature of prepaid power contracts. Any new guidance is expected to focus mainly on amounts received for gift cards, trading stamps and loyalty points that can be redeemed for goods and services.

Another issue the agency expects to address is whether interest must be accrued on distressed debt. The issue is at what point accrual should no longer be required because of little likelihood the interest will be paid.

A notice is expected this fall on inverted leases in the solar market. The lessee in such a lease claims an investment credit, and has to report income equivalent to half the credit ratably over five years. Some lessees that are partnerships between the solar company and tax equity investor are then bumping up the "outside basis" of the tax equity investor by this income. The tax equity investor eventually withdraws from the lessee partnership */ continued page 11*

Tax Equity

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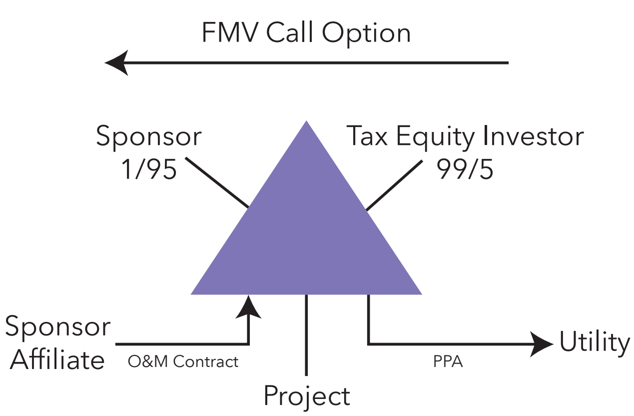
capital, and then cash went 99% to the tax equity investor until the investor got back its capital plus a return. In more recent deals, cash is more likely to be split in a fixed ratio like 40-60, 50-50 or 60-40 from the start, reflecting partly the influence of yield cos as potential buyers of the sponsor positions. Yield cos are focused on cash available for distribution.

The sponsor has a call option to buy the tax equity investor's interest after the flip, usually for fair market value determined at the time. The call price can also be a fixed price set in advance, as long as the call price is a good-faith estimate at inception of what the value will be upon exercise. Some tax equity investors require the call price to be not less than the amount the investor needs to avoid a book loss on sale of its interest or to be not less than the amount the investor requires to reach a higher post-flip yield at year 20.

Chart 1 is a diagram of a typical flip deal.

Chart 1: Basic Yield Flip



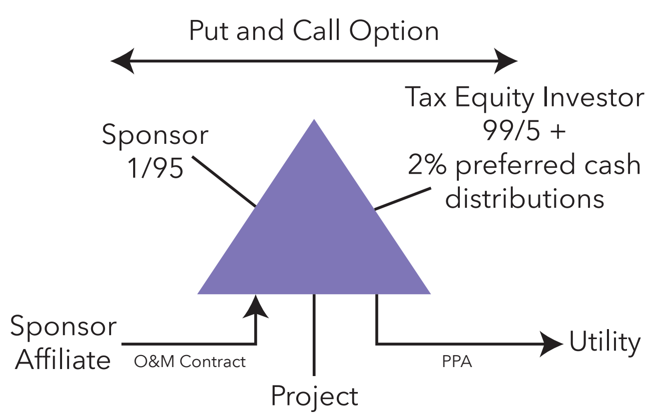
The Internal Revenue Service issued guidelines for partnership flip transactions in 2007. The guidelines are in Revenue Procedure 2007-65. They provide a "safe harbor" for transactions that conform to them. Most do. The IRS said recently that the guidelines were written with wind projects in mind and are not a safe harbor for solar transactions. (See the July 2015 *Project Finance NewsWire* starting on page 59.) The central tension in partnership flip transactions is whether the tax equity investor is truly a partner or is a lender or bare purchaser of tax benefits in substance. The latter two labels would prevent the investor from sharing in the tax benefits on the project.

There are two main variations in flip structures. In addition to the yield-based flip, there is also a fixed- or time-based flip structure that is offered by a small subset of tax equity investors and that leaves as much cash as possible for the sponsor without turning the transaction into a bare transfer of tax benefits.

In a fixed-flip transaction, the investor receives annual cash distributions from the partnership, equal to 2% of the tax equity investment, ahead of all other cash distributions. There is then a "waterfall" list of instructions for how remaining cash is shared between the sponsor and tax equity investor, with the sponsor keeping most of the cash, but the investor having a shot at more cash if the project performs well and possibly in other circumstances. The sponsor has a call option immediately after the flip to buy the investor's interest. The investor has a "put," structured as a right to withdraw from the partnership, usually a year later if the sponsor does not exercise the call.

Chart 2 is a diagram of a typical fixed-flip deal.

Chart 2: Fixed Flip



In a partnership flip transaction, the sponsor is responsible for day-to-day management of the project. Tax equity investor consent is required for a list of major decisions.

The tax equity investor may come into the transaction in one of two ways. It may invest by buying an interest in the partnership from the sponsor — a "purchase model" transaction — or by making capital contributions to the partnership — a "contribution model" transaction. The purchase model may let the tax equity investor calculate the tax benefits on a higher "tax basis."

Almost all partnership flip transactions have "absorption" issues. Each partner has a "capital account" and "outside basis" that are two ways of measuring what the partner put into the deal and what it is allowed to take out in benefits. Most tax equity investors run out of capital account before they are able to absorb 99% of the depreciation. The main way to deal with this problem is for the tax equity investor to agree to make a capital contribution to the partnership when the partnership liquidates in the amount of any deficit in its capital account. This is called a deficit restoration obligation or "DRO." However, a DRO does not help if the other measure of what the partner has put in and is allowed to take out — its "outside basis" — has also hit zero. Any losses (depreciation) shift to the sponsor once the tax equity investor runs out of capital account. Having debt at the project level makes it possible for the investor to absorb more depreciation by allowing part of the depreciation to be claimed even though the investor has run out of capital account, and the project-level debt causes the investor's outside basis to increase.

Risk allocation and timing vary among the three main solar deal structures.

Yield-based flips in the solar market usually price to reach yield in six to eight years. Fixed-flip deals usually flip at five to six years.

How the tax equity investor reaches the yield may be more important for the solar company than the yield. For example, a transaction that flips in a relatively short period and in which the yield is paid largely out of tax benefits may be more attractive than a transaction with a lower flip yield, but a later flip date, where the investor will require more cash to reach yield.

Most tax equity investors require at least a 2% pre-tax yield. Most of the market counts the investment tax credit as part of the cash return for purposes of this calculation.

Sale-Leaseback

In a sale-leaseback, the solar company sells the project to a tax equity investor and leases it back. Unlike a / continued page 12

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and deducts the outside basis as a tax loss. The IRS believes this is inappropriate.

Another issue receiving attention is the problem of congestion on the utility grid. Independent generators must connect their power plants to the grid to get the electricity to market. The local utility to whom the plant interconnects requires the generator to reimburse it for the cost of substation improvements and upgrades to the grid to accommodate the additional electricity. The cost reimbursement does not have to be reported by the utility as income as long as, among other things, the generator is careful to transfer title to the electricity from its power plant to someone else before the electricity reaches the grid. The generator must not be considered a customer of the grid for wheeling. If a utility must pay taxes on the amount, then it will charge the generator more for interconnection.

Some cost reimbursements are made today to neighboring utilities to relieve congestion in other parts of the regional grid that, if not addressed, could lead to curtailment of the independent generator's facility. The IRS is updating its guidance in this area to clarify that cost reimbursements to neighboring utilities do not have to be reported as income either. The IRS has suspended any private rulings on the subject in the meantime.

The IRS expects to issue final guidance on the tax treatment of series LLCs. Proposed regulations were published in 2010. At least nine US states, the District of Columbia and Puerto Rico have statutes that allow limited liability companies to create different pockets or cells of investments, each potentially with different owners, a different managing member and different assets. In at least three of the nine states, each series can have a separate right, in its own name, to sign contracts, hold title to assets and grant liens and security interests in the assets belonging to that series. The IRS suggested in 2010 that each cell or subsidiary of the series LLC can have a different tax / continued page 13

Tax Equity

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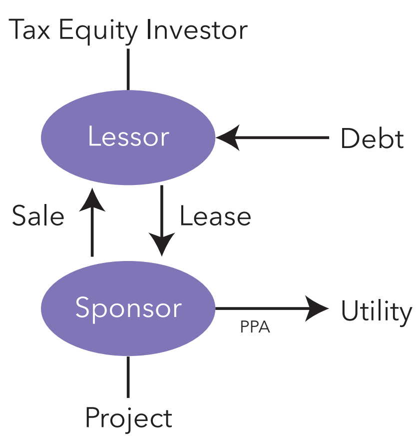
partnership flip where the investor gets at most 99% of the tax benefits and has to work through complicated partnership accounting rules to determine whether it gets even that much, all the tax benefits are transferred to the tax equity investor. The investor calculates them on the fair market purchase price that it pays for the project. The solar company has a gain on sale to the extent the project is worth more than it cost to build.

The structure is shown in chart 3.

Chart 3: Sale-Leaseback



A partnership flip raises 40% to 70% of the project value, depending on the partnership sharing ratios and other factors. A sale-leaseback raises 100% of the fair market value of the project in theory. In practice, the solar company is usually required to prepay something like 15% to 20% of the purchase price as prepaid rent. The rent prepayment is treated as a loan by the lessee to the lessor that is offset over the lease term, but that accrues interest in the meantime. The market calls such a loan a "section 467 loan" after the section in the US tax code that governs the tax treatment.

The IRS has guidelines for leveraged leases where the tax equity investor raises part of the purchase price for the project by borrowing from a bank. They are in Revenue Procedure 2001-28. The guidelines limit the term of the leaseback to 80% of the expected life and value of the project. If the lessee wants to keep the project at the end of the lease, then the lessee must repurchase it. Any lessee purchase option cannot be at a price that makes the option reasonably likely to be exercised. There also cannot be anything that will compel the lessee to exercise the option.

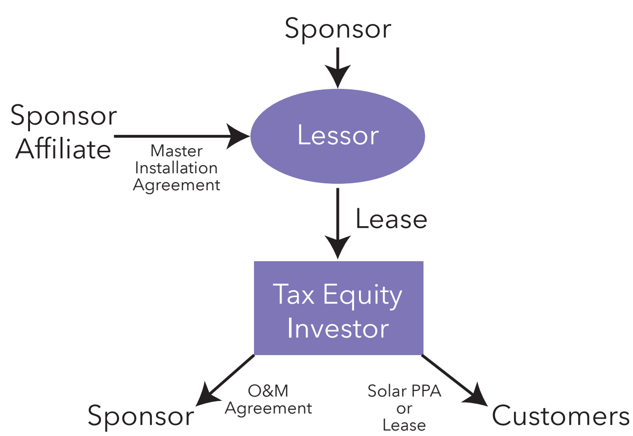
Sale-leasebacks remain common in the commercial and industrial rooftop and utility-scale solar markets. They are uncommon in the rooftop market, where the deals are split currently between partnership flips and inverted leases. Rooftop companies dislike sale-leasebacks because they feel the tax equity investors pay too little at inception for the residual value.

Inverted Leases

Inverted leases are used mainly in the rooftop market. Think of a yo-yo. The solar company assigns customer agreements and leases rooftop solar systems in tranches to a tax equity investor who collects the customer revenue and pays most of it to the solar company as rent. The solar company passes through the investment tax credit to the tax equity investor. It keeps the depreciation. The solar company takes the asset back at the end of the lease.

A diagram of the structure is in chart 4.

Chart 4: Basic Inverted Lease



Sponsors like inverted leases because they get the asset back without having to pay for it, and the investment credit is calculated on the fair market value of the solar equipment rather than its cost. Unlike a sale-leaseback, the step up in tax basis does not come at a cost to the solar company of a tax on a commensurate gain.

There are no IRS guidelines for inverted leases, unlike the other two structures. However, the structure is common in historic tax credit deals, and the IRS acknowledged it in guidelines in early 2014 to unfreeze the historic tax credit market after a US appeals court down an aggressive form of the structure in a case called *Historic Boardwalk*. The acknowledgement is in Revenue Procedure 2014-12. (For a further discussion, see the February

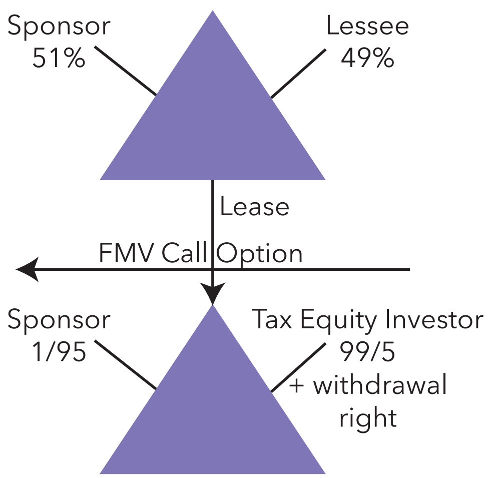
2014 *Project Finance NewsWire* starting on page 17.)

The tax equity investor must have upside potential and downside risk to be considered a real lessee. Some tax counsel like to see a "merchant tail," meaning the lease should run at least 20% longer than the customer agreements. Others focus on the amount of prepaid rent that is paid by the lessee and want to see at least a 20% rent prepayment. In the more conservative deals, the tax equity investor has a hell-or-high-water obligation to pay fixed rents to the solar company. In some deals, part of the rent is contingent on output or lessee cash flow; contingent rent adds tax risk to the structure. Some of the big four accounting firms treat inverted lease transactions as loans rather than real leases.

Inverted leases raise 20% to 45% of the project value. The central challenge in inverted leases is how the capital raised by the structure moves from the tax equity investor to the solar company. In the conservative form of the structure, it moves as prepaid rent. In a more aggressive overlapping ownership structure, the lessee makes a capital contribution to the lessor in exchange for a 49% interest in the lessor, thus giving the tax equity investor not only the investment credit but also 49% of the depreciation on the solar assets.

The overlapping ownership structure is shown in chart 5.

Chart 5: Overlapping Ownership Inverted Lease



Differences

The three structures vary in terms of the amount of capital raised, risk allocation and the timing of when the tax equity investor must invest. The solar company must turn to other sources of capital (debt and equity) to raise the rest of the project cost. / continued page 14

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classification. (For earlier coverage, see the November 2010 *Project Finance NewsWire* starting on page 7.)

Some partnership agreements use "targeted allocations." IRS regulations require partnerships to keep a capital account for each partner that tracks what the partner contributed and what he got out of the partnership. When the partnership liquidates, the capital accounts are supposed to be used by partners to divide up what remains. However, with targeted allocations, the partnership simply divides up what remains according to a business deal. It tries during the life of the partnership to share economic returns in a manner that causes the capital accounts to remain in the ratio the business deal requires any assets remaining at liquidation to be shared, but there is no guarantee the capital accounts will be in this ratio. (For earlier coverage, see the April 2014 *Project Finance NewsWire* starting on page 41.) The AICPA, the trade group for the accounting profession, urged the IRS in 2014 to address targeted allocations because of what it said is a widespread misperception that the IRS approves of such allocations. The issue is on the latest business plan.

The agency will finalize proposed guidance it issued in May 2015 about the types of activities in which master limited partnerships or MLPs may engage in an energy business. Such MLPs must have at least 90% good income each year to maintain status as a partnership for tax purposes; otherwise, they are taxed like corporations. (For earlier coverage, see the July 2015 *Project Finance NewsWire* starting on page 70.) Boardwalk Pipeline Partners LP and Westlake Chemical Partners sent letters to the IRS in July urging it to allow MLPs to produce olefins from natural gas. Both companies were issued private letter rulings by the agency in 2013 that said MLPs established by the companies could process natural gas liquids into olefins. The IRS reversed course in the proposed new guidance in May. As many as 12 companies that were issued private letter rulings granting them MLP status will not qualify under the new rules. / continued page 15

Tax Equity

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Focusing on risks, in a sale-leaseback, the solar company has a hell-or-high-water obligation to pay rent and must indemnify the tax equity investor for loss of tax benefits and any acceleration of rental income due to a lessee breach of a representation or covenant. In a flip, the investor's return turns on how well the project performs. The solar company and tax equity investor are like two passengers in a car; whatever they encounter along the road, they encounter together. The investor's protection in a partnership with the yield-based flip is that it sits on the project at a 99% level until it reaches a target yield. The risk allocation in an inverted lease is closer to a sale-leaseback.

The principal business risks in any transaction are weather, technology and offtaker credit.

"Basis risk," meaning the risk that too high a tax basis is used to calculate the tax benefits, tends to be borne by the solar company, although this has been true only since 2010 when the US Treasury started challenging the bases on which solar companies applied for cash payments from the US Treasury in place of the investment tax credit. Before then, a sponsor would represent that it gave accurate information to an outside appraiser on whom the tax equity investor relied to advise on the appropriate tax basis, and the investor relied on the appraiser.

In general, tax risks about which the solar company has special insight are borne by the sponsor. An example is facts that go to when a project was placed in service. Tax risks into which both the solar company and tax equity investor have equal insight are borne by the tax equity investor. An example is whether the transaction has been structured properly to transfer tax benefits to the investor. Risks into which neither has special insight are a matter for negotiation. An example is who takes the risk that the law will change and adversely affect the projected tax benefits. In a partnership flip transaction, risks are allocated through a limited number of sponsor representations and through a list of "fixed tax assumptions." The tax equity investor is treated as having reached its target yield on schedule even if one of the fixed tax assumptions proves untrue.

Turning to timing, the tax equity investor must be a partner in a flip deal before the project is placed in service. In some transactions, the investor makes enough of its investment before a project is put in service to be a partner and contributes the rest after final completion. Most tax counsel are comfortable that the investor is a partner if it invests at least 20% of its expected total investment before the project is in service; some are willing to go as low as 5% in large projects where 5% is a significant number. The deal papers must address what happens if the investor never puts in the remaining investment. The sponsor can have a call to repurchase the investor's interest at fair market value determined at the time. Care should be taken to avoid turning any arrangement into an option for the investor to unwind the transaction or the investor will not be considered to be a partner until the right to unwind lapses.

Inverted leases must be done before assets go into service. A sale-leaseback can be put in place up to three months after the asset is put in service. This gives the investor more time to determine whether the project is working properly before it has to invest.

Recurring Issues

The investment tax credit vests ratably over five years. The unvested credit will be recaptured, and have to be repaid to the US Treasury, if the assets are disposed of or a partner claiming the credit disposes of his interest or there is more than a one-third reduction in his share of partnership profits during the first five years. This has the effect of locking in the tax equity investor for five years.

The investment credit must be shared by partners in a partnership in the same ratio that they share in profits, or income, in the year an asset is put in service. At least one law firm worries that a shift in losses, due to an inadequate capital account, from the tax equity investor to the solar company during the first five years will cause unvested investment tax credits to be recaptured; this is not the majority view. Most solar projects do not earn a profit for tax purposes until sometime in year 4. The IRS may challenge the ratio in which investment tax credits were shared in year 1 if, by the time there is income, the ratio in which income is allocated has shifted; in that case, the income sharing ratio used in year 1 was illusory. Most tax counsel like to see at least a full year of income allocated at the year 1 ratio.

The asset basis used to calculate depreciation must be reduced by half the investment credit. In an inverted lease, since the lessee claims the credit but does not claim depreciation, it must report 50% of the credit as income ratably over five years. If the lessee is a partnership, then some tax equity investors use the income to increase the "outside basis" in their partnership interests and then claim a loss for the remaining outside basis when they withdraw from the partnership. The IRS does not believe this is appropriate. An IRS notice is expected in the fall. (For earlier coverage, see the May 2015 *Project Finance NewsWire* starting on page 1.)

Solar companies are chafing at cash sweeps in partnership flip transactions. The tax equity investor may insist that any cash that would otherwise be distributed to the solar company should be diverted to the tax equity investor to cover any tax indemnities that have to be paid. Such a sweep will complicate raising back-levered debt against the sponsor share of cash flow. Cash flow to the sponsor could also be interrupted in a fixed-flip partnership if the tax equity investor exercises a right, after the flip, to withdraw from the partnership. The partnership would be required to use cash at that point to pay the investor a withdrawal amount. A solar company planning to add back-levered debt later should also anticipate, when negotiating with the tax equity investor over restrictions on transfers of partnership interests, that the lender will need the ability to foreclose on the sponsor partnership interest.

Solar companies sometimes approach inappropriate tax equity investors. It is very hard for individuals, S corporations and closely-held C corporations to act as tax equity investors. A closely-held C corporation is a regular corporation in which five or fewer individuals own more than half the stock. Such investors are limited by passive loss and at-risk rules that make it hard to use the tax benefits.

Partnerships that earn their revenue from generating electricity cannot disaggregate the elements that go into the calculation of net income or net loss and allocate them separately. For example, such a partnership would not be able to allocate depreciation in one ratio and income, net of depreciation, in another ratio. US tax rules require any partnership engaged in manufacturing to use the inventory method of accounting, meaning it can only allocate net income or net loss each year. Generating electricity is considered manufacturing for this purpose.

There is a move toward utility-scale merchant projects in some parts of the United States. Such projects can be financed only if there is a hedge to put a floor under the electricity price. US tax rules bar a partnership from claiming a net loss — due, for example, to tax depreciation — on a project where the electricity is sold by the partnership to an affiliate. The sponsor may be tempted to enter into a power contract where it buys and resells the electricity as a way of putting a floor under the electricity price. It would be better to enter into a hedge or swap where the sponsor does not take the electricity, at least during the period the partnership could have a net loss. ◎

Another issue the IRS plans to address is whether a company that holds out equipment for sale or for lease can depreciate it while doing so. A leasing company can depreciate equipment that it uses in its leasing business. Inventory that a vendor holds out for sale cannot be depreciated because the equipment is not considered in service.

Another issue is how the installment sale rules work when part of the purchase price is contingent. Under an installment sale, the seller reports his profit as taxable income over time as a fixed percentage of each payment of purchase price from the buyer. The seller must pay the IRS interest on the deferred tax liability.

The IRS also expects to issue guidance on the "treatment of deferred revenue in taxable asset sales and acquisitions."

Finally, municipalities that issue tax-exempt bonds to finance schools, roads, hospitals and other public facilities must be careful not to allow more than 10% "private business use" of the facilities or the bondholders could end up having to pay taxes on the interest they receive on the bonds. Hiring a private company to operate and maintain a facility can be private business use, depending on the terms of the management contract. The IRS rules in this area date to a 1997 revenue procedure, Revenue Procedure 97-13. The IRS plans to update them.

The Edison Electric Institute, the trade association for the regulated electric utilities, asked the IRS to address whether homeowners who receive net metering credits for sending surplus solar electricity to the grid from rooftop solar panels should report the credits as taxable income. (For earlier coverage, see the July 2015 Project Finance NewsWire *starting on page 15.) The IRS chose not to include the item on the business plan.*

REITS take center stage in two plans to emerge from bankruptcy.

A consortium led by the Hunt family said in August that it has reached / continued page 19

Clean Power Plan Provides Boost for Renewables

by Richard Waddington, in Washington

Wind, solar, geothermal and hydropower appear to be winners under the final Clean Power Plan that the US Environmental Protection Agency released in early August to reduce US carbon dioxide emissions from fossil fuel power plants.

The plan would require a 32% reduction in carbon dioxide emissions nationwide from power plants by 2030 compared to 2005 levels.

Each state has been assigned a percentage reduction in emissions. The greatest percentage reductions will be required in the upper-Midwest.

It is up to each to decide among several options for how best to reach its emissions goal. The options include increasing the efficiency of existing coal-fired plants and shifting away from coal-fired power by investing in natural gas, renewable energy and energy efficiency. States will also have the option to participate in emissions trading markets.

EPA had issued a draft Clean Power Plan in June 2014. That plan was challenged in court by Murray Energy Corporation and the attorneys general in 12 coal-reliant states who question whether the agency has been given legal authority by Congress to regulate CO_2 emissions under section 111(d) of the Clean Air Act. A US appeals court dismissed the suits in June as premature. Lengthy litigation is expected, and the fate of the plan will probably have to be decided ultimately by the US Supreme Court.

In the meantime, the states have until September 2016 to draw up their individual emissions reduction plans. EPA has discretion to extend the deadline by two years, until September 2018, if an adequate initial submission is submitted by September 2016. The deadline for commencing implementation of the individual plans is not until 2022. These deadlines will be enforced unless any new Republican administration that takes office in 2017 withdraws the requirements, Congress cuts off funding or a court issues an injunction blocking implementation. Congress is probably not in a position to block funding as long as the Democrats retain the White House. Sixteen states have applied to a federal court of appeals to stay implementation of the final plan, and more lawsuits are expected.

The final Clean Power Plan sets a goal of 28% electricity generation from renewable energy by 2030. Wind, solar, geothermal, and hydropower are expected to contribute a substantial percentage of the increase in renewable energy. This is in part due to incentives created by the final plan. Incentives are not currently proposed for other renewable sources of energy such as biomass, but demand for such sources will probably increase given the overall increase in demand for renewables.

The draft plan had only a 22% target for renewable energy. The new higher target is a response to the concern voiced by some stakeholders that the draft plan could shift investment away from wind and solar in a “rush to natural gas.” The draft plan assumed that natural gas would account for a larger share of the energy mix in the first few years than is assumed in the final plan. The final plan assumes that gas capacity will not increase as significantly as projected earlier.

The government is now estimating that coal-fired generation will decline from approximately 39% of the US energy mix to approximately 27% by 2030. Total US generating capacity was 1.06 million megawatts at the end of 2013, the most recent year for which such data is available. The projected reduction is roughly 127,000 megawatts of generating capacity. Some consultants estimate that 100,000 MW of that capacity will be retired over the period 2017 through 2020.

State Options and Deadlines

The Clean Power Plan sets uniform emissions performance rates for existing fossil fuel power plants. The rates are in table 1. Although the performance rates are uniform, the total emission reductions that each state will be required to achieve vary significantly. The emissions performance rates required by the final plan are significantly lower than the performance rates that coal-fired and gas-fired power plants are currently capable of achieving. The aim is to compel states to reduce reliance on coal and encourage investment in renewable energy, energy efficiency and natural gas.

Table 1: CO_2 Emissions Performance Rates (Pounds of CO_2 per Net MWh)

	Interim Rate	Final Rate
Steam generating unit or integrated gasification combined cycle (IGCC)	1,534	1,305
Stationary combustion turbine	832	771

Tables 2 and 3, at the end of this article, list the interim and final emissions targets for each state.

Interim targets are phased in during three multi-year compliance periods beginning in 2022. Final targets must be reached by 2030. A state could choose to focus on the rate of emissions per megawatt hour of electricity generated, in which case the targets in table 2 would apply, or the state could focus on the actual tons of CO_2 emitted, in which case the "mass-based" targets in table 3 would apply.

The reason the targets vary by state is EPA made an assessment for each state based on the extent to which it relies on coal and natural gas for generating electricity, how much room there is for fuel efficiency improvement, the degree to which the state can transition from coal-fired generation to gas-fired generation, and the degree to which the state can replace fossil fuels by moving to renewable energy.

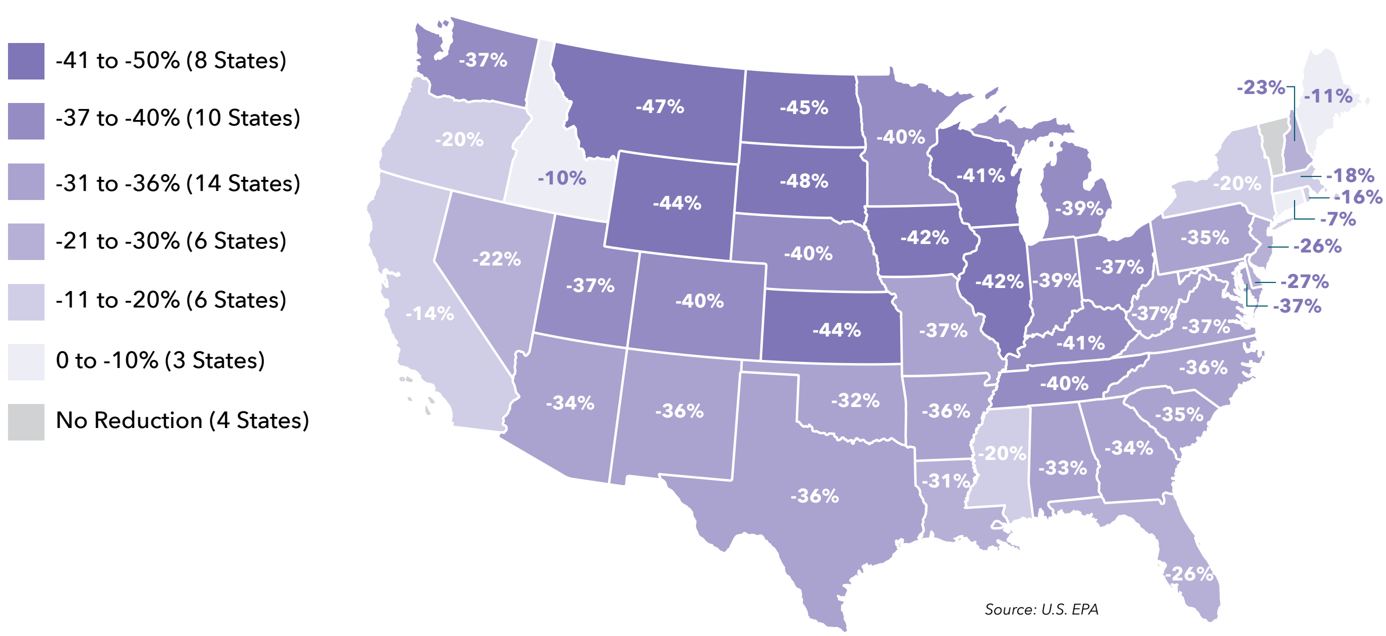
Below is a map showing the percentage reduction required by each state.

States will have a choice between two types of plans to meet their goals: an "emissions standards plan" and a "state measures plan." Under an emissions standards plan, the state would impose emissions performance rates on each power plant, but would also have the flexibility to allow emissions at some power plants to exceed the emissions performance rate, provided that the average emissions over the compliance period do not exceed the statewide emissions goal for that period. For example, a power plant could exceed its permitted emissions limit in the first two years of the compliance period, but then reduce its emissions in the final year in order to achieve the required average emissions for the compliance period.

In contrast, a state measures plan would consist of measures that a state plans to take and would not rely exclusively on imposing source-specific emissions performance rates. The measures might include a mix of renewable energy standards and programs to improve residential energy efficiency. A state measures plan must also include federally-enforceable standards that would be triggered if the state measures fail to produce the required emissions reductions.

States are free to combine any of the options in a flexible manner to meet the targets and may also join together in multistate or regional compacts such as, for example, a regional cap-and-trade program. / continued page 18

Percent Reduction of CO_2 Emissions Rate from 2012 to 2030 (lbs./MWh)



Source: U.S. EPA

Clean Power Plan

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States that choose to develop their own plans must submit the details for approval to the EPA by September 6, 2016. The federal government may grant extensions of up to two years. State implementation plans must ensure that the power plants in the respective state — either individually, together, or in combination with other measures — achieve the interim CO_2 performance rates between 2022 and 2029 and the final CO_2 emissions performance rates for the state by 2030.

States that fail to submit their own plans will have to comply with a federal implementation plan. The draft federal plan requires power plants to achieve the same uniform emissions performance standards, but also contemplates emissions trading. EPA still must issue a final rule specifying whether emissions trading under any backup federal plan imposed on states that fail to adopt their own plans would be a "mass-based" cap-and-trade program or a program that relies on trading in emission rate credits.

The percentage reductions the US is requiring in CO_2 emissions from power plants vary by state.

In a mass-based program, EPA would create a state emissions budget for each multi-year compliance period setting the tons of CO_2 that could be emitted by power plants in each state during that period. EPA would initially distribute allowances among power plants based on their historic generation rates. Subsequent allocations to each power plant would be a fraction of the initial allocation. Allowances could be bought and sold on the open market or reserved for future use. Each power plant would have to have enough allowances to cover its actual emissions. If the power plant emits less than its allowed emissions, then, at the end of the compliance period, it would be entitled to retain unused allowances, sell them into an emissions trading market or transfer them to another power plant.

In a rate-based program, power plants must meet an emissions standard, expressed as a rate of pounds of CO_2 per megawatt hour. Plants that emit above their assigned rates would have to buy emission rate credits on the open market. A utility could accumulate emission rate credits if its power plants emit less than the permitted rate or by generating electricity from wind, solar, hydropower or geothermal energy.

Renewable Energy

The final Clean Power Plan includes a "clean energy incentive program" — called CEIP — that will help states transition to greater reliance on renewables and energy efficiency.

CEIP is a voluntary matching fund designed to encourage investment in solar and wind projects and in energy efficiency projects in low-income communities. CEIP will reward states that invest early in renewable energy generation and demand-side energy efficiency measures to reduce electricity usage during one or both of 2020 and 2021 by giving the states matching allowances or emissions rate credits that can be applied toward meeting emissions reduction goals or traded in an emissions trading marketplace.

The reason the government is focusing on solar and wind projects rather than renewable energy more broadly is it believes that solar and wind projects can be on line in time to provide electricity by 2020 and 2021. Projects with more lengthy development timelines, such as offshore wind farms, may not benefit from CEIP given the short time to complete projects to qualify.

A project must satisfy five requirements in order for a state to receive matching allowances or emission rate credits for the project under CEIP. First, the project must be physically in the state. Second, the state must have submitted its own state implementation plan, and that plan must provide for state participation in CEIP. Third, the project must not already be under construction, in the case of renewable energy projects, or already be in operation, in the case of energy efficiency, on the date the state submits its state implementation plan to EPA for approval. Fourth, the project must generate or save megawatt hours in 2020 or 2021. Only wind and solar projects qualify. Energy efficiency projects qualify only if they are in low-income communities.

In addition to the incentives provided by the CEIP, EPA is proposing that 5% of the allowances allocated to each state in connection with a mass-based program be set aside for distribution to qualifying wind, solar, geothermal and hydropower projects that add generating capacity beyond what existed in 2012. Unlike CEIP, which would reward wind and solar projects for only a limited period, allowances under this proposed set aside would be available during the entire compliance period.

Reliability of the grid is a potential issue. The Clean Power Plan requires each state to demonstrate that it has considered reliability issues in developing its state implementation plan, and there are mechanisms for revision of state implementation plans to address unforeseen reliability issues and a reliability "safety valve." The safety valve would permit temporary operation of dirtier generating units to ensure grid reliability. EPA is coordinating implementation of the safety valve with the Department of Energy and the Federal Energy Regulatory Commission.

Political Uncertainty

The Clean Power Plan may be President Obama's signature environmental initiative, but its implementation and enforcement will be the responsibility of the next administration. The United States will go to the polls to elect a new president in November 2016 who will take office in late January 2017.

Any new Republican administration that takes office in 2017 would probably try to roll back the plan before it can be implemented. The Obama administration is hoping that a constituency will have developed by then to keep the plan in place, since states are required to have developed their own plans before the presidential election and the opposition to the plan has not come from the electric utilities as much as from coal mining companies. The utilities grow only by making new investments that go into rate base. New rules requiring utilities to invest in pollution control equipment or in new, cleaner power plants would allow the utilities to add to rate base. Utilities also need to be able to plan ahead. There is a widespread belief that measures to reduce CO_2 emissions are inevitable. Many utilities might rather have certainty rather than be left with no clear guidance.

On the state level, the path forward is also rocky. A number of coal states, including Texas, Oklahoma, Indiana, Louisiana, Ohio and West Virginia, have either expressly said they will not comply or have expressed doubt about their intentions to comply. Faced with the prospect of having / continued page 20

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agreement to acquire Oncor, the electric transmission and distribution company that owns 119,000 miles of power lines and serves three million customers in north and west Texas.

The Hunt consortium will acquire Energy Future Holdings, the bankrupt parent of 80% of Oncor. EFH, which also owns a separate generating subsidiary, is essentially being split in two. The generating subsidiary will be spun off tax free to a group of first-lien creditors of the generating subsidiary in satisfaction of $25 billion in debt. Secured creditors of the transmission business, who are owed another $10 billion, will be repaid in cash. The Hunt consortium will raise about $12.5 billion in new money that will be used in part to pay the creditors who are receiving cash.

Energy Future Holdings, a Dallas, Texas-based utility formerly known as TXU, filed for bankruptcy last April. The company was acquired in 2007 by two private equity groups, KKR and TPG, in a record-setting leveraged buyout. The debt burden proved too much. The Hunts offered $10.5 billion for Oncor in 2006.

The Hunt consortium will turn EFH into a real estate investment trust, or REIT, to own the transmission and distribution lines. REITs are not subject to corporate income taxes provided they distribute all their earnings to shareholders. The REIT will be owned by the consortium members, who are unsecured creditors of Oncor, and be managed by Hunt. Hunt will form a separate operating company to which it will transfer all the Oncor employees and the Oncor name. The Hunt family will own the operating company. The REIT will lease the T&D assets to the operating company, which will use them to supply electricity to Oncor customers and pay a share of the revenue to the REIT as rent for use of the assets.

The transaction will require a number of government approvals, including from the Public Utility Commission of Texas. The commission approved the Hunt family's acquisition of Sharyland Utilities, a relatively small electric utility in south and central Texas, in 2008. The Sharyland assets are also / continued page 21

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to comply with a fallback federal implementation plan if the states fail to act on their own, the coal states may eventually capitulate and adopt their own plans or delay submission in the hope that Republicans win the White House.

The Clean Power Plan has the potential to create significant investment opportunities in wind and solar over the next several years, but legal and political uncertainties remain that will have to be better understood in order to evaluate the potential. ◎

Table 2: Rate-based CO_2 Emissions Goals (Pounds of CO_2 per Net MWH)

State	Interim Emissions Goal	Final Emissions Goal
Alabama	1,157	1,018
Arizona	1,173	1,031
Arkansas	1,304	1,130
California	907	828
Colorado	1,362	1,174
Connecticut	852	786
Delaware	1,023	916
Florida	1,026	919
Georgia	1,198	1,049
Idaho	832	771
Illinois	1,456	1,245
Indiana	1,451	1,242
Iowa	1,505	1,283
Kansas	1,519	1,293
Kentucky	1,509	1,286
Lands of the Fort Mojave Tribe	832	771
Lands of the Navajo Nation	1,534	1,305
Lands of the Uintah and Ouray Reservation	1,534	1,305
Louisiana	1,293	1,121
Maine	842	779
Maryland	1,510	1,287
Massachusetts	902	824
Michigan	1,355	1,169
Minnesota	1,414	1,213
Mississippi	1,061	945
Missouri	1,490	1,272
Montana	1,534	1,305
Nebraska	1,522	1,296
Nevada	942	855
New Hampshire	947	858
New Jersey	885	812
New Mexico	1,325	1,146
New York	1,025	918
North Carolina	1,311	1,136
North Dakota	1,534	1,305
Ohio	1,383	1,190
Oklahoma	1,223	1,068
Oregon	964	871
Pennsylvania	1,258	1,095
Rhode Island	832	771
South Carolina	1,338	1,156
South Dakota	1,352	1,167
Tennessee	1,411	1,211
Texas	1,188	1,042
Utah	1,368	1,179
Virginia	1,047	934
Washington	1,111	983
West Virginia	1,534	1,305
Wisconsin	1,364	1,176
Wyoming	1,526	1,299

Table 3: Mass-based CO_2 Emissions Goals (Short Tons of CO_2)

State	Interim Emissions Goal (2022-2029)	Final Emissions Goals (2030-2031)
Alabama	497,682,304	113,760,948
Arizona	264,495,976	60,341,500
Arkansas	269,466,064	60,645,264
California	408,216,600	96,820,240
Colorado	267,103,064	59,800,794
Connecticut	57,902,920	13,883,046
Delaware	40,502,952	9,423,650
Florida	903,877,832	210,189,408
Georgia	407,408,672	92,693,692
Idaho	12,401,136	2,985,712
Illinois	598,407,008	132,954,314
Indiana	684,936,520	152,227,670

State	Interim Emissions Goal (2022-2029)	Final Emissions Goals (2030-2031)
Iowa	226,035,288	50,036,272
Kansas	198,874,664	43,981,652
Kentucky	570,502,416	126,252,242
Lands of the Fort Mojave Tribe	4,888,824	1,177,038
Lands of the Navajo Nation	196,462,344	43,401,174
Lands of the Uintah and Ouray Reservation	20,491, 560	4,526,862
Louisiana	314,482,512	70,854,046
Maine	17,265,472	4,147,884
Maryland	129,675,168	28,695,256
Massachusetts	101,981,416	24,209,494
Michigan	424,457,200	95,088,128
Minnesota	203,468,736	45,356,736
Missouri	500,555,464	110,925,768
Mississippi	218,706,504	50,608,674
Montana	102,330,640	22,606,214
Nebraska	165,292,128	36,545,478
Nevada	114,752,736	27,047,168
New Hampshire	33,947,936	7,995,158
New Jersey	139,411,048	33,199,490
New Mexico	110,524,488	24,825,204
New York	268,762,632	62,514,858
North Carolina	455,888,200	102,532,468
North Dakota	189,062,568	41,766,464
Ohio	660,212,104	147,539,612
Oklahoma	356,882,656	80,976,398
Oregon	69,145,312	16,237,308
Pennsylvania	794,646,616	179,644,616
Rhode Island	29,259,080	7,044,450
South Carolina	231,756,984	51,997,936
South Dakota	31,591,600	7,078,962
Tennessee	254,278,880	56,696,792
Texas	1,664,726,728	379,177,684
Utah	212,531,040	47,556,386
Virginia	236,640,576	54,866,222
Washington	93,437,656	21,478,344
West Virginia	464,664,712	102,650,684
Wisconsin	250,066,848	55,973,976
Wyoming	286,240,416	63,268,824

IN OTHER NEWS

held through a REIT.

Moody's Investors Service warned that the acquisition may lead to arguments over the proper tax component that Oncor is allowed to pass through to customers in electricity rates. Ratepayer groups are starting to line up for rate cuts.

The Hunts launched a separate REIT called InfraREIT as a vehicle to build a power-line business across Texas, New Mexico and Arizona.

In another use of a REIT to escape from bankruptcy, Caesar's Entertainment said in late August that it has agreement from the most senior creditors of a bankrupt subsidiary, Caesar's Entertainment Operating Co., to spin off the subsidiary's real estate assets into a new real estate investment trust that would be owned by the subsidiary's creditors and then lease them back to the subsidiary. The move is expected to reduce the subsidiary's debt by about $10 billion out of $11.7 billion in total and allow it to emerge from bankruptcy. Use of a REIT enlarges the value available to creditors since the REIT will eliminate corporate-level income taxes. The subsidiary filed for bankruptcy on January 15.

The company said it will rely on a "should" opinion from outside counsel that the spinoff will not trigger income taxes on the real estate assets. The IRS has a hold on rulings about tax-free spinoffs where passive assets with only a relatively small amount of active business are spun off together. The agency put the issue on its latest business plan, or a list of issues it hopes to tackle by the end of June next year.

There is only one casino REIT trading currently — Gaming and Leisure Properties Inc. — that Penn National Gaming spun into a REIT in 2013. The shares peaked at $46.80 a share in November 2013 and were trading as the *NewsWire* went to press at $31.37 a share.

Pinnacle Entertainment, another gaming company, said in July that it hopes to complete a spin off into a REIT in the second quarter 2016.

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The Coal Industry: Emerging Issues in Bankruptcy Cases

by Douglas E. Deutsch, in New York

The US coal industry is being forced by competition from natural gas and renewable energy to "right size." At least part of the right sizing will be done through the bankruptcy process.

An example is the bankruptcy filing by Patriot Coal, the 12th largest coal producer in the United States, in May. It was the second bankruptcy filing for the company in three years. Walter Energy and Alpha Natural Resources filed for bankruptcy protection in July and August. They are the 10th and 4th largest US coal producers. Other bankruptcy filings by coal companies are expected.

This article explores the common themes and issues that will be addressed in future coal bankruptcy cases, focusing on what a bankruptcy filing can accomplish for a coal producer, and what it is not likely to accomplish. Every coal case will have to work through a minefield of employee retiree and environmental issues.

Coal Industry Challenges

Natural gas and oil output are up significantly in the United States due to fracking. This has led to a fall in coal prices. Coal accounts for roughly 39% of US electric generating capacity. Coal plant retirements are expected to accelerate due not only to competition from natural gas and renewable energy, but also to tougher environmental regulation of mercury and carbon dioxide emissions from fossil fuel power plants. When utilities are considering options for replacement plants, cheaper and cleaner gas is almost always the preferred option. Updating plants with expensive scrubbing equipment to clean coal emissions is not cost effective and thus is almost never done. The result is a shrinking market for thermal coal.

Of course, not all coal is used to produce electricity. Metallurgical coal is used in the steel industry. However, there is not good news on that side of the coal equation either. The global steel market has softened, leading to a reduction in demand for metallurgical coal also.

Demand problems are not the only issues the coal industry is facing. Substantial legacy liabilities continue to be a major cost. Employee and retiree obligations have been huge issues for coal producers for decades. Environmental regulations have also added additional costs to coal production. Meanwhile, private litigants have brought a number of actions against coal companies that have also raised the cost of operating coal mines.

Employee Issues

Many coal companies have inadequately funded plans for retired miners. The burden of paying retirement obligations out of operating cash flow is a major burden on current operations. Federal mandates and rules specific to the coal industry are a source of additional costs. Bankruptcy may be the only option for a coal producer that must reduce employee and retiree costs to stay in business.

In a bankruptcy case, debtors are typically allowed to reject unfavorable contracts. The collective bargaining agreement between a coal producer and a union is a contract for this purpose. However, the US bankruptcy code does not treat a collective bargaining agreement as a typical contract that can be easily rejected. Such agreements are protected from outright rejection by a required negotiation process intended to provide collective bargaining agreements with special bankruptcy protections. A similar process is required for modifications to retiree benefits.

Collective bargaining agreements establish the work terms between an employer and its employees. They usually include provisions on base pay, overtime, vacation, health and retiree benefits and similar benefits, as well as work rules.

Section 1113 of the US bankruptcy code permits a bankrupt company to reject a collective bargaining agreement if certain requirements are first satisfied. These requirements include that the company must provide the union information about the company, make a formal proposal to the union to modify the collective bargaining agreement, and meet in good faith with the union in an attempt to negotiate the changes. The collective bargaining agreement can be set aside if the union then rejects the proposed changes and the bankruptcy court ultimately finds that the changes are "necessary" for a reorganization.

Determining whether a proposed modification is "necessary to permit the reorganization of the debtor" has been subject to debate. Courts in the third circuit, which includes federal courts in Delaware, have found that "necessary" means essential to prevent liquidation of a company in the short term. In contrast, courts in the second circuit, which includes federal courts in New York, believe that "necessary" requires only that the modifications will increase the likelihood of a successful reorganization.

Other interpretations also exist in other parts of the country. The result is that coal producers may have the option of selecting among venues, one of which may be more receptive to finding for the coal company than other venues.

Retiree benefits are governed by section 1114 of the bankruptcy code. As section 1114 is generally modeled on section 1113, the same criteria are used in each. That leads to the same debate as to what "necessary" means. The main difference between sections 1113 and 1114 is that, while a collective bargaining agreement can only be rejected under section 1113 (leaving the employer and the union to renegotiate employment terms), non-consensual modifications to retiree benefits can be approved under section 1114.

Special Coal Benefit Issues

In addition to addressing the substantial employee and retiree issues common in mature industries like steel and airlines, coal producers must also address a series of rules and regulations that add substantial costs to a coal producer restructuring. These falls under three headings: the Coal Act, black lung benefits and Pension Benefit Guaranty Corporation rules.

The Coal Act was passed by Congress in 1992. It was intended to address the looming insolvency of certain trusts that were paying coal industry retiree health care costs and also to address so-called "orphan" retirees. "Orphan" retirees are those who were promised medical benefits by a coal producer no longer in business.

The Coal Act requires most coal producers to make contributions based on, in part, the number of beneficiaries assigned to them by the Social Security Administration, as well as a percentage of orphan beneficiaries who worked for other, defunct coal companies.

Courts have found that Coal Act obligations can be modified by a company in a chapter 11 bankruptcy if the requirements of section 1114 are followed. Several courts have also found that coal companies can sell their assets free and clear of Coal Act obligations under section 363(f) of the bankruptcy code. However, it is also clear that Coal Act obligations that arise after a bankruptcy filing are to be treated as "administrative expenses" and entitled to priority treatment under the bankruptcy code, meaning they are paid ahead of any recovery by unsecured creditors.

The Black Lung Act of 1973 provides benefits to coal miners who are affected by black lung disease. The Act allows such a miner to file a claim with the US Department */ continued page 24*

IN OTHER NEWS

KENYA appears to have decided to waive withholding taxes on payments to foreign companies that enter into power contracts to supply electricity.

The Kenyan Treasury published the following announcement in the official Gazette on August 19: "in order to attract more investments in the energy sector for the purpose of lowering the cost of energy, as may be provided under any Power Purchase Agreement . . . the payment that shall be made to a non-resident for services rendered under a Power Purchase Agreement shall be exempt from tax." The scope of the exemption is not yet clear.

SOME US STATES are drawing up lists of tax havens.

A new Oregon statute that the governor signed in late July added more countries to a list of tax havens that the state has maintained since 2013.

Corporations filing consolidated returns in Oregon must include income from affiliated entities incorporated in countries on the list. Oregon added Guatemala, Trinidad and Tobago, and five islands that were part of the Netherlands Antilles to a list that already included such countries as Bahrain, Cyprus, Liberia, Lichtenstein and Malta. Holland and Switzerland avoided being added to the list after a group of Dutch diplomats and finance ministry officials traveled to Oregon in April. The state has decided for now not to put any large countries with significant economies on the list.

The city council in Washington, DC voted on August 11 to require combined reporting of income by DC companies with affiliated entities in tax havens. Its tax havens list has 39 jurisdictions, including the Cayman Islands, British Virgin Islands, Bermuda, Luxembourg, the US Virgin Islands, the Channel islands and Mauritius. The US Congress has 30 days to overrule the council if it chooses.

Montana also has a tax havens list.

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of Labor. The department then investigates the claim and holds the appropriate coal producer responsible for the black lung disease. If that coal producer files for bankruptcy, then a trust fund pays the required monthly benefits and medical costs and then seeks reimbursement from the coal producer. The Act provides that the trust can file a lien against that producer in a bankruptcy case, thus creating a claim with the same high priority as a tax claim. Moreover, if that claim is not paid, then the coal producer's officers can also be held personally liable for the obligation. The result is that these claims are usually paid in full by the coal company.

Coal companies trying to "right size" through bankruptcy filings face a host of issues.

The Pension Benefit Guaranty Corporation is a federal agency that steps in to pay (typically reduced) pension benefits owed to employees where the employer has gone out of business or is otherwise unable to satisfy its pension obligations. If a defined benefit pension plan is terminated during a bankruptcy, then a special rule enacted in 2006 to provide the PBGC an additional source of funding will come into play. Under this rule, the employer is obligated to pay the PBGC $1,250 per affected individual for a period of three years. That obligation cannot be discharged in bankruptcy.

Environmental Issues

Coal companies can also have legacy liabilities tied to environmental claims.

Some might argue that addressing those claims was long overdue as there has been a history of substantial damage to health and the environment caused by coal mining. Where clean-up costs could not be paid by these producers, the costs have been borne by state and federal governments. This seemingly unfair outcome led to passage of a web of laws designed to shift all costs associated with protecting the environment, remediating property that is affected by mining, and protecting the health of the population, to mining companies. However, there is a price to pay for this change. The new laws necessarily limit the steps that a coal company might otherwise take in a bankruptcy case to maximize the value of the bankruptcy estate and reorganize successfully.

Mining is regulated by a number of statutes, including the Surface Mining Control and Reclamation Act or "SMCRA," the Clean Air and Clean Water Acts, the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act also known as Superfund.

SMCRA is one of the most important of these statutes. SMCRA requires environmental protection and reclamation standards to be satisfied during mining activities. It does this through required permitting (for example, SMCRA requires a permit for, among other things, coal prospecting, mine plan development, and mine pit backfilling) and other requirements.

SMCRA requires a coal mine operator to provide a performance bond to the appropriate regulatory authority (either an office within the US Department of the Interior or, where so assumed by a state, a similar state entity) to ensure performance of all permit and regulatory requirements. The bond must be large enough in amount to remediate the coal property. Mining companies are allowed to self-bond their liabilities in a number of states. But self-bonding may create additional problems for coal companies in financial distress. Self-bonding normally requires a mining company to maintain certain financial benchmarks, such as a specific rating agency grade. A finding that a coal company is no longer qualified to self-bond is most likely to occur at the most difficult of times. For example, after reading in the press about financial difficulties being experienced by Alpha Natural Resources this spring, Wyoming concluded that Alpha could no longer satisfy the state's self-bonding requirements. While Alpha challenged Wyoming's decision, a new potential $400 million bonding obligation was essentially imposed by the state at a time when it was impossible for Alpha to afford it. This was a primary reason that Alpha filed for bankruptcy in August.

SMCRA also requires coal operators to pay reclamation fees into trust funds for unfunded remediation costs. These funds are supposed to be used to restore land and water resources degraded by poor mining practices, thus protecting public health and safety. These fees are due quarterly and are based on the number of tons of coal mined. Different rates are charged for surface mining and underground mining. In bankruptcy cases, courts have found that fees payable under SMCRA are "excise taxes" that cannot be discharged.

Coal regulators have an additional and powerful weapon if an individual (as an agent) fails to operate the mine in an appropriate fashion: a regulator can bring a civil action directly against that individual. For example, failure to remediate property as promised has led to financial liability for the individual agent who acknowledged representing a company, including with respect to promises to remediate.

Permit-blocking, a form of industry "black listing," is another substantial deterrent to individuals who are coal experts and would like to continue to work in the coal industry. If a SMCRA violation exists and has not been abated, and perhaps cannot be abated because the company has insufficient funds, the president of the company may very well not be able to work for another mine in the future. In this scenario, the mine official is placed in a difficult situation. On the one hand, environmental law requires the mine official — who could be a liquidating trustee — to remediate a property and the possible downside for not doing so is the loss of a person's ability to obtain coal industry employment in the future. On the other hand, bankruptcy law requires the mine official to maximize value of the company's assets (including by minimizing costs). It is difficult to prove that a trustee has not complied with the bankruptcy mandate. Thus, and unsurprisingly, the typical outcome in such cases is that SMCRA fees and remediation obligations are paid in bankruptcy cases.

Officers of mining companies entering into bankruptcy have strong incentives to ensure that remediation and other environmental obligations are paid in full, even if such obligations might legally be subject to compromise in bankruptcy. Nothing in the US bankruptcy code abrogates an owner or operator's obligation to continue operating the property while */ continued page 27*

IN OTHER NEWS

OREGON is considering whether to claw back profits that some buyers of state tax credits made by buying credits at a reduced price.

The state rewarded owners of new renewable energy projects in the state through a business energy tax credit – called BETC. The program ended in 2014.

Developers who were unable to use the credits could sell them. Sales could be arranged through the Oregon Department of Energy or privately. The Department of Energy had a formula for setting the sales price. DOE rules required private sales to be at the same price, but the department decided not to enforce the requirement, and private sales were sometimes at prices that were well below the formula price.

Critics charge that the private sales at low prices meant that too little of the intended subsidy ended up with renewable energy companies. The Department of Energy is proposing to amend its rules retroactively to drop the requirement that private sales be at the formula price.

However, the Secretary of State has asked the department for records relating to private sales, including notices from developers who were planning private sales. Some state legislators have said they "might consider" legislation to take back some of the tax credits sold at low prices.

There have been 43 audits of BETC transactions by the state Department of Revenue. The department found in 20 of the audits that buyers of the tax credits underpaid capital gains taxes when they used the credits.

The IRS said in an internal legal memorandum in 2011 that someone who buys a state tax credit has a capital gain, when he uses it, equal to the difference between the state taxes the credit offset and the amount he paid for the credit. Thus, for example, a buyer who pays $70 for a $100 tax credit has a capital gain of $30 when the credit is used. (For earlier coverage, see the May 2012 Project Finance NewsWire *starting on page 19.)*

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the company is in bankruptcy in compliance with environmental laws. Environmental obligations that arise after the bankruptcy filing must be paid as "administrative expenses" ahead of payments to creditors. The US Supreme Court has made clear that bankrupt companies cannot simply abandon their hazardous properties in a bankruptcy case in contravention of statutes designed to protect public health or safety.

Postscript

One of the main reasons that Patriot, a coal company, filed for bankruptcy in 2012 was to address its employee and retiree obligations. Following the required proposal and negotiation process, Patriot filed a motion to reject its collective bargaining agreement to terminate certain retiree benefits. In a 102-page opinion, the bankruptcy court found that Patriot's requests were necessary for reorganization and granted the motion. That decision was appealed to a federal district court. Meanwhile, the union and Patriot continued to negotiate. Ultimately, Patriot and the union agreed to modify the existing collective bargaining agreement and address certain retiree benefit issues. Patriot claimed that the result of the settlement was approximately $130 million in cost savings for each of the next four years. Nevertheless, the result was not as hoped.

In May 2015, Patriot filed for bankruptcy again. In first-day filings, Patriot blamed low coal prices, increased regulation costs, and legacy liabilities. Patriot said that after its emergence from bankruptcy in 2012, it was still obligated to contribute to the miners' pension plan and to make payments under the Coal Act and the Black Lung Act, each of which it said were unrelieved by the prior bankruptcy. It also said it has substantial environmental liabilities. This highlights what appears as a clear problem in coal cases: employee and retiree benefits and environmental obligations are difficult to modify, even after a bankruptcy filing.

The next coal bankruptcy filings will confirm whether this remains true, even in the most difficult of industry environments. ◎

Lessons From US Offshore Wind Projects to Date

by Keith Martin, in Washington

A number of lessons emerge from the offshore wind projects that have been attempted to date in the United States.

Deepwater Wind has a $290 million, 30-megawatt project under construction in the Atlantic ocean three miles from Block Island off the coast of Rhode Island. The project will use five six-megawatt Alstom Haliade 150 turbines. Cape Wind came very close to closing in December on the financing for the $2.5 billion, 364-megawatt first phase of a 468-megawatt wind farm in Nantucket Sound near Martha's Vineyard off the Massachusetts coast. When the financing failed to close by December, the two utilities that agreed to buy the electricity from the project under long-term contracts cancelled the contracts. Cape Wind is asserting that it is entitled to an extension of the construction-start deadline in the contracts due to force majeure: the prolonged litigation that the project has had to endure with opponents.

Talks with the developers, lenders and equity investors involved with the two projects as well as with other less advanced projects suggest more than a dozen lessons for anyone attempting another such project in the future. Chadbourne acted as counsel to the lenders on the financing for Block Island and as financing counsel to the developer of Cape Wind.

Scale and Timing

Block Island demonstrates it may be better to make the first project a small project as proof of concept before moving to a larger scale.

A developer should consider developing a large project in legally-separated phases to allow for financing of manageable tranches. This approach requires smart planning during project development in lease negotiations, interconnection queue requests, and negotiation of the framework turbine supply agreement, foundation installation contract, cable and boat contracts, and power purchase agreements. Developing a project this way does not preclude a single large portfolio financing later if market conditions permit.

These are already complicated projects because of the number of contractors involved. A large and expensive project requires lots of financing parties, increasing the difficulty of holding everything together.

Offshore wind projects are intensely political. The high capital cost per installed megawatt means the projects rely on political support to get done. Both Block Island and Cape Wind had power purchase agreements that paid the projects more than $200 a MWh. Such contracts require support from the governor and state public utility commission to pass through the wholesale power price in rates.

Move as quickly as possible though the development process. There is no time to spare. The longer the development cycle, the more likely the politics are to change and for a smaller developer to run out of money. Cape Wind saw Deval Patrick (D), who was a strong supporter of the project, leave office at the end of 2014, to be replaced as Massachusetts governor by Charlie Baker (R), who opposed the project in the past and has at best a hand's-off policy about the project, viewing it as a private contracting dispute between the developer and the utilities. Chris Christie (R) called in 2010 for turning New Jersey into a wind superpower, seemingly to lose interest around the time he started running for president, leaving a pilot wind farm proposed by Fishermen's Energy off Atlantic City to struggle.

Once the project moves into financing, move rapidly to find common ground and not let negotiations bog down.

Well-funded and determined opposition groups can kill a project. Avoid choosing a site that invites well-financed opposition. The latest offshore sites that the federal government has been putting out for lease are likely to face less interference because they are farther from shore.

Offshore wind projects involve multi-contract construction arrangements. The projects are not like conventional power projects on land where there is a fixed-price, turn-key construction contract for the entire project under which the EPC contract "wraps" construction by warranting that all the project components will work together when the power plant is fully assembled. An onshore wind farm usually has two contracts: a turbine supply agreement and a balance-of-plant construction contract. With offshore wind, there is no one or even two contractors who take responsibility for the entire project. It is important to make sure everything fits together in terms of risk coverage, timing, damages, who pays what to whom, and what happens if there are delays in construction.

Both Block Island and Cape Wind proved that lenders can get comfortable with the multi-contract construction arrangement and some legal challenges. The Block Island financing closed with such an arrangement, and the senior / *continued page 28*

IN OTHER NEWS

RENEWABLE PORTFOLIO STANDARDS survived a court challenge.

A US appeals court said in July that a Colorado statute requiring utilities in the state to deliver at least 20% of their electricity from renewable sources does not violate the part of the US constitution that forbids states from enacting laws that interfere with interstate commerce.

A lower court had come to the same conclusion earlier. The state RPS target is scheduled to increase to 30% in 2020.

The Energy and Environment Legal Institute sued the members of the Colorado Public Utilities Commission to block implementation of the state RPS statute.

The group said that the Colorado statute harms a coal company in another state that is a member of the law institute because coal-fired power plants in other states will lose business in Colorado, leading to less demand for coal. It argued that the Colorado statute regulates conduct outside Colorado in violation of the US constitution.

The court said the problem with this argument is that it would require courts to strike down all state laws that regulate health or safety by requiring manufacturers who want to do business in the state to alter their designs or labels. It said it can see how a state statute that discriminates against out-of-state rivals goes too far. An example is a state law requiring all milk sold in New York to be purchased from New York dairy farmers. However, requiring Colorado utilities to supply a certain percentage of electricity from renewable sources confers no special advantage on Colorado power producers.

The decision was in a case called *Energy and Environment Law Institute v. Epel et al*.

The law institute is waiting for a decision in another case in Minnesota before deciding whether to appeal. In that case, North Dakota and various electric cooperatives sued to block enforcement of a "Next Generation Energy Act" that Minnesota enacted in 2007 that bars construction of new power plants of 50 / *continued page 29*

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lenders were prepared to close on Cape Wind, helped by a $150 million loan guarantee that was expected from the US Department of Energy. DOE was not taking first loss, but its presence was a form of political risk insurance.

Financing

Offshore wind farms take a long time to construct. Deepwater has a 22-month construction cycle; the project is expected to be in commercial operation in the late fall 2016. Cape Wind was not expected to come on line until sometime in 2017 if the financing had closed by December 2014.

The long construction period means that it will be impossible to get a forward tax equity commitment at closing on the construction financing. It is difficult to secure tax equity commitments at construction closing more than a year in advance. Therefore, an alternate takeout will have to be negotiated for the construction debt in case tax equity cannot be arranged.

Developers might consider working with institutions that have both construction financing and tax equity capacity, but the list of such institutions is short.

There is plenty of interest among banks. At least 20 to 25 banks are potential lenders. The risk premium is only about 25 basis points over bank debt for onshore wind farms. Add another 25 basis points for other factors like litigation.

Plan for a debt tenor of construction plus five to seven years with mini-perm features and a term debt-equity ratio of 70-30. Lenders are willing to treat subordinated mezzanine debt as equity for this purpose. For comparison, onshore wind farms can reach debt-equity ratios of 90-10.

The much smaller pool of potential equity investors in US offshore wind projects means that equity can be very expensive.

Given the inability to line up tax equity at construction financing, it is better to find equity investors who can use the tax benefits themselves. The need for project-level debt means that the pool of potential traditional tax equity investors is likely to be very small. It is rare today to find mainstream tax equity investors who are willing to do partnership flip tax equity deals with project-level lenders who come ahead of the tax equity in the capital structure; most debt today is back-levered debt at the level of the sponsor that is behind the tax equity in line. Leveraged flip deals require an agreement with the senior lenders on forbearance: the tax equity will want the lenders to agree not to foreclose on the project for a period of time to let the tax equity investors reach their target yields. The market consensus on forbearance terms appeared to collapse in 2014 after K-Road was unable to close a leveraged partnership flip transaction it had fully negotiated after inability to reach agreement on forbearance. Debt is easier to combine with tax equity in sale-leaseback transactions, but sale-leasebacks are not possible in wind projects unless the project claims a 30% investment tax credit on the project cost rather than production tax credits of $23 a MWh, adjusted for future inflation, on the first 10 years of electricity output.

The high capital cost may make these investment tax credit deals rather than production tax credit transactions, but the scale of the investment credits on larger projects could require clearing the tax equity market. The investment credit is claimed entirely in the year the project is placed in service, placing greater demands on available tax capacity, rather than spreading the needed tax capacity in smaller increments over each of the first 10 years of commercial operation. The investment tax credit being projected on Cape Wind in late 2014 was $600 million, a market-clearing figure. On the other hand, a tax equity investor relying on production tax credits is taking 10 years of operating risk while the full investment credit is locked in at inception when the project is put in service.

Seventeen offshore wind projects have been financed to date in Europe. Scale eventually brings down costs, but the scale economies in Europe have not translated fully into lower costs in the United States in part because the United States lacks the port, vessel and other infrastructure required to install and maintain offshore wind turbines.

Other Wisdom

US laws and inexperience impose premiums. The Jones Act and Cargo Preference Act may add as much as 50% to transportation costs. The marine construction industry, ports, insurance and the financial markets all charge risk premiums for offshore wind farms. The whole infrastructure of ships and ports that supports European offshore wind has to be replicated in the United States.

The premiums should start to shrink once there is an operating history for Block Island. US companies have some related experience that can be transported to offshore wind. It was an "a ha moment" for the banks in Cape Wind to realize that installation of monopiles for the turbines is nothing more than driving a pipe into the seabed with a hydraulic hammer, a task that US companies do when building bridges and LNG terminals, and there are numerous US submarine transmission cables. Crane and maintenance barges may be hard to find. A project the size of Cape Wind could build its own; smaller projects have to work within the parameters of what is available on the east coast.

The US permitting process can also be a barrier to reducing costs. The Cape Wind permits were obtained well before financing and required the project to use 2002 technology. Reopening the permits would have been an 18-month process at least and would have reopened the project to more legal challenges.

The shortage of US vendors, ships and equity means all such parties can charge premiums. A turbine vendor will not do cost-plus for turbines. It will insist on value pricing.

At least a dozen lessons emerge from the offshore wind projects that have been attempted to date in the United States.

Regulatory risk and uncertainty around subsidies in the United States add costs. Tax credits for wind projects expire and are renewed in one- and two-year intervals. It is hard to accomplish something novel and complex in the face of an uncertain subsidy regime. Even if the subsidy were certain, the uncertainty around the ability to raise tax equity significantly erodes the pricing the project will find on offer from potential equity investors, since such investors assign less value to the investment.

Finding the development staff with the right experience can be a challenge. The multi-contract construction structure is not a skill set that onshore wind companies have. It would be a good idea to hire an experienced offshore construction team early in the process. It will have to be found in Europe or in offshore construction in the Gulf of Mexico. One potential bright spot is that equipment vendors and vessel companies may reach saturation or face a slowdown in Europe and start looking to the US for growth.

It is best to use the largest turbines and put them as high up and far out as possible to spread the higher cost per foundation and labor in the water on land over a larger output. Cape Wind has a 38% capacity factor in Nantucket Sound versus 48% for Block Island in the unobstructed ocean. ◎

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megawatts or more in the state that contribute to carbon dioxide emissions unless an offset project is undertaken at the same time to reduce emissions by the same amount. The statute also bars electricity from being imported into Minnesota from such power plants in other states.

The Minnesota statute complicates life for electric cooperatives that cross state lines. For example, the Dairyland Power Cooperative in Wisconsin provides electricity from a coal-fired power plant in Wisconsin that Minnesota views as a new power plant. About 16% of the electricity goes to members of the cooperative in Minnesota. The Basin Electric Cooperative in North Dakota supplies power to 135 rural electric system members in nine states, including 12 members in Minnesota. The members share the costs. Basin Electric buys a lot of electricity through requests for proposals.

A federal district court held in April 2014 that the Minnesota statute violates the US constitution because it requires coops in other states effectively to seek approval from Minnesota before undertaking a transaction in another state. The case is North Dakota v. Heydinger. *It is now before a US appeals court.*

TRANSFERS OF APPRECIATED PROPERTY TO PARTNERSHIPS get IRS attention.

The IRS is concerned about situations where appreciated assets are transferred to a partnership in which one of the other partners is a foreign affiliate of the US partner making the transfer. An asset is an appreciated asset if it is worth more than the unrecovered cost basis the US owner has in it at the time of transfer.

The United States used to require any US company contributing appreciated assets to a foreign partnership before 1997 to pay a US toll charge on the contribution.

US tax law requires a partner contributing appreciated assets to any partnership to pay tax on the appreciation, but how quickly the partner does so depends on how the partnership chooses to make something called a "section 704(c) adjustment." If it uses the / continued page 31

Developing a New Nuclear Project in Europe

by Li Zhang, in London

There are 131 nuclear power reactors with a combined capacity of around 122,000 megawatts currently operating in 14 European Union member states and managed by 18 utilities. They account for 27% of the electricity generated across all of the 28 EU member states. Despite the fact that nuclear is a proven source of low-carbon, secure and reliable electricity, the sector faces a struggle to survive within the EU, where some countries, such as Austria, Germany and Belgium, are pursuing policies that are strongly anti-nuclear. EU nuclear generating capacity is expected to decline over the period through 2030 due to the closure of a number of reactors.

Today, new construction is underway in only three EU member states: Finland, France and Slovakia. These construction projects have all experienced cost overruns and delays. Additional new projects are planned or under consideration in Finland, Hungary, Lithuania, the United Kingdom, Bulgaria, Czech Republic, The Netherlands, Poland, Romania, Slovakia, Slovenia and Sweden. The long-term future of nuclear power in the EU will depend on whether these planned projects are successfully built.

This article discusses the legal issues and challenges that developers of nuclear power projects are facing in the European Union.

Euratom Treaty

All EU member states are parties to a 1957 Euratom treaty that established the European Atomic Energy Community, now known as Euratom, to coordinate research programs in the member states for the peaceful use of nuclear energy. The Euratom treaty is a separate treaty from the main EU treaty that governs operation of the European Union. It has two major implications for nuclear new-build projects in Europe.

First, developers of new nuclear projects are required to notify the European Commission of their investment projects under articles 41 through 44 of the Euratom treaty.

This notification must be done three months before the first contracts are concluded with suppliers or, if the work is to be carried out by the developers with their own resources, three months before the work begins. In practice, a meeting would be held with the Commission to talk about the timetable and information required to be provided before any filing.

After the filing, the Commission does an assessment of the proposed project and communicates an opinion to the government of the affected country about whether the project fulfils the objectives of the Euratom treaty.

There is no time limit for the Commission to act. It can take the Commission as long as a couple years to form an opinion. The opinion has no legally binding effect. However, a project without a favorable opinion from the Commission will not be eligible for loans from Euratom or the European Investment Bank to help build the project. The Commission's favorable assessment under the Euratom treaty does not guarantee favorable assessments on environmental or competition aspects under the EU Treaty, including state aid as discussed below.

Second, article 37 of the Euratom treaty obligates EU member states to keep the Commission informed about how they plan to dispose of radioactive waste. The Commission then has six months to determine whether the proposed plan would lead to significant contamination of the territory of another member state after consulting scientific experts from the member states.

In some member states, a favorable opinion from the Commission on the article 37 notification is a prerequisite for the relevant environmental authorities to issue environmental permits for new nuclear projects. For instance, in the UK, the Environmental Agent will not issue a radioactive substance regulation permit without a favorable opinion first from the Commission on the article 37 notification. In the UK, submission of general data on radioactive waste disposal is usually made by the government, although the ultimate responsibility to provide such data resides with the project developer.

Energy Policy

Within the EU, energy policy is largely decided at the EU level, but the actual energy mix within each member state is determined at the national level.

An EU climate and energy package enacted in 2009 sets a so-called 20-20-20 target for 2020, meaning the EU is aiming by 2020 for a 20% reduction in greenhouse gas emissions from 1999 levels, a 20% share of EU energy consumption produced from renewable energy, and a 20% improvement in energy efficiency.

The EU leaders also agreed to a greenhouse gas reduction target of at least 40% compared to 1990 levels by 2030 and a new target of at least 27% for renewable energy and energy savings by 2030.

A roadmap developed by the Commission suggested further that the EU should cut its emissions to 80% below 1990 levels by 2050.

The role of nuclear energy in achieving these targets is left to each member state to decide. However, national nuclear programs are nevertheless significantly affected by EU legislation. EU regulatory barriers have the potential to cause significant delay or cancellation of new projects.

Nuclear Safety

There has been a struggle between national and European institutions for control over nuclear safety. The Commission tried to enforce European-level measures on nuclear safety and waste, but the member states with nuclear programmes have refused to cede power to the Commission due to the anti-nuclear policies pursued by several EU member states.

The battle over the sovereignty of nuclear safety was settled with the adoption of the 2009 nuclear safety directive. Responsibility for nuclear safety lies with national authorities, and the directive requires them to adopt their own national nuclear safety requirements. An amendment to the nuclear safety directive, adopted in 2014, subjects national nuclear safety regulators to a peer review system. Thus, developers of new projects apply to the national authority in the project country for nuclear safety permits and licenses covering such activities such as siting, construction or operation of nuclear power plants.

Nevertheless, two European-level associations of nuclear regulators — WENRA and ENSREG — have become important, especially after the Fukushima accident.

WENRA — the Western European Nuclear Regulators' Association — is a network of regulators with membership in 17 countries, including the EU member states with nuclear power plants and Switzerland. It was formed in 1999 and has played a major role in coordinating nuclear safety standards across Europe.

ENSREG — the European Nuclear Safety Regulators Group — is an independent expert body created in 2007 by the Commission. It comprises senior officials from the national nuclear safety, radioactive waste safety and radiation protection regulatory authorities from all EU member states and representatives of the Commission. Its role is to help establish conditions for continuous improvement and to reach a common understanding in the areas of nuclear safety and radioactive waste management. It makes recommendations to the Commission.

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"traditional method" to make the adjustment, then the partner may be able to put off being taxed on the appreciation until the partnership liquidates or otherwise sells the assets. If it uses the "remedial method," then the partner must pay tax on the appreciation over the period the assets are depreciated.

The IRS said in a notice in early August that it will collect a tax on the appreciation when the assets are contributed to a partnership in which a foreign affiliate is a partner unless the partnership uses the remedial method for section 704(c) adjustments and satisfies four other requirements.

The notice is Notice 2015-54.

The four requirements are as follows. The partnership must allocate all income and loss related to use or sale of the contributed assets in a constant fixed ratio until the full appreciation has been taxed. The contribution must be reported to the IRS. The US partner must report any remaining untaxed appreciation after certain "acceleration events." The partnership must use the same approach for all appreciated property contributed by the US partner and affiliates for at least 60 months or, if earlier, until all the appreciation has been taxed.

The IRS also plans to extend the statute of limitations for tax assessments related to taxes on such appreciation to eight years. Normally, the government has only three years to assess back taxes.

The IRS said it plans eventually to issue regulations to implement the new policy, but the policy is effective as of August 6.

The policy applies to partnerships in which the US partner and related persons own more than 50% of the partnership by share of capital, profits or losses.

A PARENT COMPANY paying expenses of a subsidiary cannot deduct them, the IRS said.

The IRS made the statement in an internal memo to an IRS international examiner that was made public in late July. The memo is Chief Counsel Advice 20153101F. */ continued page 33*

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Public Procurement

Procurement of new nuclear projects is sometimes subject to EU procurement rules, especially where the procuring entity for the nuclear power is directly or indirectly controlled by the state. The EU 2004 utilities directive has a set of procurement procedures that entities operating in the water, energy, transport and postal service sectors must follow. These rules also apply to the nuclear energy sector with certain exceptions.

There are three categories of contracts that fall within the scope of the utilities directive: works contracts, supply contracts and service contracts, but only to the extent that the relevant contract value exceeds a threshold. When awarding any such contracts for a nuclear project, the procuring entity, if it is a publicly-owned utility, would be required to issue a public tender and follow procedures and award criteria found in the utilities directive. Failure to follow these procedures could cause the contract awarded to be declared void.

There are a number of exemptions in the utilities directive, either excluding certain contracts from the directive or allowing the procuring entity to award the contracts without putting the project out for bid. For instance, the directive does not apply to the contracts awarded for purposes of resale or lease of assets to third parties, or to contracts awarded pursuant to international rules or to contracts in the fields of defense and security. In practice, we have seen some member states rely on these exemptions to award contracts directly to a particular contractor without going through a tender process. Hungary, for example, awarded the contract for construction of the Paks II nuclear project directly to Rosatom via an intergovernmental arrangement with Russia. This strategy has also been pursued by some nuclear developers when seeking to secure nuclear contracts outside the EU.

Thus, before entering into negotiations with a member state, developers should determine whether the procuring entity is able to conduct the procurement without launching a public tender.

State Aid

Challenging market conditions have led governments throughout the world to consider various support mechanisms to help finance nuclear power plants. In the EU, developers must carefully review and negotiate any proposed financing plan involving state aid and engage in discussions with the Commission as early as possible to ensure that any aid measures are compatible with the EU state aid rules.

The EU member states are prohibited in principle by the EU treaty from granting state aid that distorts competition and trade.

However, despite this general prohibition, the EU treaty allows state aid in cases where state aid may be considered to be compatible with the internal market.

The Commission has the exclusive competence to determine the compatibility of state aid under the EU treaty. As far as the nuclear sector is concerned, the current framework requires EU member states wishing to subsidize nuclear energy generation to notify the Commission of any aid measure to be granted. The Commission then decides whether to allow the aid.

The most significant state aid case to date concerning the nuclear sector involves the Hinkley Point C nuclear power project, where the Commission approved the UK government's proposed aid to support the financing of the project. There are three arrangements that were reviewed by the Commission: a contract for differences arrangement ensuring that the operator of the plant receives a stable revenue for a period of 35 years, a state guarantee of construction debt for the project of up to £17 billion, and an arrangement on compensation by the state in the event that the plant must be shut down prematurely on political grounds. Following a lengthy investigation and after the UK government agreed significantly

New nuclear projects are under construction in three EU countries, and another 10 countries have them under consideration.

to modify the terms that were originally notified to the Commission (including raising the guarantee fee and sharing project gains with UK consumers), the Commission eventually approved the UK aid measures and found them to be in line with EU state aid rules.

The Commission's decision on Hinkley Point C sets a precedent for future nuclear projects in the EU. However, the decision is currently facing two legal challenges at the EU Court of Justice: one was initiated by the Austrian government and the other by Greenpeace and nine utilities in Germany and Austria that have renewable energy in their portfolios. The challenge adds to the uncertainty surrounding the future of nuclear energy in the EU.

Source of Finance

There are two EU sources available for financing commercial nuclear power projects: Euratom loans and EIB loans.

Euratom loans are administered by the Commission. Euratom loans were initially restricted to nuclear fuel cycle facilities with an initial credit ceiling of €500 million. The ceiling was then increased to €4 billion and the funds were extended to certain eastern European countries for safety upgrades of nuclear power plants in those countries. In principle, Euratom loans could contribute to the financing of nuclear new-build projects. However, Euratom loans cannot be used as the sole source of finance for any projects and can only fund a maximum of 50% of the total costs of the projects.

The criteria for project eligibility were only that a project receives a favorable opinion from the Commission in technical and economic terms. The Commission makes the final decision. There is no formal involvement of either member states or the European Parliament in the decision. The Commission has been considering a further increase in the loan ceiling since 2004, but no decision has been made.

A Euratom loan could be complemented by a loan from the EIB. The EIB financed numerous nuclear power generation and nuclear fuel cycle projects for about two decades up to the mid-1980s. In 2007, the EIB resumed lending to the nuclear sector and has since provided about €1 billion to three uranium enrichment facilities. In principle, the EIB lending policy adopts a technology-neutral approach toward nuclear energy, meaning all nuclear energy projects are eligible for EIB financing, provided that they are technically, environmentally, financially and economically justified, taking into account the lifetime costs of the projects, and have received a positive opinion from the Commission under articles 41 through 44 of the Euratom treaty. */ continued page 34*

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A US corporation participated in an offshore joint venture. An IRS examiner said on audit that some payments that the US corporation deducted were really payments for the benefit of the joint venture so that the deduction, if any, had to be taken at the joint venture level. The amounts were capital contributions by the US corporation to the joint venture.

The IRS said the only circumstance where a deduction can be claimed by a joint venture participant directly is where the participant can show the payments are for its sole benefit rather than for the benefit of the joint venture.

PARTNERSHIP PAYMENTS to partners are sometimes disguised payments for services and should be reported by the partner as income.

The IRS explained in proposed regulations in July how to tell when that is the case.

There are three labels that the US tax authorities may put on a payment by a partnership to a partner. The payment may simply be a distribution of the partner's share of cash out of partnership earnings. It may be a "guaranteed payment," meaning a payment, like interest for use of the partner's capital, that is not tied to partnership earnings. It may be compensation for services that the partner provided to the partnership. The last two types of payments must be reported as taxable income. Cash distributions, on the other hand, are not usually taxed to a partner until the partner has received more cash than his "basis" in his partnership interest.

The IRS said it will treat a payment to a partner as compensation for services if the partner does something for the partnership, even in anticipation of becoming a partner, and receives cash distributions from the partnership that are not tied in amount to partnership earnings or where there is a high likelihood the partner will receive an expected amount regardless of how well the partnership performs.

Other factors that are less important, but that may point to a disguised payment for services, are whether */ continued page 35*

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Eligible projects include power generation, full fuel cycle, waste management, safety upgrade, lifetime extension, decommissioning and R&D.

In terms of screening and assessment criteria, the normal EIB criteria for large thermal power plants are also used for nuclear, together with additional nuclear appraisal guidelines to address specific issues related to nuclear projects, such as safety regulations, radioactive waste management, plant decommissioning, technology aspects and promoter capacities.

The Commission and the EIB recently launched a European Fund for Strategic Investments (EFSI) to support investment in strategic sectors such as transport, energy and digital infrastructure. The EFSI will support projects that typically have a higher risk profile than projects normally supported by the EIB. The United Kingdom and Poland are currently seeking funds from the EFSI to support their new nuclear projects.

In addition, the European Bank for Reconstruction and Development administers three funds for nuclear safety on behalf of the G24 countries and the EU: the Nuclear Safety Account, the International Decommissioning Support Funds for Bulgaria, Lithuania and the Slovak Republic, and the Chernobyl Shelter Fund. However, the funds are only available for nuclear safety purposes. They are not available for new nuclear projects.

Environmental Impact Assessment

Nuclear power projects are subject to an environmental impact assessment under the 2011 EIA directive, which has been transposed into the domestic EIA regimes of the EU member states.

Under the directive, the environmental impact assessment procedure can be summarized as follows. Developers of nuclear power projects must provide information on the environmental impact to the competent environmental authority. The environmental authority and the public must be informed and consulted. The competent authority then makes a decision, and the public is informed of the decision afterwards and can challenge the decision before the courts. Where a project is likely to have a significant effect on the environment in another member state, the other affected member state must be consulted. The responsibilities for the EIA lie solely with the EU member states. The Commission does not participate in such deliberations.

Transboundary impacts have recently been under judicial review in the English courts where the National Trust of Ireland challenged the legality of the UK government granting a development consent to the Hinkley Point C nuclear power project, which is 150 miles from the Irish coast. The Irish National Trust said the UK government failed to undertake a "transboundary consultation" with the Irish people about the environmental risks as required by the EIA directive before granting the development consent. The UK government argued that such a consultation was not necessary because nuclear accidents were unlikely due to the robustness of the UK regulatory regime. The English high court ruled against the Irish National Trust. The Trust appealed, but the English court of appeal rejected the appeal on the merits and also rejected the Trust's request for referral to the EU Court of Justice.

In addition to the EIA directive, developers must also consider the potential impact of other EU environmental-related legislation concerning habitats and the water framework on their projects.

Nuclear Fuel Supply

The EU imports 95% of natural uranium and about 40% of nuclear fuel and enrichment services from outside the EU.

Deliveries to EU utilities are generally well diversified across the whole nuclear fuel cycle, except in four countries: Bulgaria, Czech Republic, Hungary and Slovakia. These countries operate exclusively VVER reactors — a Russian version of the pressurized water reactor — and are dependent on deliveries of fuel assemblies from a single Russian supplier.

Within the EU, a common nuclear fuel market is maintained by the Euratom Supply Agency or ESA, an agency established by the Euratom treaty to ensure a regular and equitable supply of ores and nuclear fuels to all EU users. ESA implements a common supply policy. The ESA relies on four tools to implement its supply policy.

First, ESA has an exclusive right to conclude contracts relating to supply of ores, source materials and special fissile materials coming from inside or outside the EU. In practice, this means all such supply contracts in whatever form (sale, purchase, loan or exchange) are required to be co-signed by the ESA in order to be valid.

Second, ESA must be notified of transfer, import or export contracts for small quantities of ores, source materials and special fissile materials, as well as all transformation contracts for processing, conversion, shaping, enrichment, storage of ores, source materials and special fissile materials.

Third, ESA has the right to request the Commission to authorize export of material produced in the EU and supply contracts with durations exceeding 10 years. This procedure has to be initiated by ESA and the Commission's authorization does not substitute for separate approval by ESA. ESA recently exercised this right to intervene in a nuclear fuel deal between Hungary and Russia and requested the term of the fuel supply contract between the two countries be reduced from 20 to 10 years.

Finally, ESA has an option on all ores, source materials and special fissile materials produced in the EU. This right is normally waived by having ESA sign the supply contract involving such materials. ESA must be a party to all such supply contracts. ◎

Power in East Africa: Continuing Progress

by Rahwa Gebretnsaie, in New York

The alignment of commercial interests between the United States and East African countries has produced a number of bankable projects in the region, but certain challenges will need to be overcome in order for the Power Africa initiative the US government has undertaken to increase electricity output in Africa to achieve its full potential.

Power Africa Update

Power Africa is a $7 billion commitment by the US government to the region, but approximately $5 billion was earmarked to come from the US Export-Import Bank, which has now had to stop making any new funding commitments after a deadline passed for Congress to renew its funding authority. While Senate and House leaders have been trying to find a way to renew the bank's funding, strong opposition from key Republicans who control both houses of Congress have left the bank in limbo.

The good news for the Power Africa Initiative is that Ex-Im Bank credit requirements had largely side-lined it from participation in the financing of sub-Saharan power projects.

Of the other 11 federal agencies participating in the Power Africa initiative, the Overseas Private Investment Corporation will play an instrumental role in financing renewable energy projects in Africa. During President Obama's visit in July to Kenya, OPIC announced a new $1 billion commitment in finance and insurance products and is reportedly on track to meet that commitment by the end of 2015.

OPIC and the US Trade and Development Agency are tasked with carrying out the US-Africa Clean / *continued page 36*

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the person's status as a partner is temporary, whether the distributions are made closely in time to when the services are performed, whether the person's interest in the partnership is small in relation to the cash distributions, whether the person became a partner "primarily to obtain tax benefits for itself" that would not otherwise have been available, and whether two related partners provide services and the distributions to them are "subject to different levels of entrepreneurial risk." An example of the last factor is where a management company partner receives priority cash distributions, and distributions to a related general partner are subject to being clawed back if the cash is needed to make the priority distributions to the management company partner.

The IRS said that payments will be treated as "guaranteed payments" rather than disguised payments for services if the partner performs services in his capacity as a partner as opposed to performing them as if he were a third party. An example of the latter is where the partner provides the same services to multiple customers and not just the partnership.

Depending on the services, the partnership may be able to deduct any amounts treated as payment for services, or it may have to add the amounts to basis in a project owned by the partnership and recover them through depreciation.

> *The IRS has taken 31 years to propose how to sort out labels in this area. Congress directed that some partnership distributions should be treated as disguised payments to partners for services in 1984.*

IMPROVEMENTS VERSUS REPAIRS AT POWER PLANTS remain an area with heavy IRS audit activity.

The IRS issued an internal directive on July 6 in an effort to reduce the number of disputes.

The cost of improvements must be added to the "tax basis" in the power plant and recovered over time through depreciation. The cost of repairs can be deducted / *continued page 37*

East Africa

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Energy Finance (ACEF) program, an integral part of the Power Africa initiative. ACEF provides early-stage funding to help attract private sector follow-on investment in renewable energy projects in sub-Saharan Africa.

The East African region is becoming an increasingly attractive investment climate with its abundance of solar, geothermal and wind resources and the political will of East African governments to develop renewable energy sources.

A number of recent notable Power Africa transactions are progressing in East Africa.

OPIC approved an investment guarantee of up to $250 million to support construction of the Lake Turkana wind power project approximately five miles east of Lake Turkana in northern Kenya. The 310-megawatt, grid-connected wind farm will involve the installation of 365 wind turbines.

A number of bankable projects are emerging in East Africa.

OPIC committed $233 million in debt to support construction and operation of the Kipeto wind power project in Kajiado, Kenya, south of Nairobi. When complete, the 100-megawatt, grid-connected wind farm will be one of the first utility-scale wind projects to come on line in Kenya.

The Africa Finance Corporation, a multilateral lending agency with substantial private-sector participation, based in Lagos, provided a $25 million loan as part of a $150 million senior unsecured syndicated loan facility to the Kenya Power and Lighting Company. The facility will support the rehabilitation and expansion of the power transmission and distribution network in Kenya to increase the capacity from the current 2,000 megawatt to 5,000 megawatt by 2020.

ACEF is providing funding to support an 8.5-megawatt solar power project in Kigali. The project will be East Africa's first grid-connected, utility-scale solar energy facility.

Various Power Africa participants, including the US Department of Commerce and the African Development Bank (AfDB), are also providing legal and technical assistance to African governments to improve the conditions for private investment. The US Department of Commerce commercial law development program and the AfDB published an Understanding Power Purchase Agreements handbook that the two agencies hope will lead to greater standardization of PPAs and reduce negotiation times.

AfDB Update

The AfDB funded the cost of legal counsel to the Ethiopian government to assist with negotiation of a power purchase agreement for the 500-megawatt Corbetti geothermal project. The Ethiopian Electric Power and the Corbetti Geothermal Company signed a power purchase agreement in July 2015 for the first 500 megawatts of a potential 1,000-megawatt geothermal power plant.

The AfDB also serves as an implementing agency of the Climate Investment Fund, an $8 billion fund aimed at attracting private investment in renewable energy and climate resilience projects. The fund provides developing countries with concessionary loans, equity financing and risk mitigation instruments.

A number of notable AfDB and fund-financed projects are currently in the pipeline in East Africa. Six such projects are the 75-megawatt Aluto Langano geothermal in Ethiopia, the two Assela wind farms with a combined capacity of 171 megawatts in Ethiopia, the 150-megawatt Menengai geothermal project in Kenya, and the 15-megawatt Kopere solar PV project and the 140-megawatt Olkaria IV geothermal project, both in Kenya.

Regional Power Markets

Regional economic integration in East Africa has the potential to expand national power markets and create more opportunities for bankable projects.

The East Africa Power Pool — called EAPP — is a regional intergovernmental organization comprised of Burundi, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Rwanda and Sudan. The EAPP should eventually introduce regional power interconnection and allow power exchanges among utilities in the EAPP countries.

Actual levels of trade in energy among EAPP member countries are low due to a deficit in intra-regional transmission infrastructure. This infrastructure deficit is being addressed through financing and technical assistance programs launched by the AfDB and the International Renewable Energy Agency. If successful, regional power pools such as the EAPP should make utility-scale power projects more attractive in the region because of the potential increase in demand that could be served by a project after the initial power contract ends.

Three of Africa's largest regional economic communities, the Common Market for Eastern and Southern Africa, the East African Community and the Southern Africa Development Community, recently came together to form the Tripartite Free Trade Area. This trade area will cover 26 countries stretching north to south from Egypt to South Africa and represents a significant step towards achieving regional economic integration. The aim of the trade area is to promote intraregional trade, market integration and infrastructure development. It could facilitate the development of regional power pools. The success of these efforts is largely dependent upon the political will and alignment of incentives among member countries. ◎

CO_2 Diligence

Chadbourne held a webinar in late August on "What to Ask on Diligence in the Wake of the Clean Power Plan."

The US government is asking each state to come up with a plan to reduce carbon dioxide emissions from power plants. The amount varies by state. Overall, a 32% drop in carbon dioxide emissions compared to 2005 levels is required by 2030. Fossil fuel-fired power plants are being built, financed, and refinanced despite pending litigation, speculation about how the Clean Power Plan will fare with a new administration, and speculation about how, or even if, some states will implement the plan.

Sue Cowell and Richard Waddington, two environmental lawyers based in Washington, discussed questions that banks, tax equity investors and other project participants should ask on diligence when financing potentially-affected projects.

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immediately. The IRS tried to make it easier to distinguish between the two in 2013 by issuing guidelines that break power plants into smaller "units of property" and "major components." Replacing either of these would normally be considered an improvement. The guidelines are in Revenue Procedure 2013-24. (For earlier coverage, see the June 2013 *Project Finance Newswire* starting on page 19.)

The IRS is treating replacing "substantially all" — meaning 80% or more — of a major component as an improvement, and it is letting companies replacing less than that treat the work as a repair.

The latest directive says that IRS agents must get approval from the "assigned counsel and director of field operations" to take a contrary position and agents "should not challenge" taxpayers who use either of two calculations to determine whether the 80% threshold was reached. A taxpayer can compare the actual replacement cost to either the "undepreciated cost" or the estimated replacement cost of the major component on its financial statements.

US TAX RETURN filing deadlines for partnerships and C corporations were changed by Congress in late July under a bill to extend funding for the highway trust fund.

The changes will apply to tax returns starting with the 2016 tax year.

Partnerships that use the calendar year as their tax year will have to file returns by March 15 rather than April 15 as under current law. Partnerships with fiscal years will have to file by the 15th day of the fourth month after the fiscal year ends. Partnerships will be able to get extensions of up to six months.

Calendar-year corporations will have until April 15 to file, an extra month beyond the current deadline of March 15. Fiscal-year corporations will have until the 15th day of the fourth month after the fiscal year ends. However, corporations with fiscal years ending June 30 will not be affected by the changes until the 2025 tax year.

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CO_2 Diligence

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The first point about due diligence is it should be informed by the deadlines that states face to submit implementation plans to the US Environmental Protection Agency and the associated deadlines to show emissions reductions.

The Environmental Protection Agency issued the Clean Power Plan in August. It is a final rule that will become effective 60 days after being published in the Federal Register, which some expect will occur in October.

EPA also issued a proposed federal plan for reducing carbon dioxide emissions that will apply in states that fail to submit their own plans, and model trading rules intended to guide states in devising trading rules of their own.

EPA will be taking comments on certain aspects of the proposed federal plan and model trading rules. Unless the comment period is extended, comments will be accepted for 90 days after publication in the Federal Register.

We will highlight certain proposals under consideration and explain their relevance.

State implementation plans are due on September 6, 2016. EPA plans to approve or disapprove of a state plan within 12 months after submittal.

States also have the option to submit an initial plan on September 6, 2016 and request a two-year extension for submission of a final plan by September 6, 2018. According to EPA, such extensions will be granted if the initial plan has enough detail for the federal government to understand the final plan the state is considering and explains why additional time is required to complete a final plan. States will be granted automatic extensions if the initial plan contains the required elements unless EPA notifies the state otherwise within 90 days. States granted an extension must submit an update by September 6, 2017 of their progress toward completing a final plan by September 6, 2018.

Some states have already indicated that they do not intend to submit an initial plan. EPA has suggested that it will come up with a federal plan for each such state by the fall 2017 at the latest; however, it may do so more quickly.

States are required to begin taking steps to reduce emissions starting in 2022. The reductions will be phased in over three multi-year interim compliance periods through a final compliance deadline in 2030. During the interim compliance periods, states and affected power plants may meet their respective emission reduction obligations "on average," thereby providing a degree of compliance flexibility to affected power plants.

Covered Power Plant?

A threshold diligence question is whether the Clean Power Plan even applies to a particular power plant.

The Clean Power Plan covers existing electric generating units –- called EGUs — that were in operation or under construction on January 8, 2014 and that meet certain criteria.

Keep in mind that EPA also issued a separate set of carbon standards in August that applies to certain new, modified and reconstructed generating units, so understanding whether an EGU at a power plant is covered under the Clean Power Plan or the separate carbon pollution standards is important.

What it means to have a modification or reconstruction under the carbon pollution standards is beyond the scope of this discussion.

Determining whether an EGU was under construction on January 8, 2014 may require you to dig deeper.

As an initial matter, a new major source of carbon dioxide emissions needs a construction permit under the prevention of significant deterioration program. What is considered a new major source of carbon dioxide emissions is discussed at length in the Clean Power Plan.

There are two ways that an EGU might be considered under construction. The first is through a continuous program of "actual on-site construction" that will be completed within a reasonable time. The second is entry into binding contracts to undertake a program of actual construction that is expected to be completed within a reasonable time.

EPA offered examples of things that count as on-site construction such as placement, assembly, or installation of equipment that will form part of the structure of the new power plant. An example of something that does not generally count is site clearing.

EGUs are divided into two broad categories for purposes of analyzing whether they are covered by the Clean Power Plan: fossil-fueled steam generating units and stationary combustion turbines.

A coal- or oil-fired utility boiler or an integrated-gasification combined-cycle unit is covered by the Clean Power Plan if it serves a generator capable of selling more than 25 megawatts to a utility, has a base-load rating greater than 250 million BTUs per hour heat input of fossil fuel alone or in combination with another fuel, and historically supplied more than a third of its potential electric output and at least 219,000 megawatt hours as net electric sales during any three consecutive calendar years.

For a stationary combustion turbine, the unit is covered by the Clean Power Plan if the unit falls under the definition of a combined-cycle or combined heat and power combustion turbine, serves a generator capable of selling more than 25 megawatts to a utility, has a base-load rating greater than 250 million BTUs per hour heat input of natural gas, and historically combusted more than 90% natural gas on a heat input basis on an annual basis.

How Will It Comply?

Once an applicability determination has been made, then the next diligence question is which of the several rate-based and mass-based compliance options applies to the EGU.

Starting with rate-based compliance, under the federal rate-based proposed plan, EPA set interim and final emissions rate goals for affected steam generating units and separate rates for stationary combustion turbines. The same rate of carbon dioxide emissions will be permitted for every unit of the same type regardless of the state where the unit is located. For example, the final rate for affected steam generating units is 1,305 pounds of carbon dioxide per megawatt hour, while the final rate for a natural gas-fired unit is 771 pounds per megawatt hour. EPA also issued three interim rates for the periods before the final emissions performance rates take effect.

One important aspect of the rate-based option is that, unlike the mass-based approach, the rate-based approach is not designed to be expanded later to include new, modified and reconstructed EGUs at power plants or, as in the current California cap-and-trade program, other sectors of the economy. This may be an important consideration for some states when choosing a rate versus mass system, as the mass system can be expanded.

If a state wants to use a rate-based system, then it will have three basic approaches to choose from.

One approach is for states to adopt separate emissions rates for affected fossil-fuel-fired steam generating units and affected stationary combustion units. States choosing this approach will end up with final emissions standards for affected fossil-fuel-fired steam generating units of 1,305 pounds of carbon dioxide per megawatt hour and 771 pounds of carbon dioxide per megawatt hour for affected natural gas-fired units.

Another approach is for states to set one emissions rate that applies to all affected units in the state. EPA calculated the rate goals for each state. Each state has slightly different rate goals because the mix of generation in each state is different as are EPA's projected reductions in each state through 2030. For example, the final emissions rate for West Virginia, a state that relies heavily on coal-fired power plants, / *continued page 40*

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From 2016 through 2026, calendar-year corporations will only be able to extend the due date by five months through September 15. During the same period, corporations with June 30 fiscal years will be able to extend by seven months. All other fiscal-year corporations will be able to extend by six months.

The bill also tinkered with the statute of limitations for the IRS to assess back taxes.

The IRS usually has only three years after a return is filed to assess back taxes. However, it has six years where the taxpayer underreported income by 25% or more. The US Supreme Court held in a case called *Home Concrete & Supply* in 2012 that underreporting of gain on the sale of property, because the taxpayer claimed too high a tax basis, does not bring the six-year statute of limitations into play. The bill says that such gain should be taken into account. The change applies to tax returns filed after July 31, 2015 and to any previously filed returns that are still open for assessment.

MICHIGAN electric and gas utilities will have to pay sales and use taxes on some of their new equipment, the state Supreme Court said.

The sales and use tax rate in Michigan is 6%.

At issue was the scope of an "industrial processing exemption." Sales taxes are collected on sales of equipment in the state. Use taxes are collected on equipment bought out of state and brought into the state for use in Michigan.

Equipment that is used in "industrial processing" is exempted from taxes. It is industrial processing to convert or condition "tangible personal property by changing the form, composition, quality, combination, or character of the property for ultimate sale at retail." Electricity and gas are considered tangible products. The utilities sell them to retail customers. Lower courts in Michigan held in cases involving Detroit Edison and Consumers Energy that the exemption extends to equipment that the utilities use to transmit and distribute electricity and gas to their customers because the utilities alter the character of the / *continued page 41*

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is 1,305 pounds of carbon dioxide per megawatt hour while the final rate for Rhode Island is 771 of pounds of carbon dioxide per megawatt hour.

Finally, states can come up with their own rate-based programs. However, a state must demonstrate to EPA that its performance standards will result in meeting the overall emissions reduction goal for the state.

Now let's talk about mass-based programs. The difference between a rate-based approach and a mass-based approach is that the former sets an amount of carbon dioxide emissions per megawatt hour of electricity generated while the latter assigns each state a number of tons of carbon dioxide that it is allowed to emit. Under a mass-based program, each affected EGU is assigned a certain number of tons of carbon dioxide that it is allowed to emit. One allowance would be needed to emit one ton of carbon dioxide. Each state is assigned a budget for each of the three compliance periods from 2022 to 2030.

Investors and lenders should be asking a number of diligence questions related to the US Clean Power Plan.

The federal mass-based plan is not the only option. States that prefer a mass-based approach have several alternatives. One is to impose mass limits on individual EGUs by dividing up the state's total allowable emissions. It would be up to each power plant to remain within its emissions limit for the affected EGU.

Another alternative is to allow emissions allowances to be traded.

A third alternative is for a state to adopt a range of measures, such as renewable energy standards and energy efficiency programs, potentially as a supplement to a mass-based plan. Any state choosing this approach would have as a backstop federally-enforceable emissions standards for affected EGUs that would be triggered if the state measures plan fails to achieve the required emissions reductions on schedule.

Emissions Trading Issues

If the power plant is in a state that participates in an emissions trading program, then it is important to understand whether the trading is rate based or mass based and what difference it makes.

Under a rate-based trading program, one emissions reduction credit or "ERC" represents one megawatt hour of electric generation or one megawatt hour of reduced energy use. Under the federal trading plan, EPA would issue ERCs that could then be bought and sold or banked for use.

Under the federal plan ERCs could be generated in various ways.

One way is by operating an affected EGU so that carbon dioxide emissions are lower than what the EGU is allowed to emit. The emissions limits ratchet down over time. Therefore, a plant that earns ERCs initially because it is operating below the limit might find itself having to buy ERCs later.

Another way ERCs are generated is by shifting generation from coal-fired to natural gas-fired units. Only the incremental generation from the shift away from affected coal-fired units might qualify for ERCs. EPA is taking comments on how to measure the shift, particularly so as not to create incentives to rearrange dispatch among existing affected power plants to generate ERCs without changing the overall mix of coal versus gas plants.

EPA's model trading rule allows eligible new nuclear units and existing nuclear units that add new generating capacity and can provide data from a revenue-quality meter to generate ERCs.

What looks to be a big way to generate ERCs under the federal plan is eligible wind, solar, geothermal and hydro projects with the ability to provide data from a revenue-quality meter will qualify for ERCs. Thus, these types of renewable energy projects in states that end up living under a federal emissions trading program may receive another revenue stream on which they may not have counted: tradeable ERCs.

EPA is considering whether to add biomass projects to the list of renewable energy power plants that might receive ERCs. It wants to know how to measure ERCs from these types of power plants. EPA is also considering ERCs from waste-to-energy and combined-heat-and-power projects. EPA will also be soliciting comments on demand-side energy efficiency measures like state and utility energy efficiency programs.

States could also receive matching ERCs for projects covered under something called the "clean energy incentive program."

If you are considering possible impacts to an affected power plant that needs ERCs to cover its carbon dioxide emissions, the diligence on this may involve figuring out whether the affected power plant must buy ERCs on the market or has room to generate the ERCs it needs by adjusting how it generates electricity from its portfolio of power plants. This will be a very big part of future diligence when buying projects.

The Clean Power Plan may have an effect on how power plants are dispatched in the future in regional power pools.

About two thirds US electricity is served through regional transmission organizations, called RTOs, or independent system operators. Without going into a lot of detail, RTOs dispatch electricity from all generation in the region by using day-ahead and real-time bids from generators. Power plants get dispatched based on bids to the RTO that take into account the plant's variable costs. Under typical conditions, a grid operator in an RTO dispatches a power plant with the lowest variable cost first. EPA expects each power plant bidding into an RTO in the future might have to take into account the cost of compliance with the Clean Power Plan as part of its variable costs.

Independent power producers may be able to recover their costs to comply with environmental obligations through long-term power purchase agreements or other bilateral contracts where the utility pays an electricity price that takes into account compliance costs.

A utility facing its own compliance costs might be able to obtain cost recovery through the rates it charges its customers. The compliance costs are a cost of service. This will be an important area to watch for diligence purposes as people try to handle on the real costs to affected power plants to comply.

The market is waiting for a lot more detail about how ERCs will work. The market has some experience with a similar product — offset credits in the California cap-and-trade market. Stay tuned as more details are released by EPA on the measurement, verification and validation aspects of ERCs after the public comment period.

It will be interesting to see whether insurance products emerge to cover invalidation risk in an ERC market.

Mass-Based Trading

We have been talking about the mechanics of emissions trading in a rate-based program. Now let's dive into mass-based emissions trading.

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electricity or gas while moving it through power lines and gas mains.

The state Supreme Court disagreed after hearing an appeal of the case involving Detroit Edison.

The state tax department assessed Detroit Edison for back taxes of $13.1 million plus interest for the period January 1, 2003 through September 30, 2006. The Supreme Court said the exemption only applies to the extent equipment is used in an exempt activity, and "[s]ales, distribution, warehousing, shipping, or advertising" of the product after processing are not exempt activities. It sent the case back to the trial court to figure out the percentage of use of the transmission and distribution equipment in these downstream functions.

The case is *Detroit Edison Co. v. Michigan Department of Treasury*. The Supreme Court released its decision in late July.

MINOR MEMOS. Output from US wind farms fell 6% in the first half of 2015 compared to the same period the year before, despite a 9% increase in generating capacity, according to the US Energy Information Administration . . . . The total generating capacity of all US wind farms was 65,877 megawatts at the end of 2014 . . . . The average cost to build a US wind farm was $1.71 million per megawatt in 2014 . . . . The average electricity price in 13 power purchase agreements signed in 2014 for 1,768 megawatts of new wind farms was $23.50 a megawatt hour, according to the Lawrence Berkeley National Laboratory. Most of the contracts were for new projects in the Midwest where the prices are lowest, made up in part by a higher average capacity factor in the region of 41% . . . . Energy storage continues to grow from a low base: 40.7 megawatts of new storage facilities were installed in the second quarter of 2015, nine times more than the installations in the same period the year before, according to GTM Research and the Energy Storage Association. Most storage activity is in PJM and California.

— contributed by Keith Martin in Washington

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Under the federal plan, the total allowances would equal the number of tons of emissions that each state has been budgeted during the compliance period. A portion of the allowances would be reserved for issuance to certain affected natural gas-fired power plants and certain types of renewable energy projects. The remaining allowances would be divided among all the affected EGUs in the state.

For the initial compliance period of 2022 through 2024, affected EGUs would receive allowances equal to their average generation during the period 2010 through 2012. In subsequent compliance periods, the number of allowances would be reduced proportionately across all recipients during the initial period. EPA is taking comments on the proposed use of historic generation to allocate allowances and whether it should auction allowances rather than give them out for free. EPA will receive a large number of comments on this issue given the financial and compliance issues at stake.

Many affected power plants are still expected to need additional allowances to meet their compliance obligations and may have to go into the market to buy them, transfer allowances from other affected power plants or store unused allowances for use in subsequent compliance periods.

EPA proposes to use part of the budgeted allowances to encourage a shift from coal to natural gas and renewables.

Some allowances will be set aside for solar and wind projects under a "clean energy incentive program." New solar and wind projects that generate electricity in 2020 and 2021 will qualify for allowances. The program also will reward anyone investing in energy efficiency projects in low-income communities during the same two years. The two years were chosen for special emphasis because they are the two years immediately before the first compliance period when the government will be looking to the power sector to start showing progress on scaling back carbon dioxide emissions.

The allowances offered through the clean energy incentive program would be withheld from the total allowances budgeted for the first interim compliance period, beginning in 2022. It appears that qualifying projects that generate or save electricity in years 2020 and 2021 would be entitled to claim their allowances in or before 2022. Two allotments of allowances should be available: one allotment earmarked for qualifying projects in states subject to a federal plan, and a second matching allotment earmarked for states that elect to participate in the clean energy incentive program.

The clean energy incentive program focuses on solar and onshore wind projects rather than renewable energy more broadly. The reason appears to be that EPA believes solar and onshore wind projects can be built relatively quickly in order to provide electricity in 2020 and 2021. New renewable energy projects with more lengthy development timelines, such as offshore wind projects, would not benefit from the program, at least as currently proposed, given the requirement that qualifying projects must be generating electricity in 2020 and 2021.

The program will only apply in states that have an approved implementation plan that provides for participation in the clean energy incentive program. Not all states may decide to participate. To qualify, a solar or wind project must be physically in the state and not already be under construction. A qualifying energy efficiency project must not be in operation on the date the state submits its implementation plan to EPA.

Some allowances will also be set aside for distribution beginning in the second compliance period, 2025 to 2027, for natural gas-fired power plants that increase output from the initial compliance period to the second compliance period and subsequent compliance periods. These allowances will be used to reduce the potential for leakage. "Leakage" is the shifting of generation from existing power plants to new, modified or reconstructed power plants that are subject to less stringent emissions limits under the EPA carbon pollution standards. The concern EPA has with leakage is that displacement of existing generation by new generation could lead to a net increase in emissions. EPA hopes to mitigate leakage by providing a financial incentive to natural-gas fired power plants in the form of allowances.

Beginning in the second compliance period, a portion of the total allowances would be allocated to existing natural gas units based, in part, on their levels of electricity generation in the previous compliance period. Each eligible natural gas unit would receive a larger allowance allocation from the gas set-aside if it generates more than in the prior period. This is part of the effort to shift generation to gas. The total number of allowances available for distribution in this manner is limited.

Finally, EPA proposes to set aside 5% of each state's allowances for distribution to renewable energy. This set aside would be for developers of in-state renewable energy projects that provide capacity incremental to 2012, and would be implemented in all compliance periods.

EPA views this set aside as a tool to reduce the marginal cost of generating electricity from renewable energy. It is considering whether to increase the percentage from 5% to 10%. ◎

Environmental Update

A federal district court has dealt a setback to a United States Fish and Wildlife Service program for issuing long-term permits to wind farms and others allowing "incidental takes" of bald and golden eagles. An incidental take means an unintentional death or injury.

The Fish and Wildlife Service increased the maximum term for such permits from five to 30 years in 2013. A federal district court in California sent the new policy back to the agency for additional environmental analysis in mid-August in response to a lawsuit, called *Shearwater v. Ashe*, filed by environmental groups. The longer-term incidental take permits are no longer available and will not be available at least until the agency finishes a more comprehensive review of the environmental impacts. This complicates development of wind farms in areas where liability for possible eagle deaths is a concern.

The court said the 2013 decision to allow longer permits violated the National Environmental Policy Act because it was made without any environmental assessment or environmental impact statement.

The agency argued that the decision did not require environmental review because it was purely administrative in nature with effects too broad and speculative to allow meaningful analysis. The court disagreed. The Fish and Wildlife Service ignored its staffs' own recommendations that the agency prepare an environmental impact statement, the court said.

It is too early to tell whether the market will now settle for five-year permits, given that a five-year permit is all that is on offer and the market made do with them before 2013, or will just wait until the window reopens for longer permits. The agency has already started preparing an environmental impact statement.

Even while Fish and Wildlife was offering permits for up to 30 years, the permits still required operational reviews every five years by the agency. However, the reviews were not like having to apply for a new permit. Fish and Wildlife also reserved the right with the longer permits to modify or revoke a permit if issues arise, and ongoing monitoring for mitigation effectiveness was still required.

Federal law prohibits the taking of bald and golden eagles unless otherwise authorized, and violators risk civil penalties and jail time of up to one year for the first conviction. Felony convictions could result in significantly higher fines and up to two years of jail time.

Migratory Birds

The Fish and Wildlife Service is at work on a "programmatic" or blanket environmental impact statement evaluating proposed approaches for authorizing the incidental taking of migratory birds. The period for public comment closed at the end of July.

The Migratory Bird Treaty Act protects 1,027 bird species in the United States by prohibiting the taking of such bird species unless authorized. Fish and Wildlife has issued blanket permits for the incidental taking of regulated birds to various applicants, such as the US military for takes during combat-readiness drills, but the agency is now considering whether to provide more general authority.

Fish and Wildlife wants to provide greater legal certainty for industries and companies that have taken steps to mitigate or reduce the taking of migratory birds, and encourage conservation efforts for covered species. The agency also wants to establish a framework for obtaining adequate compensation in instances where the taking of migratory birds cannot be avoided through best practices and technologies.

The agency is considering the following actions. One possible action is to issue general authority for the incidental taking of covered species in particular activities in specified business sectors. Anyone relying on general take authority would still be required to embrace "appropriate standards of protection and mitigation." The agency is considering whether this approach can be applied to the wind industry.

The agency is also considering issuing individual, site-specific incidental take permits for activities not covered by the general authority. An environmental impact statement would have to be prepared before an individual permit could be issued. Fish and Wildlife is looking into ways to minimize the administrative burdens associated with issuing individual incidental take permits, such as relying on the environmental review already for the issuance of other federal permits.

Another action under consideration is to authorize incidental takes by other federal agencies. Each agency would have to enter into a memorandum of understanding with Fish and Wildlife agreeing to weigh and mitigate the adverse effects of their actions on covered species.

Finally, the agency may also develop voluntary guidelines that are a list of best practices and / continued page 44

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technologies to prevent or mitigate the incidental taking of covered species. Any such guidelines would be informed by the ongoing dialogue between Fish and Wildlife and industry about the hazards posed by such businesses on migratory birds. Following the guidelines would not be a license to take migratory birds, but the fact that a company has complied with the guidelines would be taken into account by the government when considering whether to bring an enforcement action against a company.

The agency could end up adopting one or a combination of the proposals. Implementation will require issuing new regulations.

Wind developers are wary that any new policies might obstruct new wind farm development. The American Wind Energy Association has told the agency it does not believe the incidental taking of migratory birds in lawful activities such as operating wind turbines should require a permit to avoid criminal liability. AWEA is urging the agency to maintain its existing approach toward wind farms of encouraging voluntary adherence to existing land-based wind energy guidelines that the agency issued in 2012, but if a new permitting program for migratory birds is established, it wants blanket permit authority to be given to wind farms. ◎

— contributed by Andrew Skroback in Washington and William Nicholson in New York

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