Contracts

The Risk Evolution

For investors, power contracts are one of the continuing risks to development. While risks add to the challenge, proper evaluation and planning can lead to success.

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Assessing, evaluating, and pricing the risks in independent power plant projects is of utmost and ongoing importance to investors. While the basic risks have remained relatively constant throughout the life of the independent power industry, changing market conditions and evolving regulatory structures necessitate that investors continually reassess the various risks.

The basic deal objective is to initially structure the project agreements to restrict the investor's risk to power plant development, construction, maintenance, and operations. A corresponding and equally important goal is for the investor to maintain the risk allocations on which its investment decision was based. In other words, if the investor succeeds in constructing and operating the project in accord with the *pro formas* which precipitated its investment, the investor should be rewarded with financial success.

The operative assumption is that an investor in a power plant project intends to invest money in a venture that will reward performance relating to the successful development, construction, operation, and maintenance of a power plant. An investor seeking to invest in natural gas futures or coal price arbitrage presumably will be attracted to an alternative investment vehicle.

Accordingly, power plant investors are encouraged to refrain from investing in projects that require making money on non-power plant related risks. For instance, it is becoming increasingly foolhardy to invest in a project with questionable economics on the expectation that it can achieve profitability by obtaining fuel at a cost less than the purchasing electric utility's corresponding fuel costs.

Project sponsors will want to strive to lay non-power plant risks off to entities who are in the business of taking these risks — and whose investors have elected to take these risks. For instance, fuel suppliers and the O&M contractors are compensated for taking the risks inherent in performing their respective functions — fuel suppliers should be rewarded or penalized for their competitive effectiveness in the fuel markets.

Fuel Supply Risk

The fuel procurement and delivery functions illustrate the fundamental risk issues associated with power plant investment and highlight the evolution and seemingly perpetual transformation of these risks.

Power purchase agreements typically index the energy/variable price component of the project's revenue stream to some market or utility cost of fuel index. This pricing structure exposes the investor to the divergences between the project's actual fuel costs and the fuel cost index used to calculate its energy payment.

The experience of California waste wood projects underscores the necessity for an appropriate linkage between the project's fuel costs and its energy payments. In the early to mid-1980s, numerous wood waste projects secured Interim Standard Offer No. 4 (ISO4) contracts. These ISO4 contract holders generally selected a pricing option which based energy prices on forecasts for an initial 10-year period and thereafter set them at the current short-run avoided costs (SRAC) as determined by the California Public Utilities Commission (CPUC). California SRACs are derived predominantly from the cost of natural gas to the purchasing electric utility.

At the time ISO4 contracts were executed, waste wood cost $10 to $15 per oil equivalent barrel and its price was projected to remain relatively constant. The combination of the initial energy price of 5 cents a kWh, which would escalate to more than 10 cents, and natural gas prices at about $40 oil equivalent barrel and projected to increase to $80, $90, or $100 per barrel equivalent by 1990, enabled the ISO4 wood projects to appear almost too good to be true. In the near term, the fixed energy prices would greatly exceed wood prices and in the out years, natural gas-driven SRACs would exceed wood prices by several multiples.

Many ISO4 wood waste deals were, in fact, too good to be true. Natural gas prices have generally stayed between $15 and $30 oil equivalent barrel and, of course, never reached the promised $80 to $100 barrel equivalent. On the other hand, wood waste has been priced in the $40 or higher a barrel equivalent range.

This dichotomy between fuel costs and fuel-related revenues has caused a number of these wood waste projects to become troubled or to even fail. Additional projects may likely fail upon the expiration of the fixed price period and the consequent dropping of their energy prices to around 3 cents a kWh.

The fuel and transportation area also demonstrates that benign or seemingly unrelated regulatory changes may alter the project risk. Through the mid-1980s, natural gas was most typically purchased pursuant to a fully bundled sales tariff. The purchaser paid the local distribution company (LDC) one aggregate price for buying, transporting, and providing the other functions necessary to deliver natural gas to the burner-tip. Thus the tariff structure alone provided the necessary linkage between the project's actual fuel costs and its energy payments.

Starting in the mid-1980s, the provision of gas services at the federal level and in numerous states, particularly California, has become increasingly unbundled. The gas user purchases discrete services such as commodity procurement, interstate transportation, intrastate transportation and storage separately.

As a result, in California and in other restructured jurisdictions, tariffs are typically no longer able to link the QF's fuel costs to its energy payments. The QF must obtain linkage through its commercial contracts. Fuel pricing and delivery reliability, which were essentially non-issues for many projects throughout most of the 1980s, have emerged into perhaps the critical risk issues for currently operating and development projects.

The Crockett Cogeneration project exemplifies an optimal structuring of unbundled gas supply and transportation arrangements. Crockett is a 240 MW cogenerator which will sell its electric output to Pacific Gas and Electric Co. (PG&E).

The Crockett power purchase agreement indexes its energy payment to PG&E's average utility electric generation (UEG) gas rate. The Average UEG gas rate equals the sum of the PG&E purchase price for gas at the California border and the intrastate gas transportation rate for utility generators.

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Crockett directly linked its gas commodity costs to its energy payment by securing a 15-year contract to purchase gas at the California border at a price indexed to PG&E's commodity purchase price. It obtained complete linkage by also securing a 15-year intrastate gas transportation agreement with PG&E to transport the gas from the California border to its burner-tip and with rates indexed to the intrastate rate for utility generators.

At least one commercial banker described Crockett as representing an excellent structure with fuel risk virtually completely hedged.

Changed Circumstances

An inherent tension exists between long-term contracts, the foundation of any power plant investment, and the charter of many state regulatory commissions to best protect ratepayer interests. This tension is typically evidenced by utility requests to alter QF power sales agreements on the grounds of changed circumstances. Recent periods, characterized by discrepancies between pricing terms in contracts which are based on prior forecasts of avoided costs and the actual avoided costs being experienced, have particularly tempted state regulatory commissions to reexamine previously approved contracts.

The Federal Energy Regulatory Commission (FERC) designed its regulations to implement PURPA to provide the investor some pricing certainty over the extended life of the power purchase agreement:

The import of this section is to ensure that a [QF] which has obtained the certainty of an arrangement is not deprived of the benefits of its commitment as a result of changed circumstances... This subparagraph will thus ensure the certainty of rates for purchases from a [QF] which enters into a commitment to deliver [power] to a utility.

States have generally adhered to FERC's admonitions and refrained from directly retroactively adjusting price terms in power purchase agreements. However, FERC's directives have not completely eliminated the spectra of changed circumstances from exposing project investors to unanticipated risks.

The litigation between Orange and Rockland Utilities Inc. (O&R) and Harriman Energy Partners Inc. illustrates this interplay among the FERC regulations, the supposed sanctity of long-term contracts, and the recurring temptations that changed circumstances pose to state regulators.

In 1991, after several years of litigation, the New York Public Service Commission (NYPSC) ordered O&R to execute a power purchase agreement with Harriman Energy. It concurrently approved contract pricing terms at rates discounted from, but based on, the New York-adopted 1988 long-run avoided costs (LRACs). In late 1992, O&R filed a petition requesting relief from the pricing terms of the agreement. It argued essentially that changed circumstances —updated and significantly lower 1992 LRACs— caused the contract prices to become excessive.

O&R's plea represents a quintessential clarion call that changed circumstances warrant, if not necessitate, regulatory intervention:

[T]here is a point at which changed

circumstances, *and the results they produce, are of such a magnitude that the Commission is compelled, in the discharge of its statutory responsibilities, to ensure that utility rates are just and reasonable, to recognize those changed circumstances, and to modify its prior orders....* (emphasis added.)

The NYPSC appropriately rejected O&R's contention that changed circumstances compelled a modification of the contract's pricing terms. Nonetheless, the NYPSC did not dismiss the O&R petition, but rather *sua sponte* fashioned a remedy — one not exceeding the FERC limitations on its power, but which nonetheless enabled it to address the pricing anachronisms it perceived.

The NYPSC directed that the parties explore and report back with a resolution of the agreement that would improve customer effects. It rationalized that had Harriman Energy represented a utility resource, the prudent course would be to defer, cancel, or modify the project.

The limited choices available to Harriman Energy are obvious: litigate the NYPSC's authority to request it to modify the power purchase agreement; to accept reduced pricing terms; to defer the project on-line date; or to sell the contract back. In June 1994 Harriman Energy announced that as part of a confidential settlement it would seize development of the project.

Altering Agreements

Purchasing utilities also have and continue to request authority to directly alter key provisions of power purchase agreements. Thus far the commissions have tended not to authorize wholesale changes in previously approved contracts. Nevertheless, utility initiatives have achieved success, and even when they fail, they have adversely affected investors.

These utility initiatives are likely to continue, even if they continue to fail on their merits. The regulatory perception that at least certain QF purchase agreements contain prices substantially above current market prices has allowed the utilities to characterize their efforts to modify or negate long-term, QF purchases contracts as zealously protecting ratepayer interests, regardless of the merit of their claim. Recent proceedings, again from New York and California, demonstrate the range of utility initiatives, the regulatory responses, and the investor effects.

In 1992, Niagara Mohawk Power Corp. (NiMo) requested authority from the NYPSC to modify its existing power purchase agreements to provide additional rights to curtail power purchases from QFs during periods of light loads. NiMo claimed that FERC's PURPA regulations impose no obligation to purchase unusable energy, and thus the utility could appropriately curtail QF purchases during periods of reduced electric demand.

The NiMo curtailment petition threatens the risk allocation on which investment decisions in New York QF projects were made. In its Oct. 4, 1993 *Creditreview*, Standard and Poors stated that the requested curtailment rights risks reducing profit margins and lowering cash flows for New York projects. It further observed that the "threat alone [of additional curtailment] has derailed financings for many [New York] projects in the past year."

The NYPSC has yet to decide the merits of the NiMo proposal. Rather, it has informally requested that NiMo negotiate individually with QFs to obtain enhanced curtailment rights.

The other proceeding involved Southern California Edison Co.'s (SCE) request to shorten the truncation period it has used to measure a QF's satisfaction of the firm capacity performance requirements. Under the California standard offer agreements, QFs fulfill their firm capacity obligations by delivering power during the on-peak hours during each peak month at a level equivalent to 80 percent of their firm capacity commitment. Truncation relates to the methodology SCE uses to measure attainment of the 80 percent performance requirement.

SCE's practice has been to calculate the QF's firm capacity performance based on the QF's aggregate on-peak hour deliveries over the month. This truncation methodology allows a QF with a 20 MW nameplate rating and a 10 MW firm capacity commitment to satisfy its firm capacity obligations by running at the 20 MW level for 40 percent of the on-peak hours.

With the support of the CPUC's Division of Ratepayer Advocates, SCE requested authority to calculate the 80 percent criteria using a 15 minute truncation interval and thus obligate the QF in the example to deliver 10 MW during 80 percent of the 15 minute intervals during the on-peak periods. The proponents argued that the existing truncation practice provided SCE neither sufficient nor truly firm capacity.

The CPUC denied the petition on a variety of the right grounds. Most important, for present purposes, it recognized the inequity to change the existing truncation rules:

This example raises an additional point. If such a ... QF made its initial commitment to firm capacity on a reasonable belief, based on the language of the contract or on other circumstances relevant to the formation of the contract, that the truncation interval would be one month, it would be inequitable now to impose a considerably shorter truncation period and effectively deprive that QF of the ability to fulfill its contract (emphasis added). CPUC Decision No. 93-11-019, issued November 2, 1993.

It would be misleading to suggest that SCE's truncation petition left the investor community unscarred. First, during its pendency, numerous projects faced substantial risk of ceasing to be viable. Second and at a minimum several transactions and financings required additional due diligence efforts, at best, or were put on hold pending its resolution, at worst.

Power plant investors are encouraged to monitor regulatory activities and understand the possible consequences of even seemingly unrelated regulatory proceedings. A project's revenue stream remains subject to a certain level of regulatory risk at all times.

As pricing for electricity moves toward a market basis, a project with a high cost structure, whose economic viability requires above-market prices, is substantially riskier than a low cost project receiving market prices. The investor's ultimate safeguard against utility and regulatory risk is a project that can provide a sufficient return by delivering power at prevailing market prices. ■

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