

**Flexible LNG Supply and Gas Market Integration:  
A Simulation Approach for Valuing the Market Arbitrage Option**

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**INTRODUCTION**

Global natural gas markets are in transition. Steady growth in gas consumption has outpaced indigenous regional supplies in key gas markets such as the U.K. and the U.S., and declining costs of liquefied natural gas (LNG) transport is drawing massive investment in new liquefaction, ships and regasification facilities to serve growing markets for gas imports. LNG transport is not a new technology; however the institutional system that has governed its trade is undergoing rapid change. Until fairly recently, the LNG trade structure functioned more like floating pipelines than other ship-based transport systems. LNG tankers moved almost exclusively on fixed routes defined by destination clauses in the gas sales and purchase agreements. Under these rigid long-term contracts, each segment in the LNG chain—liquefaction, ships, and regasification—was scaled to match long-term contractual flows between a specific supplier and gas buyer.

The opening of regional gas markets and the rapid growth of new LNG supplies portends a fundamental shift in the business model that has historically operated the LNG trade, potentially integrating previously isolated regional gas markets. Indeed, this shift in the LNG business is already underway as evidenced by the growth in short-term LNG cargo transactions, estimated to have grown to 11% of total LNG shipped in 2004 (IEA 2005). Market analysts have discussed the key drivers for this shift and sketched the

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broad outlines of a transformed LNG business, characterized by more flexible supply arrangements with cargoes directed to markets where they can earn the highest netback prices (net of transit costs), rather than according to contractually rigid trade routes (IEA 2004; Jensen 2004).

A common perception among industry analysts is that the advent of LNG arbitrage will bring about the “integration” of regional gas markets. Indeed, some researchers have already begun to examine the empirical data for evidence of the comovement of prices across regional markets using rigorous statistical techniques (Silverstovs, L'Hegaret et al. 2005). Preliminary results from these studies suggest that gas markets in the U.S. and Europe are not integrated, but this result is unsurprising given the relatively small fraction of LNG that is currently supplied to these two markets. The U.K., for example, only began importing LNG in 2005 and U.S. imports accounted for less than 5% of consumption in 2005 (EIA 2006).

However, there is a divergence in opinion on just what “integrated” global gas markets will look like. One hypothesis is that the growth of LNG trade over time will yield inter-regional price relationships akin to oil or other globally traded commodities, with tight price linkages bound by the cost of transport between regions. This assumption underpins the large body of empirical research that has examined gas market integration within the United States (De Vany and Walls 1995) and within Europe (Asche, Osmundsen et al. 2002). Other studies have focused on the transactions costs implied in LNG contracting, suggesting that the expansion of total volumes and ships should be

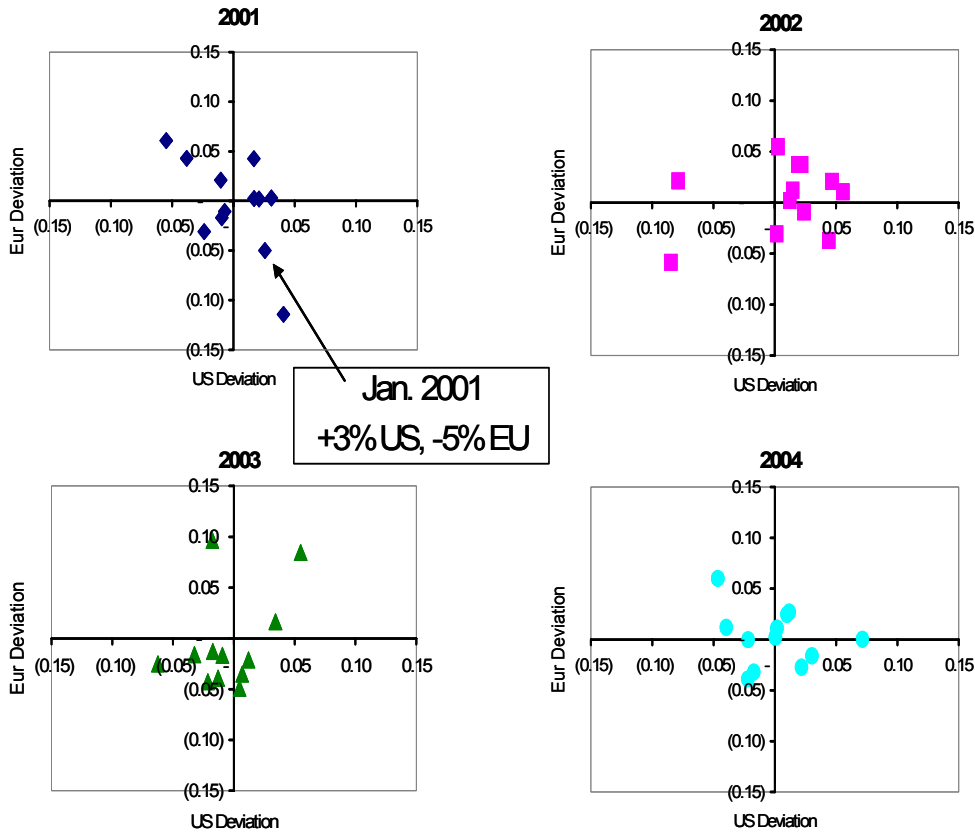
expected to drive shorter-term and more flexible contracting relationships (Hartley and Brito 2001). There is limited analysis, however, of the specific economic fundamentals that will underpin the development of any short-term and flexible trading of LNG cargoes.

In chapters 2 and 3 of this volume, a model of inter-regional gas trade was developed first generally, and then using empirical data for the U.S. and Europe. The model results showed how differences in seasonal gas demand profiles and storage costs drive expected price levels in regional markets. The variation in regional prices created the incentive for investment in additional LNG tankers and regasification capacity so that LNG deliveries could vary to each market throughout the year. LNG deliveries increased to the European market to meet peak winter demand (and capture higher price levels). LNG deliveries to the U.S. peaked in the summer months, garnering higher prices relative to Europe. These seasonal shifts in LNG deliveries required additional investment in LNG tankers and regasification capacity beyond that which would be required to provide smooth, monthly deliveries of LNG to each market. Additional ships are required for diversions to more distant markets and additional regasification capacity is required to meet peak period offloading requirements. The ABMod results in chapters 2 and 3 characterize the equilibrium between the benefits of *seasonal* LNG cargo diversions and the costs of the additional investments in LNG shipping and regasification. The ABMod results suggest that we should expect to see price differences across regional markets that vary over the course of the year—driven by heterogeneity in seasonal demand and in gas storage costs.

In addition to the seasonal gas demand and price swings incorporated in the ABMod framework, gas demand (and in turn price levels) also have a significant component of random (or *stochastic*) variability, driven by stochastic demand drivers such as daily temperatures, prices of competing fuel sources, and broader macroeconomic conditions. In regionally isolated markets, such variability in gas demand has traditionally been managed by mechanisms internal to the particular market. As with seasonal swings in gas demand, natural gas storage has traditionally been the dominant mechanism for responding to shorter-term, stochastic variations in gas demand.

The flexible routing of LNG cargoes potentially provides an additional alternative to meet such stochastic demand variability. Gas suppliers will seek to move cargoes to markets when demand and price conditions provide a profitable opportunity to do so. The scope for such physical “arbitrage” in LNG cargoes depends on the correlation of such demand and price variations between regional markets. Figure 4.1 provides some indication for the magnitude and relationship of the demand volume variability at the monthly scale in the U.S. and Europe. For example, in January of 2001 Europe experienced warmer than normal weather, while in the U.S. temperatures were colder than normal. As a result, European gas consumption was down 5% compared to normal January levels and U.S. gas consumption was up 3%.

**Figure 4.1. Monthly Deviations in Gas Demand from Average Indexed Values, 2001-2004.** Source: U.S. EIA (2006), IEA (2005).<sup>2</sup>



The plots shown in figure 4.1 show that, in general, deviations in monthly demand volumes for the years 2001 to 2004 were not correlated. (Statistical tests reveal that the correlation coefficient of the consumption deviations is not significantly different from zero.) This result suggests that there should be significant opportunities to shift supplies between markets—as in January 2001—potentially providing mutual benefits to both gas sellers and gas buyers. Moreover, the plots illustrate the magnitude of monthly gas

<sup>2</sup> To adjust for annual time trends in gas consumption, the deviations shown in figure 4.1 are calculated relative to an average monthly index of gas demand for each particular month for the period 2001-2004.

demand variations. For example, a 5% deviation in monthly demand in the U.S. market is on the order of 100 Bcf, equivalent to about 35 standard-sized LNG tankers.<sup>3</sup>

The diversion of LNG cargoes will never be the sole mechanism employed by gas sellers to manage stochastic gas demand variability. The technical realities of the gas business require that storage continue to play an important role in providing reliable supplies—particularly for responses to shorter-term day-to-day market variations. Still, as the data from the U.S. and Europe show, flexible LNG supply may play a role as a cost-effective mechanism used in the portfolio of alternatives for managing demand variability, along with storage and price-induced demand reduction.

The lack of correlation of consumption variations shown in figure 4.1 is suggestive of the potential scope for flexible LNG supply between the U.S. and Europe. The incentive for physical arbitrage by gas suppliers requires that these demand variations be transmitted to the market via a price mechanism. Currently, the U.S. and U.K. have competitive gas markets that allow LNG sellers to realize the potential price benefits of arbitrage. Competitive market-based pricing for LNG imports is also developing in continental Europe as those markets push toward broader gas market liberalization. Asian LNG buyers are also increasingly competing for LNG supplies.

For a LNG supplier, the benefits of LNG arbitrage accrue from the ability to deliver gas cargoes to markets to capture non-correlated price movements. These benefits are weighed against the costs of the ships and regasification terminals required to

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<sup>3</sup> Based on 2005 U.S. average monthly gas consumption and a 135,000 cubic meter LNG tanker.

divert gas cargoes. The movement of cargoes to respond to price increases would also be expected to moderate those price increases. Thus, the act of arbitrage would be expected to reduce the non-correlated variation in prices between markets.

In the following chapter I develop a model to evaluate the opportunity for physical LNG arbitrage for a single gas supply project, accounting for the costs of the LNG tankers and regasification. An explicit analysis of the prospective benefits and the costs of physical LNG arbitrage will provide bounds for the degree of integration that can be expected in prices in regional gas markets. The model discussed is for an LNG supplier in the Atlantic Basin, delivering gas to the U.K. or U.S. markets. The framework is extendable to other markets with competitive pricing for LNG imports.

#### **DESCRIPTION OF THE MODEL**

The model described here simulates flexible trade in LNG cargoes in the Atlantic Basin. The model represents a LNG supplier based in Egypt with the capacity to deliver a fixed quantity of gas to the U.K. market. When prices favor it, cargoes are diverted to the U.S. market. The model can be readily adapted for other sources and destinations.

The model approach consists of three key steps:

- (1) construction of a suitably realistic representation of LNG transport to reflect the critical costs and constraints on an LNG supplier to engage in physical arbitrage,

(2) representation of plausible future price series for the two potential destination markets, and,

(3) Monte Carlo simulation of the future price series and the corresponding shipping responses to obtain a distribution of values for the option to engage in physical arbitrage.

### **Model of Physical Arbitrage**

Valuation of the incentive to invest in flexible LNG capacity requires a model that represents the critical parts of the LNG train including the constraints and flexibilities of a supplier to respond to market price signals. The model is constructed in a spreadsheet modeling program, Microsoft Excel, and uses the add-in program Crystal Ball to conduct Monte Carlo simulations.

For simplicity, the model assumes a vertically integrated ‘commercial’ LNG project structure, where a partner in a gas supply and LNG project owns gas volumes from a producing field all the way through the delivery chain until gas is sold out of the regasification terminal. Liquefaction is assumed to be operated on a tolling basis, with payments providing a suitable return on investment to project owners. This approach allows all rents from LNG arbitrage to flow to the single gas supplier. The results are indicative of the total benefits available across the value chain to flexible LNG supply. Alternative organizational and contract structures would simply divide these benefits (and risks) among any partners.

The results presented here are representative of a LNG supplier taking cargoes in Egypt with contracts to deliver gas to a U.K. regasification terminal. A series of long-term contracts would likely support financing for the necessary investment in gas production, ships, and reserved regasification capacity in the U.K. Ships and regasification capacity could either be owned by the integrated project supplier or leased. Beyond this general framework, the valuation is independent of specific assumptions for feed gas costs, liquefaction costs, or the costs of regasification in the U.K. These costs are incurred whether or not cargoes are diverted to the U.S. In general, prices in the U.K. market are expected to provide a suitable return to support the project investment. A typical project might be designed to deliver one billion cubic feet per day (1 BCFD) to the U.K. with attractive margins for the supplier at prices over \$3 per thousand cubic feet (mcf). The value of flexibility to deliver cargoes to the U.S. is viewed as an additional benefit to be compared with the costs of maintaining this option.

The model assumes that the supplier will engage in physical arbitrage in those months that the price differential supports the added costs of diversion including: (1) fulfilling any volume contract commitments in the U.K. market, (2) additional ship charters required to maintain full volume deliveries for the longer shipping distances, and (3) charges for access to regasification terminals in the U.S.

If the supplier has a contract for deliveries in the U.K. market, diverted volumes would have to be replaced by purchases of gas on the U.K. spot market to maintain

commitments to U.K. buyers. For simplicity, the original long-term gas sales contract is assumed to be indexed to spot gas prices in the U.K. at the National Balancing Point (NBP). When cargoes are diverted from the U.K., replacement volumes are procured also at the NBP spot price. This simplifying assumption allows that no costs are realized related to cargo diversion in the U.K. market. Investment in the U.K. regasification terminal (or reservation of a share of offloading capacity) is sunk and should not affect ongoing operating decisions.<sup>4</sup>

The longer shipping distance from the supply source in Egypt to the U.S. would require additional ship charters to maintain full offtake and delivery volumes. The U.S. Gulf Coast is over the twice the distance from Egypt as the U.K. (one-way shipping distances of roughly 6,500 and 3,100 nautical miles, respectively). Round-trip travel time from Egypt to the U.S. is about 30 days, including one day each for loading and offloading, compared to 15 days for the contracted deliveries to the U.K. Thus, every cargo diverted to the U.S. from the U.K. requires that an additional month of charter be obtained to maintain full delivery volumes to the U.S.<sup>5</sup> Tankers are assumed to be available for short-term charter at a rate of \$52,000 per day for a 138,000 cubic meter capacity vessel.<sup>6</sup> The resulting shipping cost of arbitrage is thus \$0.52 per mcf delivered to the U.S. from Egypt.

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<sup>4</sup> The assumption of full market liquidity is reasonable for cargo diversions at the margin. Three of the standard 138,000 cubic meter tanker cargoes of LNG would constitute less than 3% of current U.K. gas consumption. The model here discusses diversions of 1 BCFD, which would likely have an impact on U.K. prices. More likely diversions relevant to a single supplier would be smaller, having less impact on the U.K. market.

<sup>5</sup> The logistics of ship charters could impose some additional costs, as ships might not be readily available in proximity to the U.K. or Egypt to redirect to the U.S. market.

<sup>6</sup> The cost of LNG tanker charter is based on conversations with industry ship brokers and industry trade press reports, e.g. World Gas Intelligence (WGI 2006). Full capital cost recovery for a new build 138,000

Cargo diversion occurs when the price the supplier can obtain in the U.S. market is more than enough to cover incremental shipping costs. By assuming that the arbitrage cargoes are delivered to the U.S. Gulf Coast, it is again reasonable to assume market liquidity, e.g. that the diverted volumes are price takers in the U.S. market. The Lake Charles regasification terminal and others under construction on the Gulf Coast are proximate to the Henry Hub, the most liquid exchange in the U.S. with robust pipeline capacity to connect to regional markets.<sup>7</sup> 1 BCFD would constitute less than 2% of U.S. demand at current consumption levels.

Unlike the tanker market, access to regasification capacity is not assumed to be available on an as needed basis. Regasification capacity is likely to be constrained in the destination market when prices are peaking and the holders of regasification capacity in the U.S. would seek to capture some of the benefits of delivering spot cargoes by raising rates for terminal access.<sup>8</sup> Therefore an LNG supplier would need to reserve access to regasification capacity over a longer period to assure that they accrue the full benefits of cargo diversion. In the model, there is no cost explicitly assigned for the lease or ownership of regasification capacity. Thus, the total returns to arbitrage can be compared

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cubic meter LNG tanker, assuming \$170 million USD capital cost, a 25-year lifetime, and a 10% discount rate is roughly 45,000 per day (IEA 2003). Tanker lease rates could also vary cyclically and depending on availability. Here we assume a constant rate.

<sup>7</sup> We assume here that spot deliveries are made to the Gulf Coast and earn prices indexed to the Henry Hub. Prices for LNG cargo deliveries to other markets in the U.S. would depend on basis differentials to the Henry Hub. Thus, for simplicity, we will use simulations of the Henry Hub price series to evaluate the arbitrage potential. The model could be adapted to other price series.

<sup>8</sup> So long as regasification terminal owners are allowed to control access, and set “market-based” rates for terminal access.

to the costs of reserving access to a regasification terminal. Returns in excess of the expected cost of regasification capacity imply arbitrage rents.

### **Simulating Future Prices**

The value of the physical arbitrage option depends on the relationship between prices in the contract market and the market for diverting cargoes. Thus, here and elsewhere in this text I abstract from the long-run evolution of gas prices and focus on the short-run (monthly scale) relationship in prices between markets. In a market with a growing share of LNG trade, where cargoes move to the markets willing to pay the highest price, we should expect prices received for LNG cargoes in all markets to move up and down together over annual time-scales and longer. Over shorter time scales, monthly or seasonally, prices for LNG cargoes could be expected to deviate more significantly between regional markets reflecting short-run demand deviations. The option value of “excess” capacity in LNG delivery capacity depends on the variability in the price spread between the two markets—and not long-run average prices, assuming long-run prices in both markets generally move up and down together over the long-term.

In chapter two of this volume I developed an analytical framework that described expected seasonal price spreads between regional gas markets with a significant share of LNG. And in chapter three I used this model to provide some estimates for the seasonal price spreads that might be expected in the Atlantic Basin when a robust trade in LNG develops. These results indicate the *expected* seasonal movement of LNG cargoes

responding to *expected* variations in the seasonal price spread. The additional option value of moving LNG cargoes to respond to *stochastic* price variations—requires a representation of the variability of price spreads from these expected seasonal levels.

In this section, I provide an overview of the two main types of models used to represent the evolution of stochastic price series. One model, the mean-reverting model, is shown to be the best choice to represent the evolution of gas prices and particularly the variation in spreads between regional markets. Using parameter estimates from historical data, and the theoretical seasonal price spreads from ABMod results, I then use the mean-reverting model to simulate future prices and spreads between the U.S. and U.K. markets.

### *Stochastic Price Models*

There is a significant body of research focused on the question of how best to represent stochastic price series. One commonly used pricing model is the Geometric Brownian Motion (GBM), or the random walk. Prices move up or down in each period, with no reference to previous price levels. This model is most effective for describing the movement of securities prices and is attractive because it allows for an analytical solution, rather than simulation to determine valuations (Luenberger 1998). The random walk is perhaps less relevant to commodity prices where underlying supply and demand fundamentals would be expected to ultimately drive prices. For example, using the GBM, if gas prices rose to \$30 per mcf in one period, we would assume that it equally likely that prices would move up in the next period as down. Such a representation does

not consider the potential for demand response, nor the underlying supply cost fundamentals. Most critically, for our purposes here, the GBM approach would not well fit our understanding about the likely evolution of price spreads between markets. If both U.S. and U.K. prices were modeled as random walks—major price deviations could be sustained for years at a time. Instead, we should expect such sustained price deviations between markets to be mitigated by the movement of LNG supplies to capture such pricing opportunities.

An alternative pricing model, which incorporates stochastic variability, but assumes that there are some price levels toward which prices tend to move over time is the mean-reverting, or Ornstein-Uhlenbeck model. The underlying assumption of the mean-reverting model is that underlying supply and demand fundamentals drive expected price levels. Stochastic deviations in supply and demand drive unpredictable deviations from expected prices—yet fundamentals, such as the ability of consumers to choose substitute energy sources, generally pull gas prices toward a long-run mean. The mean-reverting model is commonly used by market analysts for representing future gas prices (Blanco and Soronow 2001; de Jong and Walet 2003).

The basic mean-reverting model is shown in equation 4.1:

$$(S_t - S_{t-1}) = \eta * (\mu - S_{t-1}) + \sigma * \varepsilon_t \quad (4.1)$$

According to equation 4.1, the change in price from one period ( $S_t$ ) to the next ( $S_{t-1}$ ) is determined by two factors. First, there is a tendency to move toward the long-run mean ( $\mu$ ) at the mean reversion rate ( $\eta$ ). Second, random shifts move prices up or down in distances determined by the volatility ( $\sigma$ ) and randomly occurring deviations ( $\epsilon$ ). This simplified form of the mean-reverting model can be adapted to incorporate an expected price level ( $\mu_t$ ) that varies over time, either seasonally or in a long-run trend.<sup>9</sup>

#### *Model Selection and Parameter Estimates from Historical Data*

The common approach used to determine which pricing model is appropriate and to assign parameters for simulating future prices is to look at historical price data. If the fundamental operation of markets is assumed to be consistent over time, future price series would be expected to follow the behavior of historical data. However, the major upheaval in natural gas markets in recent years—especially in the U.S. and the U.K.—and the expected growth in LNG imports, suggests that historical price series may not provide a reliable predictor future price behavior.

A visual examination of historical U.S. and U.K. gas prices shown in figure 4.2 suggests that historical price data are not likely to well fit the mean reverting model. The significant increases in prices since January of 2000 in both the U.S. and the U.K. suggests that these series are trending upward over this time period rather than randomly moving around expected monthly price levels. Moreover, the relatively short history of

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<sup>9</sup> An extension of the mean reverting model incorporates time-varying “jumps” in volatility. These models may be less appropriate for monthly average price series (as perhaps would be seen by LNG importer selling gas indexed to a hub over the course of a month) than for daily gas prices. Still, such a model could be used in the model framework discussed here as an extension of this work.

U.K. prices on the NBP limits the ability to make reliable estimates of the behavior of those prices. Such a problem is often the case in simulation, as Dixit and Pindyck noted in their seminal text *Investment Under Uncertainty*: “one must often rely on theoretical considerations (for example, intuition concerning the operation of equilibrating mechanisms) more than statistical tests when deciding whether or not to model a price variable as a mean-reverting process” [Dixit, 1994 #213].

The theoretical results from chapters two and three support the use of the mean-reverting model to represent the relationship of prices between the U.S. and U.K. markets at the monthly time-scale. A modification of the mean-reverting model allows the explicit representation of the stochastic variation in the price spread between the two markets. Since our interest here is in the variation in prices between the two markets, the critical assumption we are making with the mean-reverting model is that the fundamentals assumed in the ABMod are relatively stable over time. The mean reverting model also assumes that prices between the two markets will move generally together over the long-term, linked by the growing LNG trade. The absolute price level is much less important to arbitrage than the relationship between prices in the two markets. For this, the mean-reverting model is a robust representation.

An examination of the historical data can provide some useful bounds to determine an appropriate range of parameter values. However, given the major changes underway in gas markets, volatility and mean reversion rates may shift in the future.

However, an examination of the historical data can provide a plausible range of values that can guide sensitivity analysis for each parameter.

**Figure 4.2. Monthly Average Gas Prices in the U.S. on the Henry Hub (HH) and in the U.K. at the National Balancing Point (NBP).** *Source: US EIA, Bloomberg.*

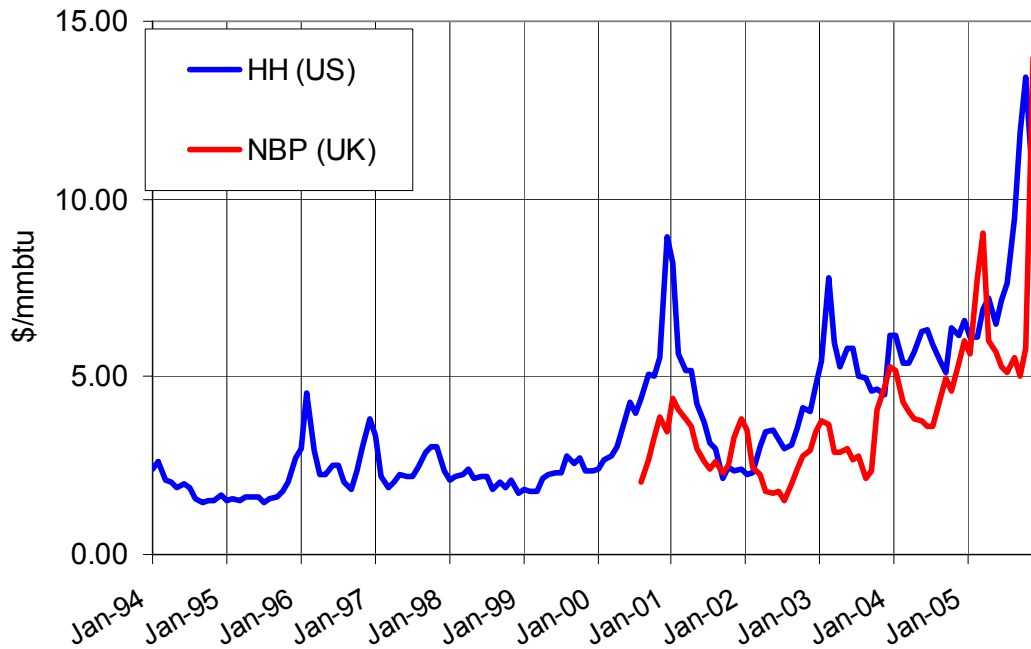


Figure 4.2 shows monthly averages of spot gas prices in the U.S. at the Henry Hub and in the U.K. at the National Balancing Point (NBP). We can use linear regression to fit this historical data to the mean-reverting model. Parameter estimates for the Henry Hub (U.S.) and the National Balancing Point (NBP) in the U.K. can be obtained using the following equations:

$$(S_t - S_{t-1}) = a + b * S_{t-1} + e_t \quad (4.2)$$

The estimates from the regression yield parameter values for the simulation of future prices:

$$\text{the mean reversion rate: } \eta = -b ; \quad (4.3)$$

$$\text{the long-term average for the respective period: } \mu = \frac{a}{\eta} ; \quad (4.4)$$

$$\text{and the volatility for the for the future price simulation is equivalent to the standard error from the historical regression: } \sigma = s . \quad (4.5)$$

As expected, most of the parameter estimates from the historical data do not prove to be robust. In the U.S., an attempt to fit the mean-reverting model to the whole period 1994 through 2005 did not yield any statistically significant parameter estimates. Thus, the U.S. time series was separated into two periods.<sup>10</sup> The period 1994-1999 in the U.S. suggests a relatively good model fit, with average Henry Hub prices of \$2.21 per mcf, volatility of \$0.39 per month, and a tendency to move 27% of the distance back toward the mean price level in each period—as defined by the mean reversion rate,  $\eta$ . Henry Hub prices fit the model less well in 2000-2005, which is not surprising given the run-up in prices over that period. There is evidence of higher absolute volatility in the later period (but actually lower if measured as percentage of the average price), and the

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<sup>10</sup> The intention here is not to draw robust statistical conclusions about any shift in market fundamentals in the U.S. The time series could be detrended, or tested for seasonal variations. However, given the fundamental evolution expected in the markets, the theoretical model results from chapters two and three are better indications of the expected future prices. The parameter estimates here are useful for providing a range for sensitivity analysis only.

tendency to move back toward the mean fell significantly—the latter likely an artifact of the strong trend over the period.

In the U.K., the sharp upward trend in prices over the period also explains why the parameters estimates are not robust. It is, however, interesting to note the similar estimates for volatility as found in the U.S. market. Future price simulations will use deviations around these estimates of volatility and mean reversion rates to observe the sensitivity of the results to shifts in these parameter values.

**Table 4.1. Parameter Estimates from Historical Price Series.**

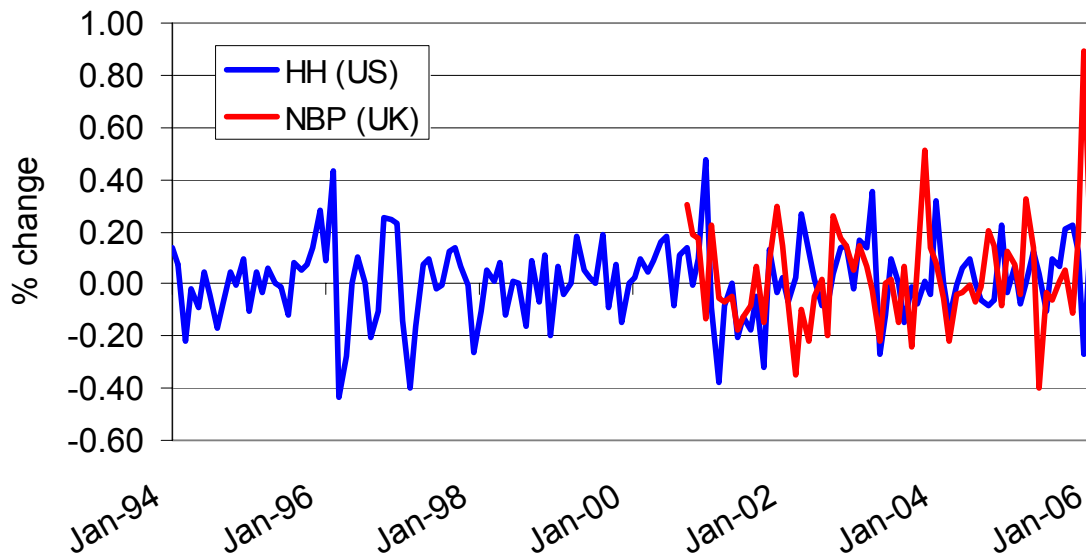
Price Series (time period)	a	b	Mean Reversion Rate $\eta = -b$	Mean $\mu = a/\eta$	Absolute Volatility $s = \sigma$	Percent Volatility (%)
Henry Hub (Jan 1994 – Dec 1999)	0.61**	-0.27***	0.27**	2.21**	0.39	17.5%
Henry Hub (Jan 2000 – July 2005)	0.69*	-0.13*	0.13*	5.45*	0.84	14.7%
NBP (Jan 2000 – July 2005)	0.50**	-0.12	0.12	4.07	0.70	17.3%

\*, \*\*, \*\*\* indicate 90%, 95%, and 99% confidence intervals, respectively.

In addition to examining how prices move in the two markets independently, the correlation between price movements in each market is also of particular interest. As discussed above, the value of flexible LNG trade is derived from moving cargoes in response to the occurrence of favorable price spreads. Figure 4.3 plots the monthly price changes in the U.S. at the Henry Hub and in the U.K. at the NBP for the period, January 2000 to July 2005. Given the limited amount of LNG that currently moves between

markets, it is not surprising that monthly price changes in the two markets do not appear strongly correlated. Statistical analysis reveals that changes in the monthly average prices over this period were only 12.6% correlated.<sup>11</sup> The growth in LNG trade—and particularly the movement of LNG cargoes to respond to pricing opportunities—would be expected to transmit price changes across markets. Simulations of future prices will use sensitivity analysis to test how increases in the correlation of price changes affect the option value of flexible capacity.

**Figure 4.3. Monthly Changes (in percent) of Gas Prices in the U.S. on the Henry Hub (HH) and in the U.K. at the National Balancing Point (NBP).** *Source: US EIA, Bloomberg.*



<sup>11</sup> A common analytical mistake is to measure market integration using the correlation of absolute price levels. This invariably over-estimates the level of integration. Correlation here tests the comovement of price changes in monthly average prices, adjusting for the mean-reverting component of each price series. Price changes, not adjusted for mean reversion were 11% correlated.

*Mean-Reverting Models for Future U.S. and U.K. Prices*

The theoretical interpretation of future price relationships developed in chapters two and three—combined with the parameter estimates from the historical data—yields a model for the simulation of future prices in the U.S. and the U.K. and their interrelationship. I assume that prices in both markets follow the mean-reverting model. Here, the basic model is extended to incorporate expected seasonal swing in prices, based on the results of chapter three. Prices in each market evolve stochastically from those monthly expected price levels—and most importantly these random variations in prices are correlated. The model for the U.S. and the U.K. are formulated as follows:

First, as shown in equation 4.6, U.K. prices in any period are determined by the previous period price ( $S_{t-1,uk}$ ), the tendency to move toward the expected monthly price level ( $\mu_t$ ), and normally distributed disturbances proportionate to the assumed volatility level ( $\sigma_{uk}$ ).

$$S_{t,uk} = S_{t-1,uk} + \eta_{uk} * (\mu_{t,uk} - S_{t-1,uk}) + \sigma_{uk} * \varepsilon_{1,t} \quad (4.6)$$

$$\text{where } \varepsilon_1 \sim N(0,1) ; \quad (4.7)$$

A similar future price curve is simulated for the U.S. Henry Hub, as in equation 4.8:

$$S_{t,us} = S_{t-1,us} + \eta_{us} * (\mu_{t,us} - S_{t-1,us}) + \sigma_{us} * \varepsilon_{3,t} \quad (4.8)$$

The correlation of monthly price changes in the two markets enters the simulation model through the error terms in each price series as in equation 4.9:

$$\varepsilon_{3,t} = \rho * \varepsilon_{1,t} + \sqrt{1 - \rho^2} * \varepsilon_{2,t} \quad (4.9)$$

The error term in the U.S. Henry Hub price series is a function of the correlation ( $\rho$ ), the randomly occurring disturbances in the U.K. price series  $\varepsilon_{1,t}$ , and a separate set of independent normally distributed error terms,  $\varepsilon_{2,t} \sim N(0,1)$ .

### Model Simulations

Unlike a Geometric Brownian Motion price model which is analytically tractable, the mean reverting price model requires repeated simulation of each price series via the Monte Carlo method to then determine the expected value and the distribution of returns of the diversion option (Dixit and Pindyck 1994). Each individual simulation of future prices generates a series of price spreads based on the difference between U.K. and U.S. prices. Cargoes are diverted from the U.K. to the U.S. when the price spread is great enough to cover the additional cost of transportation. In each simulation, the error terms in the U.K. pricing model are generated randomly, following the normal distribution. The evolution of U.S. prices, and thus the spread between the two markets, is determined by a correlated error with the U.K. price, and an error term generated by an independent sampling from a normal distribution.

Using the Monte Carlo method, 10,000 sample price series are generated for both markets over a five year period for each of four sets of parameter values as shown in table 4.2.

**Table 4.2. Selected Scenarios for Simulation**

<b>Scenario</b>	<b>Monthly Volatility (%)</b>	<b>Monthly Volatility (<math>\sigma_{us,uk}</math>)</b>	<b>Mean Reversion (<math>\eta_{us,uk}</math>)</b>
Historical volatility, low mean reversion	17%	\$0.85	0.1
Historical volatility, historical mean reversion	17%	\$0.85	0.3
Low volatility, historical mean reversion	10%	\$0.50	0.3
No stochasticity case	NA	NA	1.0

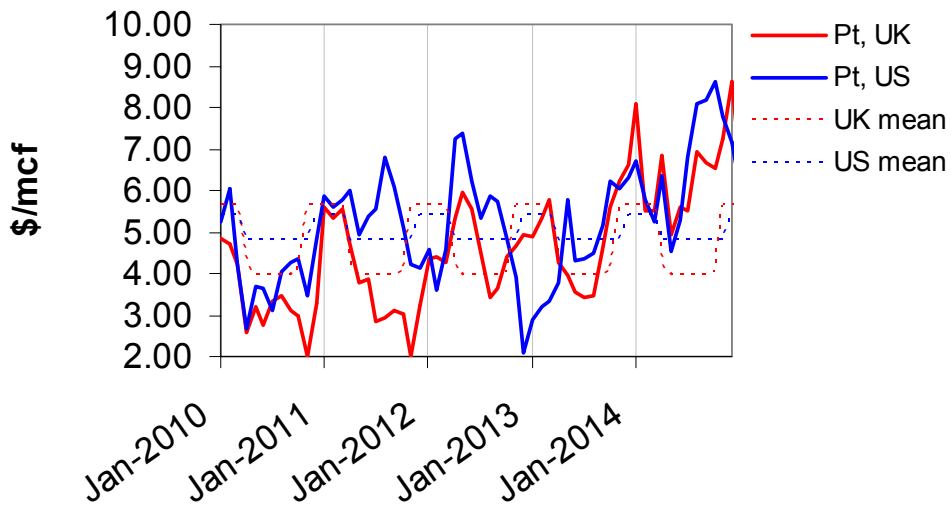
The “scenarios” in table 4.2 were selected based on the historical price series data and with the purpose of showing the sensitivity of the option value to each parameter value. For illustrative simplicity, the same parameter values are applied to the U.K. and U.S. price series in each scenario.<sup>12</sup> The “no stochasticity” is a basis for comparing the value of seasonal arbitrage to the ability to respond to stochastic price spread variability. When the mean reversion rate is equal to one ( $\eta=1$ ), prices in both markets do not deviate from the seasonal expected values.

The one metric that is tested in detail is the correlation of price changes between markets ( $\rho$ ). The expansion of LNG arbitrage would itself be expected to increase the transmission of price changes between markets. High prices in the U.K. would draw

<sup>12</sup> The historical data generally support this approximation. Certainly, these two gas markets would be expected behave somewhat differently in the future. However, price volatilities and mean reversion rates are likely to change from historical levels, due to such factors as the growth in LNG trade and also changes in gas demand composition and market structure. A rigorous analysis of the drivers for these parameter values—such as the growth of price responsive gas demand such as electric power—is beyond the scope of this work.

cargoes, thus reducing supply to the U.S. and resulting in increased prices there as well. The pricing impacts of cargo diversion are not explicitly incorporated into this model. However, the effect of such diversion is incorporated by varying the level of correlation of price changes in the model. As the net effect of diversion would be increased correlation of price changes between the two markets, the correlation level is varied from completely uncorrelated ( $\rho=0$ ), to perfectly correlated ( $\rho=1$ ). A sample of one simulation of the U.K. and U.S. price series and the expected mean seasonal prices is shown in figure 4.4.

**Figure 4.4. Sample price series.** “Historical volatility, historical mean reversion case.” Price correlation ( $\rho$ ) = 0.5; Absolute volatility ( $\sigma_{us,uk}$ ) = \$0.85; and the mean reversion rate ( $\eta_{us,uk}$ ) = 0.3.



**RESULTS**

The value of the option to divert cargoes depends on the difference, or spread, in prices between the alternative market (the U.S.) and the contract market (the U.K.).

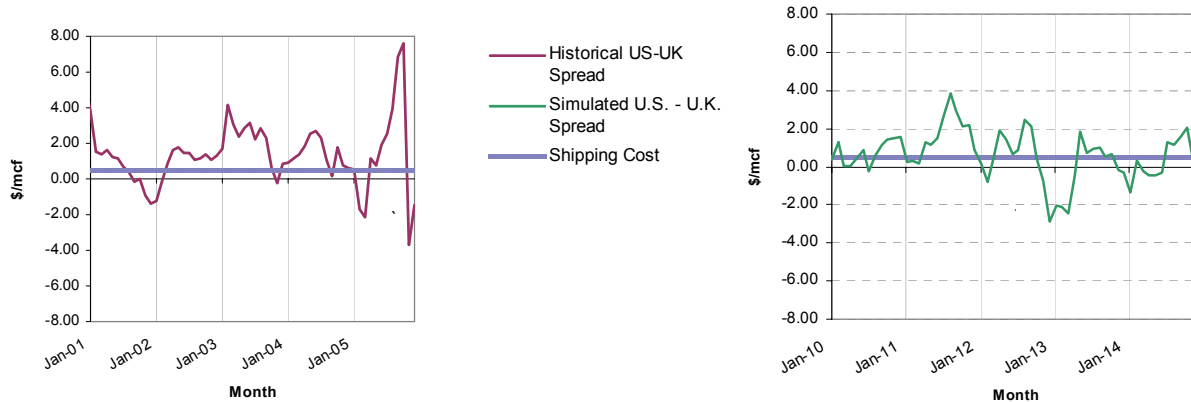
When the price spread exceeds the realized cost of transporting gas to the alternative market—an arbitrage opportunity exists, by definition. In figure 4.5, one simulation of the spreads between U.S. and the U.K. market is shown (right chart) for the “historical volatility, historical mean reversion” case. Arbitrage potential exists where the price spread (U.S. less U.K. prices) is in excess of the shipping cost—plotted here at \$0.52 per mcf.

In the simulation shown in figure 4.5 (right chart), an LNG supplier with contracted cargoes to the U.K. and 1 BCFD of U.S. regasification capacity, could reap \$425 million in additional operating profits in the hypothetical year 2011.<sup>13</sup> According to the operational assumptions in the model, 30 BCF per month is diverted to the U.S. whenever the arbitrage opportunity exists. In the year labeled 2011, this would occur in nine months out of the year, reflecting an average price spread in those months of \$2.06 per mcf in favor of the U.S. The uncertainty related to arbitrage is also evident in the model, as the year 2013 would provide arbitrage returns of only \$78 million, reflecting arbitrage potential in only four months of the year.

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<sup>13</sup> The years here are ordinal only. Simulation results are not tied to any specific base year.

**Figure 4.5. Historical and Simulated Price Spreads between the U.S. and U.K.** The simulation plot is one outcome of 10,000 scenarios evaluated for the “historical volatility, historical mean reversion” case:  $\sigma_{us,uk} = \$0.85$ ,  $\eta_{us,uk} = 0.3$ ,  $\rho=0.5$ .



It is also useful to compare the simulated results to empirical data. The left figure in 4.5 plots the pricing spreads and the transit cost for the period 2001 to 2005, as in the right hand simulated result. The chart thus shows the “arbitrage potential” that would have been available to an LNG supplier able to move cargoes between the U.K. and the U.S. in the 2001 to 2005 period. This is a hypothetical consideration, as the first regasification capacity became operational in 2005.

The expected values for the three cases described in table 4.2 are plotted in figure 4.6. Each curve represents a unique set of price parameters ( $\sigma$ ,  $\eta$ ) and the level of price change correlation is varied on the x-axis ( $\rho$ ). The expected option value for each case and correlation level is plotted on the y-axis in millions of USD per year for one billion cubic feet per day (BCFD) of regasification capacity. 1 BCFD is an average sized regasification terminal.

The values reported in figure 4.6 are net of incremental shipping costs, and thus the only remaining charge for diverting cargoes is the cost of reserving access to the regasification terminal to offload the cargoes. Maintaining the option to deliver cargoes in response to market signals would likely require full control of the desired regasification capacity. An LNG supplier could either maintain part ownership in a facility, or reserve the desired capacity from regasification facility owners on a long-term basis.<sup>14</sup> One estimate of the reservation cost is the rent that provides a suitable return on capital investment—the same return that a capacity owner would require under competitive conditions. Estimated costs of maintaining 1 BCFD regasification capacity are approximately \$60 million USD.<sup>15,16</sup> These estimates include both construction costs and fixed operations and maintenance costs, which would accrue independent of volumes delivered. The median estimate of the unit cost of regasification is plotted in figure 4.6.

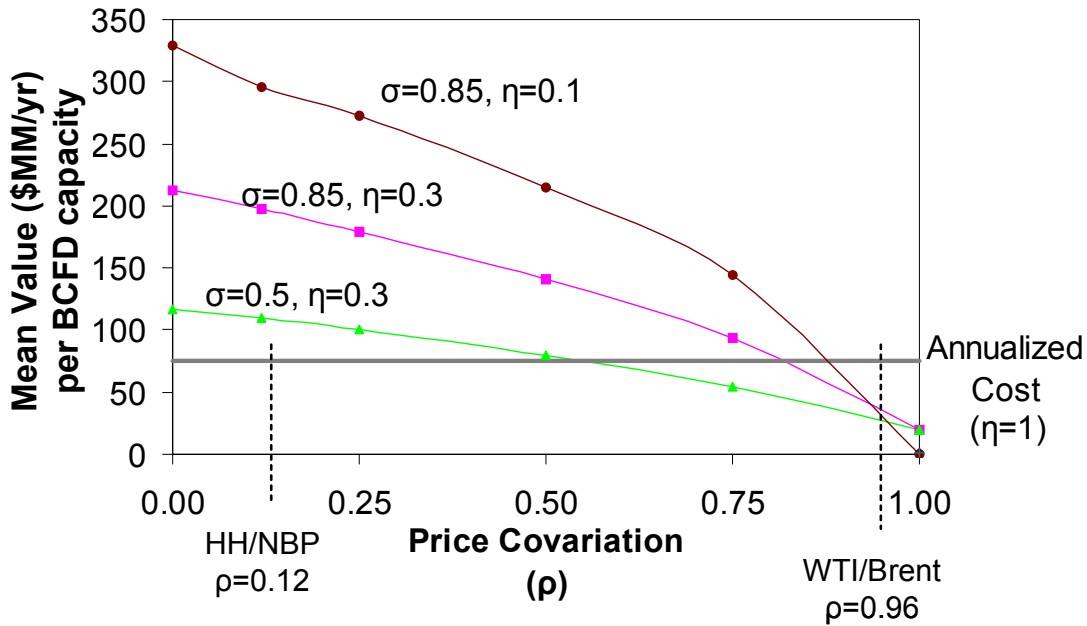
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<sup>14</sup> As discussed above, a strategy of securing regasification capacity on a short-term basis—responding to market price signals would likely result in paying increased rates for terminal access. Terminal owners would be expected to extract rents as demand for terminal access increased unless there is large over-build in regasification capacity.

<sup>15</sup> Based on capital costs for a new build regasification terminal of \$400 – 600 million USD for 1 BCFD of peak sendout capacity and fixed operating costs estimated at \$15 million USD per year (EIA 2001). Assumes 10% return on capital investment and full coverage of fixed O&M costs.

<sup>16</sup> Average unit costs are used here for representative purposes. Investors making the capacity decision at the time of construction might be more interested in how costs change for incremental increases in capacity. Jensen (2004) suggests that a 25% larger regasification facility (including additional offloading, storage, and sendout capacity) would result in a 10% increase in capital costs. The economic cost of “excess” capacity might be thus considerably lower than the average fixed cost estimate used here.

**Figure 4.6. Annual per unit Arbitrage Benefits as a Function of Volatility, Mean Reversion, and Market Price Correlation.** Results of Monte Carlo Simulation.



As an example, the top line in figure 4.6 shows the expected value of flexible LNG capacity when the absolute volatility of changes in monthly prices in both markets is assumed to be \$0.85 ( $\sigma_{us}, \sigma_{uk} = 0.85$ ), and mean reversion rates for both markets are assumed to be 0.1 ( $\eta_{us}, \eta_{uk} = 0.1$ ). This parameter pair aligns with historical volatility levels and the low end of the range of historical mean reversion rates, as shown in table 4.2. Holding these parameter values constant, the plot shows how the shift toward more strongly correlated market prices (from  $\rho = 0$ , toward  $\rho = 1$ ) would affect the expected value of the investment in the optional regasification capacity. The increasing correlation

of price changes reduces the likelihood and size of arbitrage opportunities, thus lowering the overall expected profits that would accrue to the holders of flexible LNG capacity.

The “historical volatility” ( $\sigma_{us,uk} = \$0.85$ ), “historical mean reversion” ( $\eta_{us,uk} = 0.3$ ) case is shown as the middle curve in figure 4.5. At current levels of price correlation between the U.S. Henry Hub and the U.K. NBP, the expected value of holding 1 BCFD regasification capacity in the U.S. is nearly \$200 million USD, which compares favorably to the estimated cost of per year of holding that capacity (\$60 million USD).

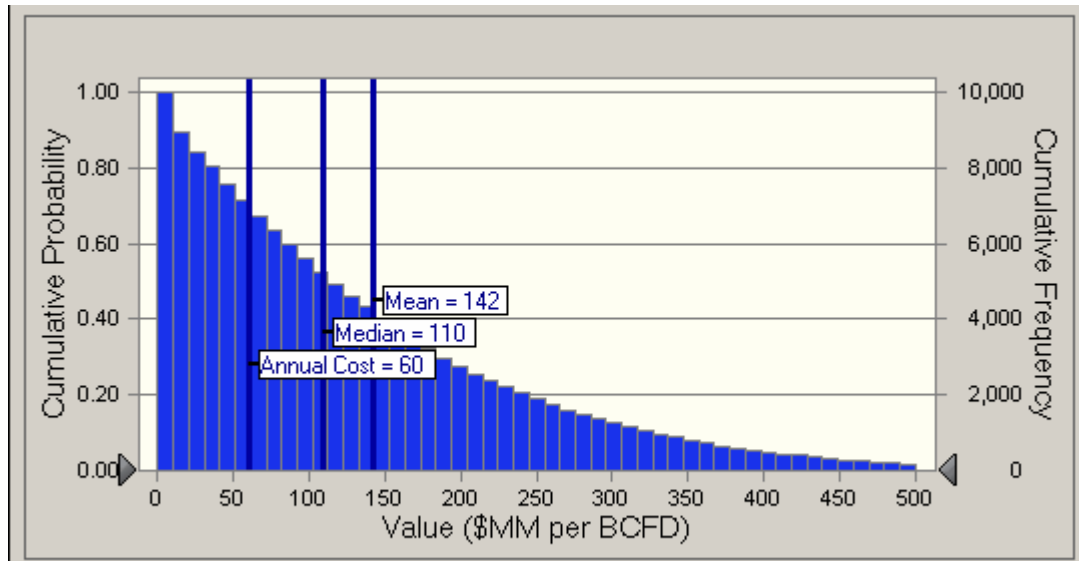
The bottom series in figure 4.6 shows the results for the lower range of volatility and faster mean reversion ( $\rho = 0.5$ ,  $\eta = 0.3$ ), reducing the occurrence and duration of price deviations that support higher option values. If price volatilities decreased from historical levels and LNG arbitrage integrated U.S. and U.K. markets such that price changes were in excess of 50% correlated, there would be no incentive to hold regasification capacity as an option as the costs of holding such capacity would be in excess of the expected benefits. (A comparison of the distribution of results and impacts on investment incentives will be discussed further below).

A gas supplier considering investment in flexible LNG supply capacity will also be concerned about the distribution of arbitrage benefits across years, as indicator of risk. Owning or reserving regasification capacity accrues a fixed annual cost. But arbitrage benefits in this example are generated only when beneficial price deviations make the U.S. market suitably attractive. Figure 4.7 shows the probability distribution of arbitrage

returns for the Egypt-U.K.-U.S. example for “historical volatility/historical mean reversion” case (parameter values:  $\sigma_{us,uk} = 0.85$ ,  $\eta_{us,uk} = 0.3$ , and  $\rho = 0.5$ ). The 50% level of price change correlation might be expected after significant LNG arbitrage is underway.

Figure 4.7 shows that in 65% of the sample years, returns were in excess of the \$60 million USD annual cost of owning the regasification facility. Conversely however, in fully one third of the years, the holder of regasification capacity in the U.S. would not cover the cost of ownership according to the model results. The high variance of returns is also evident in the skewness in the distribution. For the case shown in figure 4.7, the expected value is well in excess of the median value, indicating that a few years of exceptional returns (on the right tail of the distribution) dominate the expected value of the option. In operational terms, if the option to deliver cargoes was held for 10 or 20 years, much of the value would accrue from relatively few years where high U.S. prices and relatively low U.K. prices provide large profits.

**Figure 4.7. Reverse Cumulative Frequency Distribution of Annual Arbitrage Benefits.** Results shown are for 10,000 simulations of the price series:  $\sigma_{us,uk} = \$0.85$ ,  $\eta_{us,uk} = 0.3$ ,  $\rho=0.5$ .



## DISCUSSION

In general, the results of the simulation suggest significant profits to attract investment in physical arbitrage capacity in the Atlantic Basin, especially at recent levels of volatility and the currently low levels of correlation between U.S. and U.K. prices. If there are no barriers to entry, one would expect that investment in ships and regasification capacity would continue, increasing the capacity for cargo arbitrage and increasingly transmitting price changes across the Atlantic. Investment would continue until the level of price covariation drives the expected benefits of arbitrage capacity downward toward the costs of maintaining the flexible capacity option. In a competitive equilibrium the benefits of arbitrage would match the costs of flexibility, providing holders of capital with market returns on capital employed.

As a point of comparison, a robust spot trade in oil has existed since the 1970s, and the world oil market is assumed to be tightly integrated. Empirical tests comparing the changes in spot prices of West Texas Intermediate crude oil (WTI) and spot prices of Brent North Sea crude show tight integration over the period 1984 to 2005. Changes in average monthly spot prices for the two oil indices on either side of the Atlantic are 96% correlated.<sup>17</sup>

Natural gas markets are unlikely to approach the level of integration found in oil markets, as the costs of ships and regasification facilities are much higher than comparable ships and offloading facilities for oil. LNG tankers are roughly seven times the cost of crude tankers per unit energy cargo capacity.<sup>18</sup> Oil unloading facilities would also be expected to be significantly cheaper. Oil docks, pipelines and tanks are far cheaper than the specialized cryogenic pipelines and storage required for LNG offloading. The vaporizer required for returning LNG to its gaseous state also adds to the cost of LNG offloading capacity. Considering transit costs alone, arbitrage opportunities do not develop between the U.K. and the U.S. until U.S. prices are more than \$0.50 per mcf in excess of U.K. prices. Thus, based on transit cost differences alone, we should not expect the degree of price change correlation in gas markets that is observed in oil.

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<sup>17</sup> In addition to transit costs, the difference in WTI and Brent prices is driven by quality differences that also affect refiner demand. The persistence of the strong price correlation lends further support to the argument that oil arbitrage is relatively cheap compared to regional natural gas arbitrage via LNG.

<sup>18</sup> Based on a capital cost of \$50 million USD for a Suezmax tanker with capacity for 150,000 tonnes of oil (nearly 6 Bcf of gas equivalent), and an estimated \$170 million USD for a 138,000 cubic meter LNG tanker (~3 Bcf of gas) (IEA 2003, IEA, 2004 #1878).

According to the arbitrage model framework implemented here, the major question for investors in deciding whether to invest in LNG arbitrage capacity relates to the expected evolution of price fundamentals within each market. Long-run average prices are obviously important, but it is variability in prices that drives returns to arbitrage capacity. If investors historically high levels of volatility to persist (e.g.  $\sigma_{us,uk} = \$0.85$ ,  $\eta_{us,uk} = 0.3$ ), large investments in flexible LNG capacity would appear attractive. The realization and operation of these investments would drive much more tightly integrated Atlantic Basin markets, with price change co-variations approaching 80%.

All else equal, the movement of spot LNG cargoes would also be expected to dampen volatility. The model described here evaluates the value of cargo movements at the margin and assumes no price impact of the arbitrage volumes. Thus, no robust insights on price volatility effects can be directly derived from the simulation results. However, the movement of significant cargoes to a price spiking market would have a moderating effect, particularly as arbitrage capacity and volumes increase. Moreover, the lack of correlation of realized consumption deviations between the U.S. and European markets, shown in figure 4.1, suggests that consumption spikes (and thus positive demand pressures on price) will generally not occur simultaneously in both markets.

As an example, let us consider some future month with gas demand deviations comparable to the variations shown in figure 4.1. In any summer month, where U.S. gas consumption rose 3% above expected levels European gas consumption fell 5% below expected levels, the diversion of roughly 30 LNG tankers from Europe (including the

U.K.) could deliver enough additional supplies to the U.S. to compensate fully for the unexpected demand, thus moderating the likely price spike that would occur in the U.S. and likely increasing European and U.K. prices as well (note the U.S. price spike in figure 4.2). LNG arbitrage increases the responsiveness of gas supply to non-correlated demand swings—which would be expected to buffer overall price volatility.<sup>19</sup>

We can obtain a better understanding of the scope for the LNG diversions to respond to stochastic variability by comparing the 30 cargo diversion in this example to the results from the ABMod in chapter 3. Without stochastic variability, the ABMod solution suggested that 2.3 BCFD of the total 12.6 BCFD total U.S. regasification capacity would be used to accommodate seasonal cargo diversion. We can align this result with the arbitrage model, by removing all of the stochastic variability from the mean-reverting price simulation. This can be done by assigning a mean reversion rate equal to one ( $\eta=1$ ). In this case, prices do not deviate from expected monthly values, and prices follow exactly the seasonal swing in prices based on the results from the ABMod in chapter three.

When prices follow these expected seasonal levels, arbitrage returns match the cost of investment in the facility for all levels of price change correlation (represented by “annual cost” in figure 4.6).<sup>20</sup> This follows from the ABMod competitive equilibrium solution, where investment in regasification capacity occurred until the value of that

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<sup>19</sup> Price volatility in the Atlantic Basin markets could also be reduced by other factors such as an improved supply balance or storage expansion. If investors expect that future prices will exhibit lower volatility and stronger mean reversion, then incentives to invest in flexible LNG capacity are reduced.

<sup>20</sup> When  $\eta = 1$ , monthly price changes from expected values are zero, and thus the correlation of the deviations is irrelevant.

capacity for seasonal cargo diversion matched the unit cost of incremental capacity expansion. With no stochastic variability, seasonal diversion of LNG from the U.K. to the U.S. would regularly occur each summer. The value provided by this diversion exactly matches the cost of regasification capacity. Stochastic variability creates additional value for “excess” regasification capacity. This is reflected in the increase in option value shown in the simulation results, over and above the expected returns to seasonal arbitrage.

Stochastic variability would tend to drive spot deliveries to the U.S. more so in the summer months, as the price spread is expected to favor the U.S. in those months and thus the opportunities for arbitrage would tend to occur more frequently.<sup>21</sup> The ABMod results show that regasification capacity would already be expected to operate at full or near full capacity utilization in those summer months in the U.S. We might expect arbitrage capacity in excess of 3 BCFD to support monthly demand deviations of 5% on 2015 demand levels. This “excess” regasification capacity would be additional to the 2.3 BCFD capacity used to support the expected seasonal swing of cargoes.

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<sup>21</sup> The U.S.-U.K. price spread is expected to be \$0.86 in the summer months. Thus, any positive deviations in the price spread will favor diversions to the U.S., while the spread would have to drop below \$0.52 before detracting cargoes from the U.S. market.

**CONCLUSION**

The integration of global natural gas markets is a subject of interest to participants in the natural gas trade, gas consumers, and energy policy makers. The actual structure of this integration will depend on investment in LNG supply capacity, and the actions of market players to utilize that capacity to respond to price differentials in currently regionally isolated markets. The model presented here provides a framework for evaluating the level covariation in regional prices that can be expected, based on the economic costs to engage in cargo diversion. The results suggest quantitative boundaries on the level of price covariation due to the high capital costs of LNG tankers and regasification facilities.

In chapters two and three of this volume, the equilibrium conditions for investment in gas supply, storage and prices for regional gas markets was established. In this chapter, the stochastic behavior of gas demand and prices was introduced to explore the impacts on investment and price formation in regional markets. The results in this chapter show that the stochastic variability of gas demand (and in turn prices) creates additional value for holding access to regasification capacity over and above the expected seasonal cargo diversions.

The results here also provide further insight into the likely relationship between prices in regional markets that will result from the expanding LNG trade. Equilibrium results from ABMod illustrated the impacts of seasonal demand profiles and storage costs—in addition to transport costs—as critical determinants of pricing levels in so-called “integrated” regional markets. The ABMod provided an analytical framework to

illustrate regional pricing spreads that vary in magnitude and sign throughout a given year.

This chapter showed how the stochastic behavior of gas prices (driven mainly by variability in demand) will also determine the relationship in prices between gas markets inter-connected by the LNG trade. The volatility of prices creates the opportunity for moving cargoes to respond to advantageous pricing conditions. The movement of cargoes between markets will itself transmit price changes between markets. The returns to investment in LNG tankers and regasification capacity depends as much on the underlying behavior of gas demand and prices—higher volatility creates more arbitrage opportunities. Thus, expectations about future market fundamentals will be a critical determinant of future price relationships between markets.

The analysis presented here made simplifying assumptions about market pricing, the availability of ships, and also limited the analysis to one project and two potential offtake markets. These assumptions facilitated a clear illustration of the concepts. The insights derived from this model framework are believed to be robust beyond these specific assumptions.

For purposes of simplicity, the model framework presented here did not explicitly value the incentives for investment in excess shipping capacity. The incentives to invest in shipping capacity and to maintain speculative tanker capacity to be available for spot charters will follow expected returns, similar to the incentives to invest in spare

regasification capacity. In practice, cycles of investment in tankers and regasification could lead to periodic shortages or surpluses in either market, with scarcity rents accruing to holders of capacity in either segment of the chain. Arbitrage between markets requires that gas suppliers have access to capacity in both tankers and regasification to respond to market pricing opportunities. Temporal capacity constraints that raise tanker charter rates or the costs of access to regasification would effectively increase the cost of arbitrage—and increase the price spread between markets.

An extension of this modeling framework would examine the potential portfolio benefits of controlling flexible supply capacity in two or more markets, as well as two or more supply sources. For example, a gas supplier with access to liquefaction on the western side of the Atlantic (e.g. Trinidad) might be able to smooth the uncertainty of arbitrage returns by maintaining excess regasification capacity in both the U.S. and U.K. markets. The model framework here provides upside benefits for controlling regasification capacity in the U.S. when prices there are significantly higher than in the U.K. No flexibility benefits accrue in those years when U.S. prices are low relative to the U.K. However, if the same supplier held some excess regasification capacity in the U.K. market, and also had contractual LNG supplies normally destined for the U.S. market, the structure would provide for arbitrage returns inversely correlated with U.S. flexibility benefits, potentially yielding smoother returns across the a portfolio of project supply.

One other important caveat to the analysis presented here relates to the regulatory and institutional structure of gas markets, particularly in continental Europe and in Asia.

For purposes of exposition, U.S. and U.K. market prices have been used in this analysis. The open, competitive markets in these two countries are most congruent with the assumptions that underpin the model. Currently, however, LNG cargoes delivered to continental Europe and Asia are priced via formula linkages to oil and oil products. The development of an “integrated” global gas market, toward the equilibrium levels projected according to the simulation results, will require that buyers of LNG cargoes respond to opportunities to divert cargoes to higher willingness-to-pay markets. The persistence of more rigid contract structures effectively limits the scope for arbitrage. Such rigidity would also sustain super-normal returns for those engaged in the cargo trade willing to take advantage of pricing opportunities and buyers seeking to meet short-term supply needs with spot cargoes.

At the margin, even LNG buyers in the rigid contractual markets will face the opportunity cost of LNG cargoes in an increasingly global market. Despite the persistence of oil-linked prices for gas on the European continent and in Japan, buyers in these markets seeking spot LNG cargoes to meet unexpected increases in gas demand must pay competitive prices—often linked the U.S. Henry Hub price—to obtain additional gas cargoes (WGI 2005). Such trends support the development of a global market for LNG, but also raise important questions about the interaction of regulatory policies between natural gas markets. If these buyers are able to buy cargoes at spot rates—and then pass the costs of spot purchases on to consumers through average, regulated rates—customers in these markets may not feel the effect of global gas prices at the margin. The result may be the “export” of volatility in these regulated markets to

competitive markets such as the U.S. or the U.K. where buyers feel directly the opportunity cost of gas prices. The implications for such regulatory interaction will be considered more fully in chapter five.

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