

Projects

Energy

Structured Products and Derivatives

June 05, 2017

---

## Financial Hedges for United States Gas-Fired Power Generation Facilities

By Daniel N. Budofsky, Michael T. Reese, Michael S. Hindus and Olivia Matsushita

---

*Over the past few years, many merchant gas-fired power generation plants operating in the regional transmission organization, PJM Interconnection and in the New York Independent Service Operator (NYISO) areas have been successfully project financed by international and Japanese financial institutions. At the same time, the market has also seen the recent bankruptcy filing of a merchant gas-fired power plant in the ERCOT market in Texas. Common to each of these project-financed power generation plants was the employment of financial hedging instruments designed to ensure a stable revenue stream to help cover debt service obligations over the first several years of plant operations. In this article, we review the history of the use of financial hedges by merchant power projects, and examine the main types of financial hedges currently being used in the United States power market and whether or not they can support the bankability of merchant power projects operating in markets such as the PJM Interconnection.*

---

### Historical Development of Financial Hedges for Merchant Power Projects

Beginning in 1978 with the Public Utility Regulatory Policies Act (PURPA) and continuing with the Energy Policy Acts of 1992 and 2005, federal legislation and orders by the Federal Energy Regulatory Commission in the United States radically changed the electric power generation sector. What had essentially been a regulated monopoly for vertically integrated utilities within specific regions was replaced with a competitive market in generation, open access to transmission, the creation of independent system operators and regional transmission organizations, and wholesale markets for electric power.

The means of financing power projects has evolved with changes in the structure of power generation markets in the United States. Prior to the late 1970's, new generation facilities were financed on the balance sheets of vertically integrated utilities, which recovered their costs through a pass-through arrangement to consumers (consumer charges were required to be approved by the local public utilities commission). PURPA required utilities to purchase energy and capacity from certain non-utility owned power producers (IPPs). Many of these IPPs were smaller entities with little or no balance sheets and therefore financing generally depended on long-term (i.e., 15-30 year) power purchase agreements (PPAs) with the utilities. In effect, through the PPA, the projects were financed on the utilities' credit, but while the project debt was non-recourse to the utilities, the PPAs allocated full offtake responsibility to the utilities. This became the primary method of financing non-utility generation.

In the 21<sup>st</sup> Century, in many key markets in the United States, long-term PPAs for gas-fired electric generation became disfavored, even though there was a need for additional capacity and energy. Lenders nonetheless required assurances from new IPP project developers that revenues would be available to service debt repayment obligations. Initially, a variety of mechanisms were used, including increased levels of project equity and subordination of fuel payments. Other risk management practices developed, including financial hedge transactions such as energy swaps, contracts for differences, heat rate call options and power revenue puts.

### Revenue Puts

The most prevalent form of financial hedge in the last several years has been the revenue put option (also frequently called a "revenue put"). This is a form of downside protection for the power plant. It is analogous to a project purchasing insurance against the risk of net revenues falling below a specified threshold due to changes in the price of power and/or fuel. Thus, revenue put providers are typically sophisticated financial institutions, usually swap dealers, with the expertise to transfer this risk by trading in the futures and spot energy markets. As many banks have exited the commodity markets over the past several years, due to factors such as increased regulatory capital charges, the number of revenue put providers recently has been reduced to a few known players. There have been examples, however, of non-swap dealers acting as put providers. One such case is the Panda Temple I project, described in more detail below, where a pension fund acted as the put provider. It is unclear whether the pension fund, which was also an equity investor in the project, had entered into a back-to-back arrangement with another financial institution to hedge its potential liabilities.

The revenue put is a purely notional cash-settled contract in which the power project makes an up-front premium payment to a revenue put provider in exchange for settlement payments to the power project reflecting any shortfall of (i) a notional gross energy margin over (ii) a fixed net revenue amount. The notional gross energy margin is calculated as the excess of power revenues over gas costs that would be realized by a hypothetical power plant operating at an assumed capacity and heat rate and on an assumed schedule of starts and restarts during the year. The revenues and costs are calculated on the basis of published power and gas indices observed during the term of the revenue put. The fixed net revenue amount, on the other hand, is typically sized to ensure that the power plant will be able to meet its fixed costs and debt service obligations, taking into account any other sources of revenue, such as capacity payments. Thus, broadly speaking, if the spark spread tightens relative to the assumed level on which the fixed net revenue amount is based, the revenue put provider will make a settlement payment to help the project make up lost revenue.

Revenue puts present an interesting credit profile for a power generation project. Typically, settlement payments are calculated and made annually. Since the power generator pays the revenue put premium upfront, and the revenue put only provides downside protection in the form of payments from the revenue

put provider, the power generator generally should not have ongoing payment obligations to the revenue put provider. With such one-way credit exposure, it is the revenue put provider and not the power generator that must provide collateral.

Under typical documentation, the amount of this collateral to be put forward by the revenue put provider is typically the mid-market replacement value of the transaction less a negotiated threshold amount. Without liquid markets in revenue put transactions, the replacement value is often set by the revenue put provider on the basis of its internal models. Perhaps not surprisingly, the put premium is typically significantly higher than the revenue put provider's proposed replacement value, which means the amount of collateral the revenue put provider has to provide can be comparatively small. This dynamic of asymmetrical information suggests there is value in negotiating a precise valuation methodology upfront. Because the collateral put forward by the revenue put provider remains the property of the revenue put provider, some revenue put providers have successfully negotiated that the collateral shall not form part of the lenders' security package.

Another implication of the generally one-way credit exposure is that a power generator will seek to eliminate any credit-related events of default (including bankruptcy events) pertaining to the power project that otherwise would permit the revenue put provider to terminate the put. Notably, in the Panda Temple I project, the revenue put provider has continued to make payments to the power project even after the recent bankruptcy filing by the power generator.

In practice, revenue puts do have some two-way credit exposure. This is because to meet the project's need for cash flow during the course of the year to make debt service payments, revenue puts typically provide for interim (e.g., quarterly) estimated settlement payments. In recent transactions, these intra-year payments are structured as "advances" by the revenue put provider that are subject to a true-up at year-end when the amount of the final annual settlement payment is known. As a result, the revenue put provider may be exposed to the credit of the power generator for the amount advanced each quarter. In recent transactions, revenue put providers have been able to obtain a first priority lien to secure the repayment of any such "advances", on a pari passu basis with the lenders to the power generation project, but subject to a cap equal to the maximum amount payable by the revenue put provider annually.

Achieving the best terms for a revenue put involves seeking competitive bids from potential revenue put providers, a process that usually involves concurrent negotiations with several providers with respect to economic terms, as well as related documentation including, for example, ISDA documents, intercreditor agreements, guarantees and consents.

### Heat Rate Call Options

Another financial hedge is the heat rate call option (HRCO). Like a revenue put, the payout on the HRCO is purely notional and is not tied to the actual operations or results of the power generation facility. Under a HRCO, the project receives fixed periodic cash payments from the HRCO counterparty and, in exchange, pays to the HRCO counterparty the excess of a market power price over a market gas price multiplied by an assumed heat rate and by an assumed quantity of power. The effect of the HRCO is similar to a revenue put in that the project is protected against tightening spark spreads. However, this protection is effectively paid for in an HRCO by the project giving up the potential upside that it would otherwise realize from widening spark spreads, rather than the upfront premium payment found in the revenue put.

The mechanics of the typical HRCO achieve this by giving the financial counterparty a daily financial option, calculated with respect to each hour in the following day that, upon exercise, requires the payment of a cash settlement amount equal to the product of (a)(i) a variable price power index at a predetermined location *minus* (ii) an amount equal to a variable natural gas index multiplied by the specified heat rate conversion factors of the project and (b) a base notional quantity of power. The counterparty may choose to exercise the option for some, but not all, of the hours in the day, and the cash settlement amount also accounts for assumed fixed and variable costs of starting up and shutting down the plant during a day. If the net amount of the related option premium owed by the financial counterparty is greater than the aggregate cash settlement amount, the project receives a payment and realizes a gain. If the net amount is negative, the project must make a payment and realizes a loss.

Thus, because either party may owe a settlement payment, the HRCO is subject to two-way credit exposure, and each party may need to post collateral in favor of the other, depending on the mark-to-market of the contract.

### Contracts for Differences

Other types of hedges, such as a contract for differences, may be financially settled only, but are linked to the actual performance of the power generation facility and thus may reduce basis risk. For example, in a contract for differences, the project would sell energy in the energy markets and would receive payments from the hedge provider amounting to the positive difference between the project's revenue requirements per unit of energy as specified in the contract and its actual sales receipts. If the project's receipts, on the other hand, were to exceed its revenue requirements, it would pay the difference to the hedge provider.

### Bankability of Merchant Power Projects and the Limitations of Financial Hedging Instruments

The recent bankruptcy of the Panda Temple I project in Texas illustrates some of the limitations of financial hedging of merchant power projects. The Temple I Project was a 758MW natural gas-fired combined cycle power project operating in ERCOT in Texas, and was originally financed through a six-year \$75 million term loan A and a \$255 million term loan B. At the time, the financing by institutional investors of a capital intensive construction project through a term loan was seen as a breakthrough for the U.S. project finance market, and the trend toward the use of term loan B and private financings has continued since then. The project was unable to obtain a suitable long-term PPA, but based on a belief that ERCOT lacked adequate baseload capacity (and that old coal-fired generators were close to retirement), the project developer saw the potential for future high power prices and spark spreads. The project therefore sought to rely on market energy revenues to service its debt repayments and to hedge volatility in revenues through 4-year revenue put options entered into with the 3M Employee Retirement Income Plan, an equity investor in the project, on 600MW of generation capacity. By providing a floor on the project's gross margins, it was expected that the project could meet its debt service obligations even if spark spreads were to narrow or plant efficiency were to decrease. Unfortunately, such favorable market conditions did not materialize, and on April 17, 2017, the Temple I Project filed for bankruptcy protection after breaching its debt service reserve covenant in December 2016 and failing to make its March 2017 debt service repayment.

The inability of the project to generate enough cash to meet its debt service repayments highlights some of the shortcomings of the revenue put. For example, had the revenue put strike price been higher, it would have offered more protection to the project. Reportedly, a sister project, the Sherman Project, with a similar revenue put had a \$45 million strike price compared with Temple I's \$41 million strike price. Nonetheless, the revenue put has continued to perform, with an early payment from the revenue put provider recently coming into the bankrupt's estate, indicating that, at least, the revenue put was structured so that the insolvency of the project did not trigger a termination of the revenue put instrument.

Nonetheless, financings of gas-fired power generation facilities consisting of loans with terms equal to the construction period plus 4-5 years, supported by financial hedges, have generally been viewed as bankable in the PJM Interconnection. For example, it has been reported that a natural gas-fired power generation project in Lordstown, Ohio, was financed by a lending syndicate of eight banks in April 2016, supported by a five-year revenue put. Because it is often contemplated that the loans may be refinanced prior to their final maturity date, it is not uncommon for the financial hedges to mature on the anticipated refinancing date of the loans.