Project Perspectives




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Akin Gump
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Around Akin Gump

Akin Gump Strauss Hauer & Feld LLP is pleased to announce that Suedeen G. Kelly, a former commissioner of the Federal Energy Regulatory Commission (FERC), and George D. "Chip" Cannon Jr. have joined the firm as partners in the energy regulatory practice in Washington, D.C. Ms. Kelly also serves as co-chair of the practice. The addition of Ms. Kelly and Mr. Cannon continues the growth of the practice, which includes the arrival of practice co-chair Julia E. Sullivan in 2011, and further strengthens the firm's global energy industry practice.

Ms. Kelly and Mr. Cannon are joined at Akin Gump by Cynthia A. Marlette, a former general counsel to FERC, who will be a senior counsel in the firm's energy regulatory practice.

Internationally recognized for her work in the energy regulatory field, particularly for clients in the natural gas and electricity industries, Ms. Kelly was nominated for three terms as a FERC commissioner under President Obama and former President George W. Bush. During her tenure at FERC, she resolved thousands of disputes and is credited with strengthening FERC enforcement, as well as orchestrating change in several key regulatory policies, including integration of renewables into the transmission grid, deployment of smart grid technologies and natural gas quality standards.

Mr. Cannon maintains a broad practice handling regulatory matters before federal agencies, courts and state regulatory commissions on behalf of clients throughout the energy industry.

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California Holds First Cap-and-Trade Auction

By Matt Nesburn

This article is an update to our prior article "2012 Marks the Start of Carbon Cap-and-Trade in California" published in the Winter 2012 edition of *Project Perspectives* to report that California's first greenhouse gas (GHG) allowance auction was held on November 14, 2012 by the California Air Resources Board (CARB), instantly making California's carbon market the second largest in the world behind the European Union Emissions Trading Scheme.

The auction was successful in selling all of the 23,126,110 GHG allowances (each representing the right to emit one ton of carbon) available at the November auction for the 2013 compliance year (slightly fewer than half of the allowances that will eventually be auctioned for the 2013 compliance year) and approximately 15 percent of the 39,450,000 GHG allowances available at the November auction for the 2015 compliance year (future allowances are sold two years in advance). The GHG allowances for both 2013 and 2015 were available at a floor price of $10 per allowance, with the vintage 2013 allowances sold at a settlement price of $10.09 each and the vintage 2015 allowances sold at a settlement price of exactly $10 each. The auction was also successful in that over half of the entities covered by the GHG cap purchased allowances through the auction.

The auctions initially account for 10 percent of all available GHG allowances, with the rest being given to market participants to cover their current emissions. As the program matures, the percentage of GHG allowances given away will decrease, while the percentage of GHG allowances auctioned will increase. California entities covered by the GHG cap (oil refineries; manufacturers, such as cement makers, food processors, and electric utilities) as well as voluntarily associated entities were eligible to participate in the auction. In 2015, entities covered by the GHG cap will expand to include distributors of transportation, natural gas and other fuels.

As the auction procedure evolves, entities covered by the GHG cap will be required to surrender allowances to the CARB in November 2014 in an amount equal to 30 percent of such entity's 2013 emissions. Then, in November 2015, the covered entities will need to surrender allowances equal to 70 percent of their 2013 emissions *plus* 100 percent of their 2014 emissions. The 2013 emission cap is about 2 percent below forecasted levels for 2012, and declines an additional 2 percent in 2014, and approximately 3 percent a year from 2015 to 2020, with the target being a 15 percent reduction from today's GHG emissions by that time.

While the auction was successful in selling all of the 2013 GHG allowances available, the fact that the price barely surpassed the reserve (and equaled it for the 2015 vintage) likely indicates a degree of market uncertainty about the long-term viability of the program. Some of this uncertainty is attributable to a last-minute lawsuit filed on November 13, 2012 by the California Chamber of Commerce,[1] which has expressed concern regarding the adverse effect the cap-and-trade program is likely to have on competitiveness of California businesses. The lawsuit seeks declaratory relief to invalidate and stop the auction procedure on the basis that the CARB exceeded its authority granted under AB 32 (The California Global Warming Solutions Act of 2006) by reserving allowances for itself and then auctioning them to the highest bidder. The lawsuit alleges that this is an unprecedented "money grab" by a regulatory agency tantamount to an unlawful tax because the only revenue generation specifically authorized by AB 32 is the imposition of a regulatory fee limited to the amount administrative costs of implementing the cap-and-trade program.

Some of the factors that California courts are likely to evaluate in determining whether the auction procedure imposes an illegal tax or a permissible fee include: (1) whether the proceeds raised are limited to the reasonable costs of the regulatory scheme; (2) whether such proceeds are used for purposes unrelated to the purpose of the regulation; and (3) whether the burden of compliance is reasonably allocated between the regulated entities.[2] The current plans for the auction revenues are detailed in a November 16, 2012

[1] *California Chamber of Commerce v. Air Resources Board,* 34-2012-80001313, California Superior Court (Sacramento).

[2] *See* Sinclair Paint Co. v. State Bd. of Equalization, 15 Cal. 4th 866, 876-78 (1997).

Proposed Decision[3] issued by the California Public Utilities Commission (CPUC) which proposes to direct a large portion of the proceeds to California industries identified as "emissions-intensive" and "trade-exposed" in order to help protect them from the adverse effects of the emissions caps on their competitiveness as well as to direct additional proceeds to certain small businesses (non-residential customers consuming less than 20kW of power) in the form of credits to help offset any increase in electricity rates caused by the cap-and-trade regulations. Any remaining proceeds would be given to residential customers as a semi-annual credit or "climate dividend" intended to help offset any increases in the cost of goods and services that might result from the cap-and-trade program. The cumulative amount of revenue to be returned to business and residential ratepayers between 2013 and 2020 is expected to range from $5.7 billion to $22.6 billion.

In summary, while the CARB's cap-and-trade program is being actively implemented and the initial allowance auction can be deemed a success, it remains to be seen whether the CARB can surmount the legal challenges it faces for the auction program to continue in its present form or whether courts will compel changes to the way the CARB retains and auctions some of the GHG allowances.

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[3] http://assets.fiercemarkets.com/public/sites/energy/reports/cpuccapandtrade.pdf

Production Tax Credit Extension and Other Benefits for Renewable Energy in the Fiscal Cliff Legislation

By David Burton

On January 3, 2013, the President signed into law H.R. 8, titled "The American Taxpayer Relief Act" (the Act) that averted the so-called "fiscal cliff" of automatic spending cuts and tax increases.

The Act has a number of benefits for the renewable energy industry. First, the Act extends the production tax credit (PTC), currently 0.022/kWh, for wind projects for an additional year.

More significantly, the Act changes the requirement from a wind project having to be "placed in service" prior to the deadline to the wind project having to "begin construction." Therefore, a wind project merely needs to begin construction prior to January 1, 2014.

It remains to be seen how the Internal Revenue Service will define what it means for a wind project to "begin construction." Thomas Bartold, Chief of Staff of the Joint Committee on Taxation, testified in a Senate Finance Committee hearing on August 2, 2012, that the start of a construction standard would require "minimal construction expenditure." The wind industry anticipates that the 5 percent safe-harbor standard from the U.S. Department of the Treasury's Section 1603 Cash Grant start-of-construction rules would apply for the purpose of the PTC.

Also significant is the absence of any outside date as to when the wind project must be fully constructed and operational, as long as it "begins construction" prior to January 1, 2014. The overall implication is that the owner of a wind project could incur $5 million to purchase blades in 2013 and use those blades in a wind project with a tax basis not to exceed $100 million that is completed in 2017 (or even later); that project would be eligible for 10 years of production tax credits starting in 2017.

Wind projects that qualify for the PTC as extended may instead elect to claim the 30 percent investment tax credit (ITC), but not the Treasury Cash Grant. Such an election may be advantageous for projects with lower "capacity factors" (i.e., in less windy areas), where an ITC of 30% of the tax basis may exceed the present value of 10 years of PTC. Such an election also enables the project developer to take advantage of lease structures, which are precluded by the PTC rules.

The Act reduced the budget cuts necessary to avoid sequestration from $109.33 billion to $85.53 billion. In Mid-February, the Office and Management and Budget

is expected to confirm that this means the sequestration percentage for Treasury Cash Grants is reduced from 7.6 percent to 5% of the grant amount. Sequestration will not apply will not apply until the later of (i) March 27, 2013 or (ii) when the final budget authorization is completed by Congress. Further, agencies have up to 120 days from the later of those two dates to implement the sequester. It is important to note that it is up to 120 days, so Treasury could elect to act sooner.

Also, the 50 percent bonus depreciation is extended for another year. Many developers struggle to find tax equity investors willing to monetize bonus depreciation, but there are a handful of tax equity investors who will monetize it for particularly strong projects.

The new market tax credit, which several renewable energy projects have used, is also extended through 2013. The credit requires an allocation from the Treasury, and the project must be in certain areas with low-income populations. Therefore, it is not frequently available for renewable projects.

Finally, various tax incentives for individuals for energy-efficient appliances, energy-efficient new homes and electric vehicles, and for plug-in stations for electric vehicles are also extended.

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Recent Development Impacting Renewable Energy Development on Indian Lands

By Edward Zaelke and Jason Hauter

Despite the fact that the Department of the Interior holds approximately 56 million acres of land in trust for Indian tribes and individual Indians, and the fact that much of that land is an excellent resource for wind or solar, to date, there has been very little renewable energy development on Indian lands. Babcock & Brown's 50 MW Kumeyaay wind project on the Campo Reservation in Southern California, which was built in 2005, still remains one of the few large wind projects on tribal lands. On the solar side, the interest in utility scale development on tribal lands has been even less active. Recently, K-Road Power announced a utility scale solar project that will be built on the Reservation lands of the Moapa Band of Paiute Indians Reservation in Clark County, Nevada. That project, which will sell power to the Los Angeles Department of Water and Power, is reported to be the first major utility scale solar project to be built on Indian lands.

For the most part, wind and solar developers have found that developing on Indian lands is much more uncertain and time-consuming than developing similar projects on private or government-owned lands. For example, even if a developer is able to reach agreement with a tribal government on the terms of a wind energy or solar lease, the lease has to be submitted for approval of, and be approved by, the Department of Interior – Bureau of Indian Affairs (BIA) before it can become effective. In the past, this approval could take several years. During that time, the developer would risk changes in tax laws, changes in development and equipment costs, changes in the market price for power and changes in the tribal governing body, any of which could derail its project. As with most projects, extended time periods for development increase the risks in wind and solar development and make it more difficult to justify investment. While there are other factors that can make development on Indian lands more difficult, such as cultural resource preservation, tribal employment preference laws and tribal governance issues, it is the time and uncertainty factors, more than any others, that have caused wind and solar developers to favor development on private and government lands, where the time frames for development are generally much shorter.

Two significant developments during 2012 could change all of this for wind and solar energy development on Indian lands. On July 30, 2012, the Helping Expedite and Advance Responsible Tribal Homeownership Act of 2012 (the "HEARTH Act") was signed into law to establish a process by which Indian tribes can develop their own regulations and approve their own surface land leases. In addition, on November 27, 2012, the Department of the Interior released new Regulations on surface leasing on Indian lands (Surface Leasing Regulations). These Surface Leasing Regulations represent the first major overhaul of Indian land surface leasing rules in more than 50 years.

The HEARTH Act seeks to allow tribes to establish and administer their own leasing rules, thereby creating the ability of tribes to lease lands under certain circumstances without needing the BIA to approve each lease. Unfortunately, the process of establishing these rules, while an important step for many tribes to reach self-determination, may be several years away for many tribes. As a result, we will return to discuss the HEARTH Act a bit later in this article. The more significant change, at least in the short term, will come from the new Surface Leasing Regulations that were released on November 27, 2012.

The new Surface Leasing Regulations seek to bring some certainty to the leasing process and apply to all surface leases unless a tribe has implemented its own guidelines under the HEARTH Act. Under the Surface Leasing Regulations, the BIA has abandoned its "one-size-fits-all" leasing approach in favor of specific regulations for the different types of tribal leases (i.e., residential, business and, most significantly, wind and solar energy development). In respect to wind and solar energy development, the Surface Leasing Regulations make four significant changes in an attempt to streamline and clarify the leasing process.

First and foremost, the Surface Leasing Regulations establish a time frame for review and approval by the BIA for any surface lease submitted to it by an Indian tribe for approval. Under the Surface Leasing Regulations, the BIA must issue decisions on wind and solar project leases within 60 days of receiving all required documentation. It also sets similar timeframes for BIA decisions on lease amendments, lease assignments, subleases and leasehold mortgages. In the case of lease amendments and subleases, these documents will be deemed approved if BIA fails to act within the set time frames.

Second, the Surface Leasing Regulations, in Subpart E, recognize and define a specific process for wind energy leases and solar energy leases. Under Subpart E, the Surface Leasing Regulations define Wind Energy Evaluation Leases (WEEL) and Wind and Solar Resource (WSR) Leases to specifically facilitate the leasing of tribal lands for renewable energy projects. This establishes a two-part process for wind energy leases whereby developers may be granted a short-term WEEL to study the viability of wind development projects through the installation of wind evaluation equipment, such as meteorological towers, with an option to lease the land for actual wind energy development at the conclusion of the lease period. The BIA has not put forward a similar two part process for solar projects because the evaluation of solar energy potential is not believed to require separate up-front rights in the development site.

Under the Surface Leasing Regulations, an application for a WEEL must detail the tract or parcel of land being leased; the purpose of the WEEL and authorized uses of the leased premises; the parties to the WEEL; the term of the lease; the authorizing statute; payment requirements; and who is responsible for constructing, owning and maintaining improvements, among other requirements. The WEEL must also state how much compensation will be paid, but the BIA does not require a valuation for the lease. The Surface Leasing Regulations require the BIA to approve, disapprove or return the submission for revision within 20 days of receipt. The BIA's decision would hinge on a determination of whether the lease is in the best interest of the landowners based upon a review of the WEEL, an assessment of environmental impact and a finding that the requirements of relevant Indian lands statutes are satisfied.

A WSR lease authorizes a lessee to possess Indian land for the installation, operation and maintenance of wind and/or solar energy resource development projects. Under the proposed regulations, a WSR lease may be entered into independent of a WEEL, even though some may enter into a lease as a direct result of information gathered from a WEEL. The BIA would not require a valuation to determine fair market rental of a WSR lease, provided that documents are submitted to indicate that the tribe has negotiated satisfactory compensation, waived the BIA's valuation and appraisal process, and determined that accepting the negotiated compensation and waiving the BIA's valuation and appraisal is in the tribe's best interest. However, the Surface Leasing Regulations permit the BIA to determine fair market value for a WSR lease upon request by a tribe. Unlike a WEEL, the proposed regulations require a WSR lessee to provide a performance bond in a sufficient amount to secure all contractual obligations under the lease, unless the landowner requests otherwise.

The third significant piece of the Surface Leasing Regulations is the description of several specific provisions that must be included in a WSR lease in order for it to receive BIA approval. This is significant because, in effect, by limiting the grounds under which the BIA can disapprove such lease documents, the Surface Leasing Regulations limit the broad discretion BIA currently has to reject certain lease documents. These specific provisions include a requirement of maximum initial lease terms for a WSR lease of 25 years with the option of one 25-year extension, performance bond and insurance requirements, methodologies for establishing valuation and compensation, removal requirements for improvements on leased lands, indemnification requirements, and enforcement and remedy mechanisms.

The fourth significant provision in the Surface Leasing Regulations, as they apply to wind and solar leases, is a clarification that permanent improvements on the leased lands are not subject to state or local taxation. This is significant for many wind and solar developers, who may, in effect, be paying a premium to the tribe for the use of its land on the assumption that there will be no state or local taxes.

While the four points listed above will remove a number of the significant impediments to making projects work on Indian lands and remove a number of the time and certainty issues that have discouraged developers from developing wind and solar projects on Indian lands in the past, there are still a few areas in the Surface Leasing Regulations that will require further study. For example, if the BIA fails to meet a deadline for issuing a decision on a lease, the lease is not deemed approved and is instead subject to a potentially lengthy administrative review process.

As stated above, we believe that the HEARTH Act, which requires the development of tribal rules and guidelines regarding leasing, is less likely to be impactful in the wind and solar energy sectors over the near term due to the time required to develop these regulations. Under the HEARTH Act, tribes, at their discretion, may assume control over leasing tribal trust lands upon the Secretary's approval of tribal regulations that "are consistent with any regulation issued by the Secretary under [25 U.S.C. § 415(a)]." If a tribe opts to assume control of lease approvals, this authority is limited to tribal trust lands and does not extend to lands held in trust for individual allottees. Lease approval for allotted lands remains with the BIA.

Under the HEARTH Act, business leases approved pursuant to tribal regulations may have a term of 25 years, with an option to renew for up to two additional terms (each may not exceed 25 years). In order for tribal leasing regulations to be approved, they must also provide for an internal environmental assessment process as part of the leasing regulations. Although tribes seeking to utilize the HEARTH Act's revamped regulatory structure will first need to submit land leasing regulations to the BIA for approval, once approved, the tribal process should expedite surface land lease approvals.

It is anticipated that tribes opting to assume lease approval under the HEARTH Act will tailor their regulations to suit their needs. It remains to be seen how much latitude the BIA will have in interpreting what it means for tribal regulations to be "consistent with" BIA regulations. In addition, some commentators have suggested that tribal regulations under the HEARTH Act could be a long time in coming and have pointed to similar legislation in 2005 for energy leasing. That legislation, under 25 USC 3504, creates Tribal Energy Resource Agreements (TERA). However, at least according to one commentator, as of today, no tribe has yet to sign a TERA.[1]

In the long term, however, we think that the HEARTH Act will provide benefit to tribes, since it requires that they adopt specific environmental guidelines. These can be very useful in moving forward with wind and solar projects. In the meantime, it may be that the BIA's new Surface Leasing Regulations are a better baseline to work from and should allow tribes sufficient flexibility in either entering into wind and solar leases for their lands or for developing their internal leasing regulations, if they choose to do so.

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[1] Ryan Deveskracht, "Are Hopes for the HEARTH Act Too High?", Galanda Broadman Lawfirm Newsletter, August 2, 2012.

Renewable Energy and the Age of Adolescence: Financing U.S. Renewable Energy Projects in a Post-Subsidy World

By Daniel Sinaiko

The federal renewable energy production tax credit (PTC) was created in 1992 when Congress enacted the Energy Policy Act of 1992. The creation of the PTC for renewable energy generating projects signaled the birth of the modern renewable energy industry in the United States. In the years since its birth, the industry has grown in fits and starts, seeing the creation of the investment tax credit (ITC) in 2005 and no less than six extensions of the PTC.

With President Obama's election and the passage of the American Recovery and Reinvestment Tax Act of 2009 (ARRA) following closely on the heels of the worst economic meltdown since the Great Depression, the green energy industry emerged from its infancy, demonstrating the hallmarks of a mature industry:

- project capacities measured by the hundreds of megawatts
- tens of billions of annual investment dollars from well heeled banks and institutional investors
- photovoltaic solar penetration at the household consumer level
- growth of average monthly energy output from 10,508 GWh in 2008 to 18,777 GWh by the middle of 2012
- increase of total installed capacity to approximately 70 GW, accounting for 38 percent of all new installed capacity in the first half of 2012
- new technological concepts like offshore mega-wind and solar thermal energy capture/storage.

Undeniable as the growth of renewable energy industry has been, many hallmarks of its infancy remain:

- technological growing pains
- volatility resulting from rapid and unpredictable technological and political change
- persistent company failure and industry consolidation
- continuing dependence on government incentives.

The maelstrom of the past four years has yielded uncertainty over exactly how grown up green energy is, though emergence from the current period of stimulation promises to answer the question in short order. The potential vacuum created by the saturation and expiration of green energy incentives will present new challenges for the financing of renewable energy projects. This article examines the nature of the expiring incentives for renewable energy and what the landscape in the post-incentive financing world may look like.

Mother's Milk: Historical Renewable Energy Incentives

The renewable energy industry has been nurtured by three forms of sustenance: (1) federal tax credits, (2) accelerated depreciation and (3) state incentives. Federal tax credits have historically included the PTC, providing tax credits for each kWh of generation over a 10-year period, and the ITC, offering a tax credit equal to 10 or 30 percent of installed plant cost following initial asset deployment. Projects that commenced construction during 2009, 2010 or 2011 were eligible to convert the PTC into an ITC and claim a cash grant in lieu of the ITC under Section 1603 of ARRA.

A summary of renewable energy technologies with corresponding tax credit incentives and expiration dates is as follows:

	PRODUCTION TAX CREDIT (Expiration Date)	30% INVESTMENT TAX CREDIT (Expiration Date)	10% INVESTMENT TAX CREDIT (Expiration Date)
Wind	Y (2013 – $.022/kWh)	Y (2013)	N
Small Wind	N	Y (2016)	N
Solar	N	Y (2016)	Y (N/A)
Geothermal	Y (2013 – $.022/kWh)	Y (2013)	Y (N/A)
Biomass (Open Loop)	Y (2013 – $.011/kWh)	Y (2013)	N
Biomass (Closed Loop)	Y (2013 – $.022/kWh)	Y (2013)	N
Marine and Hydrokinetic	Y (2013 – $.011/kWh)	Y (2013)	N
Hydropower	Y (2013 – $.011/kWh)	Y (2013)	N
Landfill Gas	Y (2013 – $.011/kWh)	Y (2013)	N
Fuel Cell	N	Y (2016)	N
Combined Heat & Power	N	N	Y (2016)
Municipal	Y (2013 – $.011/kWh)	Y (2013)	N

In addition to tax credits, the federal government has traditionally permitted renewable energy project developers to depreciate 100 percent of the cost of their equipment over an accelerated five year period. Accelerated depreciation was further compressed under ARRA, permitting first-year 100 percent depreciation of a project placed into service before 2012 and 50 percent depreciation of a project placed into service before 2013[1].

Federal tax policy has been the cornerstone to U.S. renewable energy policy but, in recent years, state and local action has proven a valuable industry driver. Thirty states and the District of Columbia have established renewable portfolio standards requiring utilities to procure a portion of their energy from renewable resources. Aggressive portfolio standards have resulted in heavy utility subscription to the renewable energy and renewable energy certificate procurement markets. Consequently, many RPS programs are at or approaching saturation, procurement activity has slowed, and pricing for green energy attributes has fallen substantially.

Growing Up in a Post-Subsidy World

Federal tax incentives can represent between 50 percent and 60 percent of the installed costs for a renewable energy project. The possible expiration of incentives on which the industry has grown up has naturally led to doubts about its readiness to compete in mature energy markets. The downturn in the wind market in 2012, with tax credit expiration looming, shows, if nothing else, additional policy initiatives are needed to propel the U.S. green energy industry from adolescence to adulthood.

Loss of tax incentives and saturation of green energy programs will invariably necessitate either new sources of revenue or increased cost reductions to fill the hole in subsidy-free project economics. Short of a long-term extension of tax credits and expansion of RPS objectives, the recipe for continued industry growth may include some combination of (a) increased competitiveness, (b) feed-in tariff policy, (c) master limited partnership structures, (d) asset securitization, (e) increased strategic investment and, possibly, (f) “leveling the playing field” between renewable and conventional energy generation.

[1] 50 percent depreciation has been extended through the end of 2013 by the The American Taxpayer Relief Act of 2012.

Increased Competitiveness

In parts of the world where energy costs are high and natural resources are strong, renewable energy is competitive. However, in the United States, where natural gas and oil are abundant and inexpensive, the market for renewables is challenging. If a positive slant can be placed on the U.S. energy environment for renewable, it is the potential to drive continued technological improvement and efficiency.

A combination of technological improvement, increased scale and government policy have reduced the cost of renewable-energy deployment in the past four years. The cost of solar technology in particular has been reduced from installed costs of approximately $7.50 per watt in 2009 to as low as $2.65 per watt in 2012. Moreover, improvements in the size and efficiency of renewable technology have resulted in higher capacity factors and lower levelized energy costs. Similar improvements must continue across the industry for renewables to be a mature segment of the energy sector.

Feed-In Tariffs

For years, European countries have nurtured their renewable energy markets by implementing feed-in tariff programs that compel utilities to buy green energy at administratively determined power purchase rates. The rigid price signal from European feed-in tariffs has produced mixed results. Positively, installed capacity has grown exponentially, resulting in the creation of a vibrant renewables manufacturing and installation industry. At the same time, artificial administrative pricing has frequently resulted in overpricing and ultimately unforeseen tariff rate reductions that have injured the industry.

U.S. state and local governments are taking a cue from European markets and beginning to develop their own feed-in tariff programs, in some cases with an American entrepreneurial slant. Rather than administrative tariff pricing some U.S. tariffs, like those developed in California, award contracts based on a reverse auction, with the lowest-price bidders winning offtake contracts.

With a reverse auction, either (1) prevailing bidders will underprice their bids and projects will not be built, or (2) bidders will accurately price their bids, and projects will be successful. Under customary program rules, the capacity associated with incomplete projects is returned to the procurement pool to be re-bid. Correctly priced projects may

be elbowed out of the way by more aggressive bidders in the short term, but, in the long run, as completion costs become more certain and bids become more realistic, viable tariff rates are likely to prevail.

Master Limited Partnership

One competitive advantage that conventional energy has enjoyed over renewables is access to the master limited partnership (MLP) corporate structure. The MLP structure allows for interests in energy projects to be sold to investors in public equity markets. There is some support for applying this structure to renewable energy projects, enabling them to access a much broader range of investors and, by increasing capital supply, reduce financing costs.

Implementation of the MLP structure for renewable energy will not, absent changes to passive loss rules in the tax code, enable MLP investors to monetize tax losses and other benefits enjoyed by renewable energy companies (to the extent that they are not extinguished). Notwithstanding that inefficiency, access to the public markets would improve project economics and help drive the continued growth of the industry.

Securitization

Since 2008, the word "securitization" has been reduced to four letters. Total asset-backed securitization issuances in the United States have declined from $754 billion in 2006 to only $125 billion in 2011. Though much of the bath water has been disposed of, some, including those in the renewable energy industry, hope to preserve the baby.

Securitization structures effectively pool tranches or classes of asset-backed investments to diversify asset performance risk in a single portfolio offering. The benefits of securitization are twofold: (1) diffused risk theoretically enables the issuer to obtain a lower cost of capital, and (2) division and bundling of assets facilitates divestiture for investors and issuers. The Dodd-Frank Act imposes restrictions on securitization that may make it more complex and expensive, but the concept of improving capital cost and liquidity holds some promise for the industry.

Strategic Investment

Renewable energy investment has, for the most part, been limited to a small list of commercial banks, insurance companies, utilities and institutional investors. A few strategic investors, like Google, have become active in the market, but, for the most part, corporate America has ignored investment in renewable energy projects. This is due, in part, to the conservative return levels associated with renewable energy investment.

Still, in a volatile world where the perception of risk-free government credit is eroding, companies with significant cash reserves may be looking for safe investments that earn a reasonable rate of return. Contracted project financings may present such an opportunity for cash-rich investors, particularly when combined with the liquidity afforded by MLP and securitization vehicles. Moreover, as the industry matures, the discovery of synergies and strategic advantages in renewable energy developers and equipment manufacturers becomes increasingly likely.

Leveling the Playing Field

One view in favor of abandoning renewable energy subsidies is that the free market, rather than the government, should pick winners and losers. This argument ignores the subsidies enjoyed by the fossil fuel industry. The worldwide direct subsidization of fossil fuels has been estimated between $775 billion and $1 trillion for 2012. Comparatively, 2010 global subsidization of renewable energy has been estimated at approximately $66 billion.

If current U.S. renewable energy incentives are not renewed, the industry could stay competitive by "leveling the playing field" between renewables and fossil fuels. This would mean either eliminating existing conventional subsidies or extending them to renewable energy projects.

There are problems with this approach. First, it is not clear that renewable energy, which has enjoyed a very short period of subsidization, can compete with fossil fuel projects, which have enjoyed U.S. subsidies since 1916, on a level playing field. Further, a "level" playing field, where there is no cost to oil, gas or coal fired plants for resource protection or pollution, would not accurately portray the relative cost and benefit of renewable energy compared to fossil fuels. A comprehensive carbon pricing mechanism is needed to truly balance the competition.

The End of Adolescence?

When will the U.S. renewable energy industry emerge from its adolescence? The windup of the subsidy-rich environment enjoyed over the last decade will hold the answer, though it seems the industry will not mature further without policy initiatives that reflect the true cost and value of energy. Still, the technology-neutral policy discussion, continued equipment cost reduction and rapidly increasing competitiveness suggests that an adult renewable energy industry may not be far off.

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California Renewable Portfolio Standard: A Forecast for California Developers

By Andrea Lucan and Juliet P. H. Kane

California's Renewable Portfolio Standard (RPS) is one of the most ambitious renewable energy standards in the country. The RPS program requires retail energy sellers, such as investor-owned utilities, electric service providers and community choice aggregators, to increase their share of eligible renewable energy resources to 33 percent of their total procurement by 2020. The RPS program is California's primary method for encouraging new utility-scale, renewable energy development. The goal is to drive development and consumption by ensuring that utilities have a demand for renewable energy. The renewable energy sector has enjoyed fast growth over the past several years, stemming in part from tax incentives and government stimulus, and this has allowed the utilities to largely satisfy their near-term RPS needs. Now, retail energy sellers are looking toward fulfilling their long-term compliance needs, as well as filling any gaps in their current renewable portfolio standard with small, less-than-20-MW projects; short-term contracts; and unbundled renewable energy certificates (RECs).

This article focuses on California's three major investor-owned utilities—Southern California Edison (SCE), Pacific Gas and Electric (PG&E), and San Diego Gas & Electric (SDG&E). Together, these utilities provide 60 percent of the state's electric retail sales. All three utilities met their 20 percent renewable energy target in 2011—20.1 percent for PG&E, 21.1 percent for SCE and 20.8 percent for SDG&E. The most recent *Report Portfolio Standard Quarterly Report*, published July 31, 2012, shows that they were also on track to meet the 20 percent target again in 2012. The California Public Utilities Commission (CPUC) calculated that, at the end of Q2 2012, another 300 MW of renewable capacity had come online, and more than 2,500 MW was scheduled to come online before the end of 2012.

There are three compliance periods between now and 2020, when retail energy sellers must meet the 33 percent RPS requirement. From 2011 to 2013 (Compliance Period 1), retail energy sellers must procure 20 percent of their electricity from renewable sources; from 2014 to 2016 (Compliance Period 2), they must increase the share of renewable energy to 25 percent; and from 2017 and 2020 (Compliance Period 3) renewable procurement must reach 33 percent of energy sales. In year 2021 and each year thereafter, retail energy sellers must maintain a 33 percent renewable energy level.

At the end of 2011, the CPUC also implemented three new portfolio content categories (established in Public Utilities Code § 399.16 (b), pursuant to SB 2 (1X)) that impact RPS. These demarcate a progression of standards that retail energy sellers must meet over the course of the compliance periods, with Category 1 being the ultimate goal. Category 1 refers to products from renewable generators that either (1) have the first point of interconnection to the Western Electric Coordinating Council transmission system within the boundaries of a California Balancing Authority area (CBA), or (2) have the first point of interconnection with the electricity distribution system used to serve end-users within the boundaries of a CBA, or (3) are dynamically transferred to a CBA or (4) are scheduled into a CBA on an hourly basis without substituting electricity from another source. Category 2 specifies energy and RECs that cannot be delivered to a CBA without substituting electricity from another source—this includes firmed and shaped products. Category 3 specifies unbundled RECs, or RECs that do not meet the standards of Category 1 or 2. During each of the compliance periods, retail energy sellers must increase their amount of Category 1 procurement and decrease their amount of Category 2 and 3 procurement. The goal of SB 2 (1X) is to keep the benefits of green energy—green jobs and less pollution—instate, by favoring renewable generators that connect directly into the CBA.

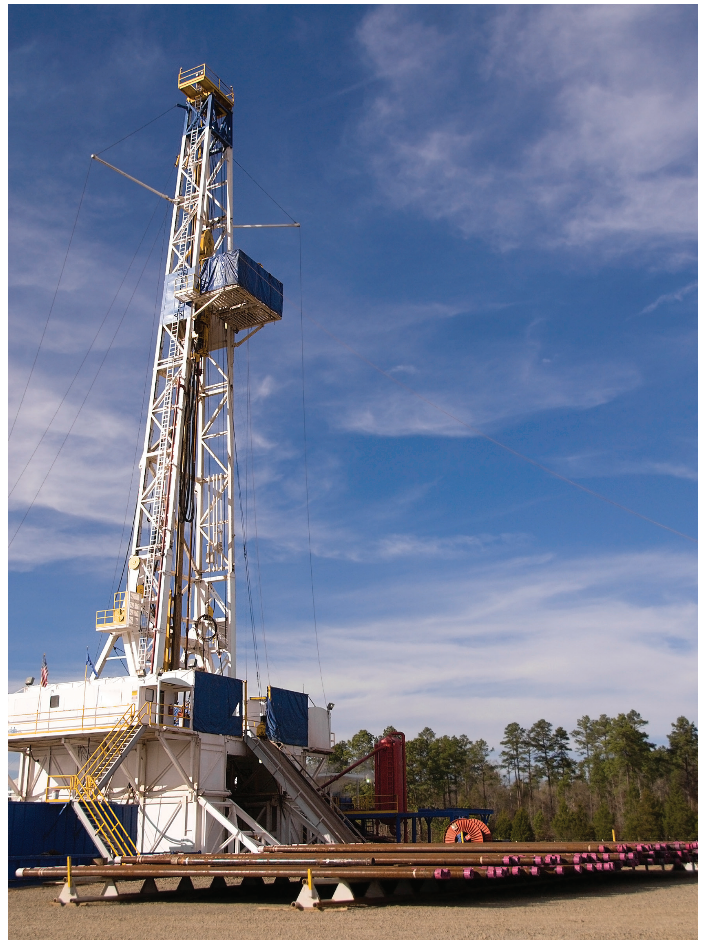
How much Renewable Energy Are Retail Energy Sellers Planning on Procuring?

Each retail energy seller must submit an RPS Procurement Plan. This plan explains the retail energy seller's RPS status, its plans for complying with California's RPS program and whether there are any factors that the retail energy seller thinks will prevent it from complying with the RPS program. From these Procurement Plans, it is possible to get a better picture of the major utilities' RPS status, as well as the near-term and long-term demand for renewable energy development in California. In making these predictions about future needs, retail energy sellers consider the predicted growth in demand for energy projects that are currently online and the pipeline of projects with which they have entered into power purchase agreements (PPAs). Retail energy sellers also take into account that utility-scale renewable projects have a success rate of between 50 and 65 percent for delivered energy from contracts that are executed but are not yet online.

As to the RPS status of the three major retail energy sellers, SCE has made the most dramatic statement by announcing that it will not have an RPS solicitation in 2012.[1] SCE has stated that it currently has enough renewable energy, either built or contracted, to meet its near term needs. Its current focus is to fulfill its need for the latter half of the decade. For the near future, SCE has stated that it will meet its need primarily through its procurement programs for smaller renewable resources (projects that are less than 20 MW). SCE considers these small projects to have a 100 percent success rate, far better than utility-scale projects.

SCE believes that it can fulfill its needs through these smaller programs without resorting to a general solicitation open to all renewable resources, which require more of SCE's resources to run. SCE will focus on several renewable energy procurement programs adopted by the state and the public utilities commission. These include (1) the Renewable Auction Mechanism (RAM) program, a simplified market-based procurement mechanism for renewable distributed generation projects greater than 3 MW and up to 20 MW; (2) SCE's Solar Photovoltaic Program, a five-year solar PV program to develop up to 250 MW of solar PV facilities in SCE's service area by leasing commercial rooftops and installing, owning, operating and maintaining solar PV; and (3) the Renewable Market Adjusting Tariff, previously known as the California Renewable Energy Small Tariff, or CREST, which will provide a feed-in tariff for renewable projects that are 3 MW or less.

PG&E projects that it has enough renewable energy, either contracted for or built to comply with all of the compliance periods between now and 2020.[2] Based on its compliance outlook, PG&E is focusing on procurement that will allow it



to continue to satisfy the ongoing 33 percent RPS requirement that will be in place by 2020. In order to achieve this goal, PG&E intends to procure approximately 1,000 GWh per year of RPS-eligible deliveries. PG&E is focusing specifically on meeting its needs beyond 2020. It is looking for products with delivery terms commencing in 2019-2020, and long-term contracts (10 years or more).

It also recommends that existing facilities that do not have contracts expiring in the near term should seek extensions now, because potentially PG&E will have sufficient capacity to meet its own RPS needs when its contracts do expire; these facilities would then have to compete with non-RPS generators to fulfill PG&E's incremental energy and capacity needs.

SDG&E[3] plans to procure renewables in order to comply with the current compliance period, as well as Compliance Period 3, which starts in 2017. For Compliance Period 1, SDG&E believes that it may have to purchase a relatively small number of unbundled RECs and short-term (less than one year) bundled

[1] All information about SCE's current RPS status and future plans come from the Southern California Edison Company's (U 338-E) First Amended 2012 Renewables Portfolio Standard Procurement Plan, August 15, 2012, filed before the Public Utilities Commission of the State of California, Rulemaking 11-05-005 (Filed May 5, 2011)

[2] All information about PG&E's current RPS status and future plans come from the Pacific Gas and Electric Company Renewables Portfolio Standard 2012 Renewable Energy Procurement Plan (Draft Version) August 15, 2012. As of the date of publication, the final version of PG&E's Renewable Procurement Plan has not been released.

[3] All information about SDG&E's current RPS status and future plans come from the San Diego Gas & Electric procurement plan, filed before the Public Utilities Commission of the State of California, Rulemaking 11-05-005 (Filed May 5, 2011)

contracts to offset the deficit that SDG&E carried into Compliance Period 1, as well as to offset unexpected delays, project failures or any other project underperformance. On the other hand, if the large volume of projects that SDG&E anticipates will commence in 2013 materially surpasses the current probability predictions, SDG&E may have a surplus of RECs and may be able to sell them starting in mid-to-late 2013.

Given its current projections, SDG&E expects that it will meet the RPS goals for Compliance Period 2 with generation from a combination of existing executed contracts and the deliveries of tax equity and utility-owned generator initiatives. Accordingly, it does not plan to solicit new projects for Compliance Period 2.

SDG&E currently anticipates that it will need to conduct new, renewable, eligible purchases (either from newly developed renewable energy projects, renewal upon expiration of existing contracts or other available existing facilities) to meet its Compliance Period 3 requirements. SDG&E plans to meet this need through solicitations in 2012, 2013 and 2014, as well as with potential tax equity investments.

The Effect of New Categories of Renewable Energy

The new categories of renewable energy are driving the type of renewable generators the major retail energy sellers are looking to procure. All three major utilities are focusing on Category 1 products, because utilities may procure an unlimited quantity of this type of renewable energy. On the other hand, retail energy sellers must decrease their reliance on Category 3 procurement over time, though, in the near term, Category 3 provides the utilities with needed flexibility to meet their RPS targets.

SCE has stated that, because there is no limitation on the number of Category 1 products that may be procured for RPS compliance, it is requesting proposals for only renewable energy that qualifies under Category 1. SCE states that this approach will provide more certainty and flexibility. In fact, SCE has not entered into any contracts for non-Category 1 products since before June 1, 2010. The continuing focus on Category 1 products will greatly limit the ability of out-of-state renewable generators to contract with SCE in the future.

Like SCE, PG&E has a stated preference for Category 1 projects. Unlike SCE, PG&E is willing to consider Category 2 and Category 3 products (in that order). PG&E notes that its need for Category 3 will diminish over time, since the ability to use Category 3 products for compliance will continue to decrease.

SDG&E has stated that, in order to fulfill its short-term needs for Compliance Period 1, it will purchase Category 3 unbundled RECs and short-term Category 1 contracts. In Compliance Period 3, SDG&E is planning on accepting bids for only Category 1 projects.

Transmission

The major utilities note that transmission availability, as well as permitting and siting, will continue to be an impediment toward bringing new renewable resources online. No matter how many PPAs retail energy sellers enter into, the utilities will not be able to meet their long-term RPS requirements if there is no transmission available for these projects or if the projects cannot be built on schedule. SCE predicts that most project proposals will be limited by the scarcity of transmission. PG&E has stated that it is looking for projects in PG&E's service territory, because those projects are likely to have fewer transmission issues.

Looking to the Future

As a developer, it is important to note that the major retailers in California are well on their way to meeting their 33 percent renewable portfolio standard by 2020. Rather than a shortage of bidders, it is siting, permitting and transmission that seem to be the biggest barriers toward complying with RPS goals. Projects that can demonstrate the fewest transmission hurdles are likely to have an advantage in the competitive bidding process. Project developers will also be able to bid now for projects that will satisfy the renewable energy needs of retail energy sellers in 2017-2020, as well as beyond 2020. This may be an unusually long development time for some project developers and may stretch their resources. For others, it may allow the use of more cutting-edge technology or projects that will take longer to build but will provide an extra benefit to the developer and the utility, such as greater efficiency or more power.

Existing project owners should also consider whether it is now a good time to renew existing contracts. As PG&E notes, once retail energy sellers meet their 2020 goals of 33 percent, there is likely to be a drop in demand for renewable energy. If a utility has hit its goal before a renewable generator's contract is up for renewal, this may greatly reduce the price at which the energy from the renewable generator can be sold.

Another option to consider is to develop smaller projects. While the major retail energy sellers have stated that they do not have much demand for utility scale renewable projects in the near future, there is a demand, as well as legislative and CPUC programs, to support small renewable and distributed solar projects.

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Los Angeles Implements The Nation's Largest Urban Solar Rooftop Feed-in Tariff Program

By Matt Nesburrn

This is a follow up article to our Summer 2012 Project Perspectives article on the growing importance of Feed-in Tariffs (FITs) for solar developers in the United States as a way to sell their power to utilities and municipalities. At the time of publication of our prior article, the Los Angeles Department of Water and Power (LADWP) had recently launched a 10MW demonstration program as a mechanism for testing the participation, pricing and structure for a larger program required under SB 32 (the California Global Warming Solutions Act).[1] Recently, on January 11, 2013, the LADWP board approved a 100MW feed-in tariff program with an additional 50MW anticipated to be presented to the board for approval in March of 2013, making the 150MW LADWP program the largest urban rooftop solar program in the nation.

The FIT program will be open to rooftop projects between 30kW and 3MW and will be offered commencing in February 2013 with the first of five 20MW allocations. A new 20MW allocation will be released each six months following the initial February allocation. Participating solar projects may be located on warehouse, commercial, retail or multi-family residential rooftops. Incorporating the lessons learned from the 10MW demonstration program, the new programs are offering set pricing instead of the auction-based pricing used in the demonstration program. This change was made in order to provide the pricing certainty that many smaller developers require in order to participate in the market. The initial price payable by the LADWP will be $0.17/kWh, a price calculated to encourage active participation based on the experience of other FIT programs in California and also informed by the weighted average price of $0.175/kWh that resulted from the demonstration program's auction procedure. The initial price will then be reduced by $0.01/kWh as each tranche of 10MW is reserved until the price settles at a floor of $.013/kWh by the fifth such tranche.

In order to encourage a broad spectrum of projects, 2MW of each 10MW tranche will be reserved for "small projects" (30kW to 150kW) with the remaining 8MW going to projects greater than 150kW; however, if the 2MW of small projects are fully subscribed in any given 10MW tranche, then any further small projects will be grouped into the 8MW of total projects until such tranche is fully subscribed. Qualifying applications will be accepted on a first come, first served basis.

Participants will sell the LADWP power via a Standard Offer Power Purchase Agreement and will connect to the grid through of a Standard Offer for Customer Generation Interconnection Agreement, both developed for and used in the 10MW demonstration program. The LADWP anticipates the implementation of the 150MW program to be complete by December 31, 2016, marking a significant acceleration of the originally projected 2026 timeline in order to enable project participants to benefit from the Federal Investment Tax Credit that is set to expire at the end of 2016.

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[1] LADWP is required to offer a 75MW FIT program under SB 1332, which amends SB 32 to provide a deadline of July 1, 2013 for publicly owned electric utilities to adopt a FIT.

North Carolina Offers Robust Tax Incentives for Renewable Energy Projects

By David Burton and Adam Krotman

As of late, we have witnessed an upsurge in investment interest in renewable energy projects in North Carolina, and commentators have noted North Carolina's efforts to incentivize the renewable energy sector.[1] In part, we attribute this interest to state incentives for renewable energy. North Carolina's renewable energy tax credit ranks among the most notable of such incentives.

North Carolina's renewable energy tax credit is equal to 35 percent of the cost of eligible renewable energy property constructed, purchased or leased by a taxpayer (corporate or noncorporate) and "placed in service" in North Carolina during the taxable year. By contrast, the federal investment tax credit is equal to only 30 percent or 10 percent of the cost of eligible renewable energy property, depending on the type of eligible renewable energy property.

Renewable energy technologies covered by the tax credit include solar, wind, biomass and hydroelectric. Renewable energy equipment expenditures eligible for the tax credit include the cost of the equipment and associated design, construction costs and installation costs less any discounts, rebates, advertising, installation-assistance credits, name-referral allowances or other similar reductions provided by public funds. For this purpose, "public funds" do not include cash grants received pursuant to Section 1603 of the American Recovery and Reinvestment Tax Act of 2009. Neither the federal investment tax credit nor the North Carolina credit reduces the amount of the other credit.

The credit is capped at $2.5 million per "installation" for all eligible systems used for a "business purpose."[2]

[1] *See* Michael A. Hannah, North Carolina Focuses On Renewable Energy, State Tax Today (April 28, 2008) (Taxanalysts, elect. cit. 2012 STT 213-2).

[2] This ceiling is increased to $5 million in the case of each installation of renewable energy property placed in service in an area certified by the North Carolina Secretary of Commerce as an "Eco-Industrial Park." *See* N.C. G.S. 143B-437.08(j) for the definition of an Eco-Industrial Park.

An "installation" is considered to be each identifiable system of renewable energy property that converts renewable energy into a useful energy product. Further, renewable energy property is placed in service for a business purpose if the useful energy generated by the property is offered for sale or is used onsite for a purpose other than providing energy to a residence. In the case of residential property, the credit cap varies depending on the type of renewable energy technology from $1,400 to $10,500 per dwelling unit.

For qualifying renewable energy systems used for a business purpose, taxpayers are required to take the credit in five equal installments beginning with the year in which the property is placed in service. While the allowable credit may not exceed 50 percent of a taxpayer's state tax liability for the year, reduced by the sum of all other state tax credits, any remaining credit amount may be carried over for the next five years. The credit can be applied against franchise tax, corporate tax, income tax or, in the case of insurance companies, the gross premiums tax. In a partnership structure, the North Carolina renewable energy tax credit is allocated in accordance with the allocation of income or loss for federal income tax purposes for the year in which the credit arises.

In the context of a lease, either the lessor or the lessee (but not both) may claim the credit. In order for a lessee to claim the credit, the lessor must provide the lessee with its written certification that the lessor will not claim the credit with respect to the relevant property. This feature of the North Carolina renewable energy credit enables transactions that use lease structures to monetize the credit, including structures tailored to bifurcate the North Carolina credit from any federal credits or cash grants and allocate them among different investors.

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Qualified Progress Expenditure Rules Allow Taxpayers to Claim ITC Earlier for Projects with Lengthy Construction Periods

By David Burton

In general, taxpayers claiming the investment tax credit (ITC) must wait until the eligible project is placed in service to claim the credit. However, in some cases taxpayers investing in projects that take more than two years to construct need not wait until the property is operational to claim the ITC. In the case of "progress expenditure property," a taxpayer can elect to treat qualified progress expenditures (QPEs) as a qualified investment eligible for the ITC in the year the expenditures are made (subject, in some cases, to the percentage of completion limitation, discussed below). QPE elections are available for each component of the ITC, including the energy credit and the qualifying advanced energy project credit under Section 48C, which was introduced in 2009 to encourage investments in facilities that manufacture "green" equipment.[1] The QPEs will qualify for the ITC of 30 percent of qualified capital expenditures provided that the project is placed in service no later than December 31, 2016. In the case of solar energy property, the credit will remain available after December 31, 2016, but at a reduced rate of 10 percent.

Progress Expenditure Property Defined

Progress expenditure property is property being constructed by or for the taxpayer that has an estimated normal construc tion period of two years or more.[2] In this context, "construction" means building or manufacturing property from materials and component parts. "Normal construction period" starts on the day when physical work begins or, if later, on January 1 of the year in which the QPE election is made.

[1] On the other hand, a taxpayer who elects to receive a Treasury cash grant forfeits eligibility for the ITC and any credit previously allowed for QPEs is recaptured.

[2] Treas. Reg. § 1.46-5(b) states an additional requirement that the useful life of the property must be seven years or more. Note that the statutory language underpinning the Regulation was deleted by the Economic Recovery Act of 1981, Pub. L. No. 97–34, §211(b)(2), 95 Stat. 172 (1981). Therefore, the seven-year useful life requirement is no longer applicable.

QPE Defined

Determining allowable QPE amounts in a given year depends on whether the property is classified as self-constructed or non-self-constructed. Property is self-constructed, if more than half of the construction expenditures will be made directly by the taxpayer. Conversely, property is non-self-constructed, if only half, or less than half, of the expenditures will be made directly by the taxpayer. For example, amounts paid to a contractor or manufacturer will generally not be considered construction expenditures made directly by the taxpayer. Amounts treated as expenses and deducted in the year paid or accrued do not qualify as QPEs.

QPEs for self-constructed property are amounts paid or incurred and properly includible in computing basis under the taxpayer's method of accounting. Both direct costs (e.g., wages, materials) and indirect costs (e.g., overhead, insurance) associated with the construction may be QPEs. Expenditures for component parts and materials are not properly includible in computing basis (and thus not proper QPEs) until consumed or physically attached to the property or until they have been irrevocably allocated to construction of the property.

The rules for non-self-constructed property are more restrictive. QPEs for non-self-constructed property include amounts actually paid (not merely incurred) by the taxpayer to another person for construction of the property, but only to the extent attributable to the portion of the construction completed during the tax year. This timing rule is known as the "percentage of completion limitation." Progress is presumed to occur no faster than ratably over the normal construction period, although the taxpayer may rebut this presumption with clear and convincing evidence. Progress is measured in terms of the manufacturer's incurred cost as a fraction of anticipated costs. Architectural and engineering estimates and cost accounting records constitute evidence of progress. Although QPEs are limited by the percentage of completion limitation, amounts paid in excess of the limitation in any year may be carried forward and treated as paid in subsequent tax years.

In addition, there are restrictions on borrowing funds to pay for non-self-construction expenses. Amounts borrowed directly or indirectly from the person constructing the property and then paid to that same person for such construction costs will not be treated as QPEs. A taxpayer cannot avoid this restriction by causing an affiliate to borrow from the payee instead. The IRS will consider such amounts borrowed by any person related to the taxpayer (using a 50 percent ownership by value test) or by any person who is part of a group of entities affiliated with the taxpayer (using an 80 percent ownership by value or voting power test for parent-subsidiary relationships and a 50 percent ownership by value or voting power for brother-sister relationships) as borrowed indirectly by the taxpayer and ineligible for QPE treatment.

If an item of property is self-constructed because more than half of the construction expenditures are made directly by the taxpayer, then no expenditures for construction of that item of property (whether made directly by the taxpayer or not) will be subject to the limitations applicable to non-self-constructed property.

Transfers of Property Eligible for QPEs

Where property is transferred during the construction period, the ability of the transferee to claim the ITC for QPEs made after the transfer is subject to certain limitations. First, in determining whether the property qualifies as progress expenditure property in the hands of the transferee, the "normal construction period" for the property begins on the date of the transfer or, if later, the date the QPE election is made by the transferee. In addition, the consideration paid for the transferred property (or interest therein) may not be considered a construction expenditure made directly by the transferee for purposes of determining whether the property is self-constructed or non-self-constructed. In most cases, a construction-period transferee seeking to claim the ITC based on QPEs must make its own election (although the transferor's election carries over to the transferee in the case of certain tax-free transfers).

QPE Election Mechanics

A taxpayer wishing to claim QPEs for investment credit must make an election on Form 3468 and file it with the original income tax return for the first year in which the election will apply. Once made, the election applies to that and all subsequent tax years and may not be revoked without IRS consent. The QPEs are included in the taxpayer's basis in eligible property for the tax year in which the QPE election is made. For this reason, taxpayers operating at a loss and taxpayers subject to AMT may find it more advantageous to forego the election and instead treat progress payments as qualified investments for the year in which the property is placed in service, when the project is more likely to have income available for offset.

Once the property is placed in service, the taxpayer must reduce its qualified investment (but not below zero) by the QPEs previously taken by the taxpayer or its transferor-predecessor for purposes of calculating the investment credit going forward. In addition, a taxpayer must reduce the depreciable basis of the property by 50 percent of the amount of the ITC claimed.

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Commercial Aspects of Deficit Restoration Obligations in LLC and Partnership Transactions

By David Burton and Vladimir Fet

This article provides an overview of the commercial aspects associated with the inclusion of a deficit restoration obligation (DRO) in a limited liability company or partnership agreement.[1] A DRO is a tax structuring technique that permits a partner to be allocated more tax losses (e.g., depreciation) or distributed more cash (or other property) than the tax rules view to be the partner's appropriate share.[2]

Negative Capital Accounts and the PIP Rule

If a partner is allocated more tax losses or distributed more money than the tax rules deem its appropriate share, it results in an "impermissibly negative" capital account. If at the outset of the partnership it is reasonably anticipated that such a situation may occur, the tax rules empower the Internal Revenue Service (IRS) to disregard the allocations provisions of the partnership agreement and to deem the allocations of tax items to be in accordance with the "partners' interests in the partnership" (PIP). Note that the IRS cannot change the cash (or other property) distribution provisions; it is only empowered to change the allocations of tax items.

Applying the PIP rule is straightforward in simple partnerships. For instance, partner A contributes $60 and partner B contributes $40 to the partnership. They also agree to share profits and losses 60/40 at all times. Under such facts, application of the PIP rule would result in the allocation of 60% of profit and losses for A and 40% of profit and losses for B. Thus, tax advisors have little to fear from the IRS's application of PIP. As a result, in partnerships that are less tax intensive, DROs are rarely used.

DROs in Tax Equity Partnerships

It is less clear how to apply the PIP rule in tax equity flip partnerships, which are commonly used as a source of funding for renewable energy projects. In flip partnership agreements, the allocation percentages do not necessarily track the capital contributions and change as financial hurdles are achieved. Here, the IRS application of PIP could result in the developer being allocated tax credits or depreciation that the partners intended to be provided to the tax equity investor. Thus, DROs are a common feature in renewable energy partnerships because the partners do not want to gamble on what the IRS would deem PIP to be.

A typical DRO provision states that after giving effect to all allocations, distributions and contributions for all periods, if the partner providing the DRO has a deficit capital account balance, such partner will be obligated to contribute cash to the partnership in a specified amount by the end of the partnership's taxable year during which its liquidation occurs

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[1] In the remainder of this article, we only refer to a partnership agreement; however, the substantive points we make are equally applicable to a limited liability company agreement.

[2] If a partner is an individual and concerned about the "at risk" tax rules that limit tax benefits associated with nonrecourse debt for which an individual does not have personal liability, it is important to note that the Tax Court has determined that providing a DRO does not make a partner at risk for such debt. *Hubert Enterprises, Inc. v. Commissioner,* 125 T.C. 72 (2005). In other words, from the Tax Court's standpoint, a DRO is not a solution to the potential at risk tax problem that individuals may face.

(or within a specified number of days after the date of such liquidation). The amount of the DRO obligation would be limited to a cap that cannot exceed the amount of the deficit balance in the partner's capital account.

Triggering a DRO

A DRO provision can only be triggered if the partnership in question has to liquidate, which under typical partnership agreement provisions would be subject to each partner's consent unless required by a court order. The likelihood of a court order requiring the partnership's dissolution is usually remote. There is a higher risk of liquidation for partnerships that own assets that are security for a loan (i.e., a "lowered" deal). In the current market, leveled deals are rare. In renewable energy projects, a court order to liquidate may result from the lawsuit by a plaintiff injured by the partnership's or its contactor's negligent acts or omissions (e.g., during construction or maintenance of a solar project). Usually, such types of losses are covered by the contractor's and/or partnership's liability insurance as well as through the contractor's indemnification obligations in the applicable project document. If, however, the above contractual measures fail to ensure that the full amount of judgment is satisfied by or through the contractor, the court may order that the judgment be enforced against the partnership's assets, which may then be attached and sold. In such an event, a court order for liquidation of the partnership may follow, which will in turn trigger the applicable partner's obligations under the DRO.

Thus, generally speaking, it appears unlikely that a partner would ever be required to satisfy the DRO, absent an unsatisfied plaintiff's judgment or foreclosure by a secured lender.

DRO Elimination

Although not required by tax rules, partners generally find it to be commercially advantageous for the DRO to be eliminated prior to the end of the transaction. To achieve this, the financial model for the transaction is structured in such a way that if the deal progresses as expected then, prior to the end of the transaction, the capital account of the partner providing the DRO will be at least zero. Thus, the DRO obligation will be effectively eliminated. Such an arrangement enables the partners to liquidate the partnership without having the DRO triggered.

In addition, it is generally market practice that if the partner providing the DRO is a special purpose entity with limited assets, then its DRO obligation needs to be guaranteed by a parent company or another affiliate that is reasonably expected to have assets sufficient to satisfy the DRO. Otherwise, there is a concern that the IRS could attack the substance of the DRO.

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Developing Projects in Uzbekistan:

Challenges and Opportunities

By Dinmukhamed T. Eshanov

Since the early days of its independence in 1991, Uzbekistan has been, and today remains, an attractive investment destination for foreign developers and international financial institutions. According to the World Bank, Uzbekistan attracted $1.4 billion worth of foreign direct investment in 2011.[1] This number is small considering the country's need to upgrade its existing infrastructure in the power, mining, oil and gas and transportation sectors and develop new facilities to meet growing domestic demand.

Uzbekistan's status as an emerging market, and the risks assumed to be associated with such status have caused foreign developers to be cautious with their investment plans in Uzbekistan. So far, foreign developers have been active with projects spearheaded by their governments and involved mainly large-scale projects in the oil and gas sector, including petrochemicals. A good example is a $4.1 billion gas chemical plant currently being developed by a consortium of Korean developers — Samsung Engineering and Hyundai Construction — in the northwest of Uzbekistan.

To date, such developers have relied mostly on their home countries' export credit agencies (ECAs) or loans provided by international development finance institutions including the likes of the World Bank and the Asian Development Bank. In the case of the project referred to above, a significant portion of financing, for instance, is being provided by Korea Exim Bank. Most projects financed by commercial banks in emerging markets typically also require a political risk guarantee from one of the multilateral agencies, including the Multilateral Investment Guarantee Agency (MIGA). A guarantee of $119.5 million issued by MIGA in 2012 to BNP Paribas – acting for a group of international lenders for the Khauzak-Shady-Kandym project – to cover a nonshareholder loan to Lukoil — is a case in point. The guarantee covers the risks of transfer restriction, expropriation, breach of contract and war and civil disturbance.

While Uzbekistan has had a certain degree of success in attracting foreign investors to develop some large oil- and gas-related projects, the country has an urgent need to develop many more projects, in particular, medium- and

[1] World Bank – Uzbekistan Partnership Program Snapshot (2012)

small-sized projects across various sectors. Medium- and small-sized projects typically tend to fall outside the orbit of foreign investment promotion agencies and developers prefer larger projects, which tend to generate hefty revenues. However, medium- and small-sized projects are as important and beneficial to Uzbekistan as large ones and therefore, the Government of Uzbekistan will need to work on making such projects attractive to foreign developers and financial institutions. In fact, financial institutions providing project financing to construction projects around the world, frequently mention that smaller-sized tickets are easier to get internal approval for, especially, in the current economic climate, and overall are easier to administer following financial close. By the same token, smaller projects do not require the formation of large consortia, which in itself is a time-intensive and complex process. The Government of Uzbekistan will need to take the following steps to draw attention of foreign developers and financial institutions to opportunities existing within the country in relation to medium- and small-sized projects.

Public/Private Partnership Schemes

Uzbekistan does not pursue implementation of projects through public and private partnership (PPP) structures. There is no legislative basis for implementing such structures under local laws. Recognizing the importance of this model, the World Bank has been working on a number of PPP-related initiatives in Uzbekistan. However, these initiatives have so far been on an ad hoc basis, focusing mostly on micro projects. The PPP model has been successfully implemented around the world, in jurisdictions with varying backgrounds, including the Middle East. The adoption of a well-structured and efficient PPP scheme could help the Government of Uzbekistan address the problem of a double deficiency — the shortage of capital and the lack of necessary technical expertise. Indeed, Uzbekistan's existing $5 billion national infrastructure fund would sit well within such model, with the Government of Uzbekistan providing equity co-financing to projects along with foreign developers.

Predictable Tariffs and Robust Financial Models

Project finance is a new phenomenon in Uzbekistan but if appropriately used, it could help the Government of Uzbekistan develop a large number of projects in various sectors. However, to do so, first the Government of Uzbekistan will need to address the fundamental premise of project finance — return of capital along with a preagreed margin recoverable from project proceeds — coupled with the right balance of risk allocation among the relevant stakeholders. This in turn, requires the Government of Uzbekistan to feel comfortable acting as an economic actor, willing to accept certain risks, ensure predictable tariffs and where necessary, guarantee the return of capital. The Government of Uzbekistan has taken a number of steps in this direction. For example, in the electricity sector, the Government of Uzbekistan has steadily increased the tariffs for domestic use of electricity and introduced a metering scheme, which has helped tackle the problem of nonpayment. The Government of Uzbekistan needs to take the same approach in other sectors such as transportation, water and communication to make them attractive to foreign developers and financial institutions. In addition, the Government of Uzbekistan may want to consider offering incentives, such as tax holidays, to foreign developers which invest in medium- and small-sized projects in certain critical sectors.

Diversity of Financing Sources: Islamic Finance

Given that Uzbekistan is a country with a predominantly Muslim population, an alternative source of financing to projects in Uzbekistan could come from financial institutions located in the Middle East and Southeast Asia in the form of Islamic tranches. Just to name a few, the potential sources of financing — both equity and debt — would be the Malaysia Export Import Bank, International Petroleum Investment Company, the State General Reserve Fund of Oman, the Islamic Development Bank and Kuwait Finance House. The Government of Uzbekistan needs to serve as an intermediary between the aforementioned institutions and foreign developers to match the capital of the former with the expertise of the latter. In addition, local laws may need to be amended to ensure that Islamic finance is placed on equal footing with conventional sources of finance.

The above-mentioned proposals are some of the significant first steps which would assist the Government of Uzbekistan in attracting further investment inflows into medium- and small-sized projects currently existing in Uzbekistan.

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Puerto Rico Renewables: Sun, Sea…Solar and Wind?

By David Markey

Puerto Rico traditionally has sourced the majority –nearly 70 percent –of its energy from oil. This leaves the island territory open to global oil price fluctuations which affect power prices for consumers to a greater extent than areas of the mainland United States. To combat this, in July 2010, the government of Puerto Rico made an aggressive attempt to spur renewable energy development on the island by passing legislation to increase the percentage of Puerto Rico's energy derived from renewable sources. The first piece of legislation was the Puerto Rico Energy Diversification through Sustainable and Alternative Policy Act (the Energy Diversification Act). The second was the Green Energy Incentives Act (the Incentives Act).[1]

[1] For a detailed analysis of the Green Energy Incentives Act see Project Perspectives (Winter 2012 Edition) – "Puerto Rico's Green Energy Incentives Act Provides New Opportunities for Commercial-Scale and Sustainable Renewable Energy Production" by David Burton and Brett Fieldston.

As a result of this legislation, the Autoridad de Energía Eléctrica de Puerto Rico (Puerto Rico Electric Power Authority or PREPA) has been entering into renewable Power Purchase Agreements with an attractive price of 15 cents per kWh for solar and 12.5 cents per kWh for wind. Combine this with strong natural resources for renewable energy production, the availability of United States federal tax credits and the introduction of Puerto Rico-specific credits and incentives and you may have expected Puerto Rico to be immediately awash with wind and solar projects ready to be placed in service.

However, like many markets new to the renewables industry, it is taking time for a strong renewable energy policy to translate into projects successfully reaching commercial operation. As with wind and solar development on the mainland United States, local developers often need the experience and capital of outside developers and third party investors. It is taking

some time for these outside developers to learn, to become comfortable with and to implement the distinctive characteristics of project development in Puerto Rico. These distinctive characteristics include the need for local on-the-ground knowledge and connections and the imposition by PREPA of certain specific minimum technical standards in its offtake agreements to ensure grid stability and island geography. At the end of 2012, the breakthrough appeared to be coming with a few utility-scale projects being placed in service.

Spurring Development - Renewable Energy Portfolio Standard and RECs

The Energy Diversification Act and the Green Energy Incentives Act attempted to spur development in a number of ways. First, the Energy Diversification Act adopted a renewable portfolio standard (RPS) for Puerto Rico. The RPS requires all retail energy providers (i.e., PREPA) to procure a certain percentage of their energy needs with renewable resources, specifically 12.0 percent in the years between 2015 and 2019, and 15 percent between 2020 and 2027. Interim targets are to be established beyond that with a mandated goal of 20 percent by 2035.

Developers of renewable energy projects are to be issued with RECs for every mega-watt hour of electricity generated and PREPA must show compliance with the RPS targets by procuring renewable energy certificates (RECs). Puerto Rico RECs are also registered on the North American Renewable Registry and therefore developers can also sell their RECs to third parties either inside or outside Puerto Rico and either bundled with, or separately from, the energy generated by the project. This gives the opportunity for Puerto Rican RECs to be traded on the mainland United States.

Tax Incentives

In addition to the RPS established by the Energy Diversification Act, the Incentives Act established a "Green Energy Fund." The Green Energy Fund is funded through various sources including state and federal incentives, taxes, donations from private entities and fines (related to the production of alternative and sustainable renewable energy). The incentives vary depending on the size of the project, but for commercial scale projects in excess of 1 MW incentives include accelerated depreciation on buildings, structure and machinery, credits for purchasing products manufactured in Puerto Rico, credits for investment in research and development and a substantial exemption from real and personal property taxes.

In addition to incentives specific to Puerto Rico, being a United States territory, Puerto Rico renewable energy projects can make use of the recently extended Production Tax Credit, or, in the case of solar projects, the Investment Tax Credit. Additionally, if a developer had successfully "commenced construction"

(including by safe harboring solar panels), the 1603 cash grant could still be available.

High Power Prices

As a result of the RPS and the traditionally high cost of energy in Puerto Rico, PREPA offtake agreements (PPOAs) are extremely lucrative at first glance. Solar PPOAs generally offer 15 cents per kWh and wind 12.5 cents. Some also include a contractual obligation for PREPA to purchase RECs on top of that. Even without the REC add on, the economic terms are likely very enticing for investors who have been looking at equivalent projects on the mainland United States.

Challenges for Developers and Investors — Local Knowledge

Despite a favorable policy landscape and high power prices, developers still face a number of challenges when trying to develop, construct and ultimately place their projects in service. Puerto Rico is an island community. First, local knowledge is important and should not be underestimated. Developers and investors that do not have ties to Puerto Rico will likely need to partner with local developers or have teams with local knowledge on-the-ground in Puerto Rico in order to manage community opposition, find available project sites with good interconnection points and maintain strong connections at PREPA. While this is true of developing projects anywhere it is particularly important given the island nature of Puerto Rico. Local developers, on the other hand, will likely need to look for investors and larger developers with experience in the renewable energy industry and who have the financial capability and experience to ultimately develop, finance, construct and operate projects.

PREPA PPOAs — Technical Hurdles

The Puerto Rico power grid is not particularly modern or stable. One of the key aspects for PREPA in implementing renewable energy is to work to achieve grid stability in light of a potentially large number of renewable energy projects being connected to it. The PREPA PPOA reflects this by being generally heavy on technical requirements for project design and interconnection. There are specific prescribed minimum technical requirements which the project must meet including some which center around frequency response and ramp rate control. These requirements may require certain technical aspects to a project design that a developer may not need to consider in the mainland United States, including careful consideration of inverter and management systems and the need for battery storage. Developers will want to ensure that they have solid technical advice from an early stage so that they do not fall foul of these requirements. They will also need to factor in additional costs involved in compliance. In addition, developers will want to ensure that their PPOA includes clear provisions surrounding what cost they will bear for any future changes in the minimum technical requirements.

Land Use and Opposition

Unlike the wide-open spaces of the United States Midwest or South, Puerto Rico is a relatively small island. In many areas of the mainland United States, land control, although still an issue, can be fairly manageable. Many renewable energy projects are sited on large parcels of land that are not used by the owner for their livelihood. However, Puerto Rico does not have space comparable to the large swathes of unused land in the United States Midwest. If the RPS is to be met, many sites will need to be found for renewable energy projects and securing land control early could become increasingly important.

A further issue stemming from these land use issues is opposition to projects, particularly wind. Opposition to renewable energy projects in certainly not uncommon in a variety of jurisdictions. However, again, island geography, less unused space and aggressive development may lead to increased opposition. Even if suitable sites are found to develop a project, neighboring farmers or residents may actually living and working closer to a wind turbine than, say in the mainland United States. Certain developers have already experienced opposition to their projects, including concerns about migratory birds.

Again local knowledge will be important in order to deal with both these issues. Further, these land use items may be a factor in Puerto Rico in favoring solar as a resource when trying to meet its aggressive targets.

Success to Date

Despite the challenges, signs of a renewable energy breakthrough are starting to be seen. In October 2012, AES announced that its Guayama solar project had reached commercial operations. Later that month Pattern Energy's Finca de Viento wind farm opened in Santa Isabel (95 MW). Gestamp started construction of a 23 MW wind project in Naguabo in August 2012. Other projects have since started construction and are expected to be online in 2013.

Final Note

A strong legislative framework, the availability of United States-based tax credits and high power prices are likely to be attractive to developers and investors. There are certain challenges to developing projects in Puerto Rico, but, the fundamentals appear to be in place and would suggest that Puerto Rico may become a hotbed of activity for renewable energy development over the coming years.

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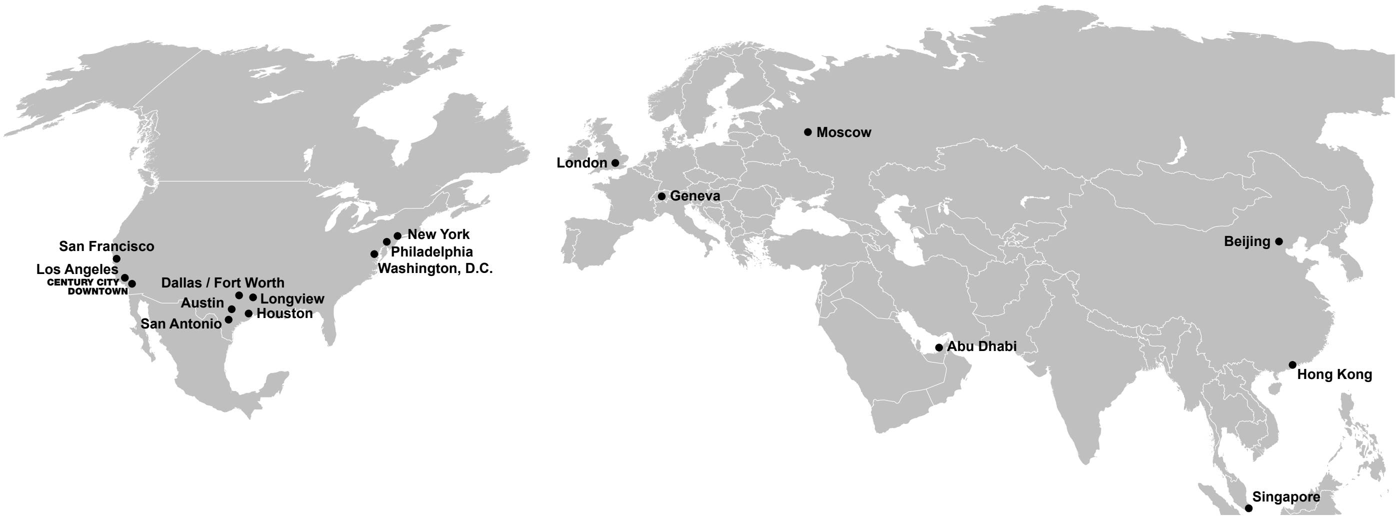

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