Chapter 4
Flexible LNG Supply and Gas Market Integration: A Simulation Approach for Valuing the Market Arbitrage Option

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4.1. Introduction

In chapters 2 and 3 of this volume, a model of inter-regional gas trade was developed first generally, then using empirical data for the U.S. and Europe. The Atlantic Basin Model 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 gas demand and in gas storage costs. These expected spreads between regional prices create the incentive to provide swing LNG deliveries to each market. 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, attracted by higher prices relative to Europe. The model results characterize the equilibrium between the benefits of *seasonal* LNG cargo diversions and the costs of the additional investments in LNG shipping and regasification.

In addition to the expected seasonal gas demand and price swings incorporated in the Atlantic Basin Model framework, gas demand also has 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 regional market – usually gas storage.

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The flexible routing of LNG cargoes – increasingly possible in a growing global market for LNG – provides an additional alternative for gas suppliers in regional markets to meet stochastic demand variability. Gas suppliers will seek to move cargoes to markets when demand (and price conditions) provides 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, in this sample month, European gas consumption was down 5% compared to normal January levels and U.S. gas consumption was up 3%.

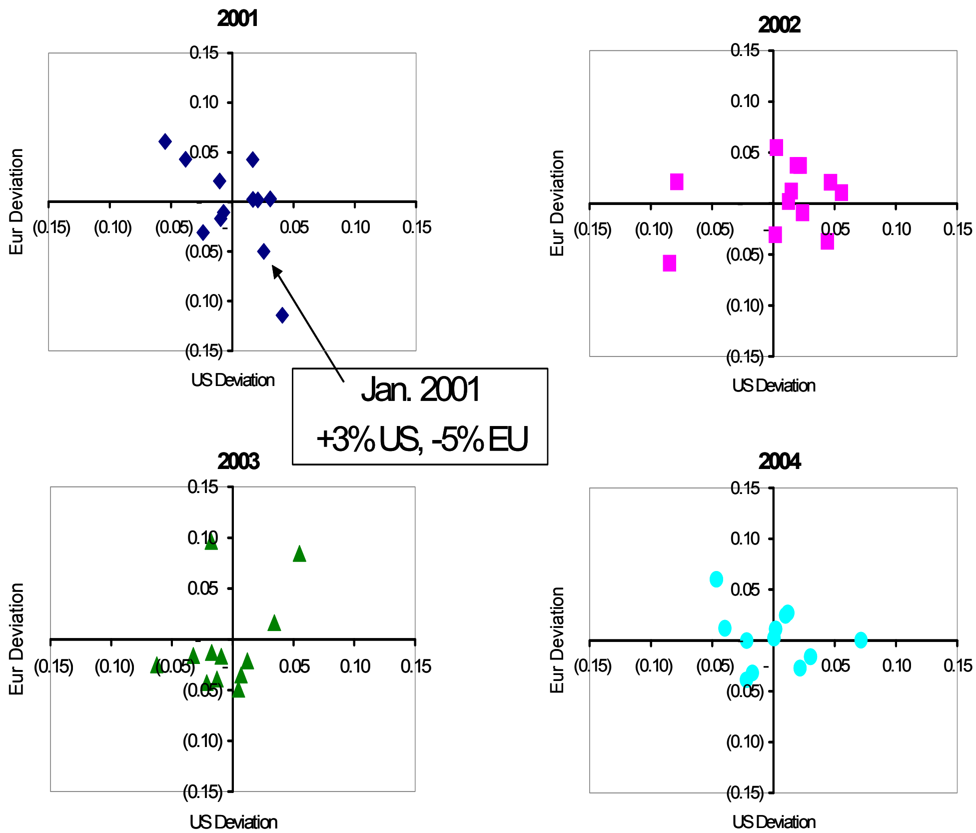

Figure 4.1. Monthly Deviations in Gas Demand from Average Indexed Values, 2001-2004. Source: U.S. EIA (2006), IEA (2005).[2]

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

[2] 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 30 standard-sized LNG tankers.[3]

The diversion of LNG cargoes will never be the sole mechanism employed 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 will 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 price mechanisms. Currently, the U.S. and U.K. have competitive gas markets that allow LNG sellers to realize the potential price benefits of arbitrage. In continental Europe and Asia, LNG buyers are usually monopoly gas and electric companies that do not operate in competitive wholesale markets. Chapter 5 will discuss the implications of these institutional barriers to flexible gas trade and price integration. For our purposes here, I model the interaction of two competitive markets for natural gas. The model framework used in this chapter is extendable to analyzing the interaction between other gas pricing structures.

[3] Based on 2005 U.S. average monthly gas consumption and a 150,000 cubic meter LNG tanker which carries an equivalent of 3.3 Bcf of vaporized natural gas.

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 price covariation (or size and duration of price spreads between markets) that can be expected with increasingly interconnected regional gas markets.

4.2. Description of the Model

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 the difference (the spread) between the U.S. and U.K. 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 model of LNG transport to reflect the critical costs and technological 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 resulting shipping responses to obtain a distribution of values for the option to engage in physical arbitrage.

4.2.1. Model of Physical Arbitrage

The arbitrage model represents the critical parts of the LNG train, including the constraints and flexibilities of a supplier to respond to market price signals. To facilitate solution, I use a spreadsheet modeling program, Microsoft Excel, and the add-in program Crystal Ball™ to conduct Monte Carlo simulations.

A vertically integrated 'commercial' LNG project structure is assumed, 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 at the market price. 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.

In the model a LNG supplier takes cargoes in Egypt and has contracts to deliver gas to a U.K. regasification terminal. A series of long-term contracts would likely support financing for the investment in gas production, ships, and reserved regasification capacity necessary to deliver gas to 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 1 Bcf/day to the U.K. with attractive margins for the supplier at prices over $3 per 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 supplier will engage in physical arbitrage in those months that the price spread between the two markets supports the added costs of diversion including: (a) fulfilling any volume contract commitments in the U.K. market, (b) additional ship charters required to maintain full volume deliveries for the longer shipping distances, and (c) 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. 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.[4]

[4] The assumption of full market liquidity is reasonable for cargo diversions at the margin. The model here discusses diversions of 1 Bcf/day, which would be more 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.

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.[5] Tankers are assumed to be available for short-term charter at a rate of $54,000 per day for a 150,000 cubic meter capacity vessel.[6] The resulting shipping cost of arbitrage is $0.52 per mcf delivered to the U.S. from Egypt.

Cargo diversion occurs when the 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

[5] 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.
[6] 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 150,000 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.

capacity to connect to regional markets.[7] 1 Bcf/day would constitute less than 2% of U.S. demand at current consumption levels.

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

4.2.2. Simulating Future Prices

The difference (spread) between regional prices is the critical driver for arbitrage value. Thus, I abstract from the long-run, multi-year evolution of gas prices and focus on short-run prices in each region to determine the possibly for spread-responsive LNG cargo movement. 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

[7] 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.

[8] So long as regasification terminal owners are allowed to control access, and set "market-based" rates for terminal access.

cargoes in all markets to move up and down together over annual time-scales and longer. Over shorter time scales, monthly or seasonally, regional prices may deviate more significantly between regional markets reflecting the structural factors considered in chapters 2 and 3, and also short-run stochastic demand deviations.

In chapter 2 of this volume I developed an analytical framework to describe the fundamental interaction of regional gas markets connected by LNG trade. And in chapter 3 the Atlantic Basin Model provides estimates for the *expected* seasonal movement of LNG cargoes responding to *expected* variations prices between the U.S. and Europe.

The additional option value of moving LNG cargoes to respond to *stochastic* variability requires a representation of the variability of regional prices from these expected seasonal levels. In this section, I review two types of models commonly used to represent the evolution of stochastic price series. One model, the mean-reverting model, is chosen to represent the stochastic evolution of gas prices in regional markets. Using parameter estimates from historical data and the *expected* seasonal prices series from Atlantic Basin Model results, I then use a mean-reverting model to simulate future prices in the U.S. and U.K. markets. The simulation of these individual price series yields a price spread that determines the opportunity for physical arbitrage between the two regional 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 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 the spread in prices between markets. If both U.S. and U.K. prices were each individually 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 profit opportunities.[9]

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

[9] Even prior to the movement of LNG cargoes, gas prices in the U.S. and U.K. have tended to trend together over the long-term (see figure 4.2) – contrary to the basic GBM model. This suggests a common factor may drive prices in each region (most likely oil prices). The connection between gas and oil prices has been studied elsewhere (Brown 2005; Bachmeier and Griffin 2006).

the mean-reverting, or Ornstein-Uhlenbeck model. The underlying assumption of the mean-reverting model is that underlying supply and demand fundamentals drive long-run expected price levels. Stochastic deviations in supply and demand drive unpredictable deviations from these 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 for an individual price series is shown in equation (4.1):

$$(P_t - P_{t-1}) = \eta * (\mu - P_{t-1}) + \sigma * \varepsilon_t \tag{4.1}$$

According to equation (4.1), the change in price from one period (P_t) to the next (P_{t-1}) is determined by two factors. First, there is a tendency to move toward the long-run mean (μ) at the mean reversion rate (η). Second, random shifts move prices up or down in distances determined by the volatility (σ) and randomly occurring deviations (ε). This simplified form of the mean-reverting model can be adapted to incorporate an expected price level (μ_t) that varies over time, either seasonally or in a long-run trend.[10]

Model Selection and Parameter Estimates from Historical Data

Examination of historical data would typically guide selection of the appropriate model and parameter values. If the fundamental operation of markets is assumed to be

[10] 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.

consistent over time, future price series would be expected to follow past behavior. 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 trade suggests that historical price series may not provide a reliable predictor future price behavior.

The significant price increases since January of 2000 in both the U.S. and the U.K. is evident in figure 4.2. These series are trending upward over this time period, rather than randomly moving around expected monthly price levels. Moreover, the relatively short history of 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 and Pindyck 1994).

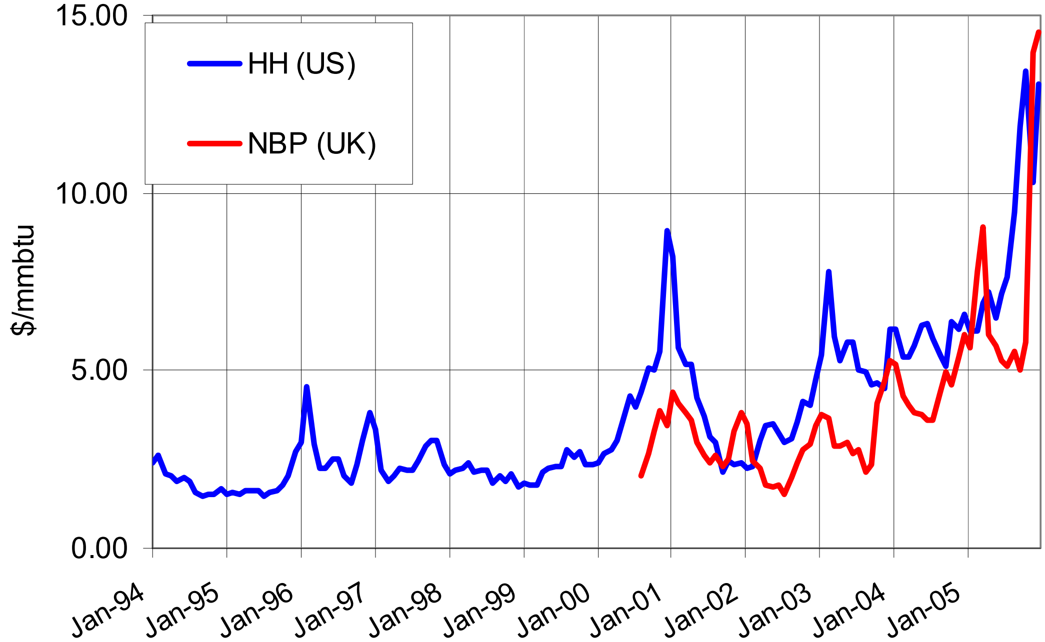

Figure 4.2. Monthly Average Gas Prices in the U.S. on the Henry Hub (HH) and in the U.K. at the National Balancing Point (NBP).
Source: US EIA, Bloomberg.

In this analysis, I model the two regional price series separately and use the results to derive the price spread between the two markets. There are thus two sources of stochastic variation and such an approach is therefore called a two-factor model (Soronow and Morgan 2002). An alternative approach would be to model the price spread between the U.S. and U.K. markets as a single mean-reverting series, with one stochastic source of variability. Such an approach is particularly applicable when representing prices between two fungible trading points, where the only limitation between the two markets is the cost of transportation. This description does not well fit the Atlantic Basin gas market. As discussed in chapter 3, significant structural differences (such as the cost of gas storage) between the U.K. and the U.S. are likely to persist over time. The two-factor model maintains the flexibility to represent such structural differences in the two markets.

Historical data for U.S. and U.K. markets provides useful benchmarks for the simulation of future prices. However, given the major changes underway in gas markets, volatility and mean reversion rates may shift in the future. Historical data thus provides a plausible range of values that can guide sensitivity analysis of the parameters values for each regional price series.

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). The historical data for each region is fit to the mean-reverting model using linear regression. Parameter estimates for the Henry Hub (U.S.) and the National Balancing Point (NBP) in the U.K. can be obtained using the following equation:

$$(P_t - P_{t-1}) = a + b * P_{t-1} + e_t \qquad (4.2)$$

Estimates from the regression yield parameter values for the simulation of future prices for each region: the mean reversion rate: $\eta = -b$; the long-term average for the respective period: $\mu = \frac{a}{\eta}$; and the volatility for the for the future price simulation is equivalent to the standard error from the historical regression: $\sigma = s$.

U.S. prices for the whole period 1994 through 2005 do not yield statistically significant parameter estimates for the mean-reverting model. The steady increase in prices since 2001 creates a significant trend rather than a mean-reverting process.[11] Thus, the U.S. time series was separated into two periods.

Prices for the period 1994-1999 provide reliable parameter estimates, with average Henry Hub prices of $2.21 per mcf, a volatility of 18% per month, and a mean reversion rate (η) of 0.27 (see table 4.1). The estimated mean reversion rate implies that the price tends to move 27% of the distance back toward the expected mean price level in each period, notwithstanding the effects of stochastic disturbances.

For the period 2000-2005, parameter estimates were less reliable, also due to the run-up in prices over that period. The absolute level of volatility was higher in the latter period, but consistent if measured in percentage terms. The estimated mean reversion rate in Henry Hub prices apparently fell significantly relative to the earlier period.

The time series of historical data from the National Balancing Point in the U.K. is considerably shorter than the U.S. Given the upward climb in prices of this period, parameter estimates from the model were also not robust. It is, however, interesting to note the similar estimates for volatility as found in the U.S. market. The simulations of future prices for each market will use deviations around these estimates of volatility and

[11] 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 2 and 3 are better indications of the expected future prices. The parameter estimates here are useful for providing a range for sensitivity analysis only.

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. 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.[12] 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.

[12] 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. Testing for correlation of absolute price levels could easily mask a common underlying driver – such as oil prices – that drives longer-term prices in both markets.

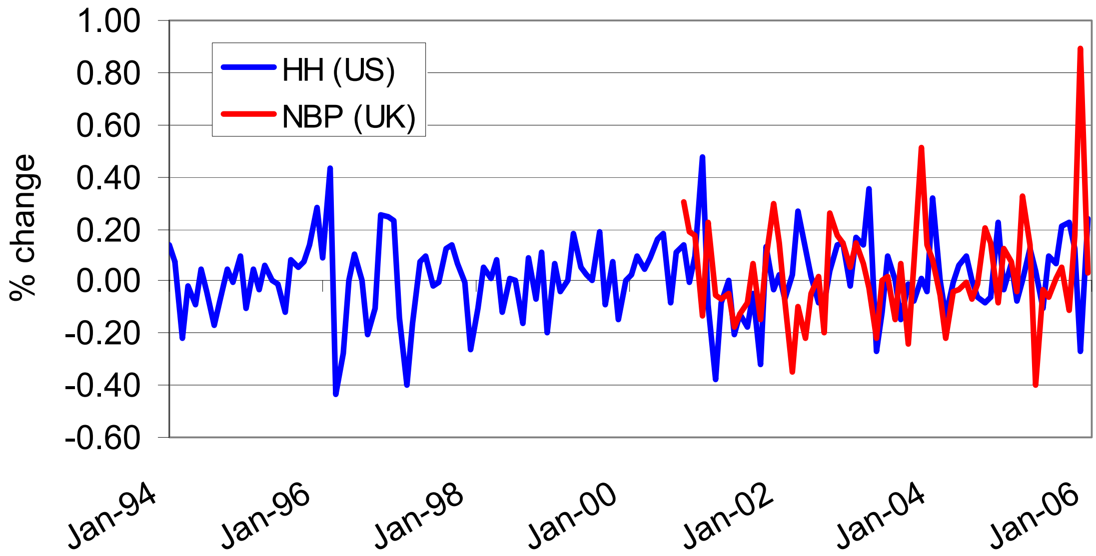

Figure 4.3. Monthly Changes (in percent) of Gas Prices in the U.S. on the Henry Hub (HH) and in the U.K. at the National Balancing Point (NBP). *Source: US EIA, Bloomberg.*

Non-correlated variability in prices – as shown in figure 4.3 – creates spreads between U.S. and U.K. gas prices. The size of price changes (volatility, σ), and the tendency to return to the mean (mean reversion rate, η) in each price series determine the absolute value and duration of the price spread. The value of flexible LNG trade is, in turn, derived from moving cargoes in response to the occurrence of favorable spreads between the U.S. and U.K. markets.

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

For each regional market, the basic mean-reverting model is extended to incorporate expected seasonal trends in prices for each market, based on the results of chapter 3. The mean-reverting model then adds stochastic variation to each regional series. The model for the U.S. and the U.K. are formulated as follows:

First, as shown in equation (4.3), U.K. prices in any period are determined by the previous period price ($P_{t-1,uk}$), the tendency to move toward the expected monthly price level (μ_t), and normally distributed disturbances proportionate to the assumed volatility level (σ_{uk}).

$$P_{t,uk} = P_{t-1,uk} + \eta_{uk} * (\mu_{t,uk} - P_{t-1,uk}) + \sigma_{uk} * \varepsilon_{1,t} \qquad (4.3)$$

where $\varepsilon_1 \sim N(0,1)$ (4.4)

A similar future price curve is simulated for the U.S. Henry Hub, as in equation (4.5):

$$P_{t,us} = P_{t-1,us} + \eta_{us} * (\mu_{t,us} - P_{t-1,us}) + \sigma_{us} * \varepsilon_{3,t} \qquad (4.5)$$

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 (4.6):

$$\varepsilon_{3,t} = \rho * \varepsilon_{1,t} + \sqrt{1-\rho^2} * \varepsilon_{2,t} \qquad (4.6)$$

The error term in the U.S. Henry Hub price series $\varepsilon_{3,t}$, is a function of the correlation (ρ), the randomly occurring disturbances in the U.K. price series $\varepsilon_{1,t}$, and a separate set of independent normally distributed error terms, $\varepsilon_{2,t} \sim N(0,1)$.

In this model formulation, the size and duration of the spread in prices between the two markets is determined by the respective mean-reversion rates (η), the volatilities in each region (σ), and the correlation of the error terms. In general we would expect that higher volatilities would generate larger spreads, and lower mean reversion rates would make spreads longer in duration. However, if deviations in both markets are strongly correlated, then prices in each region will move together tending to reduce price spreads.[13]

4.2.3. Model Simulations

Four sets of assumed volatility and mean reversion rates are selected for each region. Pairs of parameter values are grouped into four "scenarios", as shown in table 4.2. Using the Monte Carlo method, 10,000 potential price series are generated for each set of parameter values and an assumed correlation term (ρ). Each individual simulation of future prices for the U.S. and the U.K. generates a series of price spreads. When the price spread is enough to cover the additional cost of transportation, cargoes are diverted from the U.K. to the U.S.

The scenarios in table 4.2 were selected based on historical price series data in table 4.1, and also to illustrate the relationship of price spreads (and thus arbitrage value) to each respective parameter value. In general, volatility levels are increased across the

[13] Even when the error terms are perfectly correlated (e.g. $\rho = 1$), differences in the size of regional price volatilities and mean reversion rates can create positive spreads between two markets. The implications of varying particular parameter values are illustrated in the simulation analysis of various scenarios below.

first three scenarios. Scenario 4 which is used to show the value of expected seasonal spreads separate from the value introduced from stochastic variability.

Table 4.2. Selected Scenarios for Simulation.

Scenario		**Monthly Volatility (%)**	**Monthly Volatility ($)**	**Mean Reversion (η)**
S1	U.K.	15%	$0.70	0.30
	U.S.	10%	$0.50	0.30
S2	U.K.	15%	$0.70	0.10
	U.S.	15%	$0.70	0.30
S3	U.K.	25%	$1.20	0.30
	U.S.	15%	$0.70	0.10
S4	U.K.	0%	0	1
	U.S.	0%	0	1

There is some evidence from historical data that the U.S. Henry Hub may exhibit lower volatility than the NBP in the U.K. Thus, the simulation of S1 represents arbitrage between a lower volatility U.S. market with a higher volatility U.K. market. S1 also illustrates the outcome when the mean reversion rates for both markets are equal.

S2 depicts a scenario where volatilities are the same in both the U.S. and U.K. market, but the mean reversion rate is faster in the U.S. than the U.K. This case most closely matches the parameter estimates from the model. The faster U.S. mean reversion corresponds to η=27%, estimated from the 1995-1999 period.

In S3, the U.K. is assigned a higher volatility and faster mean reversion rate (η=0.3), and the U.S. is assigned a relatively lower volatility and a slower η=0.1. Though S3 does not correspond to historical data, in general we might assume that faster mean reversion rates tend to occur with higher volatilities. S3 allows the exploration of one such scenario. S4 is a special case that illustrates the value of seasonal arbitrage without any stochastic variability.

Each of the four scenarios is sampled across a range of correlations (ρ) of the error terms in the U.K. and U.S. price series. All else equal, increasing the correlation of error terms will decrease the proportion of non-correlated error, thereby reducing the magnitude of price spreads between the two markets. In physical terms, the expansion of LNG trade and physical arbitrage is expected to increase the transmission of price changes between markets. A cold weather event in the U.S. would be expected to draw cargoes from the U.K., thus reducing supply to the U.K. and increasing 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. The correlation of error terms ($\varepsilon_{1,t}$ and $\varepsilon_{3,t}$), is varied from completely uncorrelated (ρ=0), to perfectly correlated (ρ=1). A sample of simulation S2 and the expected mean seasonal prices is shown in figure 4.4.

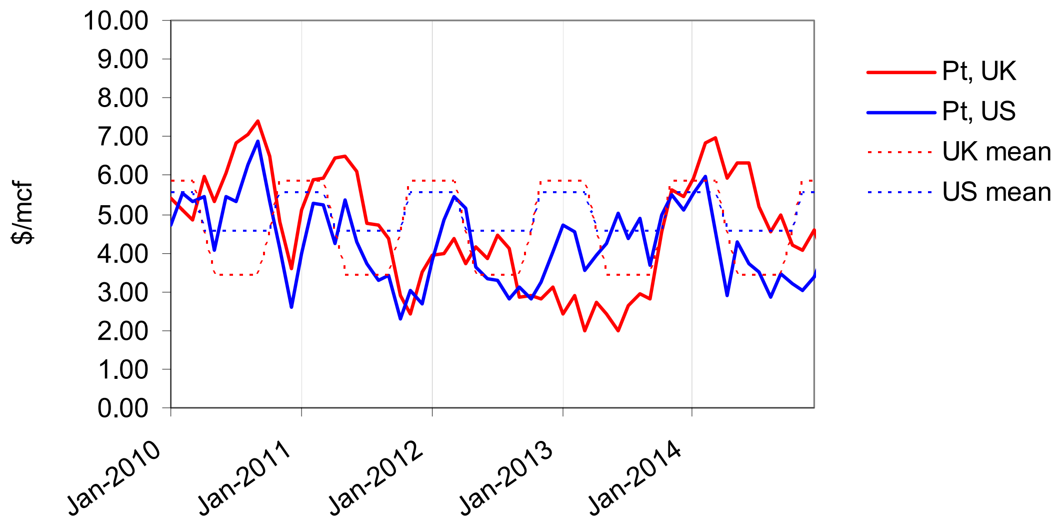

Figure 4.4. Sample price series from scenario S2. The simulation plot is one outcome of 10,000 scenarios evaluated for the scenario S2 where: $\sigma_{uk} = \sigma_{us} = 15\%$, $\eta_{uk} = 0.1$, $\eta_{us} = 0.3$, and the correlation of error terms, $\rho = 0.5$.

4.3. RESULTS

The model simulates the underlying price series, but the arbitrage value can be shown most directly by examining the spreads between the U.S. and U.K. prices. In figure 4.5 (right chart), the same simulated price series shown in figure 4.4 are displayed as the difference (spread) between U.S. and U.K. prices. Arbitrage potential exists where the price spread is in excess of the added shipping cost to divert cargoes from the U.K. to the U.S.—plotted here at $0.52 per mcf. Based on the results of this single simulation, an LNG supplier contracted to deliver 1 Bcf/day of cargoes to the U.K. could reap $348 million USD in additional operating profits in the year 2013 by diverting cargoes.[14] In this simulated year 2013, cargoes would be diverted in nine months out of the year, reflecting an average price spread in those months of $1.79 per mcf in favor of the U.S.

[14] The years here are ordinal only. Simulation results are not tied to any specific base year.

The uncertainty related to arbitrage is also evident in the model, as the only other year providing arbitrage potential in this simulated five year period is 2012, yielding arbitrage returns of just $67 million USD.

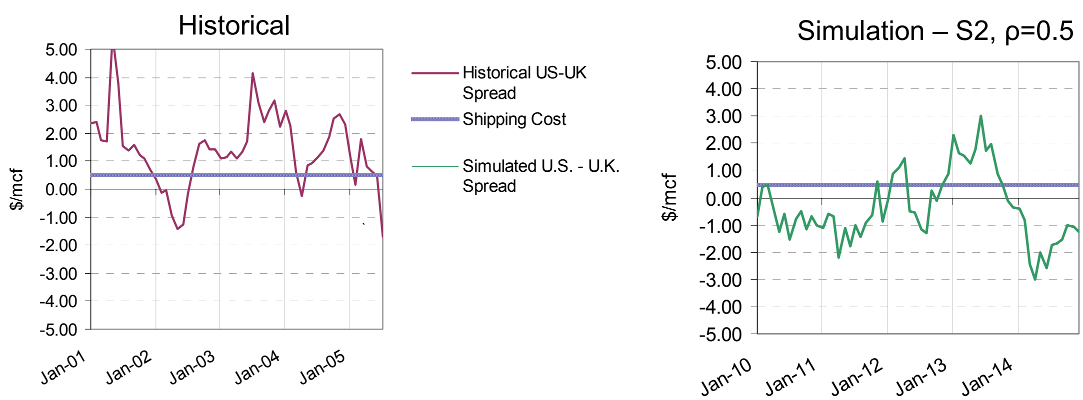

Figure 4.5. Historical and Simulated Price Spreads.

A useful benchmark is to compare simulated results to historical data. The left chart in figure 4.5 plots historical price spreads and the transit cost for the period 2001 to 2005. The historical chart 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. during the 2001 to 2005 period. This is a hypothetical consideration, as the first regasification capacity in the U.K. only became operational in 2005.

The mean estimated arbitrage values for each of the four scenarios in table 4.2 are plotted in figure 4.6. Each curve (S1, S2, S3) represents a unique set of price parameters (σ_{us},σ_{uk}, η_{us}, η_{uk}). For each scenario the level of price change correlation (ρ) is varied on the x-axis. Each point on the respective S1, S2, S3 and S4 plots in figure 4.6 represents the mean value over 10,000 simulations of possible price series for both the U.S. and the U.K. The value on the y-axis is the mean arbitrage value in millions of USD per year for 1 Bcf/day of diversion capacity.

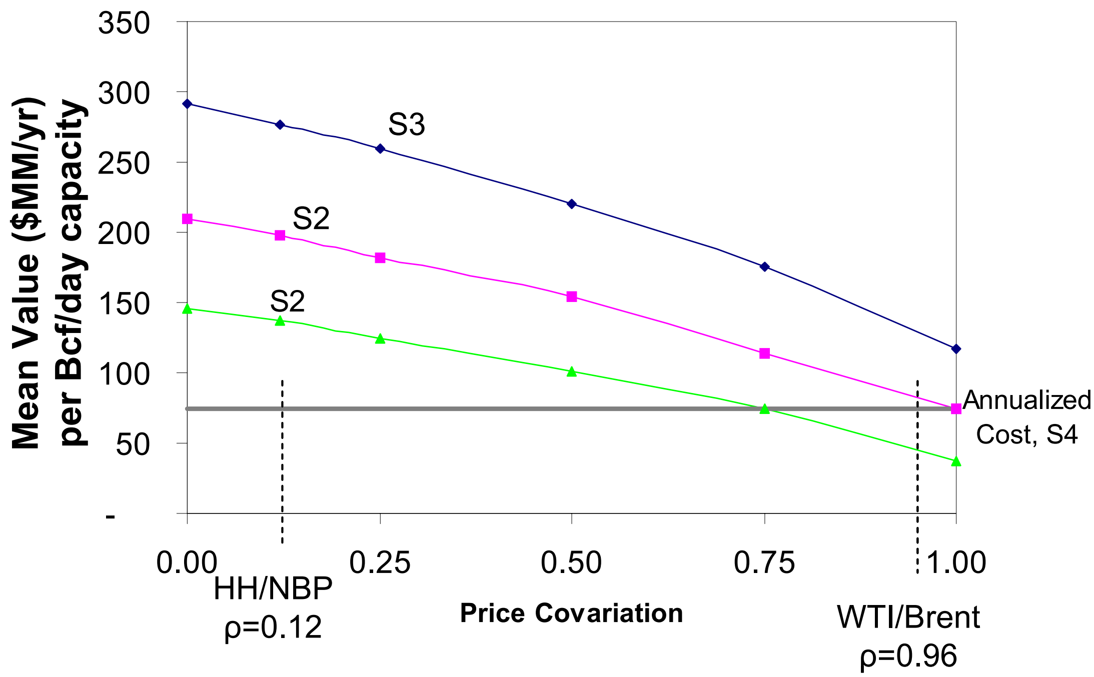

Figure 4.6. Estimated Mean Annual Arbitrage Benefits from Monte Carlo Simulations.

The values reported in figure 4.6 are net of incremental shipping costs. Access to regasification capacity in the U.S. is the only remaining cost of physical arbitrage. The arbitrageur could either own (or contract long-term) or purchase terminal receiving capacity on an as needed basis. Long-term contracting would ensure the supplier gained all of the arbitrage rents, but would require a fixed commitment by the supplier. Short-term rates for access to U.S. regasification are likely to vary with the U.S. – U.K. price spread. Positive spreads would encourage other suppliers to also divert cargoes to the U.S., and therefore charges for access to regasification capacity would be likely to increase with the scarcity value of terminals.

It is illustrative to compare the full rents from arbitrage to the fully capitalized cost of regasification capacity. This shows the benefits of full vertical integration to own the arbitrage option. The estimated cost of maintaining 1 Bcf/day of regasification capacity is approximately $75 million USD per year.[15,16] These estimates include both construction costs and fixed operations and maintenance costs, which would accrue independent of volumes delivered. The estimated cost of regasification is also plotted in figure 4.6.

Key Relationships between Parameters and Arbitrage Value

The results in figure 4.6 show three key relationships between arbitrage value and the underlying fundamentals of internal market prices.

First, each scenario (S1 – S3) shows the clear inverse relationship between the correlation of disturbances in U.S. and U.K. prices (from $\rho=0$ to $\rho=1$) and expected arbitrage returns. For each scenario, increased correlations of random price disturbances reduce the <u>magnitude</u> of any price spreads between the two markets. Regional spreads

[15] Based on capital costs for a new build regasification terminal of $600 million USD for 1 BCFD of 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.

[16] 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.

are generated from non-correlated variability. Increasing the correlation of the error terms reduces spreads and lowers the overall expected profits to physical arbitrage.

Second, volatility tends to increase arbitrage value. In scenarios S1 to S3 the volatilities of both the U.S. and the U.K. (σ_{us}, σ_{uk}) are generally increased—and the chart shows that the expected returns to arbitrage also increase with volatility. All else equal, price volatility in each of the underlying price series increases the magnitude of non-correlated movements in either of the price series, and thus increases the magnitude of price spreads and returns to arbitrage.

The third result illustrated in figure 4.6 is the general inverse relationship between mean reversion rates and price spreads. Mean reversion rates (η_{us}, η_{uk}) are fastest in S1 then lower (depending on price series) for S2 and S3. Arbitrage values generally increase across the scenarios. Slower reversion to the mean increases the persistence of non-correlated deviations between the two price series. In terms of spreads, slower mean reversion increases the duration of spreads between U.S. and U.K. prices. Increasing the tendency to sustain any price spread will increase the likelihood that a particular positive U.S. – U.K. spread lasts longer and allows more ships to be diverted to generate arbitrage returns.

A more careful consideration of the relationship between mean reversion rates for each region (η_{us}, η_{uk}) shows that a difference in η values for the individual price series also increases arbitrage potential. From S1 to S2 the major change in parameter values is to introduce heterogeneity in η for the two regions, with U.K. prices tending to revert to mean more slowly than the U.S. price series. The significant increase in arbitrage values in S2 relative to S1 is a result of somewhat larger price spreads to due increase in U.S. volatility – but mostly due to the longer <u>duration</u> of those price spreads as lower U.K. prices are slower to return to mean than U.S. prices. Thus, when a positive price spread occurs with U.S. prices above the U.K., these spreads are sustained over several months increasing the total arbitrage potential.

If prices in both regions tend move toward their long-run mean at the same rate, as in scenario S1, prices are more likely to move together and spreads are generally lower. To illustrate this point, when e.g. $\eta_{us} = \eta_{uk}$, the two price series in scenario S1 can simplified to a single formulation of price spreads. Assuming a common mean reversion rate η and where Δ_t is the difference between U.S. prices and U.K. prices in time period *t*, the following result is obtained by subtracting equation (4.3) from equation (4.5) :

$$\Delta_t = \Delta_{t-1} + \eta * \left[\left(\mu_{t,us} - \mu_{t,uk} \right) - \Delta_{t-1} \right] + \sigma_{us} * \varepsilon_{3,t} - \sigma_{uk} * \varepsilon_{1,t} \qquad (4.7)$$

And restating equation (4.6), we also note that:

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

In the extreme case where ρ=1, e.g. the direction of disturbances in either price series are perfectly correlated, equation (4.7) becomes:

$$\Delta_t = \Delta_{t-1} + \eta * \left[\left(\mu_{t,us} - \mu_{t,uk} \right) - \Delta_{t-1} \right] + \varepsilon_{1,t} * (\sigma_{us} - \sigma_{uk}) \qquad (4.8)$$

According to (4.8), when $\rho=1$ the only stochastic component of the price spread is generated by any difference in the magnitude of price volatilities in the respective markets. Similar manipulation of equations (4.6) and (4.7) shows that under assumptions of common mean reversion rate ($\eta_{us} = \eta_{uk}$), positive correlation between price disturbances in two respective markets ($0<\rho<1$) tends to reduce the magnitude of price spreads between markets relative to a case where $\eta_{us} \neq \eta_{uk}$.[17]

The Risk Profile of Physical Arbitrage

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 would accrue 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 scenario S2 and $\rho = 0.5$. The 50% level of price change correlation might be expected after a significant number of tankers and regasification capacity are available to engage arbitrage between the U.S. and the U.K.

Figure 4.7 shows that for a single year, 57% of the simulation results provided price spreads between the U.S. and the U.K. in those twelve months great enough to

[17] Conversely, where ($-1 < \rho < 0$) the direction of errors are negatively correlated in the two markets. Thus, the any increase in volatility in either market tends to increase overall spreads. There is little intuition, however, to support a hypothesis where prices in two regional markets for the same commodity could be inversely correlated. Such a condition could exist where there is no ability for trade between regions, but the possibility of any trade opens the opportunity to move supplies between markets, thus creating some co-variation of prices.

generate returns in excess of the $75 million USD. ($75 million is the estimated annual cost of owning the regasification facility.) Conversely, in 43% of the sample years, the owner of firm regasification capacity in the U.S. would not cover the cost of holding this physical option to deliver arbitrage cargoes.

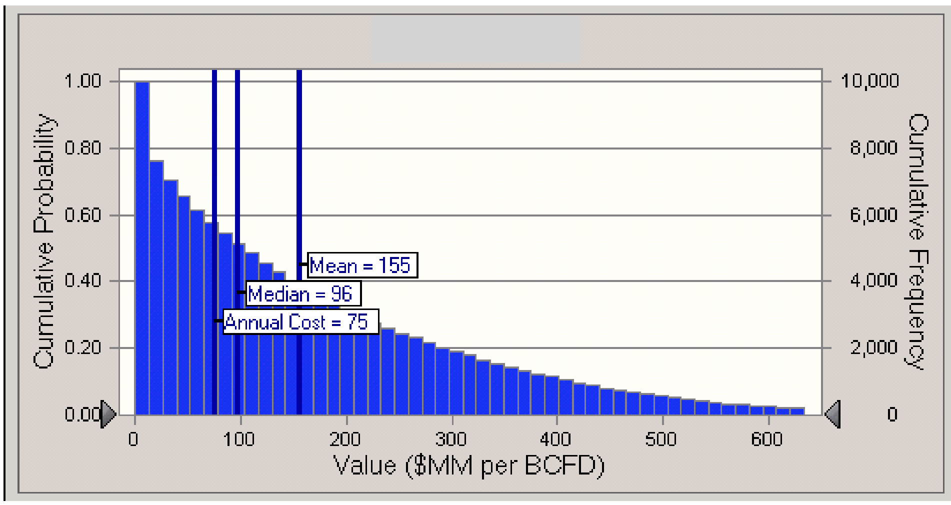

Figure 4.7. Reverse Cumulative Frequency Distribution of Annual Arbitrage Benefits. Results shown are for 10,000 simulations of scenario S2 where: $\sigma_{uk} = \sigma_{us} = 15\%$; $\eta_{uk} = 0.1$, $\eta_{us} = 0.3$, and the correlation of error terms (ρ) is assumed to be 0.5.

The high variance of arbitrage returns is also evident in the skewness of 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 over several months of that year.

4.4. DISCUSSION

In general, the results of the simulation suggest significant rents to arbitrage in the Atlantic Basin. In nearly all of the scenarios, which tested a range of feasible volatility and mean reversion rates for U.S. and U.K. prices, arbitrage returns were in excess of estimated cost of reserving offloading terminal capacity in the secondary market. Arbitrage rents are likely to persist so long as the level of correlation of price changes between the two markets continues at historical levels (e.g. $\rho = 0.12$ from 2001 to 2005 for the Henry Hub and National Balancing Point.).

If LNG transport is itself a competitive market, e.g. there are limited barriers to entry, one would expect that investment in ships and regasification capacity would be attracted to the LNG trade seeking these excess returns to arbitrage. Such increases in physical arbitrage capacity and the movement of LNG tankers to respond to attractive price spreads will have the effect of transmitting price changes across the Atlantic. In terms of the model used here, increased cargo diversion would increase the correlation of random changes in U.S. and U.K. prices (ρ). Increasing the correlation of price movements would narrow price spreads between the regions. Assuming an efficient, competitive market, investment will continue until the expected occurrence of price spreads provide returns sufficient only to cover the costs of maintaining the flexible capacity option and a normal economic return.

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.[18]

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.[19] Oil unloading facilities would also be expected to be significantly cheaper. Oil docks, pipelines and tanks are less costly and capital intensive than the specialized cryogenic pipelines and storage required for LNG offloading. The vaporization racks required for returning LNG to its gaseous state also add to the cost of LNG offloading capacity. Considering transit costs alone, arbitrage opportunities in natural gas do not develop between the U.K. and the U.S. until U.S. prices are $0.52 per mcf in excess of U.K. prices. Thus, based on transit cost

[18] In addition to transit costs, the difference in WTI and Brent prices is driven by quality differences that also affect refiner demand for the respective crude oils. 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.

[19] 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).

differences alone, we should not expect the narrow spreads in regional gas prices that are observed in oil.

If stochastic variability were the only source of price spreads, we would expect that arbitrage returns should be zero when the random disturbance terms in each market are perfectly correlated (e.g. $\rho=1$). However, figure 4.6 shows that in scenarios S1, S2, and S3 positive arbitrage returns exist even when $\rho=1$. For S3, these returns are in excess of the annualized cost of regasification capacity.

Arbitrage potential persists, even when non-correlated stochastic variability is removed, as the underlying price levels in each region are expected to vary by month, following the results of the system model of the Atlantic Basin described in chapter 3. In the system model, price changes in each region moved directionally together each month, but differing gas storage costs and seasonal demand profiles supported price spreads that favored Europe (here the U.K.) in the winter and positive price spreads to the U.S. in the summer months. The Atlantic Basin model indicates that such time-varying, regional price spreads should be repeated over consecutive twelve-month period, irrespective stochastic variability due to other factors such as weather, or local economic variability.

In the arbitrage model used in this chapter, we can examine the returns to expected seasonal arbitrage by removing all of the non-correlated stochastic variability from the two mean-reverting price simulations – but keeping the expected seasonal variations in prices (and spreads) from the Atlantic Basin model. Scenario S4 illustrates this result. In S4, both price series are assigned a mean reversion rate of 1.00 (η=1) and no stochastic volatility ($\sigma_{us} = \sigma_{uk} = 0$). Prices thus, do not deviate from the expected monthly values, and prices follow exactly the seasonal swing in prices based on the results from the ABMod in chapter 3.

When regional prices (and the resulting price spreads) follow the expected seasonal levels, arbitrage returns match the cost of investment in the regasification. Under the assumptions of S4 and in the Atlantic Basin model results, diversion of LNG from the U.K. to the U.S. would regularly occur each summer. Since there are no remaining stochastic errors, this condition holds for all values of ρ. Thus, S4 corresponds exactly with the "annualized cost" of regasification plotted in figure 4.6.[20] This follows from the Atlantic Basin competitive equilibrium solution, where investment in regasification capacity occurred until the value of that capacity for seasonal cargo diversion matched the unit cost of incremental capacity expansion.

Seasonal arbitrage is thus expected to occur each year – usually to the U.S. in the summer months. When the correlations of random price disturbances are less than one, or mean reversion rates are different in each region, stochastic variability tends to increase price spreads and arbitrage potential relative to the expected seasonal arbitrage. Such non-correlated stochastic variability widens price spreads from the expected seasonal levels and adds value for "excess" regasification capacity. Only in scenario S1, when mean reversion rates in each market are equal (thus reducing duration of spreads)

[20] When η = 1, monthly price changes from expected seasonal prices are zero, and thus the correlation of the deviations is irrelevant.

and U.K. volatility is in excess of the U.S. volatility (σ_{uk} = 15% > σ_{us} = 10%), are arbitrage returns reduced below seasonal arbitrage with high levels of correlated disturbances (ρ > 0.75). In this scenario, higher U.K. volatility erodes the expected seasonal arbitrage without adding significant stochastic variability.

In addition to unit-level arbitrage considerations, gas suppliers and buyers will also be interested in the scope for arbitrage in total volume terms. A specific estimate of the number of tankers and the level of regasification capacity that can still generate positive returns is not feasible here, as the model framework used here does not explicitly incorporate price response due to cargo diversion. It is possible to estimate when the bulk of spot cargo diversion will occur and compare the scope for stochastic arbitrage to the expected seasonal diversion of cargoes described in chapter 3.

The Atlantic Basin Model solution suggested that 14.5 Bcf/day of the total 18.5 Bcf/day total U.S. regasification capacity would be used to accommodate seasonal cargo diversion. Positive price spreads to the U.S. in the summer attracted an additional 14.5 Bcf/day of LNG to the U.S. market over and above the 4 Bcf/day of winter LNG imports. As the Atlantic Basin model does not incorporate uncertainty in demand, regasification is scaled to match the summer peak LNG imports, and operates at full capacity in the summer months.

Since the U.S. – U.K. price spread is positive in the summer months, stochastic deviations on these price levels will also be more likely to occur in the summer months.

Winter spot arbitrage to the U.S. can occur. Summer arbitrage will be more frequent and attractive to LNG traders.[21] Considering the monthly deviations in demand illustrated in figure 4.l, demand volume swings in excess of 5% may regularly occur in the U.S. and in Europe. Thus, additional capacity of ships and regasification terminals to deliver 3 Bcf/day to the U.S. would provide a 5% supply increase in the U.S. market to match a similar spike in U.S. gas demand.[22]

4.5. Conclusions

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. Equilibrium results from the Atlantic Basin model in chapter 3 illustrated the impacts of seasonal demand profiles and storage costs—in addition to transport costs—as critical determinants of expected seasonal prices and spreads in so-called "integrated" regional markets.

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 and price spreads) creates additional value for holding access to regasification capacity over and above the expected seasonal cargo diversions.

[21] The U.S.-U.K. price spread is expected to be $0.86 in July, August and September. 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 cargos from the U.S. market.
[22] Based on projected average summer month consumption of 60 Bcf/day in 2015 from Atlantic Basin model results.

Non-correlated variability in regional prices drives spreads, which in turn create positive returns to the option to divert LNG supplies toward the positive spread market. The movement of cargoes between markets will itself transmit price changes between markets, increasing the level of correlation of price changes between markets – thereby reducing price spreads between regional markets.

Even with extensive physical arbitrage, positive price spreads will still be created between regional gas markets. Internal market fundamentals, such as the flexibility of gas demand and the availability of short-term gas storage, will make prices in individual regional markets respond differently to supply and demand shocks. In terms of the model here, such differences would be exhibited in different volatilities and mean reversion rates.

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. Arbitrage between markets requires that gas suppliers have access to capacity in both tankers and regasification to respond to market pricing opportunities. 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. 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 additional important caveat to the analysis presented here relates to the regulatory and institutional structure of gas markets, particularly in continental Europe and in Asia that is the focus of chapter 5 that follows. 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, as are the internal gas prices in these markets. Such oil-indexed pricing exhibits much lower volatility compared to competitive market pricing. More importantly oil-linked prices also do not respond to the supply-demand balance for gas within each market. Thus, the persistence of such rigid oil-linked contract structures are likely to create and maintain large spreads and arbitrage returns between competitive and oil-linked contract markets, as the movement of cargoes between the regions has no impact on the oil-linked prices in continental Europe or Asia as it would have when supplies are diverted to/from competitive markets. The implications of the interaction of these differing market institutions in continental Europe and in the U.S. for gas price volatility within these regions are discussed further in chapter 5.

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