Project Perspectives




Global Project Finance

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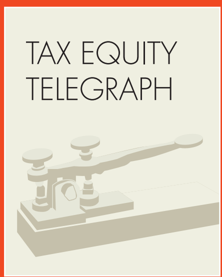
Akin Gump
STRAUSS HAUER & FELD LLP

Akin Gump Announcements

Introducing the Tax Equity Telegraph



Akin Gump Strauss Hauer & Feld LLP is pleased to announce the launch of the blog Tax Equity Telegraph. The Tax Equity Telegraph blog can be viewed at www.taxequitytelegraph.com.

The Tax Equity Telegraph blog is intended to address the intersection of tax policy and energy policy in the United States. This topic is of particular interest to renewable energy developers that need to raise tax equity and financial institutions and other corporations that provide tax equity. The posts are also intended to be of interest to companies that purchase energy projects outright partly to obtain the tax benefits and to utilities that contract with renewable energy projects.

David Burton is the editor of the Tax Equity Telegraph. Contributors include our tax lawyers, who advise clients on a variety of tax matters, with a particular emphasis on global project finance and energy transactions.

Akin Gump is pleased to announce the promotion of Joshua R. Williams, an attorney in our Tax and Global Project Finance practices in the New York office, to partnership, effective January 1, 2013. Mr. Williams has demonstrated his dedication and commitment to our clients and to our firm. Mr. Williams advises on a broad range of U.S. and international tax matters, with a focus on the formation and operation of domestic and offshore private investment funds and on the tax aspects of project finance and renewable energy transactions.

On April 15, 2013 the Internal Revenue Service released its long awaited "commencement of construction" guidelines for wind tax credit qualification. Our PTC Construction Guidance Worth the Wait client alert, released on April 16, 2013, analyzes the guidelines in detail. The alert can be found at http://www.akingump.com/en/news-publications/ptc-start-of-construction-guidance-worth-the-wait.html.

Contents

Eight Lessons for Tax Equity Investors from Recent Tax Shelter Cases

By David Burton and Brett Fieldston

Institutional investors in the renewable energy industry have thus far been spared the pain of tax litigation. Nonetheless, a recent string of government wins in corporate tax shelter cases in the federal appellate courts offer lessons for the renewables industry. Below are eight lessons from these cases that industry players should heed.

I. A Good Cause is not Enough

Courts will take a critical view of aggressive transactions, even if the transaction raised capital for a good cause. Specifically, the 3d Circuit ruled against a historic tax credit transaction that provided capital for the refurbishment of Boardwalk Hall in Atlantic City.[1]

Prior to this case, some participants in historic tax credit transactions believed they had a relatively free hand to structure the transactions in a manner most convenient from a commercial perspective, because it was thought that the government was unlikely to challenge a transaction that provided capital for a worthy cause, like refurbishing a landmark building.

The lesson from the case for the renewable energy industry is that tax equity investors cannot merely wrap themselves in "green" flags and structure transactions without careful adherence to common law tax principles, like substance over form and the step transaction doctrine, and key regulatory guidance like the partnership capital account rules.

II. No Negative Cues to the Government

The current trend in tax litigation is for the government to attack transactions on "economic substance" grounds. Determining economic substance is time consuming and necessitates a detailed analysis of facts by the Internal Revenue Service (the "Service"), Department of Justice and the courts. Humans by nature seek to minimize time and effort required to complete complicated processes. This has led courts and the government to look for cues that shortcut the analytical process.[2] Tax equity investors are well-advised to avoid these cues.

Specifically, tax equity investors need to ensure that documents prepared internally for underwriting and portfolio management purposes are consistent with the tax requirements of the transaction. In one case, an internal accountant justified a transaction as a "finance lease" for purposes of Financial Accounting Statement 13 of Generally Accepted Accounting Principles based on the fact that the counter party was likely to exercise its fixed price purchase option. This statement conflicted with the intended tax structuring and a third party appraisal. The internal accountant later retracted his statement that the fixed purchase option was likely to be exercised. Nonetheless, the government used the retracted statement as a sword in litigation and the Fed. Cir. cited the statement as one of the pillars of its analysis in ruling against the taxpayer.[3]

III. Business Purpose First

It is preferable for the non tax business purpose of a transaction to be known to the taxpayer before a tax advisor says: "we need a business purpose". Tax advisors who concoct a business purpose after the execution of a tax-advantaged transaction have been indicted; some have even been convicted of criminal offenses.[4] Taxpayers that do not think about pre-tax profit until they need a business purpose in litigation are not viewed favorably by the courts.[5] If pre-tax profit is the taxpayer's business purpose, there should be a clear calculation of the pre-tax return in the first deal model, and a pre-tax return should be specified in term sheets and proposals and should be included in management approval documents as one of the benefits of the investment.

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[1] *Historic Boardwalk Hall, LLC v. Comm'r, 694 F.3d 425, 462-463 (3d Cir. 2012).*

[2] *See Jasper L. Cummings, Jr., Magical Thinking and Tax Shelters, 138 Tax Notes 981, 983 (2013).*

[3] *Consol. Edison Co. v. United States, 703 F.3d 1367 (Fed. Cir. 2013).*

[4] *See United States v. Coplan, 703 F.3d 46, 106-108 (2d Cir. 2012).*

[5] *ACM P'ship v. Comm'r, 157 F.3d 231, 258 (3d Cir. 1998); CMA Consol. v. Comm'r, T.C.M. 2005-16, *26 (2005).*

IV. What is said in PowerPoint Matters

Marketing documents prepared by financial advisors and brokers matter to courts, even if the definitive contracts vary from what was written in the sales pitch. In one instance, a broker's pitch described, as a purchase of tax credits, what was intended for tax purposes to be an equity investment. The definitive contracts went to some lengths to avoid any such references, but the 3d Circuit found the transaction to be effectively a sale of tax credits, which is not permitted by the Internal Revenue Code, and relied in part on the broker's pitch to reach that conclusion.[6] It is critical to remember that—from the first email—tax equity investors are creating an evidentiary record that will be examined with a critical eye.

V. The Judge may have a Different Perspective

Lawyers render opinions based on the law to date, but an appellate judge may not appreciate (i) the historical development of the tax law in a particular area or (ii) the consequences for various industries in changing long-standing common law principles. The Fed. Cir. ruled that a cross-border lease was not a lease in substance, because the user of the leased asset was "reasonably likely" to exercise its purchase option.[7] A "reasonably likely" standard had not previously been articulated as the benchmark for evaluating whether a lease purchase option would cause the lease to be recharacterized for tax purposes. If, at the time the transaction was executed, a poll had been taken of leading law firms regarding the standard to evaluate a lease purchase option, it is likely none would have responded that the standard is "reasonably likely". It is not the standard published by the Service[8] or used by the Supreme Court to evaluate a real estate sale-leaseback that provided the lessee with multiple fixed price purchase options.[9] Nonetheless, a judge that disliked the transaction before him concocted it to avoid a taxpayer victory. Therefore, tax equity investors need to consider how a judge may react to their transaction, rather than merely seeking confident tax opinions based on existing law and filled with assumptions. Tax opinions certainly have an important role and are an excellent mechanism to ensure all tax issues are considered in a transaction, but they are neither crystal balls nor insurance policies.

[6] *Historic Boardwalk Hall, 694 F.3d at 433-436.*
[7] *Consolidated Edison, 703 F.3d at 1381.*
[8] *See Rev. Rul. 55-540, 1955-2 C.B. 39, 1955 WL 10043, *3 (a lease should be recharacterized as an installment sale if the asset "may be acquired under a purchase option at a price which is nominal in relation to the value of the property at the time when the option may be exercised, as determined at the time of entering into the original agreement, or which is a relatively small amount when compared with the total payments").*
[9] *See Frank Lyon Co. v. United States, 435 U.S. 561, 583-584 (1978).*

VI. Accountants can Undermine Evidentiary Protections

If a taxpayer provides a lawyer's opinion to its accountants, the taxpayer appears to waive the work-product doctrine[10] and the attorney-client privilege with respect to that opinion. These are protections under the rules of evidence that preclude an adversary in litigation (e.g., the Service) from obtaining certain documents and communications. The work-product doctrine appears to be waived, because it only applies to work in contemplation of litigation, and the preparation of financial statements was held by the 1st Circuit to be outside of that scope, even when the accountants were considering the posting of reserves for tax risks that could be litigated. The attorney-client privilege appears to be waived, because the opinion has been shared with a party that is not the client, the attorney or an agent of the attorney.

When a public company enters into a complex transaction, the company's financial statement auditing firm will frequently ask whether a reserve for the tax risk related to the transaction should be booked in the company's financial statements. A common way to ameliorate the accounting firm's concern is to provide it with a copy of an opinion from the taxpayer's transaction counsel. However, providing the law firm's opinion raises the problem of the waiver of the work-product doctrine and the attorney-client privilege.

A potential, but expensive solution to this problem is for the public company to request that the accounting firm's tax experts review the transaction and determine its merits rather than providing the legal opinion to the accounting firm. This could happen either contemporaneously with the execution of the transaction or when the accounting firm inquires about the transaction. It should be noted that under this line of thinking the accounting firm's own work also could be likely obtained by the government in certain circumstances, but such an approach at least avoids a broad subject matter waiver that could permit the government to question the taxpayer's attorney about confidential conversations with the client. Further, the accounting firm would ideally limit its analysis and written memorialization to the minimum required by financial statement preparation standards.

VII. Avoid "Put" Options

If the expected tax benefit requires the tax equity investor to be a "partner" or an "owner," the investor would be well-advised not to give itself the benefit of the option to "put" its interest back to the developer (or the right to withdraw from the equity structure, which is a put option by another name). This advice is contrary to the structuring practices of some

[10] *United States v. Textron, Inc., 577 F.3d 21 (1st Cir. 2009) (en banc), cert. denied 130 S. Ct. 3320 (2010).*

tax equity investors that included put options in their deals in order to assure themselves the ability to exit the investment. For instance, the 3d Circuit found that a Pitney Bowes affiliate was not in substance a partner in a partnership that owned a building eligible for the federal historic tax credit because, if the other partner did not exercise a call option that required it to pay an amount sufficient to provide an agreed return to Pitney Bowes, the Pitney Bowes affiliate—two years later—was entitled to cause the other partner to purchase its interest at an amount that provided it an agreed return.[11] This cross-put call arrangement is particularly worrisome, but a best practice would be to avoid puts even if there is not a call option. If a tax equity investor needs a put right in order to be comfortable investing in a tax-advantaged asset, it might be better served to invest its money somewhere else.

VIII. 99.99 Percent is too Much

The Service has generously blessed wind production tax credit transactions that allocate 99 percent of the credits to the tax equity investor and a mere 1 percent to the developer.[12] If it is important that a structure be characterized as a partnership, the allocations of tax items should not exceed 99 percent (unless required by the "regulatory allocation" rules). An allocation of 99.99 percent is inviting scrutiny; the additional .99 percent is not worth it. For instance, in Historic Boardwalk Hall the Pitney Bowes partner was allocated 99.99 percent of the tax credit and, for a variety of reasons, was unable to persuade the 3d Circuit it was a genuine partner.[13]

* * *

The takeaway: tax equity investors need to regularly compare their structuring techniques to developments in the tax law. They also need to carefully consider their communication with respect to tax advantaged transactions. Consulting with tax counsel early in the transaction process can aid tax equity investors in avoiding costly pitfalls.

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[11] *Historic Boardwalk Hall, 694 F.3d at 462-463.*
[12] *Rev. Proc. 2007-65, 2007-45 I.R.B. 967, § 4.02.*
[13] *Historic Boardwalk Hall, 694 F.3d at 459.*


Photo courtesy of SunPower Corporation

FERC Guidance on Transfer of Control Capacity to Mitigate Market Power

By G. Philip Nowak and Scott Johnson

The Federal Energy Regulatory Commission (FERC) recently declined to authorize under Section 203 of the Federal Power Act (FPA) a proposed transaction pursuant to which MACH Gen, LLC (MACH Gen) would sell, and Saddle Mountain Power, LLC (Saddle Mountain) would buy, all outstanding equity interests of New Harquahala Generating Company, LLC (New Harquahala) (Proposed Transaction).[1] Since the Proposed Transaction, absent mitigation, failed the FERC's screens for horizontal market power by a wide margin, the applicants proposed to transfer control over a generating plant owned by New Harquahala (Harquahala Facility) to Twin Eagle Resource Management, LLC (Twin Eagle) an independent third party, pursuant to an Energy Management Agreement (EMA). The FERC determined that the EMA did not transfer "unlimited discretion and control"[2] of the Harquahala Facility to Twin Eagle, and, therefore, the proposed mitigation was insufficient to address the market power concerns raised by the Proposed Transaction.

The Proposed Transaction

MACH Gen is a holding company that owns 100 percent of the interests in three electric generating companies, including New Harquahala. MACH Gen is owned by financial institutions. The Harquahala Facility is a natural gas-fired, combined-cycle electric generating plant with a summer rating of approximately 1,054 megawatts (MW). The Harquahala Facility is located in the balancing authority area of Arizona Public Service Company (APS BAA).

Saddle Mountain, which is a wholly-owned subsidiary of Wayzata Opportunities Fund II, L.P. (WOF II), was formed to acquire the equity interests of New Harquahala. WOF II and Wayzata Opportunities Fund, LLC (WOF I), which are commonly managed by Wayzata Investment Partners, LLC (Wayzata), each own a 50 percent interest in Sundevil Power Holdings, LLC (Sundevil), which in turn owns two of the four

generating units (combined summer rating of approximately 1,167 MW) at the Gila River natural gas-fired electric generating facility in Gila Bend, Arizona (Gila River Facility). The Gila River Facility interconnects with the transmission grid in the APS BAA.

The applicants recognized that, absent any horizontal market power mitigation measures, the Proposed Transaction would result in the failure of the FERC's screens for horizontal market power due to the large percentage of generation capacity that New Harquahala and its affiliates would own and control in the APS BAA. Under the economic capacity analysis, the relevant market would be highly concentrated and the changes in the Herfindahl-Hirschman Index (HHI) resulting from the Proposed Transaction would be above the FERC's threshold for seven of ten seasons/load periods. Under the available economic capacity analysis, the Proposed Transaction also would result in HHI changes exceeding 1,000 for seven of ten seasons/load periods. Hence, mitigation would be necessary to eliminate the

[1] MACH Gen, LLC, 142 FERC ¶ 61,178 (2013). MACH Gen, Saddle Mountain, and New Harquahala are collectively referred to herein as Applicants.
[2] Id. at P 29.

possibility that New Harquahala and its affiliates would have market power following the Proposed Transaction.

The Proposed Mitigation of Horizontal Market Power

The applicants' proposed mitigation included the following:

- New Harquahala would relinquish control of all available capacity and of the authority to dispatch the Harquahala Facility to Twin Eagle on a rolling 12-month basis.
- Twin Eagle's responsibilities to New Harquahala, as provided in the EMA, would include the economic dispatch, marketing and execution of short-term transactions for capacity and related energy products, scheduling transmission, administering settlement and payment for its transactions, procuring fuel, and scheduling and tagging power.
- Twin Eagle would create a daily marketing plan based on the available capacity at the Harquahala Facility (as communicated by the operations and maintenance operator), the generation cost for the day at various output levels, and Western Electric Coordinating Council protocols. New Harquahala would have the right to audit the daily marketing plans only 30 days after the close of the most recent calendar quarter, by which time all of the information would have been disclosed in Electric Quarterly Reports filed with the FERC.
- New Harquahala would have limited rights to terminate the EMA only under the following circumstances: upon insolvency or default; where either party undergoes a change in control or a change in status that might affect its ability to make sales at market-based rates; if the FERC determines that mitigation is no longer necessary; or upon 60 days' prior written notice if New Harquahala has elected a successor energy manager which is approved by the FERC.

The applicants explained that certain parameters were set forth in the EMA to guide Twin Eagle's operation of and sales from the Harquahala Facility to avoid uneconomic dispatch. Specifically, under the EMA, New Harquahala would establish the Harquahala Facility's operating limits, dispatch and efficiency curves and operating costs, all of which are factors within the dispatch model and Energy Management Plan, an attachment to the EMA. In addition, New Harquahala would be responsible for operation and maintenance of the Harquahala Facility. Finally, New Harquahala retained the right to enter into long-term agreements for energy or capacity from the Harquahala Facility that would commence at least one year after the date of execution of such agreements and that would be subject to prior FERC approval.

The FERC Order

The applicants' ability to exercise market power was of particular concern to the FERC because the Harquahala Facility and the Gila River Facility (the two facilities that would be commonly-owned and controlled by Wayzata in the APS BAA) operate using similar generation technology (combined-cycle, natural gas-fired turbines). Under competitive conditions, each facility would have a similar dispatch cost and could be available at a similar point on the supply curve. The FERC highlighted three reasons why, in its judgment, New Harquahala's proposed transfer of control via the EMA was insufficient to address the market power concerns raised by the Proposed Transaction.

First, under the EMA, Twin Eagle would have to follow a detailed, prescribed methodology for dispatching the Harquahala Facility, from which methodology it would have little discretion to deviate. Under the EMA, New Harquahala would establish the operating limits, dispatch and efficiency curves and operating costs of the Harquahala Facility. Thus, New Harquahala, its parent, Saddle Mountain, and its affiliates under common control of Wayzata, including Sundevil, would have advance knowledge of the short-term marketing strategy for the generation output of the Harquahala Facility. Sundevil, which already owns and controls 1,167 MWs of capacity at the Gila River Facility, would have access to information that would allow it to make anticompetitive sales from that facility. For example, Sundevil could choose to withhold output from that facility or dispatch energy from its capacity at the Gila River Facility at a higher price than would result from a competitive process to maximize its overall profits. Notably, as the FERC found, such a withholding strategy would not require any overt cooperation between Sundevil and Twin Eagle.

Second, New Harquahala would be responsible for operation and maintenance of the Harquahala Facility.

Third, New Harquahala would retain the right to enter into long-term contracts for sales from the Harquahala Facility. According to the FERC, "Applicants cannot credibly argue that the Harquahala Facility will be under someone else's control when New Harquahala reserves the right to control the facility itself for purposes of marketing it for long-term sales."[3]

The FERC declined to authorize the Proposed Transaction without prejudice to the applicants making a new filing that proposes mitigation that would be sufficient to remedy the identified failures of the FERC's market power screens.

[3] *Id. at P 32.*

Some Further Guidance and More Questions

The FERC has provided little guidance on when an entity has control of capacity pursuant to an energy management or comparable agreement such that the capacity can be attributed to that entity for purposes of determining whether to grant that entity the necessary authorizations under the FPA to provide jurisdictional services or whether to authorize a proposed transfer of facilities subject to FERC jurisdiction. The FERC has never authorized a proposed transaction pursuant to FPA Section 203 where the ability to exercise market power has been mitigated through the transfer of control over generation facilities pursuant to such an agreement.

In its Notice of Proposed Rulemaking regarding market-based rates (MBR),[4] the FERC considered whether, in the interest of providing greater certainty and clarity regarding the determination of control for the purpose of authorizing MBRs, it should make generic findings or create generic presumptions regarding what constitutes control. In particular, it sought comment on whether any of the following functions should merit a finding or presumption of control and, if so, on what basis: directing plant outages, fuel procurement, plant operations, energy and capacity sales and/or credit and liquidity decisions.

In Order No. 697,[5] the FERC declined to adopt a presumption of control regarding energy management and comparable agreements or the above-described functions listed in the NOPR. The FERC concluded:

> *[E]nergy management and comparable agreements do not necessarily convey unlimited discretion and control away from the entity that owns the plant. In this regard, . . . it is the totality of the circumstances that will determine which entity controls a specific asset.*[6]

Accordingly, Order No. 697 provides little guidance regarding when an entity has control of capacity for purposes of determining whether to permit the entity to charge MBRs. As the FERC noted, it will provide such guidance on a case-by-case basis.[7]

[4]*Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils., 71 FR 33102 (Jun. 7, 2006), FERC Stats. & Regs. ¶ 32,602 (2006) (NOPR).*
[5]*Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils., Order No. 697, FERC Stats. & Regs. ¶ 31,252 (2007) (Order No. 697), clarified, 121 FERC ¶ 61,260 (2007), order on reh'g, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, clarified, 124 FERC ¶ 61,055, order on reh'g, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), order on reh'g, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), order on reh'g, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), aff'd sub nom. Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011), cert. denied sub nom. Pub. Citizen, Inc. v. FERC, 133 S. Ct. 26 (2012).*
[6] *Order No. 697 at P 197.*
[7]*Id.*

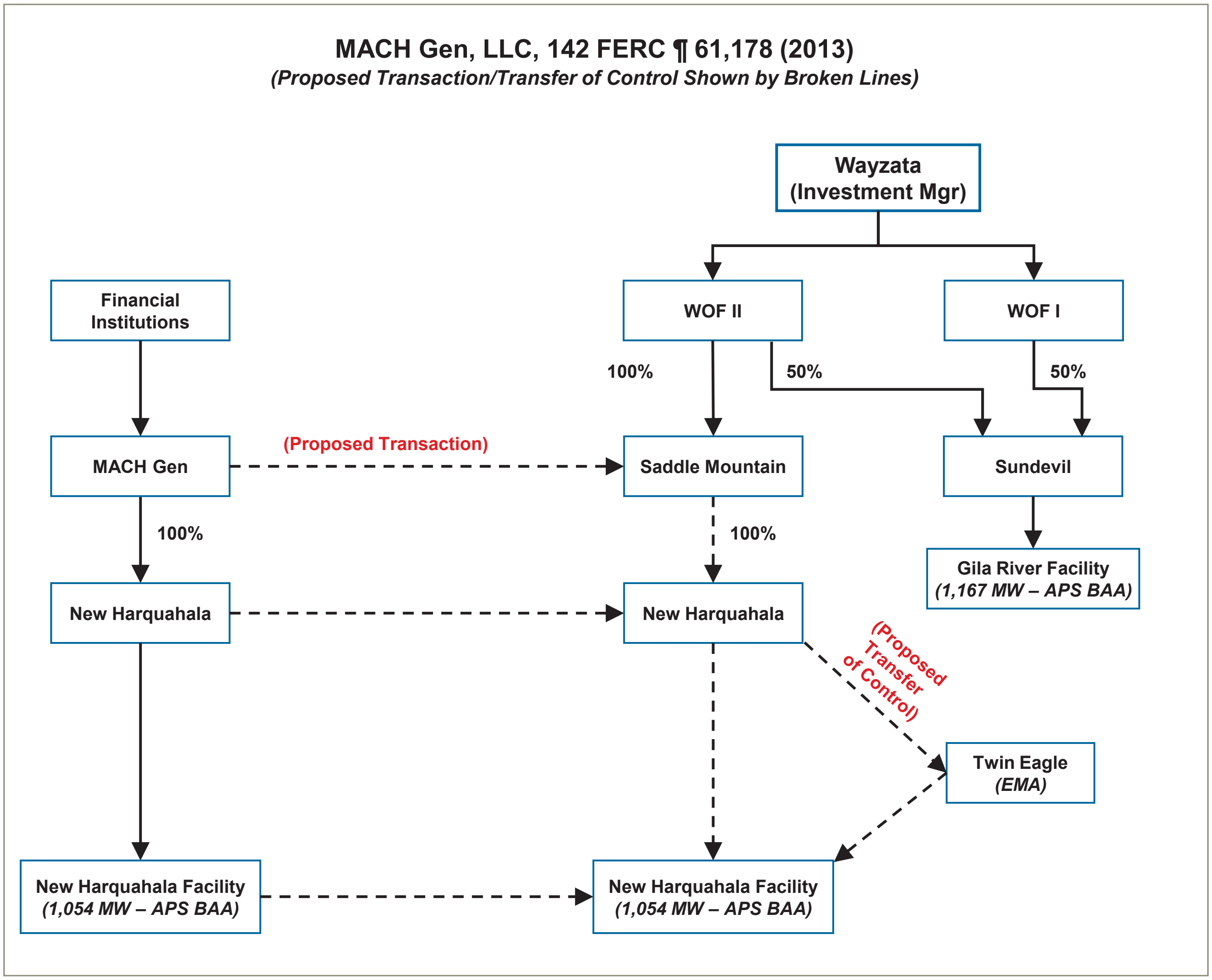
Likewise, the FERC has provided little guidance regarding when the transfer of control will be sufficient in an FPA Section 203 proceeding to mitigate the failure of the FERC's horizontal market power screens. In MACH Gen, the FERC provides some limited guidance in this regard. First, as in the case of MBRs, the FERC will determine on "the totality of the circumstances" whether there has been a transfer of control. Second, in order for the proposed mitigation to address the potential adverse impact the transaction will have on competition, there must be a transfer of "unlimited discretion and control." This would appear to establish a very high standard that will be applicable at least with respect to the transfer of control in FPA Section 203 proceedings. Finally, the proposed mitigation will not be sufficient to the extent that the entity establishes, and thus has knowledge of, the operating limits, dispatch and efficiency curves and operating costs of the relevant facility; operates and maintains the facility; and has the right to enter into long-term (for more than one year) sales contracts.

However, *MACH Gen* lacks certainty and clarity in other respects, and raises more questions. First, the FERC does not indicate whether the retention of any one of the above listed responsibilities or right would result in a denial of an FPA Section 203 application for failure to transfer "unlimited discretion and control."[8] Second, the FERC was concerned because New Harquahala, its parent, Saddle Mountain, and its affiliates under common control of Wayzata, including Sundevil, would have access to "relevant information to which no other market participant [would] have, namely, advance knowledge of the short-term marketing strategy of the generation output of the Harquahala Facility."[9] Henceforth, the FERC apparently will consider both whether the entity has the ability to control the output of the facility and, if not, whether it nonetheless will have access to relevant non-public information that would enable it to engage in anticompetitive sales even without any overt cooperation between parties. Finally, the FERC seems to

[8]*Likewise, in Westar Energy, Inc., 115 FERC ¶ 61,228, at P 76 (2006), to which the FERC cites, it found that there was not a transfer of control for FPA section 203 purposes because the entity retained:*

> *The sole right and responsibility to, among other things: (1) establish all marketing plans for Power, Fuel or Ancillary Services and approve or disapprove of any deviations from such Marketing Plans that may be recommended by the Energy Manager . . . from time to time; (2) establish short-term and long-term fuel and energy trading strategies; (3) establish Risk Management Policies and Strategies; (4) approve all short- and long-term fuel and power transactions; (5) determine the amount of otherwise non-contracted power available from the facility at any time; and (6) determine the amount of fuel to be supplied to the facility.*

In addition, the entity would operate the facility. Again, it is not clear whether the retention of any one or more of these functions, as the FERC notes, among others, would defeat the transfer of unlimited discretion and control sufficient for the mitigation of horizontal market power in an FPA section 203 proceeding.
[9] *MACH Gen at P 31.*



suggest that what constitutes a change of control for mitigation purposes under FPA Section 203 may differ from what would suffice in an FPA Section 205 proceeding. In distinguishing MACH Gen from Acadia Power Partners, LLC,[10] the FERC stated that "that proceeding involved a change in status filing pursuant to Order No. 652, and analyzed the EMA in the context of affiliate sales rather than its effect on competition."[11]

Parties such as MACH Gen, for whom transferring control to an independent third party may be the only practicable manner in which to mitigate horizontal market power,[12] apparently will have to await further guidance from the FERC, provided on a case-by-case basis, on what it will deem to be the transfer of "unlimited discretion and control." In the meantime, entities seeking to mitigate horizontal market power through the transfer of control to an independent third party will have to give careful thought to the functions they can continue to perform or the rights they can retain, if any, and, whether they do, the extent to which they may have access to non-public information that could permit them to engage in anticompetitive sales to maximize their overall profits.

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[10] *115 FERC ¶ 61,228 (2006).*
[11] *MACH Gen Order at P 29 n.36.*
[12] *The FERC has indicated that horizontal market power mitigation measures include, but are not limited to, joining or forming a Regional Transmission Organization, implementation of an independent coordinator of transmission arrangement, generation divestiture, virtual generation divestiture, and proposals to build new transmission to provide greater access to third party suppliers. E.g., Duke Energy Corp., 139 FERC ¶ 61,194 at P 4 (2012).*

Twisting in the Wind:

Will Transmission Line Upgrade Delays Prevent Wind Farms From Being "Placed in Service"?

By Anne Levin-Nussbaum

Photo courtesy of Element Power's Macho Springs I Wind Project in New Mexico

An issue that frequently comes up in the context of tax equity investments in wind farms and other power projects is when the asset will be considered "placed in service." This is because U.S. tax rules do not permit a project owner to take depreciation deductions, or receive tax credits[1] or a cash grant under Treasury's Section 1603 Program until its placed in service date. A recent private letter ruling provides some helpful guidance on this issue by concluding that a wind farm can be considered placed in service even if its turbines are being operated on a rotating basis because of external factors (in this case, capacity limitations on the transmission lines) that limited the ability of the grid to accept the full amount of power that the turbines were capable of producing.[2]

Before discussing the ruling it is helpful to understand what is meant by "placed in service," and how it can be that this is something that is difficult to determine. An asset is first considered "placed in service" when it is "placed in a condition or state of readiness and availability for a specifically assigned function."[3] In layman's terms, the concept is that construction is complete and the asset is operating as intended.

This concept is not so simple when considered in light of an asset like a wind farm or other generating facility that becomes operational in stages. For these types of assets, questions arise as to where along the continuum the asset is considered ready and available for its specifically assigned function. Can the project be considered complete if there are still punch-list items or if the contractor is correcting defects discovered during testing? Similarly, at what point is a facility considered operational or ready to be used in its "assigned function"?

[1] *It should be noted that in the case of the investment tax credit, there is an exception for certain "qualified progress expenditures" incurred to build an asset with a long production period (generally, longer than two years), which does permit the taxpayer to claim the credit prior to completion of the asset. The eligibility rules for this exception are described in detail in the Winter 2013 edition of Project Perspectives. See, David Burton, Qualified Progress Expenditure Rules Allow Taxpayers to Claim ITC Earlier for Projects with Lengthy Construction Periods, [Project Perspectives: Global Project Finance (Akin Gump Straus Hauer & Feld LLP Client Publication),] p. 17-18 (Winter 2013), [http://cdn.akingump.com/images/content/2/2/v2/22173/Project-Perspective-Newsletter-Winter13.pdf]*

[2] *PLR 201302007 (Jan. 11, 2013).*

[3] *Treas. Reg. § 1.167(a)-11(e)(1)(i). See also, Treas. Reg. §1.46-3(d)(1)(ii).*

Photo courtesy of Element Power's Macho Springs I Wind Project in New Mexico

If that function is thought of as producing power for sale, must the wind farm actually sell power or is it enough to be through critical testing such that it can be determined that the facility will be able to do so?

While the law in this area depends largely on the facts and circumstances of the specific situations addressed, there are some minimum conditions that generally must be satisfied before an energy project can be considered placed in service. These are that: (1) all licenses and permits that are needed to operate the facility have been obtained; (2) the contractor has turned over control of the project to the taxpayer; (3) all critical testing has been completed; (4) regular commercial operation of the project has commenced; and (5) the facility has been connected to, and synchronized with, the power grid and thus is able to generate income from the power produced.[4] Even with this general set of guidelines, questions arise every day and practitioners are faced with the task of applying this highly factual body of law to the unique situation at hand.

A frequent concern, and one which is addressed in the recent ruling, is whether and when capacity limitations will affect the in-service determination.[5] Under the facts presented in PLR 201302007, the Internal Revenue Service (IRS) considered whether a wind farm could be considered placed in service prior to completion of certain upgrades to a third-party transmission line, which were needed in order for the project to operate at full capacity. The IRS concluded that it could.[6]

PLR 201302007 involved a wind power generating facility being developed by the taxpayer's subsidiary. The project was expected to include some unspecified number of wind turbine generators and their associated towers and tower foundations, each of which would be a self-contained unit that could operate independently.

The project was being built in a region where there was an identified need for additional transmission lines on the local distribution system, which was owned by a third party. Work on the local distribution system upgrades had commenced, but there were indications that the segment that would be used to transmit power from the project might not be available until a year after the turbines were ready to be placed in service. Such a delay would not prevent the project from selling power into the grid, as a lower-capacity transmission line and a substation were being constructed as part of the project. However, a delay in the availability of the new segment would mean that the project could not operate all of the turbines simultaneously at full capacity.

[4] *See, e.g., Rev. Rul. 76-256, 1976-2 C.B. 46 and Rev. Rul. 76-428, 1976-2 C.B. 47. The industry standard typically used by practitioners is that the asset must be connected and synchronized to the grid and capable of producing and delivering commercial quantities of electricity on a regular basis. The exact boundaries of what constitutes production of "commercial quantities" of electricity remains unclear.*

[5] *It has generally been held that an electric power plant can be considered placed in service prior to the time when it can produce power at its rated capacity. See e.g. Sealy Power, Ltd v. Comm'r, 46 F.3d. 382 (5th Cir. 1995), nonacq. 1995-2 C.B. 2 (facility operating on a regular basis but not producing projected output); Rev. Rul. 84-85, 1984-1 C.B. 10 (solid waste plant unable to operate at capacity, but regular operations were producing saleable steam). However, the IRS indicated in its Action on Decision for Sealy Power that some minimum level of output is required; the facility must be able to reliably produce "commercial quantities" of power on a sustained basis. Sealy Power, AOD 1995-010. Similarly, under the Treasury Regulations, an asset can be considered placed in service even though it is undergoing testing to eliminate defects. Treas. Reg. § 1.46-3(d)(2). See also, Rev. Proc. 79-40, 1979-1 C.B. 13.*

[6] *It should be noted that private letter rulings are binding only with respect to the specific taxpayer and facts addressed, and cannot be relied on by other taxpayers. Nonetheless, the principles set forth in PLR 201302007 provide some much-needed and helpful guidance on this topic.*

The project owner intended to begin commercial operation as soon as the turbines were complete, even if it meant operating at less than nameplate capacity for some period of time. Until the needed segment of the local distribution system was complete, the project owner would use the captive transmission line and substation. The project owner's plan was to operate all of the turbines simultaneously when the wind velocity was low enough that the project's existing transmission system could handle the energy flow. When the wind velocity was higher, the project owner would curtail capacity, including by rotating operation of the turbines in a manner that balanced the number of operating hours for each turbine.

The conclusion in the ruling is premised on the assumption that the project would be in regular and continuous operations selling power and would be capable of operating at nameplate capacity absent the capacity limitations that would occur if there were delays in completing the needed segment of the local distribution system.[7] The IRS stated that the "focus in determining a placed in-service date is on ascertaining from the relevant facts and circumstances the date the unit begins supplying product in such a manner that it is routinely available and is consistent with the unit's design."[8] Following precedents dealing with the issue of limitations on capacity, the IRS concluded that the turbines did not need to be operating daily at full-rated capacity in order to be considered placed in service. In reaching this conclusion, the IRS noted that failure to operate at nameplate capacity could also occur due to wind conditions. The point focused on by the IRS was whether the turbines were capable of operating in accordance with their designed function - not whether they actually operated that way.

PLR 201302007 is an important ruling because it considered capacity limitations caused by external factors — in particular, network upgrade delays. Most of the existing law prior to this ruling addressed capacity limitations caused by defects in the asset itself.[9] In contrast, the wind facility considered in PLR 201302007 was assumed to be fully capable of functioning as intended. Any need for a ramp-up period would be due to factors other than the functionality of the facility.

This type of situation is not uncommon in the context of power plants, where distribution system upgrades are frequently needed. Such upgrades may affect a project's operations in ways other than curtailment of capacity. For example, some offtake agreements with utilities provide different fee structures depending on whether the project has been certified as a reliability resource, which in turn may depend on certain upgrades being made to the distribution system. These upgrades may not be the responsibility of the project owner. Nonetheless, prior to this ruling, a practitioner might have had some concern about whether the plant could be considered placed in service prior to the completion of the network upgrades due to the fact that the project could not receive full compensation under the offtake agreement until that time. This ruling makes it clear that needed upgrades to a third-party distribution system should not automatically prevent a power project from being considered placed in service.

Another aspect of the ruling that is helpful is that it considers the concept of rolling use of generating equipment to address the curtailment issue. Such rolling usage would mean that each generator is not operating continuously. Absent this ruling, such non continuous use of a facility might cause concern that the facility would not satisfy the requirement of being in regular operation and thus could not be considered placed in service.[10] Based on PLR 201302007, it would appear that there can be some latitude in this regard.

While PLR 201302007 addressed the in-service date question in the context of the taxpayer's ability to take depreciation deductions, it should be remembered that this issue comes up in other contexts, too. The availability of tax credits also depends on the asset being placed in service. Moreover, this date is often used as the cut-off date for eligibility of tax benefits with limited duration. For example, placed in service date has been used to determine eligibility for Treasury's Section 1603 cash grant program. It has also been used for purposes of the bonus depreciation benefits that have been available from time to time in recent years and to set the dividing line for eligibility for certain renewable energy tax credits.[11] In these contexts, getting the date right can be particularly important.

In short, the issue of when energy property is considered placed in service can have significant tax consequences, and it is useful to know that delays in third-party transmission line upgrades will not necessarily be fatal to that determination.

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[7] The construction contract required the following conditions to be satisfied by a certain date: (a) all necessary licenses and permits have been obtained; (b) the turbines are synchronized with the power grid; (c) completion of all critical testing; (d) transfer of control of the WTGs to the project owner; and (e) sale by the project owner of a non-de minimis amount of electricity generated by each turbines. The IRS relied on satisfaction of these terms in concluding that the minimum standards under Revenue Ruling 76-256 would be satisfied.

[8] PLR 201302007.

[9] See, footnote 4 above.

[10] See e.g., Ogelthorpe Power Corp. v. Comm'r, T.C. Memo 1990-505 (coal-fired electric generating plant not placed in service until capable of regular operations); Consumers Power Co. v. Comm'r, 89 T.C. 710 (1987) (facility must be capable of full operation on a regular basis to be considered placed in service).

[11] Under recent legislation extending some of these benefits, including the production tax credit available for certain wind farms, a "begun construction" standard replaced the placed in service date cutoff line.

State Tax Update

A summary of recent state renewable energy tax law developments.

By David Burton and Oz Halabi

Connecticut – Connecticut's tax law grants tax exemption benefits to certain renewable energy systems, such as solar and wind. However, due to an apparently inadvertent omission in the drafting of the exemption, these benefits are only provided to systems that are situated on residential and farm property. Systems on industrial and commercial property are not afforded the same exemption. Consequently, Connecticut lawmakers are working on passing the additional exemption required to cure this omission.

Many systems are currently being installed without the exemption and some contracts are being delayed due to the uncertainty of whether the bill will eventually pass. Some town assessors, such as Stratford, have written letters of forgiveness to commercial businesses stating their renewable energy systems will not be taxed; some jurisdictions, such as New Haven, are calling for the commercial tax exemption to be retroactive to October 1, 2012. However, some towns, such as Bloomfield, are taking a harder stance that exemptions will only be granted to farms and residential systems. The question, therefore, is whether the General Assembly should force municipalities to grant the exemption or simply give them an option. The Department of Energy & Environmental Protection, which is implementing much of the energy plan presented by Gov. Dannel Malloy to make energy cleaner, cheaper and more reliable, is pushing for a voluntary exemption. Among member s of the energy committee, however, views are divided: Sen. Bob Duff (D-Norwalk), co-chair of the committee, favors a voluntary exemption, while Rep. Lonnie Reed (D-Branford), the second co-chair, is leaning towards a mandatory exemption.[1]

Maine – On February 25, 2013, the Joint Committee on Taxation hosted a debate between the Republicans and Democrats. This time the issue was about Sen. Geoffrey Gratwick's (D - Penobscot) proposal (LD 361) to promote the sale of electric vehicles. The proposal provides substantial tax benefits to individuals that purchase new electric vehicles - vehicles which likely retail for more than $35,000. Gratwick's tax credit for $1,000 is in addition to the $7,500 tax subsidy the federal government currently provides. "It goes without saying that only people who can afford to buy plug-in electric vehicles will benefit," he said. "Republicans support tax cuts," said House Republican Leader Ken Fredette (R-Newport), "but we oppose market-distorting handouts to the green energy industry that benefit only those who need the money the least."[2]

Michigan – In December 2012 the Michigan Tax Tribunal ruled in Richard C. Schmitt v. Charleston Township[3] that a 147 kW photovoltaic (solar) electric generating facility consisting of 126 solar panels should be considered personal property, rather than real property for local taxing purposes. Under the General Property Tax Act, MCL Section 211.1, et seq., real property is generally taxable to the owner of the property, whereas personal property is taxable to the personal property owner and not the owner of the underlying land. In this case, the owner of the land leased a parcel of land on a 10- year lease. The lessee (Kalamazoo Solar) was recognized in the lease agreement as the owner of the electric generating facility and it was also stated that, either at the end of the lease term or upon earlier termination of the lease, the lessee is required to remove the solar facility from the land.

The tax tribunal addressed the issue of whether alternative energy generating systems, like the solar facility located on a person's land, should be classified as real property (and thus tax that person as the owner of the land) or as a person's personal property. The owner of the solar facility argued that a solar facility is a fixture, and therefore, for tax purposes, it is part of the realty and is taxable to the land owner.

The tax tribunal concluded that the solar facility had to be taxed as personal and not real property.[4] This holding required an analysis to overcome the common law argument that the solar array could be deemed real property as it was affixed to the land. The authority for the decision was founded, in part, on tax exemption provisions of the Next Energy Authority Act.[5]

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[1] *Brad Kane, CT Rushes to Fix Hole in Solar Tax, at* www.hartfordbusiness.com *(Feb. 4, 2013)*

[2] *Douglas Rooks, Maine: Main Republicans Fight Proposed Credit for Electrical Vehicles, 2013 STT 39-13 (Feb. 27, 2013).*

[3] *Richard C. Schmitt v. Charleston Township Nos. 385540 and 414722 (Mich. Tax Tribunal, December 21, 2012).*

[4] *Bruce Goodman, Favorable Tax Decision on Solar Array,* The National Law Review *at* http://www.natlawreview.com/print/article/favorable-tax-decision-solar-array *(Jan. 31, 2013).*

[5] *Michigan Next Energy Authority Act, Act 593 of 2002, § 207.826.*

Energy Storage:
Clearing the Path for a Breakthrough

By Kerin Cantwell, George "Chip" Cannon, Jr. , and Miles Killingsworth

Numerous energy storage technologies have now reached technological maturity and are being deployed in various electricity market segments. Competing new technologies are also in research and development. Barriers nonetheless persist at the state and federal levels and within the organized wholesale power markets, preventing energy storage providers from commercializing their products and services in a way that attracts necessary investment capital at acceptable rates of return and at costs that are fair to ratepayers.

The United States **Federal Energy Regulatory Commission,** various state public utility commissions (most notably in California and Texas), regional system operators, and state and federal legislatures and agencies are attempting to address these barriers. Some utilities, independent transmission and generation developers, and regional system operators have placed energy storage systems in use despite the absence of clear market regulations and even guaranteed cost recovery. The immediate need for such systems is acute and their deployment cannot be deferred until the market and regulatory rule-makers catch up with the technical demands of the grid. This article describes energy storage applications and recent changes in energy storage regulation, and makes recommendations as to how to remove legal and market barriers to foster full commercial implementation of energy storage systems.

What is Energy Storage?

Energy storage means many different things to different industry stakeholders depending on where and how it is used in the electricity value chain. Sensitive to the many uses of the term, the **California Public Utilities Commission** (CPUC) formally adopted the definition of an energy storage system contained in the California Public Utilities Code in its "Decision Adopting Proposed Framework for Analyzing Energy Storage Needs" issued on Aug. 6, 2012 (the August 2012 Rulemaking). The code defines an energy storage system as a commercially available technology that is capable of absorbing energy, storing it for a period of time and thereafter dispatching the energy. The system must be cost-effective and accomplish one of the following purposes: reduce greenhouse gas emissions, defer or replace generation, transmission or distribution assets, or improve the reliability of the grid. The system must also meet at least one of the following characteristics: 1) use mechanical, chemical or thermal processes to store energy that was generated at one time for use at a later time, 2) store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time, 3) use mechanical, chemical or thermal processes to store energy generated from renewable resources for use at a later time, or 4) use mechanical, chemical or thermal processes that would otherwise be wasted for delivery at a later time.[1] In the absence of an industry-standard definition of "energy storage" California's definition is reasonably comprehensive, but does not include research-stage and emerging technologies, which should also be considered.

There are numerous energy storage technologies in various stages of commercial development and use. Generally, they break down into mechanical or electrochemical technologies. Mechanical energy storage technologies include pumped hydro, compressed air and flywheels. The advantages of mechanical systems are that they are long established, proven (and therefore bankable) technologies, and many have been in commercial operation for decades. Pumped hydro, for example, constituted approximately 22,000 MW of the 23,250 MW of installed energy storage capacity in the United States in 2011. The downsides of mechanical systems for certain applications are low energy efficiencies and slow response times. In addition, pumped hydro and compressed air systems have geographical and geological constraints, long construction lead-times, and high capital costs.

There are several types of electrochemical technologies (*i.e.*, batteries) for large-scale energy storage that are either commercially available or close to commercialization. Lithium-ion has been the battery technology of choice in recent years due to its high energy density, high efficiency, and relatively long lifecycle. However, lithium-ion batteries are expensive and present safety issues. Traditional flooded or sealed lead-acid battery technology has high energy density and is currently the lowest-cost battery technology, but it has relatively low efficiency. Moreover, the batteries need to be charged at low temperature, requiring an HVAC system that results in higher balance of plant and operating costs than certain other battery technologies. Advanced lead-acid batteries, also known as lead-carbon batteries, which use a hybrid technology that is part lead-acid battery and part supercapacitor, have lower energy density than traditional lead-acid batteries, but have life cycles estimated at five to 10 times that of traditional lead-acid batteries. Lead-carbon batteries are fast charging, with charge acceptance rates estimated at 10 to 20 times that of earlier generation lead-acid technologies. Sodium sulfur batteries have an energy efficiency of approximately 89 percent, but must be kept at 300°C, are expensive, and also present safety issues. Flow battery technology, which is a cross between a conventional battery and a fuel cell, has an energy efficiency of approximately 80 percent. Flow battery chemistries include zinc-bromide and all-vanadium redox.

There are many more energy storage technologies in the research and development stage that may eventually prove more cost-effective for certain applications. The United States Department of Energy, through its **Advanced Research Projects Agency-Energy**, provided $43 million in funding to 19 new projects in 2012 to advance national policy goals of improving the efficiency and reliability of the grid, advancing electric vehicle technology, and promoting energy security. The projects focus on the development of new battery chemistries and designs and battery sensing and control technologies. For example, in a project at the **University of Southern California**, which received earlier ARPA-E funding, researchers are developing an iron-air battery. This battery can store the same amount of energy as a lithium-ion battery, but at an estimated 10 percent of the cost. If successfully developed, this technology would result in a low-cost, environment-friendly, high-energy density battery capable of 5,000 deep charge/discharge cycles.

The "End-Use" Approach to Defining Energy Storage

California Assembly Bill 2514, which was signed into law in September 2010 by then **Governor Arnold Schwarzenegger**, requires the CPUC to determine appropriate targets, if any, for mandating energy storage for load-serving entities by Oct. 31, 2013. In December 2010, the CPUC issued an order instituting rule-making outlining the first of two phases designed to implement AB 2514. The first phase focused on overall policies and guidelines for energy storage systems. This phase concluded in July 2012 and is summarized in the August 2012 Rulemaking. The second phase, which began in December 2012, will address the costs and benefits of energy storage and establish how they should be allocated. Various stakeholders collaborated to develop "use cases" which were filed with the CPUC for its consideration in connection with the goals of AB 2514.

In the August 2012 Rulemaking, the CPUC used an "end-use" approach to adopting a framework for analyzing the state's energy storage needs. This approach is helpful in understanding the "big picture" of energy storage, its various uses in the organized electricity markets, the multitude of governmental and quasi-governmental agencies which regulate or influence the uses and potential uses of energy storage, and

[1] *Pub. Util. Code § 2835(a).*

how certain energy storage technologies are best suited to particular applications at various points in the electricity value chain. The end-uses are summarized in the following chart contained in the August 2012 Rulemaking:

Who Are the Stakeholders in Energy Storage?

As ratepayers, of course, we all are. In California, for example, retail electricity consumers are represented by the CPUC Division of Ratepayer Advocates. Other key stakeholders in the uses, valuation, cost recovery and return on investment in energy storage systems are the independent system operators and regional transmission operators which operate the regional grids and the organized power markets, other balancing area authorities, utilities, independent power producers, independent transmission providers, distribution companies, ancillary services providers, energy storage technology companies, "technology agnostic" energy storage system suppliers, and state and federal policymakers, lawmakers and regulators. Additional interested parties include energy storage trade associations, consumer advocacy groups and environmental protection organizations.

There has been some mischaracterization of AB 2514 in the media, some of which have reported that AB 2514 will or is likely to result in energy storage mandates similar to the renewable portfolio standards or goals in place in 40 states, Washington, D.C. and four United States. territories. AB 2514 directs the CPUC to determine appropriate targets, if any, for each load-serving entity within California to procure viable and cost-effective energy storage systems. To date, the California investor-owned utilities and the Division of Ratepayer Advocates, as well as many other stakeholders, are unified in their opposition to RPS-like energy storage mandates. Certain other stakeholders, such as the California Energy Storage Alliance and the Sierra Club, support energy storage procurement targets for the reasons set forth in the next section.

Commercialization of Energy Storage and the Regulatory and Market Barriers to Its Economically Feasible Deployment

For each of the "end-uses" for energy storage, there is a market driver creating demand for that use. The challenge for regulators and stakeholders is to figure out the relationships among energy storage uses, the optimal technology for the particular use, the cost of the technology and the market value of that use.

For example, the increased penetration of renewable energy - an intermittent, variable resource – creates stress on the grid. When a cloud passes over a solar photovoltaic power plant, the sudden disparity between supply and load must be balanced by injecting additional energy into the grid, a process known as "frequency regulation." There is value for the rapid and accurate frequency regulation promised by certain energy storage technologies, but this value must be quantified, choices need to be made about what technology will best meet the need for frequency regulation, who can or should own that particular energy storage solution, and who makes these decisions.

With effective storage, energy can also be generated and stored off-peak (for example, at night when wind assets are most productive but electricity demand is low) and scheduled and discharged at peak demand times of day. This energy shifting to reduce generation costs (energy arbitrage) has a very different value than frequency regulation. Other end-uses present separate market demand and potential value to stakeholders. At the transmission level, energy storage that is used for peak capacity support can be valued at the deferred cost to add or upgrade transmission facilities. In a nodal pricing market such as California's, energy storage located in a constrained part of the transmission system will have a higher market value than energy storage located in a less congested area. At the distribution level, energy storage systems can be used for many purposes, but can be particularly valuable for automatic islanding during a grid outage, for example, in severe weather conditions or in the event of an intentional attack on the grid. Growing electric vehicle market acceptance will put more stress on the distribution system as cars are charged primarily at night, although smart-grid technologies may allow the grid operator to remotely control charging and discharging of electric vehicles and home appliances to meet system needs.

Most of the policy debate among stakeholders has focused on whether an energy storage procurement mandate should be implemented. Given the complexity of the analysis required to value energy storage systems, most utilities and ratepayer advocates oppose such mandates. They argue that mandates will fail to remove legal and regulatory barriers to cost-effective energy storage and distort the market, creating short-term profit incentives for investors and long-term dependency on those incentives. Such policies would result in a misallocation of resources to regulatory affairs rather than research and development—better, they argue, to implement policies that create a level playing field and a competitive market. On the other hand, proponents of procurement mandates argue that a statutory requirement for procurement is the best way to ensure effective implementation. Some of these proponents, including the California Energy Storage Alliance, favor mandates as a policy tool analogous to RPS targets. Others, including the Sierra Club, argue that mandates need not be based on a specific quantity of energy storage to be procured by load-serving entities, but could use other criteria such as reduction in peak load or certain air pollutants. Opponents counter that renewable energy provides non-monetary benefits to society (air pollution reduction) that justify a subsidy policy to promote the industry, even though renewables may be uneconomic when compared to fossil fuels. They argue that, unlike renewables, energy storage has location and technology-specific value, which a mandate would not capture. Parties on all sides of the debate seem to agree that the need for energy storage is here and growing. Estimates of the California ISO's storage needs to safely operate the grid in 2020 range from 3,000 to 4,000 MW (not including pumped hydro) - more than 450 times the current installed capacity of 6.5 MW.

FERC's Role in Energy Storage Regulation

FERC has jurisdiction over the sale at wholesale and transmission of electricity in interstate commerce, including the provision of energy storage services into the bulk power grid. Among other things, FERC must determine that the rates and terms and conditions under which jurisdictional services are provided are "just and reasonable." While FERC has taken a number of steps over the past few years to address the unique regulatory issues posed by energy storage, in particular with respect to the appropriate compensation mechanisms for providing storage services, it has yet to formulate a comprehensive policy. Indeed, given the multiple storage technologies and the differing benefits they provide to the grid, it is unlikely that a single comprehensive policy is warranted. FERC's efforts thus far have been in large part focused on evaluating the appropriate ratemaking treatment for energy storage projects given that the historic regulatory paradigm for the electricity industry was designed around the three traditional business functions in the industry: production, transmission and distribution. Storage does not fit neatly or exclusively within one of those distinct business models.

In 2006, FERC deferred ruling on a request by Nevada Hydro to treat its proposed Lake Elsinore Advance Pump Storage project as a transmission asset for rate recovery purposes, a request that presented an issue of first impression. FERC subsequently granted a request by **Western Grid Development**, an independent developer, to treat its proposed energy storage projects in California as wholesale transmission facilities, thereby making them eligible for the incentive ratemaking treatment made available pursuant to the Energy Policy Act of 2005 to encourage investment in transmission infrastructure. FERC announced in the Western Grid order that a determination of whether a particular storage project would be categorized as a transmission asset, at least for purposes of determining eligibility for transmission incentive rates, would be made on a case-by-case basis after evaluating the facts of a particular project.

FERC's most recent attempts to clarify the ratemaking treatment of energy storage assets have been in the context of generic rulemaking proceedings. On June 11, 2010, FERC staff requested comments from the industry on the rate treatment of services provided by storage technologies. Staff initially noted that, while the traditional functions of generation, transmission and distribution assets within the electric grid are well understood and their cost recovery mechanisms well established, the same was not necessarily true for energy storage, especially given that storage technologies are often deployed by independent developers rather than vertically integrated load-serving entities. Staff concluded that, "[u]nder appropriate circumstances, storage can act like any of the traditional asset categories, and also like load."

Based on the comments submitted in response to the FERC staff's request and to a subsequent FERC Notice of Inquiry, FERC issued a Notice of Proposed Rulemaking (NORP) on June 22, 2012. The NOPR's primary focus is on fostering the development of competitive markets for the supply of ancillary services, which are generally defined as those services necessary to support the transmission of electricity from resources to loads while maintaining the reliability of system operations. As noted by the California Energy Storage Alliance, FERC's proposals would help reduce barriers to new market entrants, including energy storage technologies, that can provide ancillary services. The NOPR also proposed to revise FERC's Uniform System of Accounts to better account for and report transactions associated with energy storage assets. FERC's current accounting regulations and related reporting requirements were developed to capture financial and operational information aligned with the industry's traditional production, transmission and distribution functions. Because storage has operational characteristics of each of these distinct functions, and can provide multiple types of services simultaneously, FERC's proposed accounting and reporting revisions would potentially enable developers of storage assets to seek multiple methods of cost recovery for their investments.

On the same day it issued the NOPR, FERC issued a Final Rule in a rule-making proceeding on the integration of variable energy resources into the grid. The increased deployment of generation resources that do not consistently produce power in relation to demand, such as solar and wind resources, has further underscored the system benefits to deploying storage assets that can be used to "bank" renewable energy for use during peak periods when demand, and prices, are highest. While the scope of the Final Rule was limited and not focused on the use of storage to firm up variable resources, it is nonetheless significant for advancing the regulatory discussion as to the optimization of such resources. The California Energy Storage Alliance commented in the proceeding that FERC should initiate a separate rulemaking dedicated exclusively to the use of energy storage to further integrate variable resources.

Of particular significance, FERC issued a Final Rule in October 2011 in a rulemaking proceeding regarding the compensation mechanism for the provision of frequency regulation in the electricity markets administered by RTOs and ISOs. Frequency regulation is generally provided by generators that respond to an RTO/ISO's automatic generator control signal, but can also be provided by storage providers that have the capability of ramping production up and down quickly. The Final Rule requires RTOs/ISOs to pay higher rates to companies that provide the fastest and most accurate frequency regulation service. While storage providers will not be the only beneficiaries of the Final Rule, FERC's policy is anticipated to play a significant rule in further encouraging the deployment of storage technologies.

While FERC has been formulating general policy with respect to the appropriate regulatory treatment of energy storage technologies to reduce the barriers to their market entry, the RTOs and ISOs and their stakeholders have been developing market rules and other structures to operationally integrate storage into their respective regions. For example, in May 2009 FERC accepted a proposal by the New York ISO to permit a new class of resources, referred to as Limited Energy Storage Resources, to participate in the day-ahead and real-time regulation services markets. In May 2010, the New York ISO issued a White Paper to further evaluate integration efforts given the statue of maturing storage technologies. Similarly, PJM, the independent administrator of the Mid-Atlantic regional grid, is currently evaluating the use of storage technologies to meet NERC reliability standards.

Another policy measure to promote energy storage at the federal level is the planned re-introduction of a bill in Congress that would allow a 20 percent investment tax credit for energy storage projects connected to the grid. According to recent media reports, the goals of the tax credit are to manage peak load needs more efficiently and to encourage the continued growth of renewable energy.

Conclusion

The regulatory and policy regimes that will determine the future of energy storage in the United States are just beginning to take shape. At this point, active participation of all stakeholders—public *and* private—is critical: given the numerous applications, evolving technologies, competing market interests and complex analysis required to optimize energy storage implementation, a flexible and holistic strategy that combines bottom-up and top-down approaches, accounts for the interests of all stakeholders, and incorporates inter-agency knowledge sharing is necessary. Such a strategy would include the use of pilot projects, coordinated multiagency rulemaking and market and stakeholder feedback based on real-world experience. Using a flexible approach in which regulations can be adjusted based on operational experience and cost-effectiveness would avoid the pendulum effect of unilateral decision-making and provide the highest and best value for all energy storage market participants and consumers.

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UK Law on Decommissioning of Petroleum Installations

By Marc Hammerson and Anthony Martinez

1. Background

The United Kingdom has a long history of petroleum production. Oil was extracted from shale in Scotland as early as the nineteenth century. The United Kingdom became a significant oil-producing nation with the discovery of oil in the North Sea in the late 1960s. Output peaked in 1999 – and the country is now considered a mature oil province. Because of the United Kingdom's long history of hydrocarbon production, many fields have now been decommissioned (in whole or part) or are subject to decommissioning programmes.

The United Kingdom's legal and contractual framework allocates costs and risk associated with decommissioning through a hierarchy of obligations. Governmental commitments contained in international conventions are implemented by domestic legislation. Statute, primarily contained in the Petroleum Act 1998 ('the 1998 Act') as well as the Energy Act 2008 ('the Energy Act'), provides a framework for these obligations to be enforced. However, the 1998 Act does not provide detail on the method, timing, entirety or quality of performance. This is determined on a case-by-case basis in decommissioning programmes agreed between parties responsible for decommissioning and the Department of Energy and Climate Change ('DECC'). The statutory framework grants DECC discretion to decide on whom to serve notices of responsibility, the contents of a decommissioning programme and verification of performance. Government policies on standards to be included in decommissioning programmes (and subsequently required to be performed) can be derived, more generally, from DECC-issued guidance notes ('Guidance Notes'). Based on this statement of government practice, commercial parties can allocate responsibility amongst themselves, estimate likely future costs, make financial provisions for these costs and put in place contingencies for counterparty default.

2. UK law on decommissioning

Government has a choice of instrument to enforce its decommissioning policy: statute, soft law, statutory instrument and licence model clauses. However, DECC chooses not to rely on the last two instruments.

The 1998 Act is the primary legislation governing decommissioning in the UK. The decommissioning process begins with the service of a notice ('the Section 29 Notice') on parties with potential liability for decommissioning. This asks them to submit a decommissioning programme providing information required to be contained by the 1998 Act. The Guidance Notes provide advice on both the process and the content of the programme. The Secretary of State may approve or reject a decommissioning programme conditionally or unconditionally and with or without modifications. The 1998 Act also contains a variety of sanctions to compel those with liability for decommissioning to comply with their obligations.

A Section 29 notice may still be served even after the decommissioning programme has been approved in cases where the approval is withdrawn. Moreover, the Secretary of State retains a degree of flexibility to amend the decommissioning programme and to add or release parties. Once the programme has been approved, the parties are jointly and severally liable to implement it.

The Secretary of State's right to serve a Section 29 notice on anyone who could have been served a notice (even after the date when the first Section 29 notice was issued or the programme approved) means that non-served parties never fully escape liability until the installation has been fully decommissioned in accordance with the plan. Likewise, the withdrawal of a Section 29 notice does not guarantee that a released party will have no decommissioning responsibilities. Parties must, therefore, allocate potential liability amongst themselves by including provisions in sale, joint venture and decommissioning security arrangements.

3. Enforcement

If a decommissioning programme is not carried out, the Secretary of State may serve notice. A person who fails to comply with a notice is guilty of a criminal offence unless he/she proves that he/she has exercised due diligence to avoid the failure. If a notice is not complied with then, the Secretary of State may carry out remedial action.

In addition, the Energy Act introduced a new provision in the 1998 Act allowing the Secretary of State to require more specific information to be provided, including: a detailed estimate of the costs of decommissioning; predictions of future revenue; the costs and benefits of any plans for further development; or current management accounts. This information enables the Secretary of State to assess whether to require financial security to be provided.

4. Gas storage and carbon capture

Demand for natural gas in the United Kingdom is highly seasonal and storage has long played an important role in smoothing supply. Storage technology has been used at gas fields for several years.

The importance of gas storage will continue to grow as UK production declines. This fact is acknowledged by the amendments introduced by the Energy Act, which put in place a licensing regime in respect of gas storage that operates on the basis of the same three-phase approach (exploration, appraisal and development and operation) used for petroleum production licences. The effect of the amendments made to the 1998 Act by the Energy Act (and further amendments which may be introduced in the future) is to create a standard regulatory framework for decommissioning, gas storage and carbon capture and storage.

5. Residual liability

The possibility of partial decommissioning creates the risk that an installation left partly in place will pose a danger to shipping. Because no contractual relationship exists between the persons responsible for decommissioning and an injured claimant, the risk of damage caused by leaving installations partly in place could arise in tort only and, in particular, through the tort of negligence.

However, certain factors suggest it is likely that residual liability will be significantly mitigated if the decommissioning programme has been implemented correctly and other obligations set out in the Guidance Notes are complied with, including notifying the United Kingdom Hydrographic Office of a change in status of decommissioned installations and pipelines as well as installing and maintaining navigational aids.

In addition, the UK oil and gas industry, through Oil & Gas UK, has undertaken various initiatives to mitigate the risk to the fishing industry stemming from partly decommissioned installations.

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Iraq Energy Infrastructure
An Update

By Shawn Davis and Essam Al Fraihat

Oil and Gas Infrastructure

Iraq is a global energy player — it has the world's fifth-largest proven crude oil reserves and, by the end of 2012, surpassed Iran to become the second-biggest producer of crude oil within the Organization of the Petroleum Exporting Countries (currently producing approximately 3.15 million barrels per day). Five years ago, international oil companies in Iraq tended to invest for generally short-term production returns. Now, as a consequence of reforms of the Government of Iraq, including its Ministry of Oil, designed to ensure the long-term success of the Iraq oil and gas industry, international oil companies are far more focused on long-term projects to develop permanent infrastructure, which is encouraging since Iraq's energy infrastructure is often classified as deteriorating and requiring large amounts of capital for upgrades in combination with greenfield investments.

According to Iraqi Oil Minister Abdul Kareem Luaibi, the Government of Iraq plans to invest at least US$170 billion over the next 5 years to increase oil production in the country. As part of these investment efforts, Iraq plans to invest in its oil and gas upstream activities and refineries to increase oil production to 8.9 million barrels per day by 2018.

Iraq faces many challenges in increasing oil production since its refining and export infrastructure is severely constrained; but it has been slowly making progress in its efforts. For example, capacity in southern Iraq was expanded in 2012 with the commissioning of a single-point mooring system. Iraq plans to install 4 more such systems by 2014.

Other plans include a new export pipeline from Basra to Haditha in northwest Iraq and another from Haditha to the Port of Aqaba in Jordan. The existing strategic pipeline, which transports oil from northern to southern Iraq, is materially damaged and is being repaired. In addition, the country's small and older refineries require capital urgently and the construction of 5 new refineries is planned over the next 10 years.

Iraq will also have to increase natural gas injection to maintain oil reservoir pressure to increase oil production. Associated gas that is currently being flared (Iraq is one of the five largest natural gas flaring countries) could potentially be used for this purpose.

Steps to increase production will have a flow-through effect in the country's economy and will need to be met with a corresponding expansion of transport, storage and export facilities.

Power Infrastructure

The Government of Iraq plans to spend approximately US$27 billion on electricity projects by 2017 with the goal of increasing power production. This investment is needed to upgrade, repair and replace power plants, substations and transmission lines damaged over the past 25 years in addition to providing investment for new power projects.

While recent years have seen notable growth in net daily production, demand still outweighs supply in Iraq, with just over half of the power demand currently being supplied. It is an immediate priority of the Government of Iraq to build a modern electricity system with sufficient generation capacity to stop the daily occurrence of power outages and the extensive use of back-up diesel generators. While Iraq is seeking to end power shortages, it has encountered many challenges including feedstock shortages and delays in tender processes.

To increase the efficiency of existing infrastructure, plans currently exist in Iraq to repair older power plants and convert single-cycle power plants to combined-cycle plants. In addition, Iraq is looking to generate 400MW of electricity, by 2016, by relying on renewable sources of energy, which would amount to approximately 2 percent of Iraq's total power generating capacity. Initial projects will focus on solar and wind, and, eventually, biomass technologies will be exploited as well. Bids are currently under consideration for the first stage of this renewable power program.

Challenges

Years after the fall of Saddam Hussein's Baathist regime, Iraq remains one of the poorest Arab countries in spite of its vast oil and gas resources and governmental efforts to expand such resources.

In addition to the numerous challenges Iraq faces to further develop its energy infrastructure, corruption (Iraq is ranked 169 out of 174 countries and territories in the 2012 Transparency International Corruption Perceptions Index), political instability, disagreement between Federal Iraq and the Kurdistan region of Iraq with respect to the development of oil and gas assets, sectarian violence, sabotage and relatively limited investment in human capital in Iraq inhibit economic and institutional progress.

In order to achieve its lofty goals to further develop its energy infrastructure, Iraq will need to make substantial and ongoing progress in ensuring political stability, enhancing security and investing in human capital.

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Mexico's Power Sector Attracts New Investors

Opportunities abound in the Mexican energy market as investors rediscover one of Latin America's breakout markets.

By Dino Barajas

Photo courtesy of Element Power's Macho Springs I Wind Project

Opportunities abound in the Mexican energy market as investors rediscover one of Latin America's breakout markets.

Forget sluggish economies in the United States, the European Union and certain Asian countries; Mexico has emerged as a lightning rod for international infrastructure investment. As energy investors assess changing global opportunities, Mexico continues to offer numerous stable investment prospects. Mexico's investment-grade credit rating provides potential investors one of the few high quality investment environments in Latin America.

The Mexican economy has been bolstered by the strong international demand for its commodities and a competitive labor force favored by numerous U.S. industries following a re-evaluation of a production chain previously outsourced to China.

As a result, continued economic growth has strained Mexico's power generation and transmission systems. The long-term relative stability of Mexico's economy provides investors with safe, profitable power sector development opportunities. Savvy political technocrats in the country are using the current investment window to attract foreign investors.

With a change in administration following last year's presidential election and a push by the federal government to further modernize the country's infrastructure, Mexico's power sector will continue to provide opportunities for private equity investors, development companies, construction companies and lending institutions. One of the challenges is to understand the inherent risks of investing and operating in Mexico.

During the 1980s and 1990s, Mexico was a darling of the investment community. Many region-specific private equity funds emerged. Infrastructure development companies formed dedicated Latin American teams. But as competition for infrastructure development grew and profit margins declined, investors and developers soon turned to other markets — such as Eastern Europe, Russia, the Middle East and Asia — that were experiencing infrastructure development booms and offering more profitable investment opportunities.

Investors and developers also looked to the U.S. and Europe, which were experiencing economic prosperity and an aggressive infrastructure build-out. With this shift in regional focus, many private equity players and developers deemphasized their capital deployment efforts in Latin America and disbanded their "LatAm" teams.

The demise of these region-focused teams meant a loss of institutional knowledge for these firms and an opportunity for smaller regional developers to gain a foothold in Mexico. Now, as large institutional players return to the region, successful firms will need to retain external advisers with a deep knowledge of the Mexican market in order to judge market opportunities and investment risks.

The sharp reduction in power sector opportunities in the U.S. and Europe has catalyzed recent interest in Mexican power. Mexico's power sector has attracted attention from foreign investors, who have developed large fossil fuel-fired power plants, the culmination of 20 years of work by the country to leverage its strong credit rating and stable economic growth to attract investors.

In the early 1990s, the Mexican government embarked on a massive infrastructure build-out program in its electricity sector. Mexico developed a well-defined legal framework to permit private investors to participate in the development and ownership of power generation facilities to supply the national electric utility, *Comisión Federal de Electricidad* (CFE), as well as large direct industrial customers. The CFE independent power project (IPP) program has become one of the most effective international power plant development programs anywhere in the world.

The speed of power plant deployment and the low costs associated with the long-term energy pricing demonstrate the competitive and transparent bidding environment which CFE has fostered. CFE's IPP program allowed the government to refocus its own capital investments in the national transmission grid.

Private sector thermal power plant developments are the foundation of Mexico's modernized power sector. By promoting gas-fired plants to replace aging diesel and oil-fired units, Mexico has achieved cleaner burning facilities and reduced the country's carbon footprint and inventory of conventional pollutants. Controlling the size and locations of the plants in each IPP request for proposals, CFE has been able to strategically leverage private investor funds to meet the public demand for electricity in regions of the country in greatest need of additional power generation capacity. During the last 18 years of Mexico's IPP program, CFE has targeted power generation development in the most power starved regions of the country.

An unintended shortcoming of CFE's otherwise successful IPP program has been pressure on the country's natural gas supply. During the course of two decades, Mexico moved from a natural gas exporter to a net importer. Natural gas demand has increased to the point that Mexico has had to promote liquefied natural gas regasification facilities throughout the country (including in Altamira, Baja California and Manzanillo) to augment its domestic supplies. In order to accommodate new entry points for natural gas supplies, the Ministry of Energy will need to expand Mexico's vast pipeline network.

Similar to the activity in the U.S., Mexico has seen a surge in activity surrounding renewable energy. CFE has been addressing issues of wheeling power, which hindered the past development of renewable power projects. CFE's preexisting wheeling structure failed to account for wind's intermittent nature and penalized wind power projects for failing to produce a stable, constant electricity supply. Today, CFE's wheeling arrangements account for wind power's intermittency. CFE has created a system where a renewable energy project can "bank" excess energy production during periods when an off-taker does not require energy from the project and allow the user to access the "banked" energy during periods when the power project produces insufficient energy to meet the user's needs. Additionally, postage-stamp wheeling charges earmarked solely for renewable energy have benefited renewable energy production. As a result, buyers of wind power see energy sale rates that directly compete with fossil fuel generated energy.

The true test of whether the projects are viable is determining if third-party non-recourse financing is available. In Mexico, commercial lending institutions are actively looking for lending opportunities to well-structured infrastructure projects. Multilateral lending institutions, such as the International Finance Corp. (IFC) and the Inter-American Development Bank (IADB), are also working in the Mexican market with creative financing structures.

In addition to multilateral financing institutions and commercial lenders, international development banks, such as FMO (the Netherlands), have supported infrastructure projects that promote certain economic, environmental or social objectives. Some international development banks have even prioritized the Mexican market as a target lending environment in order to spur the development of various projects, such as renewable energy power plants.

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Renewable Energy in Korea to Face New Standards

Impact of the Renewable Portfolio Standards (RPS) on Market Outlook

By Albert Suh

When the Korean government introduced the Renewable Portfolio Standards (RPS) last year to replace the existing system of feed-in tariffs (FIT) many industry observers predicted a decline in investment in the renewable energy sector. Prior to implementation of the RPS, energy firms, through the assessment of FIT, had received subsidies to cover the difference in costs of producing electricity from fossil fuel power generation and RE. In contrast, the RPS now requires that certain energy utilities generate a mandatory supply of electricity from RE sources.

Under the RPS, the "renewable portfolio" for power generators having a capacity of at least 500 MW was set initially at 2% in 2012, with the rate increasing by 0.5% annually until 2016, and by 1% annually until 2022 (up to 10%). Currently, there are 13 state-run and privately-owned companies that fall under the regulatory scope of the RPS. To address concerns that solar energy technology was less economically viable, the government provided for carve-out provisions relating to solar energy quotas, effective from 2012 to 2016.

The rationale for the change in policy was that while FIT purported to lower the entry barrier for participants, it led to the overheating of fields such as solar energy and wind power. The RPS is viewed to be more effective in spurring competition and innovation, as well as allowing for prices to be determined by market forces. It will also likely relieve financial pressures on the government. However, whether the RPS will be able to invigorate the RE market in Korea is still in question, as sales performance of local RE firms in 2012 was down from the previous year.

There have been some signs that the RPS system will eventually serve as a stimulus for investment. Notably, Hanhwa SolarEnergy, an affiliate of Hanhwa Chemical (a member of Hanhwa Group, one of the largest conglomerates in Korea), was reported in February to be consulting Korean module manufacturers for OEM production of solar modules as the company expects the RPS to increase demand for solar energy. Hanhwa's push for domestic production of RE equipment is a bold move, and the first made by a major Korean corporation in 2013.

Other firms are less confident. Since President Park Geun-hye was sworn into office earlier this year, have been mixed predictions as to the new administration's stance toward RE. The campaign pledges of President Park had placed more emphasis on nuclear power generation, and Park, known as a fiscal conservative, could potentially steer toward a reduction in the RE budget. The outlook for the domestic RE market in 2013 will therefore depend largely upon the level of risk that those firms remaining on "standby" are willing to take in responding to the requirements of the RPS.

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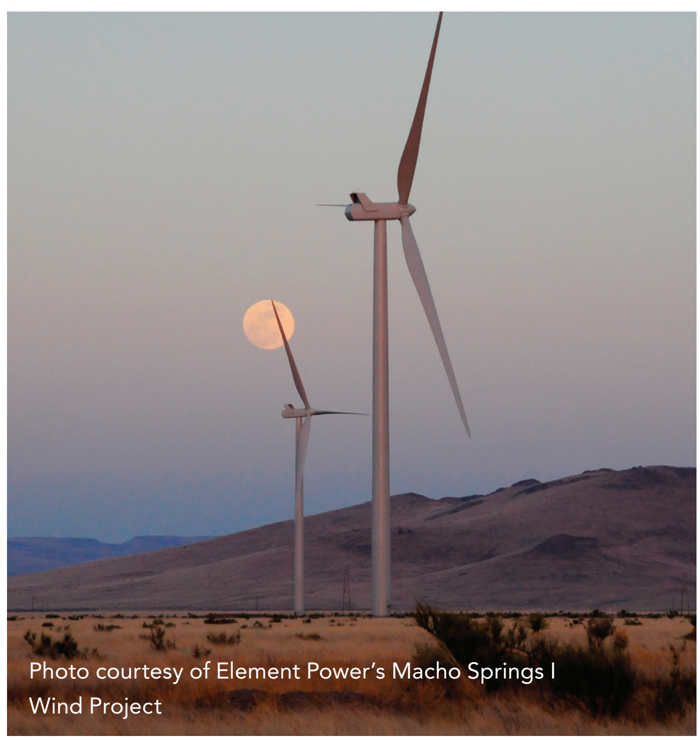

Photo courtesy of Element Power's Macho Springs I Wind Project

Effective Feedstock Management is Essential to a Successful Biomass Conversion Facility

By Michael Keller and Elliot Hinds

Although wind and solar power tend to dominate attention in the renewable energy market, biomass represents a significant portion of the market and is growing rapidly. Biomass feedstocks currently supply an estimated 14 percent of global primary energy.[1] Wood and waste biomass power alone accounted for approximately 30 percent of the renewable energy produced in the United States in 2012.[2] The Energy Information Association also estimates that biomass will be one of the fastest growing renewable energy resources in the United States through 2035, with a projected annual growth rate of 6 percent.3

Biomass also has a wider range of implemented uses than most renewables from producing electricity (using a variety of processes and including the ability to provide baseload power), space and water heating and transportation fuel. In addition, distributed power generation fueled by dedicated energy crops or crop residue can support conversion technologies in areas where the sun or wind may not be sufficient to support an economic renewable energy project. Fallow land can be utilized at rates far below those charged for fertile farmland, and some dedicated energy crops such as jatropha or miscanthus can be grown in poor soil not capable of supporting a food crop. In highly fertile areas such as the Mississippi Delta and the Midwest, crop residue can be obtained for relatively low costs since the grower is getting paid for his crop, and is not relying on income from the plant material left over after harvest. Hence the low cost availability of feedstock pared with

[1] *Source: Pike Research*
[2] *Annual Energy Outlook 2012, U.S. Energy Information Administration (June 2012)*
[3] *Id.*

higher electricity rates and/or mandates from renewable portfolio standards (RPS) can make a biomass conversion project financially attractive.

Feedstock is the Lifeblood

Biomass and biofuel projects have three distinct operational components: the feedstock (upstream), conversion of the feedstock into the useable fuel (mid-stream) and the offtake of the useable fuel and any other byproducts (downstream). Being on the front-end of the process, feedstock is the lifeblood for any conversion project because if there are any interruptions, even for short periods, the operations, and therefore financial performance, will be adversely affected. One of the most significant challenges for any biomass project—and according to experts, a major challenge to the industry's growth—is the access to a reliable supply of feedstock.[4] For this reason the efficient structuring and management of the project's feedstock arrangements deserve the close scrutiny of all involved in the biomass/ biofuel project.

There is great diversity in feedstock—in terms of its characteristics when it is to be used and the process it undergoes in order to be usable as feedstock. Figure 1 describes some of the processes required for bioproducts to become usable feedstock.

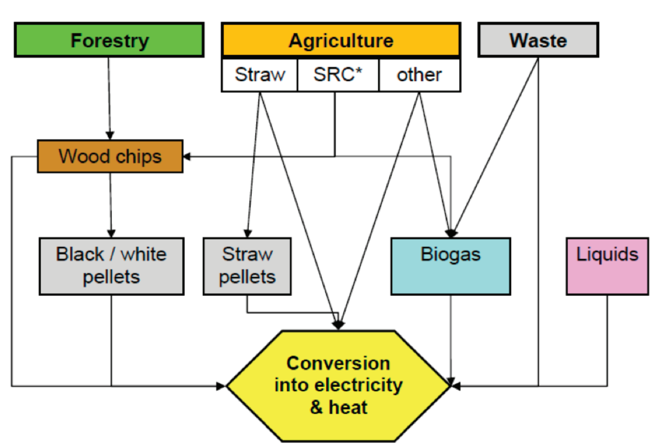

Figure 1: Overview of biomass primary resources input into electricity and heat production (SRC= short rotation coppice)*

Source: Biomass 2020: Opportunities, Challenges and Solutions, Eurelectric (October 2011)

We think it is useful to conceive of the central components of a successful feedstock arrangement as being "double QC:" Quantity, Consistency, Quality and Cost.

[4]*Access to Feedstocks Remains a Key Barrier to the Growth of Biopower, Pike Research (June 14, 2012)*

Quantity

Facility size will be most directly tied to the minimum quantity of fuel that is available. Fuel production will be determined by the quantity of feedstock that is available. Developers and financiers have to evaluate the available suppliers and scrutinize those suppliers' ability to meet the conversion facility's tonnage demands. Even for a supplier with a long and strong track record along with financial strength, it will be important to carefully examine the supplier's historical production (on an annual, monthly and even daily basis) along with the factors that could impact that supplier's ability and willingness to maintain feedstock supply according to its historical levels.

It is well known that weather (most notably, heat wave/ drought, flood, insect infestation, fire and hurricanes) creates real and direct risks to feedstock supply quantities. However, the wise conversion facility developer also will conduct a piercing evaluation of the supplier's motivations. Crop economics differ from supplier to supplier—in some situations, a feedstock supply contract relieves an existing cost but in others, the supplier has competing uses for that feedstock which may create an increased risk of that supplier breaching for better economics. It is difficult to obtain meaningful credit support from feedstock suppliers so the conversion facility needs to protect itself by using market intelligence and back-up planning. Back-up planning is useful whether there is a supplier breach or a change in land ownership (through death, bankruptcy or otherwise), and it covers a broad array of possibilities from recording the facility's interest in the feedstock in the land records or obtaining a land purchase option (that would be binding on the current or future owner of the land) to establishing firm or optional arrangements with alternative suppliers.

Know Your Grower's Market: A Lesson: In recent years a variety of biofuel and green chemical technologies have emerged that require sugar or a byproduct from processing sugar as its feedstock. One such company decided to convert a chemical processing plant (known as a "brownfield project") for very understandable economic reasons. The plant literally was surrounded by thousands of acres of sugar cane and it was managed by a strong growers' cooperative. The site was purchased, and the work commenced without a careful consideration of what the cane growers were doing with their crop. It turned out that virtually 100 percent of the crop was pre-sold to various candy manufacturers, several of which were owned by the growers themselves. Understandably the cane growers were reluctant to sell to anyone else, or even have another buyer at all, since the increased demand could result in increased prices due to competition. This type of vertically integrated scenario made obtaining any feedstock far more expensive than the conversion facility expected resulting in considerable additional costs associated with obtaining and transporting the sugar cane from outside of the intended area.

The frequency and duration of scheduled interruptions also will be important to know and those expectations along with notice requirements and coordination provisions should be an established part of the supplier/conversion facility relationship. What is the supplier's history of equipment failure or other unscheduled supply reductions or interruptions? Can the supplier maintain its feedstock supply quantities during its production shutdowns? If a cannery experiences a shutdown, for example, it still may be able to deliver the fruit and vegetable feedstock but the composition might change from being just production byproducts (e.g., rinds) to the entire fruit.

Mitigants Against Supply Interruptions: A number of mitigants can be implemented to protect against supply chain interruptions. One of the most obvious is to contract for excess supply quantities (often at a 2:1 margin). The conversion facility may be able to obtain that excess from the primary feedstock supplier. Excess either can be acquired in advance and stored or obtained on an as-needed basis. To enhance operational certainty and alleviate financiers concerns about access, providing adequate storage is generally required. The best practice will be to place the storage facility on the conversion facility's site rather than with the feedstock suppliers. Not surprisingly, the capital cost (real estate and equipment acquisition) and operational logistics and costs of storage should be examined carefully to preserve the quality of the biomass material and to reduce the risk of fire and release of dangerous gases. In addition, the conversion facility's storage should be designed to optimize density. For example, if the conversion facility requires 100,000 tons per year (tpy) of baled switchgrass, the bales will be required to be kept dry. Calculating the size of the storage area depends directly on the bale density.

Whether or not storage is integrated, the developer also should evaluate whether secondary suppliers are readily available to the conversion facility and the extent to which those secondary suppliers are likely to be affected by the same circumstances as the primary. A secondary supplier would be a good mitigant against equipment breakdowns since those are less likely to impact multiple suppliers at the same time. But a nearby secondary supplier with the same feedstock may not serve as a good mitigant against adverse crop conditions or problems that occur in the market for that supplier's goods. Additional considerations associated with accepting feedstock from another supplier are differences in feedstock composition (see "Quality" discussion below) and managing possible fric-

tion associated with the suppliers being competitors with one another.

Transportation & Logistics: The facility's ability to efficiently receive the supply also requires a careful examination of transportation logistics and facility design from the feedstock supplier to the point of use including trucking (or other transportation) availability and cost, road quality and capacity, and how the feedstock is packaged (loose form, bundles, bales, bags, pellets or other form), delivered and off-loaded at the conversion facility site. The delivery time schedule also may be important from the standpoint of permitting (e.g., road use may be limited by permit) or efficient facility operations. The developers of the facility must consider how logistics and design will be affected if back-up or secondary suppliers are used more heavily because of interruptions in supply from the primary suppliers. These criteria can impact where the facility can be or should be built.

Other Considerations: While most focus is placed on potential reductions in feedstock, increases in the supplier's feedstock supply also need to be examined as both an opportunity and a challenge. Will the conversion facility be able to accept, store and use the increased amount of waste? If the supplier has other uses for the feedstock, it may insist upon a right to divert quantities for that other opportunity but if the supplier considers the feedstock to be a nuisance, it may require the conversion facility to take the entire feedstock. The facility therefore will have to calibrate the impact of those approaches throughout the operational and cost chain for the facility.

Consistency

We believe it is appropriate to distinguish the consistency of supply from quantity in order to maintain focus on the typically delicate nature of feedstock. Whereas traditional fuel sources are not seasonal, most biological feedstock has some seasonal or harvesting timetable associated with it. Whereas feedstock can be stored, it can be accomplished under carefully maintained conditions and still has a maximum "shelf life." Consistency of supply may impact quantity or quality of feedstock or both.

Leading strategies for improving the consistency of feedstock supply include:

- using perennial crops (can be harvested without the need for replanting) rather than annual crops;
- using fast-growing crops (such as switchgrass);
- diversifying feedstock suppliers by supplier identity, type of dependent crop or both;
- including in the feedstock supply agreement special notice and observation rights and potentially step-in rights during any critical "harvest windows" so that problems are addressed immediately;
- accounting for excess available supply that can serve as a form of storage and protection against underproduction. Ideally, the conversion facility will be able to contract for more supply than it needs—it should include the rights to obtain that excess supply in its feedstock agreement; and
- incorporating new technologies especially to improve the amount of BTUs per ton and make the material more moisture resistant.

These strategies do not come without complications. For example, in the case of diversifying feedstock by type of dependent crop supply, a year's supply of feedstock probably will still be subject to seasonal impacts; tomato waste will be supplied only while they are producing in the fields, while other crops such as wine grapes, olives or nuts would be on different seasonal cycles. Seasonal cycles vary in length requiring thoughtful storage planning and operations execution to maintain the facility's volume requirements and evenly manage the changing composition of the feedstock.

The term length of a feedstock agreement is also an issue of consistency and often a significant stumbling block with suppliers (particularly farmers). Many suppliers view 18 months as an appropriate term of agreement , which is far too short to finance nearly any conversion facility. Therefore, the developer may need to explain why a seven-year, 10- year or even longer term is necessary and why the supplier's termination rights are subject to extended notice and cure rights in favor of the conversion facility and its lenders.

Quality

The quality or composition of the feedstock is critical to the viability of nearly all biomass facilities. This important issue frequently leads to a "chicken and egg" dilemma during the planning stage: The facility wants to secure long term supply agreements as quickly as possible to facilitate financing, but it and its investors want to avoid firm purchase commitments without as much qualitative data as possible. Quality tends to be easier to control in the case of a dedicated crop or crop residue.

The qualitative measures fall into two general categories: moisture content and chemical content.

Moisture content is an extremely important component of quality. The lower the moisture content, the higher the BTU level. The conversion facility typically applies moisture standards to biomass. Too much moisture adds unnecessary cost to the buyer because the weight of the feedstock increases, raising the price without a corresponding increase in volume. Furthermore, excessive moisture can reduce efficiency especially for conversion combustion technologies. A relatively high moisture rate also will cause some feedstock to begin to compost such as with bale plant material. The bales will begin to heat up from the inside, and can ignite, with catastrophic consequences. Bale fires are relatively common and are always costly, so careful attention should be paid to moisture content.

Figure 2: Bale Fire

Buyers of organic feedstock also need to know the chemical composition of the material before committing to a purchase order. Fertilizer can lead to emissions in some conversion technologies. Some woody biomass contains chlorides, which, if co-fired with coal in a boiler results in chlorine gas, a lethal substance. The timing of the application of various fertilizers and soil inputs can affect emissions as well.

In the case of anaerobic digestion facilities, the byproducts they produce include raw biogas used for power generation as well as a solid component called "digestate." Digestate has a commercial value as fertilizer, and can be returned back to the soil or sold to a third party. This positive resultant has value that should be accounted for in the pricing of the arrangement.

Quality of feedstock also carries regulatory implications. In recent years many US developers desiring to take advantage of the increasing demand from European utilities began exploring the best way to create a product capable of being "co-fired" with coal. This new and surging demand for biomass was driven by a mandate from the European Union to reduce greenhouse gas emissions. One requirement was that the biomass must be derived from a sustainable source. Timber production in the United States is not considered sustainable by the EU, so that meant that ag-based biomass was the only near term solution. Ag-based solutions included dedicated energy crops such as miscanthus or switchgrass, but crop residue required a more complicated analysis.

Cost

Clearly the cost of feedstock will be a central point in the establishment of any feedstock arrangement and in determining the economic viability of the conversion facility because of its direct impact on the price of the facility's end product (whether power price or biofuel price).

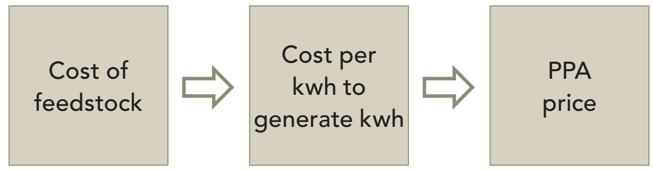

Figure 3: Feedstock Feeds into Price of the End Product

The cornerstone of the feedstock price (often referred to as a "tip fee" or "tipping fee") is volume (price per cubic meter or ton). However, several other factors should be taken into account in determining the feedstock price formula:

- the level of reliability being required of the supplier and replacement costs in the case of under delivery;
- the supplier's future disposal costs;
- Adjustments for qualitative differences in deliveries including additional processing costs due to quality deficiencies (and, if required by the supplier, bonuses for exceeding qualitative measures);
- transportation costs and logistics (a common goal is to have 100% of its feedstock available within a 10 mile radius);
- storage costs including operational and insurance costs as biomass can be combustible and emit harmful gases;
- finance costs; and
- proper adjustments for future changes in the foregoing items such as indexing for inflation or commodity price changes (e.g., if a particular additive is needed for storage or to adjust for qualitative differences, price changes in that additive should be considered).

Again, knowing the supplier and its macro- and micro-economics can provide vital information for structuring the cost arrangement. Some feedstock arrangements can be structured as forms of financing for suppliers by being a consistent cash source or cost offset that may bridge its main end product payments. If that is the case, the financing costs should be factored into the feedstock price.

We advise the exercise of caution before contracting to accept all feedstock output from a supplier. Such an arrangement could result in unintended excess due to wildly abundant crop in one or more season(s) or technological changes that impact output. Therefore, a ceiling and a floor on quantity, cost or both always are recommended in order to preserve the facility's economic projections.

The conversion facility should minimize "touches" to the feedstock because costs tend to increase with each "touch" (often each "touch" adds $10 of cost per ton of the feedstock). Each segment of the supply chain should be carefully studied to determine ways in which transfers can be made more efficient. For example, using containers for shipping and storage can significantly reduce loading and unloading costs.

Using a "closed loop" system can lead to an extremely efficient conversion project. The "closed loop" system is one in which the conversion facility is built adjacent to a facility that produces a byproduct that can be used as feedstock. The conversion facility turns that "waste" material into power that is then sold back to the host facility. A good example of this is a food packer that uses fruit to make its final product. There is typically organic material that is not usable and is disposed of, usually at a cost to the manufacturer. The conversion facility developer proposes that the host facility pay the developer a tip fee to use the waste for energy conversion instead of paying a trucking company to haul it to the dump. The conversion facility uses the material to produce power and then sells that power back to the host, thereby creating a "closed loop system."

- Applying the double QC approach, a closed loop conversion facility needs to understand:
- how much feedstock the host facility generates in a year (It may not generate enough material to make the project financially feasible);
- the seasonality of the supply (It may produce a sufficient quantity, but is it available year round?);
- the consistency of the quality over time;
- the willingness of the host to pay the tip fee all year and the risk the host may find another party willing to buy the material or at least take it for free.

At face value this type of arrangement makes a lot of sense, but areas of concern include interruptions of feedstock due to scheduled and unscheduled maintenance, season supply issues due to weather, acts of God etc. Further, if the conversion facility is providing baseload power back to the host, (or a third party in an open loop scenario) what is their backup plan if you fail to supply the required power? Often the local utility will charge a sharply higher cost per kilowatt to be on standby, and higher still if it is required to deliver power.

Conclusion

It is of paramount importance to completely and thoroughly understand the feedstock supply chain in order to design a supply agreement that will meet a conversion facility's needs. While it is tempting to lock up the feedstock arrangement as early as possible, a wise course would be to finalize it when there is clear visibility in other key areas such as land acquisition, construction design and transportation costs so that unknown costs are not borne by the conversion facility. In highly competitive markets, greater attention should be placed on liquidated damages for breach, confidentiality and trade secret protection as well.

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