Project Perspectives




Global Project Finance

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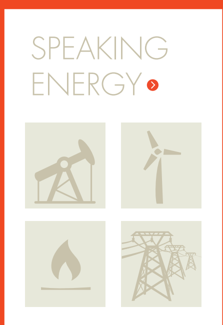

Akin Gump Strauss Hauer & Feld LLP is pleased to announce the launch of the ***Speaking Energy Blog.***

For over 65 years, Akin Gump has been speaking energy across the globe. As the industry continues to grow and change with new technologies, markets and resources, we have created this blog to provide

our clients and readers with information and content including:

- legal analysis of timely issues
- industry sector and legal topics
- updates on regulatory changes
- updates on legislation and court decisions affecting the industry
- a regularly updated newsfeed.

Contributors of the blog include attorneys from across our practice areas who work in the Energy Industry.

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Tax Indemnity Considerations for Developers Entering into Investment Tax Credit Transaction

By David Burton

There are a number of renewable energy developers who are licking their wounds after having agreed to indemnify tax equity investors for shortfalls in Treasury cash grant proceeds. There are generally two causes of such shortfalls: (i) budget sequestration as enacted by Congress and (ii) Treasury hair cutting the cash grant due to skepticism regarding the fair market value of projects.

As the cash grant program winds down, some of these developers may be rethinking their willingness to protect a tax-equity investor's expected tax benefits and might believe they should refuse to provide indemnity protection for the investment tax credit (ITC) in new transactions so as to avoid the outcome suffered in the cash grant transactions. Giving in to that reflex could turn out be a less than optimal decision.

In the current market, where the demand for tax-equity exceeds the supply, if tax equity investors are not provided ITC indemnities, the tax-equity investors will assume the worst in their pricing models. Thus, developers' deal economics will be comparable from the ITC benefit to what would have occurred if the IRS aggressively audited every deal and prevailed. However, not every deal will be audited, and the IRS will not prevail on every ITC audit it initiates.

Second, an IRS audit is a completely different animal from the Treasury cash grant process. At Treasury, the administrators of the grant program are effectively prosecutor, judge and jury. If they approve less than an applicant applied for, the applicant is left appealing to those same administrators in an informal process. Fortunately, the IRS has more robust checks and balances.

Most tax equity investors are audited continually. Therefore, an ITC audit would start with the IRS team assigned to the tax equity investor.[1] If the issue cannot be resolved with the audit team in a manner satisfactory to the taxpayer, the taxpayer may appeal to a relatively independent IRS Appeals Officer (or a panel thereof for large or complex issues). The Appeals Officer is responsible for "applying the tax laws reasonably and impartially in an effort to achieve the primary goal of settlement. The Appeals Officer … is authorized to enter into settlement(s) … based on the perceived hazards of litigation."[2]

Further, if a taxpayer is unhappy with the outcome of the appeal within the IRS, there is more flexibility in litigation strategy than there is with the cash grant program. The taxpayer has the choice of three venues: bring an action in Tax Court or pay the tax in question and bring a suit for a refund in its local federal district court or the Claims Court. For the cash grant program, there is only one venue: the Court of Claims.

Having forum options not only provides the taxpayer with key strategic choices, it also means improved chances of prevailing. For instance, the Tax Court may be less likely to brush aside taxpayer favorable precedent, as Treasury has done in some instances.

It is worth noting that in the case of a partnership transaction, the developer would have the ability to negotiate directly with the IRS because the audit would be conducted at the partnership level and controlled by the "tax matter partner," which would typically be the developer. Of course, the developer would need to consult with the tax equity investor partner and obtain its consent before settling, etc.

It is relatively customary in tax indemnities in leases that the tax equity investor, if requested by the developer, must contest the dispute through the trial court level. In contrast, cash grant indemnity contest rights are typically quite limited.

In cash grant transactions, the developer's contest rights are limited for three reasons. First, as discussed above there is no formal administrative appeals process. Second, many tax-equity investors are financial institutions regulated by an arm of the

[1] *The audit process is different for a partnership. The partnership can elect to have the audit occur at the partnership level. Then the developer, as the "tax matters partner," leads the audit process. This form of arrangement provides the developer with more discretion; however, the developer will need to consult with the tax equity investor partner and obtain its consent before settling, etc.*

[2] *Donald C. Alexander and Brian S. Gleicher, IRS Procedures: Examination and Appeals, 623 Tax Mngt. Port. (BNA) IV, A (2012).*

Treasury, so they do not want to be obligated to do anything that could potentially antagonize a regulator. Finally, the cash grant program is subject to disclosure to Congress and under the Freedom of Information Act (FOIA). Therefore, tax -equity investors are concerned that contesting a cash grant dispute could lead to unwanted attention from Treasury, Congress or the press. Thus, many cash grant indemnities provide that the tax-equity investor will enter into informal discussions with Treasury only to the extent the investor determines that doing so is unlikely to harm its interests.

Fortunately, like tax returns, tax audits are confidential and cannot even be disclosed to other components of the federal government. Therefore, there is no question of disclosure to the Treasury, Congress or the public as long as the dispute is within the jurisdiction of the IRS. However, once the tax-equity investor brings an action in court, the dispute is part of the public record.

Many developers found the cash grant indemnity process to be jarring. The tax-equity investor would receive an “award letter” from Treasury providing for a smaller cash grant than the parties anticipated. Several days later, Treasury would wire the reduced grant amount, and then the developer would receive a notice from the tax equity investor demanding payment of the indemnity. All of this can happen in a short time frame; if it occurs at the end of a quarter, it may provide the developer with insufficient time to prepare for the financial statement consequences.

In contrast, an IRS audit starts with a “notice of proposed adjustment.” The tax-equity investor must notify the developer of that notice (or vice versa in the case of a partnership transaction). The audit followed by the appeal within the IRS will likely take at least several months, so the developer is unlikely to be surprised by an indemnity demand.

Generally, under the indemnity terms, in a lease transaction the tax equity investor selects the counsel for the dispute, decides whether to bring an appeal within the IRS and selects the forum for any litigation. This allocation of discretion in favor of the tax equity investor is a function of the fact that the developer’s transaction is unlikely to be the tax equity investor’s sole dispute with the IRS. Nonetheless, the developer does have some ability to have input into the process. Tax-equity investors are generally obligated to consult in good faith with the developer and its counsel regarding strategic decisions (e.g., venue), and provide the developer’s counsel with drafts of documents and pleadings and consider developer’s counsel’s comments in good faith.

Finally, as most developers do not have tax appetite, a tax-equity investor permits the developer to unlock value that

is otherwise unavailable to it. To the extent the developer has presented the transaction to an investor as providing a certain level of investment tax credit or cash grant benefit, it is reasonable for the investor to request an indemnity for any shortfall. The only way this expectation as to risk allocation is likely to change is if there is a shift in supply and demand in the tax equity market in favor of developers.

Thus, the process for tax disputes is sufficiently different from the process for cash grant disputes that developers should not conclude from their cash grant indemnity experience that the answer in investment tax credit transactions is to refuse to provide indemnities. However, there are best practices that developers should follow in agreeing to tax indemnities:

1. The developer's management should understand the scope of the tax indemnity and the potential exposure. If the indemnity relates to fair market value, the developer's management should review the fair market value methodology used in the transaction (e.g., the appraisal) and seek to understand, and minimize if possible, any differences between that methodology and conclusions and the developer's internal valuations.
2. If "controlling" the audit process is important to the developer's management, the developer should consider opting for a partnership structure in which it is the "tax matters partner."
3. A tax indemnity in a lease structure should include the following protections for the developer with respect to contest rights:
    - The tax equity investor must be obligated to promptly notify the developer upon receipt of a notice of proposed adjustment or other writing indicating that the IRS has an issue with the transaction.
    - The tax equity investor must forgo any right to indemnity if it settles the dispute without the developer's consent.
    - The tax equity investor must be obligated to consult with the developer and its counsel regarding strategic decisions, like venue and pursuing IRS appeals.
    - The tax equity investor must be obligated to keep the developer apprised of the progress of the audit.
    - The tax equity investor must be obligated to consider in good faith the developer's counsel comments to pleadings and other documents.
    - The tax equity investor must be prohibited from paying the tax without the developer's consent, as doing so will preclude bringing an action in Tax Court.
4. In a lease transaction, "exclusions" from the tax indemnity obligation are one means for a developer to limit its potential exposure to tax risk.
    - The general rule of thumb is that the more competition there is for the tax-equity investment opportunity then the broader the exclusions are (i.e., more favorable to the developer).
    - Typical exclusions include: (i) any loss due to the tax equity investor having insufficient tax appetite to benefit from the tax benefits from the transaction; (ii) any loss due to a change in tax law; (iii) any loss due to the transaction lacking various forms of "economic substance"; and (iv) any loss due to the tax equity investor voluntarily transferring its interest. However, the allocation of tax risk in each particular transaction varies.
        - ◊ Similar principles apply in partnership flip transactions, but then these concepts are called "fixed tax assumptions". Even if the IRS overturns a fixed tax assumption, the flip is calculated assuming the assumption to be true.

As noted above, developers would be wise to provide tax indemnities in ITC transactions, as doing so is likely to mean significantly better economics for the developer. The tax protections afforded to both the tax equity investor, and the developer in terms of its arrangement with the investor, are substantially different under the Internal Revenue Code than with respect to Treasury's cash grant program, where there is not much in the way of formal procedures for challenging a reduced award.

David Burton is a partner in Akin Gump's New York office and is the editor of Tax Equity Telegraph*. He can be reached at 212.872.1068.*

FERC's Office of Enforcement Takes Aim at the Financial Industry

By George (Chip) Cannon, Jr. and Julia E. Sullivan

Prior to 2005, the Federal Energy Regulatory Commission (FERC) had limited authority to impose civil penalties on market participants for violations of the Federal Power Act (FPA) or the Natural Gas Act (NGA). FERC's oversight and enforcement activities typically focused on ensuring that regulated electric and gas utilities complied with the provisions of their tariffs and FERC regulations, primarily with respect to rate-related issues.

That changed when Congress responded to the Western Energy Crisis of 2000-2001 by passing the Energy Policy Act of 2005 (EPAct).[1] Among other things, EPAct amended the FPA and NGA to prohibit the use or employment of manipulative or deceptive devices or contrivances in connection with FERC-jurisdictional transactions.[2] EPAct also empowered FERC to impose civil penalties of up to $1 million per day per violation (up from $10,000 per day) and increased the maximum fines and imprisonment time in criminal cases. Since EPAct was enacted, FERC's Office of Enforcement has increased from a staff of approximately 20 to one of more than 200, including investigators, analysts and economists.

This article provides an overview of where FERC has been focusing its newly-acquired market oversight and enforcement authority and where it is likely to go.

FERC's Anti-Manipulation Rule

EPAct's anti-manipulation sections track the prohibited conduct language in Section 10(b) of the Security and Exchange Act of 1934 (Exchange Act),[3] and the phrase "manipulative or deceptive devices or contrivances" in EPAct mirrors the meaning those terms have in the Exchange Act.[4] In order to implement EPAct, FERC promulgated the "Anti-Manipulation Rule," which it modeled after the Securities and Exchange Commission's (SEC) Rule 10b-5.[5] SEC Rule 10b-[5] has long governed fraudulent conduct in financial markets.

[1] *Energy Policy Act of 2005, Pub. L. 109-058.*

[2] *See 16 U.S.C. § 824v; 15 U.S.C. § 717c-1.*

[3] *15 U.S.C. § 78j(b).*

[4] *Prohibition of Energy Mkt. Manipulation, 114 FERC ¶ 61,047 at P 6 (2006) (Order No. 670).*

[5] *18 C.F.R. pt. 1c. SEC Rule 10b-5 implemented Section 10(b) of the Exchange Act.*

FERC's Anti-Manipulation Rule prohibits an entity from:

(1) *Using a fraudulent device, scheme or artifice to defraud or to engage in a course of business that operates as a fraud or deceit.* Manipulation may arise from an artificial increase or decrease in the price of electricity or natural gas.[6]

(2) *With the requisite scienter.* Consistent with the SEC's enforcement activities under Rule 10b-5, FERC has held that an entity can violate the Anti-Manipulation Rule if it acts either intentionally or recklessly.[7] Moreover, while an entity's business purposes will be relevant to an inquiry into manipulative intent, a "legitimate business purpose" is not an affirmative defense to manipulation.[8]

(3) *In connection with a FERC jurisdictional transaction.* In general, FERC has jurisdiction over purchases and sales of electric energy or transmission services or natural gas or natural gas transportation services. As described below, the U.S. Court of Appeals for the D.C. Circuit recently found that FERC has no jurisdiction over the manipulation of prices in natural gas futures markets, which are subject to the exclusive jurisdiction of the Commodity Futures Trading Commission (CFTC).[9]

A finding of market power is not required for FERC to conclude that an entity has violated the Anti-Manipulation Rule.[10] FERC makes a distinction between the structural issue of market power and the behavioral issue of market manipulation, by which average prices are moved at a particular point through speculative trading, even in the absence of market power. FERC has held that "[t]he two are not identical and the absence of one does not entail the absence of the other."[11]

FERC has demonstrated its resolve to aggressively use its new enforcement authority and appears to be subjecting financial institutions to particular scrutiny. In fiscal year 2012, FERC's Office of Enforcement, Division of Investigations obtained more than $148 million in civil penalties and ordered the disgorgement of more than $119 million in unjust profits.[12] As described below, the civil penalties imposed thus far in 2013 significantly dwarf any amounts that FERC has previously imposed.

Major Developments in 2013

In announcing its priorities for fiscal year 2013, the Office of Enforcement stated that "[c]onduct involving fraud and market manipulation poses a significant threat to the markets overseen by [FERC]."[13] FERC's Office of Enforcement has focused its oversight and enforcement activities in particular on the practice of trading in one market for the purpose of changing prices in a related market. For example, FERC has aggressively pursued allegations of so-called "uneconomic trading," which is the practice of intentionally incurring losses in one market to benefit a position in another market.

Given its long history of regulating the sale, purchase and transportation of electricity and natural gas under the FPA and NGA, FERC is very familiar with those physical markets. However, FERC historically had relatively little experience with the use of financial energy products and the market participants who create and trade them. Following the Western Energy Crisis of 2000-2001, utilities and independent generators increased their use of financial hedging products. A number of new hedging products are now traded in FERC-regulated organized power markets, including financial congestion revenue rights (CRRs), which are financial instruments that enable the holder to manage the variability in congestion costs. Other energy-related financial products are traded on exchanges that are subject to exclusive CFTC jurisdiction. FERC's recent oversight and enforcement activities have focused on the interrelationships between the physical markets that FERC has historically regulated and the increasingly prevalent financial products.

For example, on January 22, 2013, FERC approved a Stipulation and Consent Agreement between its Office of Enforcement and Deutsche Bank Energy Trading LLC (Deutsche Bank) to resolve an Order to Show Cause proceeding stemming from alleged manipulation in the California wholesale power markets.[14] As part of the settlement, Deutsche Bank agreed to pay a civil penalty of $1.5 million and disgorge $172,645 in unjust profits. The Office of Enforcement found that Deutsche Bank had violated the Anti-Manipulation Rule by entering into physical transactions to benefit its CRR position at the Silver Peak intertie. Deutsche Bank stipulated that its physical "exports at Silver Peak raised prices at Silver Peak and caused its CRR position to gain value."[15] The Office of Enforcement concluded that Deutsche Bank's physical transactions "were not consistent with the fundamentals underlying the market price of Silver Peak, e.g., supply and demand, but rather were undertaken with the intent to change the value of CRRs."[16]

On July 16, 2013, FERC fined Barclays and four of its individual traders a combined $453 million and ordered the bank to disgorge approximately $35 million in unjust profits for manipulating electricity markets in the western U.S. At the time, this was by far the largest civil penalty ever imposed by FERC.

[6] *Id.*
[7] *Order No. 670 at P 53.*
[8] *Barclays Bank PLC, 144 FERC ¶ 61,041 at P 61 (2013) (Barclays).*
[9] *Hunter v. FERC, 711 F.3d 155 (D.C. Cir. 2013) (Hunter).*
[10] *Barclays, 144 FERC ¶ 61,041 at P 59.*
[11] *Id.*
[12] *Federal Energy Regulatory Commission, 2012 Report on Enforcement at 3 (Nov. 15, 2012), available at http://ferc.gov/legal/staff-reports/11-15-12-enforcement.pdf.*

[13] *Id at 2.*
[14] *Deutsche Bank Energy Trading, LLC, 142 FERC ¶ 61,056 (2013).*
[15] *Id. at P 12.*
[16] *Id. at P 19.*

According to FERC, between November 2006 and December 2008, Barclays's traders engaged in a series of physical trades designed to manipulate the index price of electricity at a trading hub, which in turn benefitted their financial swap positions. FERC rejected Barclays's arguments that the trades were for a legitimate business purpose. Even assuming there was a legitimate business purpose, FERC concluded, that would be just one factor in determining whether Barclays intended to engage in manipulative trading.[17] FERC found that the scheme was complex, widespread in location and time, involved large volumes of electricity, and affected the electricity prices paid by both wholesale and retail consumers. FERC also noted that Barclays and the traders made no attempt to remedy the violation and that the scheme only ended after FERC's investigation began.

Barclays and the traders elected to use a procedure under FPA pursuant to which FERC assesses a penalty without undergoing a trial-type hearing. If Barclays and the traders do not pay the penalties and disgorgement within 60 days of the order, then FERC must seek to affirm the penalties from a federal district court. The court is authorized to review the penalties and disgorgement *de novo*, and may enforce, modify or set aside FERC's penalty.

On July 30, 2013, FERC approved a stipulation and consent agreement in which JP Morgan Ventures Energy Corporation (JPMVEC) agreed to pay $410 million in penalties and disgorgement for allegations of market manipulation stemming from its bidding activities in electricity markets in California and the Midwest from September 2010 through November 2012. JPMVEC also agreed to waive certain claims against the California grid operator and agreed to implement other compliance measures, including a complete audit by outside counsel of its power trading practices.

FERC investigators determined that JPMVEC engaged in 12 manipulative bidding strategies designed to make profits from power plants that were usually "out-of-the-money" in the marketplace. In each of those schemes, according to FERC, JPMVEC submitted bids designed to create artificial conditions that forced the grid operators to pay JPMVEC non-market, premium rates. FERC investigators determined that JPMVEC knew that the grid operators received no benefit from these inflated payments, thereby defrauding the system operators by obtaining payments for benefits that JPMVEC did not deliver beyond the routine provision of energy. FERC investigators also determined that JPMVEC's bids displaced other generation and altered day-ahead and real-time prices from the prices that would have resulted had the company not submitted the bids.

[17] *Barclays, 144 FERC ¶ 61,041 at P 61.*

The Impact of the D.C. Circuit's *Hunter* Decision

FERC's aggressive approach to the use of its enforcement authority has not been without hiccups.

In 2011, FERC determined that Brian Hunter, who had been a natural gas trader for Amaranth Advisors LLC, manipulated physical natural gas markets in violation of the NGA and the Anti-Manipulation Rule.[18] Hunter traded natural gas futures contracts on the CFTC-regulated New York Mercantile Exchange (NYMEX). FERC found that Hunter intentionally manipulated the settlement prices of those futures contracts to benefit his swap and option positions in other trading platforms, such as the Intercontinental Exchange. FERC concluded that, due to the relationship between the financial and physical natural gas markets, Hunter's manipulation of futures contracts affected the price of FERC-jurisdictional physical natural gas transactions. FERC imposed a $30 million civil penalty against Hunter.

Hunter appealed FERC's decision to the U.S. Court of Appeals for the D.C. Circuit, arguing that FERC did not have jurisdiction over commodity futures contracts. The CFTC supported Hunter's jurisdictional argument, claiming that the Commodity Exchange Act granted it exclusive jurisdiction over futures trading. On March 15, 2013, the D.C. Circuit found that FERC did not have the authority to fine Hunter for manipulating natural gas futures markets. Rather, the court held that the CFTC has "exclusive jurisdiction over all transactions involving commodity futures contracts" and that EPAct did not repeal the CFTC's exclusive jurisdiction over transactions conducted in futures markets like NYMEX.

Hunter clearly illustrates the close interrelationship between the physical and financial electricity and natural gas markets. *Hunter* also demonstrates that there are limits to FERC's enforcement of the Anti-Manipulation Rule. While it is unclear how the *Hunter* decision will impact FERC's enforcement activities in other cases involving trading practices in financial markets, FERC will likely continue to aggressively pursue what it perceives as fraudulent schemes that impact the markets subject to its jurisdiction, in order to determine exactly where those limits are.

George "Chip" Cannon and Julia Sullivan are partners in Akin Gump's Washington D.C. office. Mr. Cannon can be reached at 202.887.4527 and Ms. Sullivan can be reached at 202.887.4537

[18] *Brian Hunter, 135 FERC ¶ 61,054, at PP 47, 53, 62, reh'g denied, 137 FERC ¶ 61,146 (2011).*

Minding the Gap:
Managing Interface Risks Under Turbine Supply and Balance of Plant Agreements

By Lloyd J. MacNeil

If we have learned anything from the frequent, though sometimes retroactive, extensions of the production tax credit (PTC), it is that there should be an uptick in the execution of turbine supply agreements (TSAs) and balance of plant (BOP) agreements during the latter half of this year as buyers race to "begin construction" of their wind projects by year end in order to qualify under the Internal Revenue Service guidance for the PTC extension.[1] The top tier turbine vendors are quickly filling their production slots, the remaining vendors are salivating in anticipation and the better BOP contractors already are in very high demand.

TSA/BOP Agreement Interface Risk

Buyers, though, should pause long enough to recognize that the wind energy sector remains unlike most traditional energy sectors in which a single contractor builds the entire project under one engineering, procurement and construction (EPC) agreement. Instead, the majority of wind projects continue to be constructed under a separate TSA with a turbine vendor and a BOP agreement with a BOP contractor. Each agreement is heavily negotiated with the buyer trying to allocate construction risks to the counterparties and the counterparties pushing back.

But the battle to get the best deal should not subordinate the buyer's primary goal of constructing the project on time and within budget. It is much more important that the agreements work together to allocate all construction risks among the parties than it is for the buyer to get the lowest initial price but suffer delay and additional cost throughout construction because of gaps in risk allocation, most of which will be borne by the buyer. Because the cost of failing to "mind the gap" can be significant, managing and reducing interface risk should be a major concern for the buyer.

The balance of this brief article examines several interface risks under the TSA and BOP agreement and what the buyer can do to allocate these risks either to the turbine vendor or to the BOP contractor.

[1] *See "Production Tax Credit Extension and Other Benefits for Renewable Energy," by David Burton, in Project Perspectives, Winter 2013.*

Scope of Supply and Services

Typically, the buyer is careful to select turbines (including optional equipment) that the project site and transmission operator require. However, the buyer also must fully understand how the turbine vendor's equipment and services will dovetail with those of the BOP contractor. To fail to do so introduces interface risk. If, for instance, the turbine vendor provides power and communication cables from the nacelle to the base of the tower but no farther, the buyer will want to include in the BOP contractor's work scope the procurement of sufficient cable to reach the padmount transformer located elsewhere on the foundation as well as the obligation to make appropriate connections between components. Although gaps in equipment procurement and provision of services can be filled by change orders under either agreement, the careful buyer will take the time upfront to identify and avoid these gaps and allocate the obligations to the BOP contractor or the turbine vendor.

Another interface risk arises out of the issue of which party will be responsible for obtaining tower service lift permits and when those permits should be obtained. Frequently, the vendor will assume the obligations under the TSA. Regardless of who gets the permits, if service lifts cannot be used because they are not timely permitted, then climbing towers for installation and completion checklist walk-downs will be time consuming, fatiguing and potentially dangerous to employees. The incremental time and effort presented by an absence of service lifts may ultimately put pressure on project completion milestones. Additionally, the buyer must manage interface risk. If the BOP contractor will be performing installation and mechanical completion of the turbines, as is customary, the buyer must be careful not to overpromise to the BOP contractor that the service lifts will be permitted and operational. Otherwise, if the BOP contractor has a contractual right to use the lifts, the buyer should expect a change order if the BOP contractor cannot.

Turbine equipment frequently includes foundation setting templates, anchor plates and anchor bolts which must be delivered by the turbine vendor earlier than the major turbine components so they can be incorporated by the BOP contractor into foundation construction. Because these are critical interface items, late delivery often carries a provision for liquidated damages that is similar to the provision for late delivery of major turbine components. However, the buyer must be careful that the damages paid by the turbine vendor for late delivery of foundation components do not fall short of the change order claims that the BOP contractor will submit to the buyer for delay, or again the buyer will be caught in the gap of having to pay out more to the BOP contractor than it receives from the turbine vendor. Typically (as we'll see later in this article), liquidated damages are insufficient to fully compensate the buyer, but this risk can be offset during the early construction stages with covenants from each contractor to accelerate its work to recover the project schedule if it starts to slip. The buyer may also be able to completely allocate the risk to the BOP contractor by requiring the BOP contractor to provide the foundation setting components; many turbine vendors are often willing to cede this responsibility.

These are just three examples. Since a wind project comprises hundreds of thousands of components, it is the buyer's tedious mental challenge to connect each component so the turbine vendor and BOP contractor can do so physically, and so the buyer can sidestep the pitfalls of interface risk. The diligent buyer will attach a division of responsibility checklist to each of the TSA and the BOP agreement so each party knows what equipment and services each is to provide and to afford each party the chance to evaluate whether there will be any gaps in responsibilities. If project construction has been financed, the buyer might want the independent engineer to review the division of responsibility for obvious gaps.

Delivery, Unloading and Installation

Delivery, unloading and installation of turbine components present several interface risks. Typically, the turbine vendor will obtain all permits and post all bonds (or provide other applicable security) imposed by federal, state or local authorities to repair any damage caused by turbine delivery. The BOP contractor will do similarly for its scope of work. However, it may be that the combined bonding costs can be split equitably between the contractors, which may provide the buyer with tangible cost savings. Thus, the interface issue in in this example is not so much a risk but an opportunity for the buyer to lower the combined contract prices for the construction of its project.

Turbine unloading is a complicated procedure involving multiple parties—the turbine vendor who provides the components, the transporter (usually a subcontractor of the turbine vendor) whose equipment provides delivery, the BOP contractor who unloads the components, the crane operator (usually a subcontractor of the BOP contractor) whose equipment does the heavy lifting, and the buyer who must manage the procedure with the precision of an orchestra conductor. The timing of unloading turbine components is critical, and an obvious interface risk. The turbine vendor will promise component deliveries according to an agreed schedule; the BOP contractor will promise to unload components within agreed time periods; the transporters and crane operators will assume that everything will run without incident and will charge high hourly or daily rates if anything does not. Delivery schedules and unloading time periods must work together under both the TSA and the BOP agreement, and both the turbine vendor and the BOP contractor must bring their respective subcontractors in line with the principal contracts (because they, too, must manage interface risks with their subcontractors and the buyer).

Concurrently with turbine negotiations, the buyer often will be working with the BOP contractor with respect to road construction within the project site perimeter. The specifications for these access roads should be provided to the turbine vendor as early as possible so the vendor can offer comment on whether the delivery vehicles will be able to deliver the turbine components (assuming the access roads are built according to specification). The buyer should limit the scope of turbine vendor's comments to a handful of specifications (such as road width, grade and cross slope, turning radius, crown humps in the direction of travel, and overhead or underground restrictions) and ensure that the BOP contractor's specifications govern access road construction. Otherwise, the buyer will likely have to engage in a "battle of the specifications" with the turbine vendor when it claims that its specifications were not followed, resulting in increased delivery costs or excusable delivery delays. Of course, the buyer may not have the luxury of concurrently negotiating the TSA and the BOP Agreement; sometimes the TSA will have been executed first (particularly if the buyer desires turbines from a top-tier vendor whose turbines are in high demand), and the buyer may be bound by the vendor's turbine specifications for access roads. Other times, the ink dries first on the BOP agreement. In these latter situations, the second party to the negotiating table with the buyer has to work with what's been agreed to with the first party.

If turbine installation falls to the BOP contractor, then the BOP contractor will prefer to have each major turbine component arrive at the time it is supposed to be erected. This "just in time delivery" is an extreme challenge however, and the turbine vendor will seldom accept the obligation unless there is an adequate staging area beside each turbine site and unless the turbine vendor can deliver components earlier than the contracted dates which will give the vendor the flexibility to comfortably take the risk of delivery exigencies. A vendor's requests for staging areas and early delivery are not always achievable: project site geography might eliminate or restrict the use of staging areas, and seasonal restrictions might prevent the BOP contractor from completing access roads any earlier. Again, the buyer must be careful not to extend to the BOP contractor covenants under the BOP agreement that the buyer cannot cause the turbine vendor to keep under the TSA. The same caution applies to the buyer's promises to the turbine vendor.

Reporting

The buyer should require the turbine vendor and the BOP contractor to report early and often. Many times a buyer will sign the TSA, pay its down payment, and wait for the turbine equipment to arrive at the project site. Often deliveries are late, which precipitates a dispute over liquidated damages for late delivery. Much of this can be avoided or at least substantially mitigated if the buyer scrupulously monitors all elements of turbine production to discover delays as soon as they occur, or even before they occur, and then impose on the turbine vendor the obligation to accelerate production or provide alternative solutions—steps which likely are cheaper and easier to agree to than the quantum of liquidated damages. In addition, early notice of component delay allows the buyer to engage with the BOP contractor to delay mobilization of erection crews and cranes. The costs of idle cranes and crews are prohibitively expensive, and the buyer is incentivized to avoid this significant interface risk.

Delivery Delay Damages

Speaking of liquidated damages, although the amounts and categories of damages may differ among TSAs, all TSAs contain provisions to limit a turbine vendor's liability in two ways: first, on a daily basis as an amount certain for each late turbine; and second, on an aggregate basis as a percentage of the overall turbine price.

While, there will be statements in the TSA about how the liquidated amounts are a reasonable estimate of the overall damages that the buyer will suffer as a result of late delivery, both the buyer and vendor know that these and similar statements are wildly inaccurate and that the limits in most TSAs are a poor reflection of the buyer's actual damages. Consider what's at stake for the buyer as a result of project delay: lost energy revenue, lost PTCs and other tax benefits, additional interest expense if the project has closed construction financing, and potential liquidated damages or other expenses under key project documents such as the power purchase agreement. Receipt of a small amount from the turbine vendor for each late turbine hardly puts the buyer in the same position it would have enjoyed had deliveries been timely made. Consider the additional costs the BOP contractor will seek to recover for itself, its subcontractors, and their equipment if the turbine vendor's late deliveries cause delay. Here's yet another example of interface risk. Unless the buyer has convinced the BOP contractor to accept similar limitations on what it can claim from the buyer, there will be a big gap between what the buyer will receive from the turbine vendor and what the buyer will have to pay to the BOP contractor. Careful attention to these areas is critical for the buyer to avoid substantial cost escalation if project scheduling is stressed.

Force Majeure and Weather Delay

Force majeure and weather delay are always a major focus of the parties under the TSA and the BOP agreement and for good reason since it is the rare construction period that does not involve at least one party claiming relief under these provisions. The parties will explore the limits of possibility and creativity as they list inclusions and exclusions from the definition of force majeure. The concept of weather delay may be buried in the definition of force majeure, or it may be implied from the change order provisions of the TSA or BOP agreement, but most likely the concept will be described in the agreements in such detail as to make a meteorologist blush.

However, the concepts are additionally important to the buyer since each is an obvious source of interface risk. If, for example, the turbine vendor claims that a snowstorm delayed component deliveries by a week, the vendor will seek schedule or cost relief (or both) from the buyer to avoid paying delay damages during the storm period. Similarly, the BOP contractor may claim that the same snowstorm delayed the installation of previously delivered turbine components and will seek schedule or cost relief (or both) from the buyer under the BOP agreement. The buyer will be squeezed from both ends! Similarly, a weather delay event under the BOP agreement might allow the turbine vendor to seek relief from the buyer under the TSA. Demurrage charges are a key example: if it is too windy to unload a delivery truck (a BOP contractor responsibility), then the redeployment of that delivery truck will be delayed and the transporter will expect compensation from its counterparty, the turbine vendor, who in turn will try to pass the costs through to the buyer. Unless careful attention is given to the drafting of the relief provisions under both agreements, the buyer can get caught in the interface gap and be required to grant schedule or cost relief under the BOP agreement and provide demurrage payments to the turbine vendor under the TSA. So, great care must be taken by the buyer to ensure that the concepts of force majeure and weather delay are bilateral under the TSA and the BOP agreement to limit double-dipping into its own pocket for claims by the turbine vendor and the BOP contractor. It may not be possible or economical for the buyer to allocate all of the force majeure or weather delay risks to the counterparties; some risks such as hurricanes may be left with the buyer because no counterparty will be willing to accept them.

Disputes

The final interface risk is easily overlooked. Since many disputes involve the buyer, the turbine vendor and the BOP contractor, a buyer must make sure the TSA and the BOP agreement contain materially identical dispute resolution provisions, and consolidation or joinder provisions. Otherwise, it will be a challenge to get all parties in the same room to resolve disputes about common facts.

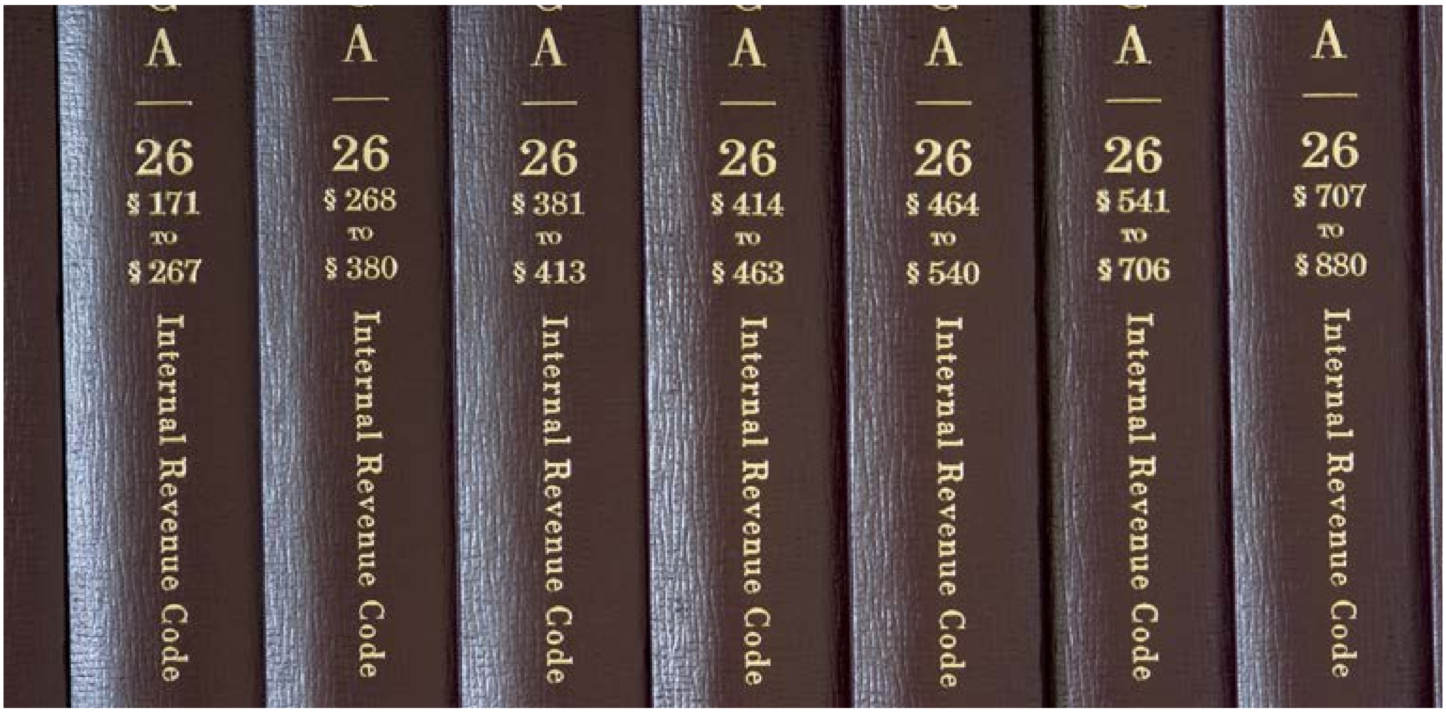
Wrapping Up

The TSA and the BOP agreement cannot be entered into as independent agreements. They are symbiotic. The buyer must be cognizant that the negotiation of a provision in one agreement likely will affect a provision in the other. The buyer must mind the gap.

Lloyd MacNeil is a partner in Akin Gump's Los Angeles Downtown office. He can be reached at 213.254.1313.

Flip Partnership Tax Credit Structure Demystified

by David Burton and Joseph Sebik[1]



For more than ten years, sophisticated investors have been investing in what are known as "tax-equity flip partnership structures," predominately at first for wind farm investments. This article will explain in high-level terms the structure of the investment and the basic tax rules that govern such structures.

Tax Background

Since the enactment of the income tax, Congress has provided tax incentives for targeted investments. To encourage investment in wind and other renewable energy technologies, Congress created the production tax credit (PTC). The PTC is a tax credit that is based on the actual production of electricity calculated on a rate per kilowatt produced and is available to the ***producer*** of the electricity for 10 years from the date a facility is originally placed in service. Alternatively, the owner of the renewable energy facility may elect to claim an Energy Tax Credit (ETC) (this is also referred to as an investment tax credit or ITC) equal to 30 percent of the eligible alternative energy asset cost. In the case of highly efficient facilities, the present value of 10 years of the PTC will exceed the ETC. Therefore, the federal government is subsidizing ***at least*** 30 percent and often more of the cost of construction. In some instances, there are also tax or cash incentives available from the state in which the project is located.

With respect to the PTC, a lease structure is available only in the case of biomass. If a biomass project is subject to a lease, the lessee is the one entitled to the PTC. For the other renewable energy technologies (e.g., wind) having the project under a lease results in the loss of the PTC (although, a ground lease of the land the project is on is permissible). Therefore, for tax-equity investors who desire PTCs from wind or geothermal projects, a lease structure is not available. There are no such restrictions for ETCs.

The American Taxpayer Relief Act of 2012 has established a final end date for new PTCs, which will only be available for facilities that start construction during 2013. IRS Notice 2013-29

[1] *Director of Tax Reporting for Siemens Corporation.*

describes the requirements a project must satisfy to be deemed to have started construction in 2013; one of them is that, after 2013, the project must be subject to "continuous construction," except for events like inclement weather and parts shortages. Unless renewed, after 2013, the PTCs and ETCs will no longer be available for newly constructed wind farms. Solar is eligible for a 30 percent ETC for facilities placed in service by the end of 2016. After that, solar facilities are eligible for a 10 percent ETC, which is a permanent provision in the tax law.

Although the credits appear attractive, often a wind farm developer does not have sufficient tax liability to use the credits. The developers are usually either independent companies that plan the development of the site or a utility that will develop a wind farm themselves. Due to the high cost of such wind farms, and the large tax benefits created, developers often are unable to utilize the tax benefits efficiently. That is the reason for a tax-equity flip partnership structure.

A flip partnership transaction usually starts with the formation of a limited liability company that, for federal income tax purposes, is taxed as a partnership. A limited liability company does not owe tax, rather, the tax benefits and tax liabilities "flow through" to the partners. There are typically two classes of partners: the developer, who acts as the managing member and makes day-to-day decisions, and the tax-equity investors, who are relatively passive.

Flip partnerships are subject to highly technical partnership tax regulations and a safe-harbor promulgated by the Internal Revenue Service for wind farms in Revenue Procedure 2007-65.

In a nutshell, tax regulations allow for cash distributions, taxable income and loss, and tax credits of the partnership to be allocated in a manner that is different from the ownership percentages. The partnership agreement is written so that the partnership initially allocates free cash, PTCs or ETCs, and early-year tax losses to the tax-equity investors since they have a capacity to use such tax benefits. Under partnership tax rules, a partner's tax basis is increased or decreased by taxable income or losses allocated to it, decreased by cash distributions, but not affected by allocations of tax credits.

The partnership is called a "flip" because the allocation of cash and tax benefits changes over time upon the occurrence of certain events; in effect, it flips between the developer and the tax-equity investors. For instance, upon the tax-equity investors achieving a targeted after-tax internal rate of return, the allocation of cash, tax credits, and taxable income or loss will change from 99 percent to the tax equity investors to only 5 percent.

Generally, the flip is expected to occur (i) in five years in the case of an ETC transaction, since that is when the ETC has fully vested, or (ii) after the 10-year period for which PTCs are available.

The typical transaction goes through several phases as summarized in the table below and explained further thereafter. Each change in the allocation is a flip. The percentages in this illustration are actually what are shown in the Revenue Procedure.

		DEVELOPER		TAX-EQUITY INVESTORS	
PHASE	PHASE DESCRIPTION	FREE CASH	TAX BENEFITS	FREE CASH	TAX BENEFITS
1	Initial tax-equity period	100%	1%	0%	99%
2	Tax-equity earning period	0%	1%	100%	99%
3	Post flip period	95%	95%	5%	5%

Phase 1: The funding contributed by the tax equity often pays down some of the construction debt balance remaining and repays the developer some of its investment. Once the facility is placed in service and the facility starts to produce power, the developer is allocated a substantial portion of free cash to start recouping its investment, while up to 99 percent of tax benefits are allocated to the tax-equity investors.

Phase 2: After the developer has taken out the agreed-upon cash, the partnership makes its first flip, and, generally, the partnership agreement provides that 100 percent of the free cash is distributed to the tax-equity investors. During this phase, the tax-equity investor is commonly allocated the maximum allowable allocation of tax benefits (i.e., 99 percent) as provided by the Revenue Procedure.

Phase 3: If the transaction is a PTC transaction, the partnership is usually structured so that the tax-equity investors achieve a targeted after-tax IRR ("AT-IRR") around the time the PTCs expire. If the transaction is an ETC transaction, the targeted AT-IRR occurs around the fifth year, after the ETC is no longer subject to recapture as the result of transfers or changes in allocations. Once the targeted AT-IRR is achieved, the developer is commonly provided by the partnership agreement an option to buy out the tax-equity investors' partnership interests. By that time, the tax-equity investors allocation of tax benefits and right to distributions is reduced to as little as 5 percent of each, shared among the tax-equity investors as an investor class.

Investment Analysis

The tax-equity investor is receiving the majority of tax credits and tax losses and whatever estimated free cash is needed to achieve the AT-IRR through the second flip point.

The components of the tax-equity investors' return can be illustrated in the following example which has been substantially simplified for illustrative purposes:

Investment

Project Cost	$100.00 million
Developer Investment	$50.00 million
Tax-Equity Investors' Investment	$50.00 million

Sources of Return of and on the Tax Equity Investors' Investment

Energy Tax Credit ($30M x 99%)	$29.70
After-tax effect of tax depreciation allocated (($100M – 15% ETC basis reduction) x 99% x 35% tax rate)	29.45
Cash distributions $25M – 35% tax ($8.75M)	16.25
Total payback of investment plus "yield"	**$75.40**

In the interest of simplicity, income tax from income allocated to the tax-equity investors from the sale of electricity during Phase 1 (i.e. when the developer is sweeping all of the cash) is omitted from this example.

Thus, the tax-equity investors have received $29.7 million from the tax credit, $29.45 million from the allocated tax depreciation deductions and the balance from after-tax free-cash distributions.

This is a very simplified approach to looking at the economics, but the fact is that it is not so far from a typical structure. A PTC deal is directionally similar, but with slightly different numbers.

To ensure that the tax-equity investors are able to claim the anticipated PTCs and depreciation, it is critical to comply with the "capital account" tax regulations. Those regulations are beyond the scope of this article, but they require careful attention to the deal model and to the drafting of the partnership agreement. For instance, once a partner's "outside basis" reaches zero, its ability to claim further tax losses is **suspended** until it is allocated an offsetting amount of taxable income.

Typically, at the end of the PTC period or the ETC recapture period, the developer has a right to buy out the investment of the tax-equity investors. The buyout price is usually defined as the greater of the fair market value of tax-equity investors' partnership interests and the value needed to ensure that the tax-equity investors achieve their targeted AT-IRR. The developer usually negotiates a buyout right because it wants the option to own the facility outright.

Lastly, while the flip partnership structure itself is not going away, absent a legislative extension the PTC and 30 percent ETC (but not a 10 percent ETC for solar) will expire in coming years. Companies may want to consider investing now to capture premium returns available from the tax credits.

Another version of this article was published in the May/June 2013 issue of Equipment Leasing & Finance Magazine.

David Burton is a partner in Akin Gump's New York office and is the editor of Tax Equity Telegraph*. Mr. Burton can be reached at 212.872.106. Joe Sebik is Director of Tax Reporting at Siemens Corporation.*

Will Latin America and the Caribbean Save Renewable Energy or Will Renewable Energy Save Latin America and the Caribbean?

By Dino Barajas

While most jurisdictions within Latin America and the Caribbean (with the exception of Brazil and Costa Rica) have based their core electric generation asset portfolio around fossil fuels, renewable energy technologies are now changing the energy landscape throughout the region. Wind, solar, hydro and geothermal power plant developers have begun focusing their efforts on transforming Latin America and the Caribbean into more eco-friendly power generators. In turn, the governments in the region have modified their electric utility regulatory frameworks to accommodate the introduction of renewable energy into their electric distribution systems.

The renewable energy development activity throughout the region has resulted from the perfect storm of global events that have occurred in the last 24 months. Wind power project developers and their tax investors have faced challenges in the United States (U.S.) with uncertain tax policies that have resulted in choppy boom and bust development cycles. Solar power plant developers, who had gained a competitive advantage over wind developers as a result of declining panel prices, were dealt a crippling blow in the U.S. after Chinese solar cell manufacturers were subjected to antidumping tariffs on product imported into the U.S. The same solar power developers have been also been sided within the European Union with the threat of high tariffs being imposed on Chinese manufactured solar panels. Additionally, Spain (which had been a darling of renewable energy developers) retroactively lowered its renewable energy feed-in tariffs and threw the certainty of Europe's renewable energy industry into a tailspin.

With the downturn and uncertainty in the European and U.S. renewable energy markets, developers have turned their attention and development dollars to Latin America and the Caribbean. The region, which has been plagued with high energy production costs due to the need for expensive imported bunker fuel and diesel, offers a market where renewable energy can compete directly on an economic basis with existing power generators without the need for governments to enact favorable renewable energy tax policies or feed-in tariffs. The predictability of these energy markets offers renewable energy developers a long-term stable development environment where success is solely determined by the economic competitiveness of their technologies rather than the whims of public opinion and policy makers.

The introduction of renewable energy into the generation portfolio of these countries will assist numerous jurisdictions in achieving energy independence and greater energy security through the utilization of the respective country's natural resources. As more countries in the region gain greater control over their energy production costs, their susceptibility to wild swings in imported fuel prices would be minimized and their industries which require vast amounts of energy in their production processes would become more competitive on a global basis. These benefits will also allow the region to attract a greater variety of industries to their markets and permit higher value processes to be done locally, thus allowing a greater amount of the value chain to remain at home.

Renewable energy companies entering the Latin American and Caribbean markets are quickly learning that the potential rewards available in the region are not without their challenges. Successfully navigating the legal and business environments in these jurisdictions has been the determining factor as to whether a new market entrant is ultimately successful. Seemingly simple tasks, such as securing site control and permitting, have been the Achilles heel of numerous projects. Projects on the verge of achieving financing have collapsed upon the discovery that sloppy or ill-informed actions during the early stages of project development require the project developer to redo the fundamentals of its project.

Successful renewable energy developers in the region have leveraged the lessons learned from previously developed projects in the respective jurisdictions. The complex project contracting and equity infusion structures developed over the last 20 years are serving today's renewable energy pioneers well by helping them create the most efficient tax structures possible for their projects and, in turn, preserving their projects' rates of return. Given that the markets within Latin America and the Caribbean do not resemble the markets in the U.S. and Europe in any way, knowledge of the terms and structures of existing power project deals is essential for achieving early success in these markets.

Many developers have turned to joint venturing with local companies to gain market knowledge where possible. Others have reassembled the external advisory teams, both legal and technical, responsible for structuring earlier power project transactions in order to gain valuable market access and knowledge.

Given the existing high energy prices found in the Latin American and Caribbean markets, renewable energy developers entering the region are finding some of the most lucrative projects found anywhere in the world. The secret to navigating these rich environments is assembling the right team armed with market knowledge, language skills and business acumen.

Dino Barajas is a partner in Akin Gump's Los Angeles Century City office. He can be reached at 310.552.6613.

Update on Electricity Production Capacity in Iraq

By Shawn Davis and Din Eshanov

Iraq has been suffering from an acute electricity shortage for more than a decade. This has hindered the economic and social development of the country by causing disruptions in commercial production and undermining the effects of capital investments. The country's power grid is capable of supplying only about half of the demand, which is currently approximately 14,000 megawatts and is growing.

The government of Iraq has not, to date, proposed a strategy to address the issue in a comprehensive and coordinated manner. However, various officials, including those from the Electricity Ministry of Iraq, have asserted that the country's electricity shortage will be solved in the near future, and have made regular announcements about the development of new power plants or the upgrading of existing ones. The signing of a USD 1.05 billion contract in June 2013 between Metka, a Greek construction company and the Ministry of Electricity of Iraq, to build a 1,642 megawatt combined cycle power plant in Anbar is a recent example.

According to the *Middle East Economic Digest*, Iraq has experienced 63.2 percent growth from August 2012 to July 2013 in the value of projects, planned or underway, with nearly USD 500 billion earmarked for energy and infrastructure projects.

A caveat is in order with respect to the Kurdistan Region of Iraq (the "Kurdistan Region"). The demand for electricity in the Kurdistan Region has grown at a rate of 10 to 25 percent in recent years. However, the Kurdistan Regional Government ("KRG") has, for the most part, been successful in meeting such demand through a combination of policies and streamlined governmental decision-making. Consequently, the Kurdistan Region has nearly uninterrupted power supply whereas cities in central and southern Iraq often experience power outages of up to 10-12 hours per day. A number of large scale power related projects are currently underway in the Kurdistan Region. In July 2013, Mass Global Investment Company, the owner of three power plants in the Kurdistan Region, selected General Electric of the United States to supply steam turbines to convert a power plant in Erbil from single to combined cycle operation, thus increasing the output by 470 megawatts (enough additional electricity to supply 100,000 Iraqi households) and making the plant one of the most efficient power plants in Iraq. Additionally, ABB of Switzerland will build four new transmission and distribution substations in the Kurdistan Region, as part of the strategy to expand and strengthen the regional power grid and the KRG is soon expected to award a USD 1.5 billion contract for the installation of a smart meter system across the Kurdistan Region.

It appears that the government of Iraq lacks a well-designed strategy and it seems to address the issue on an *ad hoc* basis. For this strategy to work, certain elements will need to be present.

- First, the government will need to adopt a coordinated approach to determine the current demand and future forecasts for electricity.

- Second, boosting power production through building additional power plants and upgrading the existing ones could be supplemented by the introduction of smart grid technologies, including meter readers. This is especially important given that currently there is no check on usage of power by end users in Iraq and a large number of them are overdue in payment of electricity bills. The contract signed between LS Industrial Systems and ABB to deliver utility communications systems for transmitting data within seven electricity distribution control centers in Iraq is a step in the right direction.
- Third, diversifying electricity sources by introducing renewable energy such as solar and wind, could minimize the need for using gas and oil for producing electricity.
- Fourth, the government will need to streamline the process of subsidizing end users to ensure the sustainability of the industry.
- Finally, the government could engage private financial institutions and export credit agencies to create additional sources of funding for power projects in Iraq.

A combination of the above may not provide immediate results; however, it would help establish a multipronged strategy and attract important players whose resources and expertise could be beneficial to Iraq.

Shawn Davis is Counsel and Din Eshanov is an associate in Akin Gump's Abu Dhabi Office. Mr. Davis can be reached at 971.2.406.8581 and Mr. Eshanov can be reached at 971.2.406.8577.

State Tax Update: A Summary of Recent State Renewable Energy Tax Law Developments

By David Burton and Oz Halabi

Arizona: The Department of Revenue ruled that a solar equipment leasing company (an LLC taxed as a partnership) that installs, at its own cost, solar energy devices on the premises of a single-family residential property and leases the devices to its customers is not eligible for a solar energy device tax credit. The ruling explains that under A.R.S. § 43-1085(A)(1), only a taxpayer who has a solar energy device installed in its facility for commercial, industrial or any other nonresidential application qualifies for the solar energy device tax credit. As the devices are not installed and used on the company's facility, the solar energy device tax credit is not available to the leasing company.[1]

Colorado: On May 28, 2013, Colorado extended the carry forward period of the enterprise zone investment tax credit by eight years.[2] The extension set the time limit in which a company can carry forward its tax credit to 20 years. The credit applies for renewable energy companies. Many such companies do not become profitable for several years and so the prior statutory 12-year limitation had prevented them from claiming enterprise zone investment tax credits (which can only be credited against taxes on profit). The extension allows renewable energy companies to utilize the investment tax credit when they are required to pay taxes, saving these businesses money and allowing them to offer energy at a more competitive price.[3]

Connecticut: On June 3, 2013, Connecticut enacted SB 203[4] which addresses property tax exemptions for renewable energy sources. The aim of the bill is to encourage commercial and industrial property owners to install renewable energy. The bill provides that for assessment years beginning on or after October 1, 2013 municipalities are allowed to abate up to 100 percent of the property taxes on Class I renewable energy sources (e.g., solar or wind power) if they were installed between January 1, 2010 and December 31, 2013.[5] The exemption must be approved by the applicable municipality's legislative body or, if the legislative body is a town meeting, the board of selectmen. The energy source or facility receiving the abatement cannot be in a distressed municipality with a population between 125,000 and 135,000. For assessment years starting on or after October 1, 2014, the bill exempts from the property tax renewable energy sources that (1) are installed on or after January 1, 2014, (2) are for energy generation or displacement for commercial or industrial purposes and (3) do not have a nameplate capacity that exceeds its location's load (i.e., do not produce more energy than the location will need). It applies to (A) Class I renewable energy sources, (B) Class II renewable hydropower facilities and (C) solar thermal (e.g., solar heated water) or geothermal renewable energy sources that meet these criteria. In a distressed municipality with a population between 125,000 and 135,000 (e.g., New Haven), the exemption would apply to assessment years starting on or after October 1, 2013 and it will apply to the same renewable energy sources installed as early as January 1, 2010.[6]

Indiana: On May 11, 2013, Indiana enacted a tax credit for heavy duty (gross vehicle weight rating of more than 33,000 pounds such as trail trucks) natural gas powered vehicles.[7] The bill offers a $15,000 tax credit per vehicle, $150,000 per taxpayer and $3 million per year among taxpayers. The credit will apply to purchases of dedicated natural gas Class 8 vehicles from July 1, 2013 through June 30, 2016. Purchases must be made in Indiana, for primary operation in Indiana. The bill increases the maximum weight limitation for a vehicle that uses natural gas as a motor fuel by 2,000 lbs. According to Rep. Frye (R-Greensburg), the bill is expected to decrease Indiana's dependence on foreign oil, decrease unemployment by creating jobs and protect the environment.[8]

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[1] *AZ. LR 13-001 (March 12, 2013).*

[2] *SB 13-286.*

[3] *See http://www.coloradosenatenews.com/?q=content/brophy-passes-bill-extend-tax-credits-alternative-energy-companies*

[4] *Public Act No. 13-61.*

[5] *Current law exempts Class I renewable energy sources and Class II hydropower from the property tax if they were installed on or after October 1, 2007, to generate electricity for farm and residential use on farms and private residences.*

[6] *Neil Downing, Connecticut Law Makers Approve Renewable Energy Tax Break for Businesses. 2013 STT 99-10.*

[7] *H.B. 1324.*

[8] *See http://greaterindiana.org/hb-1324-passes-indiana-house-of-representatives-and-indiana-senate/*

Louisiana: On June 3, 2013, Louisiana enacted a law phasing out by 2017 the solar energy tax credit that it has been providing to homeowners since 2009 and to leasing companies since 2010. Until July 1, 2013, Louisiana's solar energy tax credit gives homeowners or leasing companies a credit of 50 percent on up to $25,000 when they installed solar panels. Beginning July 1, 2013, the credit is only available for solar panels on single-family residences and no longer applies to wind power and solar systems on multi-unit residences.

Beginning January 1, 2014, the tax credit will cover a smaller percentage of solar panel installation costs and decrease to 38 percent of a system up $25,000, $21,000 beginning July 1, 2014, $16,000 beginning July 1, 2015. No more tax credits will be issued after December 31, 2017. In supporting the phase-out legislation, some lawmakers asserted that the state credit combined with the 30 percent federal tax credit was excessive. "I submit to you that everyone in this room would be successful if they got the government to pay 80 percent of whatever you do." Sen. Robert Adley (R-Bossier City).[9]

Nebraska: Effective June 4, 2013 Nebraska provides incentives for renewable energy projects under the Nebraska Advantage Act. The new law provides that renewable energy projects that invest more than $20 million would qualify for sales tax refunds with respect to purchases of materials and equipment (e.g., turbines, towers and other wind farm components) under the Advantage Act. Not only wind projects but solar, geothermal, hydroelectric, biomass and cold fusion projects would also qualify.[10]

Vermont: During the 2012 legislative season, Vermont passed a new taxation method for renewable solar projects. According to this method, plants 10kW or less are exempted from both the statewide education property tax and the municipal property tax. The exemption extends for ten years until January 1, 2023. Plants over 10kW are subject to the statewide uniform capacity tax that goes to the education fund but might be exempt from the municipal property tax.[11] The new uniform capacity tax applies to the fixtures and personal property, not to real property. The tax applies to plants connected to the grid, whether solely for the sale of electricity or for purposes of net metering. The new uniform capacity tax is an annual tax of $4 per kW of plant capacity[12] and is payable on or before April 15.[13]

David Burton is a partner and editor of Tax Equity Telegraph. *Oz Halabi is an associate. Both are located in Akin Gump's New York Office. Mr. Burton can be reached at 212.872.1068 and Mr. Halabi can be reached at 212.872.7455.*

[9] *David Hammer, State Senate passes bill to phase out state tax credits for solar panels at www.wwltv.com.*

[10] *See http://www.omaha.com/article/20130529/NEWS/705309944/1707*

[11] *Municipalities may vote exemptions or stabilizations pursuant to 32 VSA § 3845 and 24 VSA § 2741 without incurring any obligation to the education fund.*

[12] *Plant capacity is defined in 30 V.S.A. § 8002(15) and is tied to the rated electrical AC nameplate for the plant.*

[13] *Vermont department of taxes technical bulletin, Uniform capacity tax on renewable energy plants commissioned to generate solar power, TB-67.*

Climate Check:

A Roundup of Noteworthy U.S. Wind and Solar Transactions From Q2 2013

By Daniel Sinaiko

The second quarter of 2013 was punctuated by the persistent low interest rate environment. The result was over $2.2 billion of closed project debt financings and almost $1 billion of new corporate debt issuance. Utility scale tax equity markets continued to be thin, although SolarCity and SunRun once again demonstrated fundraising acumen, accounting for approximately $1.2 billion in tax equity commitments for distributed commercial and residential solar projects. There was also sustained strength in the M&A market, with transactions relating to more than 1.6 GW of generating capacity, led by First Solar's ongoing drive to sell solar modules through project acquisition and disposition. Finally, Q2 saw one major strategic transaction: the sale of PowerOne, one of the world's largest solar inverter manufacturers, to ABB Group for just over $1 billion.

Project debt issuance was robust in both the wind and solar markets.

- Mid American followed its foray into the utility scale solar bond market with a 26 year, $250 million encore Series B bond raise for its 550 MW Topaz Solar Farm in San Luis Obispo County, California and a supersized 19 year, $1 billion Series A bond offering for its 579 MW Antelope Valley Solar Project in Kern and Los Angeles Counties, California.

- Terr-Gen raised another $550 million for its Alta Wind Energy Center in Tehachapi, California, this time financing phases X and XI of the project, totaling 226.5 MW of generating capacity.

- The 300 MW Cape Wind Project, to be located off the Massachusetts coast, continued its push toward completion, raising $200 million in mezzanine financing from PensionDanmark, a Danish investor with offshore wind investment experience.

- NextEra Energy raised $254 million in 18-year term debt for its 163 MW North Sky River Wind Energy Project, located in Kern County, California, from a lending group that was reported to include CoBank, Bank of Tokyo-Mitsubishi UFJ, Banco Sabadell SA, Sumitomo Mitsui Banking Corp. and Siemens Financial Services Ltd.

Several corporate players also exploited the current yield-starved environment by making major issuances.

- SunPower Corporation issued $300 million of .75% senior 5-year convertible debentures, mostly to its parent affiliate Total Gas & Power USA SAS. The debentures are convertible into SunPower Equity at a rate of approximately 40 shares per thousand dollars of debt.

- AES announced an offering of $250 million in 10-year bonds at 4.875%. The issuance was intended to refinance other outstanding corporate obligations.

- NextEra sold $250 million of 10-year debentures at 3.625%.

- SolarCity continued its aggressive fundraising, issuing $175 million of 5-year convertible notes. The issuance could be upsized, as underwriters have the option to purchase an additional $26.25 million of debentures.

The tax equity markets were dominated by the distributed solar players.

- SolarCity continued to impress, raising a $500 million portfolio lease fund with Goldman Sachs and a $76.5 million installment of its "Solar Strong" program with Bank of America.

- SunRun demonstrated its position as a leader in the solar market, raising $630 million of tax equity for its residential portfolio from J.P. Morgan Chase.

A number of noteworthy wind and solar project M&A transactions closed in the quarter.

- First Solar continued its strategy of sustaining utilization through project M&A, first acquiring the 150 MW Solar Gen 2 project from Goldman Sachs and the 60 MW North

Star Solar project from NorthLight Power (a subsidiary of Renewable Energy Corporation and Summit Power Group) and then selling the 139 MW Campo Verde Solar Project to Southern Company. First Solar modules will be used in the construction of each project. Solar Gen 2 will be built near El Centro, California and sell power to San Diego Gas & Electric under a 25-year power purchase agreement. North Star will be built near Fresno, California and sell power to Pacific Gas & Electric under a 20-year power purchase agreement. Campo Verde will be constructed in Imperial County, California and sell power to San Diego Gas & Electric under a 20-year power purchase agreement.

- Enel Green Power S.p.A increased its stake in two wind projects co-owned with GE Energy Financial Services from 49% to 75% and sold a 51% stake in another wind farm to GE EFS. Enel reacquired 26% of the 235 MW Chisholm View Wind Project, located near Oklahoma City, Oklahoma, and the 200 MW Prairie Rose Wind Farm, located near Jasper, Minnesota. In a transaction that is being similarly structured, Enel sold 51% of the 250 MW Buffalo Dunes Wind Project to GE EFS, with an option to re-acquire 26% of the project at a later date. All of the projects will use GE wind energy technology. Chisholm View and Buffalo Dunes will sell power to Alabama Power Company (a Southern Company subsidiary) on a committed 20-year basis, while Prairie Rose will sell to Xcel Energy.
- Consolidated Edison acquired 300 MW of photovoltaic solar projects from Sempra Energy, including the 150 MW Copper Mountain 2 project located near Boulder City, Nevada, and the 150 MW Mesquite Solar project, located near Arlington, Arizona. Each project is contracted to Pacific Gas & Electric under a 25-year PPA.
- EDF Renewable Energy acquired the remaining 40% interest in the 161 MW Spinning Spur II Wind Ranch from Cielo Wind Power LP. Spinning Spur II is being constructed in Oldham County, Texas with 87 GE 1.85 MW, and will sell its power to Xcel Energy.
- NRG Solar acquired 40 MWs of generating capacity, the Kansas South and TA High Desert projects, from Recurrent Energy. The projects will respectively sell power to Pacific Gas & Electric and Southern California Edison under long-term offtake arrangements.
- Duke Energy acquired the aggregate 21 MW Highlander I and II projects from SolarWorld AG. SolarWorld will construct the projects in Twentynine Palms, California and, when completed, the projects will sell power to Southern California Edison under a 20-year power purchase agreement.

A single major U.S. corporate M&A transaction was announced in Q2 2013.

- Inverter manufacturer PowerOne, Inc. agreed to merge with ABB Group in a $1.028 transaction. PowerOne shareholders received $6.35 in cash per share. The deal closed in July 2013.

Daniel Sinaiko is a partner in Akin Gump's Los Angeles Downtown office. He can be reached at 213.254.1211.




Adam S. Umanoff
Partner, Practice Co-Chair | Los Angeles
213.254.1300
aumanoff@akingump.com

Edward W. Zaelke
Partner, Practice Co-Chair | Los Angeles
213.254.1234
ezaelke@akingump.com

Jacob J. Worenklein
Partner, Practice Co-Chair | New York
212.872.1027
jworenklein@akingump.com

Contact Information

To learn more about our global project finance practice, please contact:

Andrew Abernethy
Partner | Hong Kong
852.3694.3020
aabernethy@akingump.com

Robert W. Aulsebrook
Partner | London
44.020.7012.9611
raulsebrook@akingump.com

Dino E. Barajas
Partner | Los Angeles
310.552.6613
dbarajas@akingump.com

David Burton
Partner | New York
212.872.1068
dburton@akingump.com

Stephen D. Davis
Partner | Houston
713.220.5888
sddavis@akingump.com

Thomas I. Dupuis
Partner | Los Angeles
213.254.1212
tdupuis@akingump.com

Baird D. Fogel
Partner | San Francisco
415.765.9522
bfogel@akingump.com

Marc C. Hammerson
Partner | London
44.020.7012.9731
mhammerson@akingump.com

Elliot Hinds
Partner | Los Angeles
310.229.1035
ehinds@akingump.com

Suedeen G. Kelly
Partner | Washington, D.C.
202.887.4526
skelly@akingump.com

Lloyd J. MacNeil
Partner | Los Angeles
213.254.1313
lmacneil@akingump.com

Bill W. Morris
Partner | Houston
713.220.5804
wmorris@akingump.com

Gregory D. Puff
Partner | Hong Kong
852.3694.3010
gpuff@akingump.com

Chadi A. Salloum
Partner | Abu Dhabi
971.2.406.8580
csalloum@akingump.com

Jeremy R. Schwer
Partner | Washington, D.C.
202.887.4471
jschwer@akingump.com

Daniel P. Sinaiko
Partner | Los Angeles
213.254.1211
dsinaiko@akingump.com

Julia E. Sullivan
Partner | Washington, D.C.
202.887.4537
jsullivan@akingump.com

Thomas B. Trimble
Partner | Washington, D.C.
202.887.4118
ttrimble@akingump.com

Richard J. Wilkie
Partner | Houston
713.220.5880
rwilkie@akingump.com

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