After the storm

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The failure of Enron, the California electric sector crisis, the recent sharp decline in electric power prices, scepticism regarding complex financing structures and the general weakness of the economy have converged in the past year to create a dramatically different and extremely challenging environment for participants in the US energy industry.

Regulatory considerations

Enron's demise and the new focus on credit quality in the energy sector have led many to speculate that the momentum favouring electric sector ?deregulation? initiatives will inevitably stall. Thus far, however, there seems to be broad consensus that energy markets have dealt remarkably well with the failure of Enron, the largest energy trader. Several FERC Commissioners have publicly rejected the notion that Enron's demise is the death knell for competition in energy markets or justifies nationwide reimposition of traditional cost-based regulation of electricity. They see Enron's failure as being unrelated to electric industry deregulation.

Though some state representatives have argued to the contrary, and some state legislatures have slowed the pace of their state's deregulation efforts, it appears that most acknowledge that there is no going back to an electric power sector in which competition is forbidden and regulated utilities alone are permitted to provide required energy supplies and delivery infrastructure. The US Supreme Court's recent affirmation of FERC's imposition of ?open access? requirements on the transmission of power as part of unbundled retail transactions appears to give the upper hand to federal policymakers pursuing the continued restructuring of the electric power industry (see New York v. FERC, Nos. 00-568 and 00-809, 535 U.S. ___ (Mar. 4, 2002); 70 U.S.L.W. 4166 (Mar. 5, 2002)).

FERC policy favours the development of Regional Transmission Organisations (RTOs) that would have oversight and control over electric transmission networks in most parts of the US. FERC is prepared to lean quite heavily on electric utilities to adhere to its RTO program, in ways that could constrain the expansion of some integrated utilities that would otherwise appear to be in a position to capitalise on the current weakness of other independent power industry participants. For example, FERC has proposed to deny generators authorization to charge ?market-based? rates (as distinct from ?cost-based? rates established through traditional cost-of-service calculations) for sales of their output in markets served by its utility affiliate where the utility affiliate is not a member of an RTO and appears to have market power. If FERC were to carry through with this proposal, several of the electric utilities most likely to seize the initiative and expand their presence in the independent power sector (through acquisitions) will be unable to participate as independent generators in their home markets, but will be forced to look for opportunities outside their traditional service areas. Thus FERC could indirectly limit the degree to which certain players will be able to concentrate their holdings in the independent power sector.

Regardless of the trajectory of regulatory change in the energy sector, it is abundantly clear that in light of recent events (e.g. California's attempted abrogation of power contracts entered into during its crisis period), regulatory considerations have taken on a renewed importance in energy sector acquisitions and financings. The stability and predictability of the regulatory regime under which energy assets will be operated, perhaps taken slightly for granted before recent events, will once again be an important element in the calculus of would be acquirers and developers.

Power sale paradigms ? a return to the past?

In the past several years the emphasis in the energy sector has moved sharply away from long term power sale agreements as the most common foundation for project development and financing, to a bias toward ?merchant? plants selling into the wholesale market unburdened by long term contracts and able, through marketing arrangements, to compete for short-term, medium-term or long-term market opportunities. Many of these facilities became the basis for the development of large scale energy trading operations which benefited from the inherent optionality of owning generating assets. Given the dramatic fall in electricity prices in the past year, the confidence of developers and the financial community in forward price projections has been soundly shaken. Until a substantial reversal in this trend occurs, it is apparent that a merchant power facility, particularly on a stand-alone basis, will be an unattractive development or financing prospect. Projects will need to mitigate price risk through any combination of tolling arrangements, power purchase agreements, or arrangements that otherwise lock in positive margins. Groupings of projects into portfolios that combine facilities operating in different markets with different risk profiles may also be employed. Finally, we have seen some recent proposed transactions in which a creditworthy sponsor absorbs the risk of cash shortfalls arising from power market conditions through capital support or similar arrangements. Some form of these protections may be necessary to obtain financing or investment commitments in the near term.

The availability of market based rates, which had become a relative certainty in recent years, may be subject to new limitations. FERC recently announced a new market power test called the Supply Margin Assessment (SMA) which attempts to determine whether a supplier is a ?pivotal' supplier in a market. It has used this test to deny market-based rates to some utilities and utility affiliates for sales within the utility's service territories. The FERC has stated that it will not apply the SMA test if the utility is a member of an RTO or Independent System Operator (ISO) that has a FERC approved market mitigation measure plan in place.

If FERC continues to apply the SMA screen (which it is reviewing now in light of industry complaints), it will have significant implications for suppliers. The SMA encourages (as FERC surely intends) utilities to join RTOs and for RTOs to develop FERC-acceptable market monitoring and mitigation plans. FERC hopes that RTOs will expand power markets (by eliminating rate pancaking among other things) and wants RTOs to be the first line of defence against market power.

For a utility that cannot or will not join an RTO that meets FERC's market monitoring requirements, adoption of the new SMA test will mean that the utility and its affiliates may not be able to obtain market-based rates for sales within the utility's service territory. For the future this may mean that such companies will buy or build generation outside their current region. If the utility or its affiliate has a plant coming on line soon for which it cannot meet the SMA test, that option may not be viable. If the supplier cannot obtain market-based rates, how does it sell its output? Traditional cost based rates are an option but are inflexible. If the market will not pay the cost based rate at least at some times, to whom does the supplier sell its output?

There is one possible option that some utilities (and at least one independent power producer) have successfully implemented in the past. This is the so-called ?up to rate'. This rate couples cost based concepts to market flexibility. Basically, the supplier submits cost data to FERC. FERC uses the data to set a maximum allowable rate which the supplier is authorised to discount if the rate is above market. The principal disadvantage is that the rate is effectively the lesser of cost or market. However, it allows sales at the full embedded cost of the unit if the market price is at or above the ?up to rate' and allows the supplier to sell at a lower price (that covers incremental costs and, hopefully, some contribution to fixed costs) at other times. While issues concerning the SMA test are being sorted out, this provides at least one option in the near term for those companies that fail the SMA screen.

Acquisitions

The 1990s saw very significant and large-scale acquisition activity in the energy sector. The disaggregation of vertically integrated utilities encouraged through regulatory initiatives resulted in a number of large-scale transactions involving disposition of generating assets. A number of these deals were done through auctions where significant demand resulted in high prices for the capacity being sold. Strong valuations were premised on aggressive electricity price projections. The demand was fuelled by industry participants whose objective was to garner market share, transmission access or expansion sites.

This was a ?seller's' market and the deal technology reflected that fact. Bidders were given limited diligence opportunities, technical consultants were hired in advance by the seller and, because of aggressive schedules, bidders had little choice but to rely on their reports; acquisition agreements were heavily slanted toward the seller, with receipt of regulatory approvals generally being the only substantive condition to closing. Little or no risk associated with the assets was retained through conventional indemnities.

Now, in response to the pressures of the current environment to strengthen balance sheets, a number of energy sector companies have announced proposed sales of assets. This time around, however, the lay of the land should be quite different. Valuations will obviously be less aggressive. Buyers' diligence will be more focused and acquisition agreements will not be signed on an ?as is, where is' basis with minimal conditions. We can expect to see meaningful material adverse change ?outs', and perhaps financing conditions. In addition, the old paradigm, in which the seller transferred virtually all liability associated with the assets and retained none, will probably not be standard in the current environment in the absence of significant price concessions.

Financing

While a number of developers have either delayed or cancelled plans for construction of greenfield power projects, a number of financings will nevertheless need to be consummated. For one, a number of power plants were financed in the past five years with so-called mini-perm structures, which will require refinancing or restructuring. Projects under construction that have been carried through with internal funding may require external financing at some point. In addition, there will be requirements for the financing of acquisitions.

As noted above, where the financing of generating projects is concerned, predictability and stability of cash flows will regain importance in debt underwriting decisions. Capital structures are likely to be less aggressive.

Since the Enron debacle has given complex financing structures a black eye, there may be a significant bias toward more conventional lending or capital markets debt financing. Moreover, moves underway in the accounting profession may make synthetic leasing more difficult, if not unattainable. The recent heightened scrutiny of off-balance sheet structures notwithstanding the use of leveraged leases as a financing tool for construction loan takeouts, as well as for asset acquisitions, has increased significantly in recent years ? a trend expected to continue. Unlike a synthetic lease or many other off-balance sheet vehicles, a leveraged lease transfers substantially all of the risks of ownership to the lessor and meets almost all of the requirements regarding transparency of disclosure and exposure of the lessor to residual value risk that accounting rules are now attempting to address. Accordingly, generators that are acquiring older assets or which have construction projects that are nearing completion will likely keep leveraged leases as an option when considering different financing structures to meet their income statement and balance sheet objectives. In this regard, it is worth noting that the Summary of Tentative Decisions released by the FASB on March 20, 2002, in connection with their review of entities that lack sufficient independent economic substance, specifically excludes from its scope leveraged leases subject to the provisions of FASB 13.

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