FLEXIBLE LNG SUPPLY AND GAS MARKET INTEGRATION:
A SIMULATION APPROACH FOR VALUING THE MARKET ARBITRAGE OPTION

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ABSTRACT

This paper introduces a methodology to value investment in the physical LNG capacity required to arbitrage regional natural gas markets. Forward price series are simulated for both the U.S. and the U.K. based on historical data. A model then allows an LNG supplier to respond to favorable price conditions to move cargoes to the highest netback market. Repeated Monte Carlo simulations provide an estimate of annual returns to the holder of arbitrage capacity, depending on assumed price volatility levels and other pricing fundamentals. Current levels of volatility and price correlations between U.S. and European markets imply positive returns to the holders of such arbitrage capacity. Results also suggest a relationship between the cost of maintaining surplus tanker and regasification capacity and the level of integration that can be expected in regional gas market prices. The relatively high costs of LNG shipping and regasification will prevent the tight integration of gas prices across regions.
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1. INTRODUCTION

Global natural gas markets are in the midst of a much discussed 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 the 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 on fixed routes defined by destination clauses in the sales and purchase agreements. Each segment in the LNG chain--liquefaction, ships, and regasification--was scaled to match long-term contractual flows for a specific trade route.

The opening of regional gas markets and the rapid growth in LNG transport 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 [1]. Market analysts have discussed the key drivers for this shift and sketched the 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, rather than according to contractually rigid trade routes [2, 3].

While the broad outlines of the shifting trends in the LNG business have been much discussed among analysts, this author is not aware of any quantitative assessment in the open literature of how far the LNG trade may move toward the flexible commodity-like trade necessary to achieve tight integration in global gas markets. The analysis presented here seeks to directly address the question of market integration by valuing the flexible LNG capacity required to inter-connect regional gas markets.

Value of flexible LNG supply

The flexibility of LNG shipments provides the only physical arbitrage mechanism between otherwise isolated, continental gas pipeline grids (e.g. North America, Europe, Korea and Japan). Gas demand in all these markets is highly variable on daily, weekly and monthly scales. The size and scope of seasonal swings in gas consumption varies in each market, based on climate characteristics and demand composition. These seasonal shifts in gas demand are traditionally managed with gas storage and some variations in gas deliveries by pipeline or LNG, within contract specifications. Flexible routing of LNG cargoes based on seasonal variations can provide a cost-effective alternative to other swing management alternatives. Korea, for example, has a strongly winter-peak gas demand for residential heating while Japanese gas demand has relatively stronger summer peak for gas consumption to generate electric power. The potential benefits of adjusting LNG deliveries to match the gas demand profiles are relatively easily realized. At the project scale, one liquefaction facility loads Japan-bound cargoes in the summer and then loads Korean-bound cargoes in the winter. The cost savings of such seasonal flexibility (most likely in reduced gas storage costs in both markets) are weighed against the incremental costs of maintaining excess regasification capacity to allow for the seasonal swings in LNG receipts.

Such seasonal variations1 in gas demand are largely predictable and consistent year over year for each market. There is also a significant component of natural gas demand that is random (stochastic) in nature. Stochastic drivers include weather, economic disruptions, or variations in the prices of competing energy sources (especially oil). The variations in gas prices caused by these drivers are realized on daily, weekly, monthly or longer intervals and each has no a priori knowable trend. These stochastic variations in gas demand are typically managed with storage capacity levels that provide some “cushion” so that supplies are available to meet highly variable consumption levels. Gas utilities with the obligation to serve factor these uncertainties into their storage management

1 In statistical terms, seasonal variation is a stationary trend.
decisions. Where regulatory institutions have moved toward competitive market-based pricing for wholesale natural gas (as in the U.S. and the U.K.), variations in gas demand—both seasonal and stochastic—are revealed in traded gas prices. Figure 1 shows monthly averages of spot gas prices in both the U.S. and the U.K.²

**Figure 1. Monthly Average Gas Prices and Price Changes in the U.S. on the Henry Hub (HH) and in the U.K. at the National Balancing Point (NBP).** Inset chart is of changes in prices, also in $USD per gigajoule. *Source: US EIA, Bloomberg.*

Scope for flexible LNG supply

For isolated markets, variations in gas demand can only be managed by mechanisms internal to the regional gas markets. Flexible LNG supply offers the possibility to move gas supply to markets to respond to demand swings—offering a potentially cost-efficient alternative to respond to demand uncertainty in the regional markets. A cold-weather driven spike in U.K. natural gas prices can be moderated by the ability to attract LNG cargoes originally intended for the U.S. The LNG shipper gains the higher price in the U.K. market, while U.K. customers also benefit from a moderated price compared to what might have been realized without the additional supplies.

The potential scope of such flexible LNG trading in the Atlantic Basin is evidenced by both the seasonal and stochastic variations in gas consumption in the U.S. and Europe. Total gas consumption in the two regions is similar in size. For the 2001-2004 period, U.S. consumption averaged $3 \times 10^9$ cubic meters per month (1,857 Bcf) compared to $2 \times 10^9$ cubic meters per month (1,496 Bcf) for the OECD Europe region. Europe experiences a stronger seasonal swing than the U.S., with average January consumption nearly twice average July consumption levels. U.S. consumption is less seasonal, due in part to greater use of gas for electric power generation. The very weak summer

² In the U.S. trading of natural gas is conducted on the New York Mercantile Exchange (NYMEX), for physical deliveries at the Henry Hub in Louisiana. Similarly, short-term trading of gas in the United Kingdom is conducted on the International Petroleum Exchange (IPE) for deliveries at the National Balancing Point (NBP).
demand in Europe compared to the U.S. suggests that the U.S. may tend to pull cargoes in the summer, while the stronger winter peaks suggest that Europe may tend to pull cargoes in the winter.  

Flexible LNG may also provide increased ability for gas supply to respond to the less predictable stochastic variations in gas demand. Figure 2 plots monthly deviations of U.S. and OECD Europe’s gas consumption—compared to monthly averages over the same four year period. For example, during January 2001 Europe experienced warmer than normal weather while the U.S. experienced colder than normal temperatures. As a result of these weather variations European gas consumption fell 8% in January compared to the four-year average for that month. U.S. consumption was up 4% for the same month.

Figure 2. Monthly Consumption Deviations from 4-Year Average: U.S. vs. OECD Europe. 
Source: EIA, IEA.

Indeed, LNG import trends in recent years tend to follow these seasonal characteristics. U.S. LNG imports tend to increase in the summer months, and Europe tends to acquire the majority of available Atlantic Basin cargoes in the winter [4]. The benefit to the system as a whole from this seasonal arbitrage would depend on the relative cost of flexible LNG supply to storage costs in each market. These storage-LNG flexibility tradeoffs are discussed in a separate paper which analyzes Atlantic Basin gas markets at the system level [5].

OECD Europe includes the EU 15: Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, The Netherlands, Portugal, Spain, Sweden and the United Kingdom, and also the Czech Republic, Hungary, Iceland, Norway, Poland, Switzerland and Turkey.
The plots in figure 2 show that in general deviations for the years 2001 to 2004 were not strongly correlated, revealing opportunities to shift supplies between markets potentially providing mutual benefit to gas sellers and buyers. Statistical tests reveal that the correlation coefficient of the consumption variations is not significantly different from zero.\(^5\) Moreover, the plots illustrate vividly the size of monthly gas demand variations—an appropriate scale for LNG tankers to play a buffer role. A 5% positive deviation in monthly demand in the U.S. market is on the order of \(3 \times 10^9\) cubic meters of gas (100 Bcf), equivalent to about 35 standard-size LNG tankers. All of these variations will never be managed by LNG diversions alone. 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 market variations. Still, flexible LNG supply can 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 seasonal and stochastic trends in consumption in the two major regional gas markets is only suggestive of the potential scope for flexible LNG supply to serve the Atlantic Basin. The incentive for arbitrage requires that there also be a price mechanism that transmits demand signals to potential sellers. The U.S. and U.K. markets have liquid markets that allow shippers to realize the potential price benefits of arbitrage.\(^6\) The inset chart in figure 1 shows the realized variations in monthly average prices between the U.S. and U.K. indices. Variations do not appear to move together, even if overall price levels in both markets have moved upward over the last five years.\(^7\) The U.S. and U.K. prices series illustrate the potential financial benefits to flexible LNG shipments. An LNG supplier with the ability to deliver gas to either market could adjust shipments to maximize returns. Markets are also developing on continental Europe, such as Zeebrugge, that would facilitate spot-trading to the continent as well.

Demand fundamentals and market-based pricing create the incentives for flexible LNG trade. The realization of price-responsive LNG transport—and the ensuing integration of regional gas markets—require that investments in shipping and regasification capacity be realized to allow for physical arbitrage to occur. For example, the owners of LNG supplies from Trinidad with capacity to deliver a steady supply of gas (e.g. 20 Bcf per month) to the U.S. Gulf Coast cannot divert 2 or 3 cargoes to the U.K. to respond to a market opportunity without chartering additional tankers (due to the longer shipping distance) and without access to regasification capacity in the U.K. Flexible LNG supply depends on the availability of “excess” capacity in both shipping and regasification terminals.\(^8\) Investors making decisions on whether to build ships and regasification capacity beyond contracted gas flows will look for returns to justify this additional capital outlay.

**Simulation approach**

This paper introduces a methodology for valuing investment in flexible LNG capacity. The value of flexible supply depends not on average price levels, but rather on the ability of the LNG delivery chain to respond to uncertain price developments. A simulation approach is used to generate thousands of potential scenarios of gas market prices, and a hypothetical LNG supplier responds to these prices by moving cargoes in an optimal manner. The results reveal the expected value and probability distribution of profits from the investment in flexible LNG trade capacity, which can be readily compared to the estimated costs of these investments.

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\(^5\) Six months of 2002 did have greater than average demand in both the U.S. and Europe. However, even in these cases integrating markets would create the potential for customers with the lowest willingness to pay across both markets to undertake demand reductions—yielding net lower prices in both markets.

\(^6\) This assumes that cargoes can be delivered and priced at the index price. The discussion here does not address the issue of basis risk if cargoes are delivered away from the Gulf coast of the U.S. The same principals would apply, with the added dimension of local market pricing and differentials from the Henry Hub traded price.

\(^7\) The statistical relationship will be discussed further below.

\(^8\) The high capital cost of liquefaction as a fraction of the total LNG supply chain suggests that these facilities will always run as close to full capacity as possible.
2. DESCRIPTION OF THE MODEL

The model described here simulates flexible trade in cargoes in the Atlantic Basin. The model represents a LNG supplier based in Trinidad with the capacity to deliver a fixed quantity of gas to the U.S. market. When prices favor it, cargoes are diverted to the U.K. These trade routes were selected as each as both the U.S. and the U.K. already have well developed market-based pricing, with historical data to benchmark forward price simulations. The model can be readily adapted for other sources and destinations. There are three main steps in constructing the model to value destination flexibility: (1) estimation of plausible price series for the two potential destination markets, (2) construction of a suitably realistic model of LNG transport to reflect the critical costs and constraints on an LNG supplier to engage in physical arbitrage, and (3) Monte Carlo simulation of the price series and the corresponding shipping responses to obtain a distribution of values for the option to engage in physical arbitrage.

Estimating Future Price Series

Plausible boundaries for the behavior of future gas prices can be obtained by an examination of historical price data. Significant structural change has happened in both the U.S. and U.K. gas markets over the past decade. Gas prices generally rose in both markets from 2002 through 2005 in both markets (see figure 1). Price volatility also appears to have increased in the U.S. since the 1990s. Thus, in conducting the empirical analysis we examine different periods to provide a range of parameter values that might describe future market price fundamentals.

A commonly used model for describing the movement of natural gas prices is the basic mean reverting model shown here in equation 1.1. According to this relatively simple model, there is a long-run price of natural gas—assumed to be connected to the long run cost of supply—and deviations in this model occur randomly [6].

\[
(S_t - S_{t-1}) = \eta \ast (\mu - S_{t-1}) + \sigma \ast \varepsilon_t \tag{1.1}
\]

According to equation 1.1, 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 \((\varepsilon)\).

Linear regression using historical data provides parameter estimates for the mean-reverting simulation of future price series. Following equation 1.2, parameter estimates for the Henry Hub (U.S.) and the National Balancing Point (NBP) in the U.K. are obtained as shown in table 1.

\[
(S_t - S_{t-1}) = a + b \ast S_{t-1} + e_t \tag{1.2}
\]

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9 A model to incorporate seasonal price swings was also estimated for this analysis. However, the results from simulation did not show a significant effect compared to the simple stochastic mean-reverting model. Thus, for simplicity the analysis uses the simpler model.
<table>
<thead>
<tr>
<th>Price Series (time period)</th>
<th>a</th>
<th>b</th>
<th>η = -b</th>
<th>μ = a/η</th>
<th>s = σ</th>
</tr>
</thead>
<tbody>
<tr>
<td>Henry Hub (Jan 1994 – Dec 1999)</td>
<td>0.61**</td>
<td>-0.27***</td>
<td>0.27</td>
<td>2.21</td>
<td>0.39</td>
</tr>
<tr>
<td>Henry Hub (Jan 2000 – July 2005)</td>
<td>0.69*</td>
<td>-0.13*</td>
<td>0.13</td>
<td>5.45</td>
<td>0.84</td>
</tr>
<tr>
<td>NBP (Jan 2000 – July 2005)</td>
<td>0.50**</td>
<td>-0.12</td>
<td>0.12</td>
<td>4.07</td>
<td>0.70</td>
</tr>
</tbody>
</table>

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

the mean reversion rate: \( \eta = -b \); \hspace{1cm} \text{(1.3)}

the long-term average for the respective period: \( \mu = \frac{a}{\eta} \); \hspace{1cm} \text{(1.4)}

and the volatility for the for the future price simulation is equivalent to the standard error from the historical regression: \( \sigma = s \). \hspace{1cm} \text{(1.5)}

The parameter estimates in table 1 show the significant shift in the behavior of U.S. prices after 1999. 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. The intention here is not to draw robust statistical conclusions about any shift in market fundamentals in the U.S. Rather the varying parameter values from the two periods will provide useful benchmarks for the inputs into the simulation model. Recent experience might reflect the upper end of future volatility behavior, while the earlier period provides a reasonable lower bound on volatility.

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 the ability to move cargoes to respond to beneficial price variations between the markets. Thus, in simulating the forward price series, sensitivity analysis will reveal how the increasing integration of markets affects the value of flexible capacity. The correlation of price changes is a useful measure of integration.\(^{10}\) For reference, from January 2000 to July 2005, price changes in the U.S. at the Henry Hub and price changes in the U.K. at the NBP were only 12.6% correlated.\(^{11}\)

Using the parameters from the historical data, simulations of future prices can be constructed using the mean reverting model in equation 1.1. First, U.S. prices follow the form in equation 1.6:

\[
S_{t, U.S.} = S_{t-1, U.S.} + \eta_{U.S.} \ast (\mu_{U.S.} - S_{t-1, U.S.}) + \sigma_{U.S.} \ast \varepsilon_{1, t}
\]  \hspace{1cm} \text{(1.6)}

where \( \varepsilon_{1, t} \sim N(0,1) \); \hspace{1cm} \text{(1.7)}

\(^{10}\) A common analytical mistake is to measure market integration using the correlation of absolute price levels. This invariably over-estimates the level of integration.

\(^{11}\) 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. More robust statistical analysis by Silverstovs et. al. [7] using unit root tests supports the lack of integration of U.S. and U.K. prices for this time period.
A similar price curve is simulated for the U.K. NBP, as in equation 1.8:

\[ S_{t, uk} = S_{t-1, uk} + \eta_{uk} * (\mu_{uk} - S_{t-1, uk}) + \sigma_{uk} * \epsilon_{3, t} \]  

(1.8)

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 1.9:

\[ \epsilon_{3, t} = \rho * \epsilon_{1, t} + \sqrt{1 - \rho^2} * \epsilon_{2, t} \]  

(1.9)

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

Thousands of sample price series are generated for both markets over a ten year period using the parameter values from the historical price series. Figure 3 shows one scenario of a simulated price series for each market. Note that a floor price of $2.11 per 10^9 joules ($2 per mcf) is the lower bound in all scenarios.

Figure 3. Sample price series.

Model Structure

Valuation of the incentive to invest in flexible LNG capacity requires a model that represents the critical parts of the LNG train, with 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 for Monte Carlo simulation.

For simplicity, the model assumes a vertically integrated ‘commercial’ LNG project structure, where a partner in a gas supply and LNG project owns the gas volumes from the producing field through gas sales 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 Trinidad with a contract to deliver cargoes to U.S. Gulf Coast regasification terminal. A long-term contract would likely support financing for the necessary investment in gas production, ships, and reserved regasification capacity in the U.S. 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 cost assumptions on feed gas costs, liquefaction, shipping and regasification for shipments to the U.S. In general, prices in the U.S. market are expected to provide a suitable return to support the project investment. For illustrative purposes, the project might be designed to deliver 6.9 x 10^9 billion cubic meters per year of gas (5 mtpa LNG) to the U.S. with attractive margins for the supplier at prices over $3.17 per 10^9 joules ($3 per mcf). The value of flexibility to deliver cargoes to the U.K. 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.S. market, (2) additional ship charters to maintain full volume deliveries for the longer shipping distances, and (3) payments for access to regasification terminals in the U.K.

If the supplier has a contract for deliveries in the U.S. market, reduced deliveries would have to be replaced by spot purchases on the U.S. market. Market liquidity is assumed, and thus spot market procurements to replace the diverted cargoes have no significant effect on U.S. (Henry Hub) prices. This is a reasonable simplifying assumption, so long as monthly diversions range from 80 – 250 x 10^6 cubic meters (3-9 Bcf of gas, or 1-3 of the standard 138,000 cubic meter tanker cargoes of LNG) constituting less than 1% of U.S. consumption in any given month. These assumptions provide that no costs realized in the U.S. market related to cargo diversion. Investment in the U.S. regasification terminal (or reservation of a share of offloading capacity) is sunk and should not affect current operating decisions.

The longer shipping distance to the U.K. would require charters of additional ships to maintain full offtake and delivery volumes. The U.K. is over 60% further from Trinidad than the U.S. Gulf coast (one-way shipping distances of roughly 3,700 and 2,300 nautical miles respectively). The model assumes that tankers are available for short-term charter at a rate of $50,000 per day for a 138,000 cubic meter capacity vessel. Round-trip travel time from Trinidad to the U.K. is about 18 days, including one day each for loading and offloading. However, the logistics of chartering and moving a tanker to the Trinidad-U.K. route each time an arbitrage transaction is arranged could easily take a week or longer. Thus, the model allocates a full month of ship charter cost for each cargo delivered to the U.K. Simulation results suggest that the spot charter would usually be called on to make a return trip thus improving the overall efficiency. However, the one-month per charter is used for each cargo, regardless of whether a one-month or three-month charter is actually utilized in the model. The resulting shipping cost of arbitrage is thus conservative at $0.72 per 10^9 joules ($0.68 per mcf) delivered to the U.K. from Trinidad.

Finally, the LNG arbitrageur requires access to regasification capacity in the U.K. to offload spot cargoes. The model does not assign a specific cost owning or reserving regasification capacity in the U.K. Thus, model results reflect the total potential value accrued from each cargo delivered into the U.K. when prices net of incremental shipping costs. The arbitrage cargoes delivered are also assumed to be price-takers in the U.K. market, which is a less conservative than the liquidity assumption in the U.S. given the smaller size of the U.K. market, but not wholly unrealistic so long as

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12 The Gulf Coast assumption avoids the complexity of a significant basis differential to the liquid trading volumes at the Henry Hub.
13 Separately valuing the option value of delivering to the U.K. market makes the calculation straightforward, although an integrated project structure would allow any positive returns from arbitrage to support the overall project investment.
14 For the range of parameter values used in the simulation, price deviations supporting arbitrage generally last longer than one month duration.
diverted volumes are less than 80 – 250 x 10^6 cubic meters per month (3-9 Bcf of gas, less than 3% of U.K. gas consumption in most months).

**Model Simulations**

Using a range of parameter values drawn from the historical price data for the U.S. and U.K. (Henry Hub and NBP, respectively) Monte Carlo simulations are run over 120 months. Results are recorded for the distribution of values for a typical year, such as year 7. The accumulation of data from 20,000 simulations, each a randomly occurring realization of the two mean-reverting price series, provides a robust estimate of the expected value and the probability distribution of values that would accrue a supplier that maintained the destination flexibility option.

3. **RESULTS**

Figure 4 includes simulation results, showing the change in option value for different assumptions on price parameters and the level of price covariation. The option value is expressed as the expected profit in millions of USD per year, per unit capacity. (Values on the left axis are per Bcf/month and on the right axis are expressed per 10^9 cubic meters/year capacity).

**Figure 4. Annual per unit Arbitrage Benefits as a Function of Volatility, Mean Reversion, and Market Price Correlation.** Results of Monte Carlo Simulation.

\[ \sigma = 1, \eta = 0.1 \]
\[ \sigma = 0.5, \eta = 0.1 \]
\[ \sigma = 0.5, \eta = 0.3 \]

**15** Early years (years 1-3) are affected by the starting price for each market. Thereafter, values do not change from year to year.
For illustrative simplicity, the same pairs of parameter values are used for each of the U.S. and U.K. price series in figure 4. Long-term mean prices in both markets are assumed to be a constant $5.28 per 10^9$ joules ($5 per mcf) through all scenarios. As an example, the top line in figure 4 shows the expected value of flexible LNG capacity when the volatility of both price series is assumed to be 1.0 ($\sigma_{us,uk} = 1$) and the mean reversion rates for both markets are assumed to be 0.1 ($\eta_{us,uk} = 0.1$). This parameter pair approximates the upper bounds of volatility and slowest mean reversion rate from the historical Henry Hub and NBP time series shown in table 1. Holding these parameter values constant, the chart then shows how the shift from non-integrated markets to completely integrated markets (from $\rho = 0$, toward $\rho = 1$) affects the expected value of the investment in flexible LNG capacity. Increasing covariation of prices reduces the likelihood that an arbitrage opportunity develops, thus lowering the overall expected profits that would accrue to the holders of flexible LNG capacity.

The bottom series in figure 4 shows the results for the lower range of volatility and faster mean reversion ($\rho = 0.5$, $\eta = 0.3$)—both reducing the occurrence of the price deviations that support higher option values.

The values reported in figure 4 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. 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. Average unit costs of maintaining $1 \times 10^9$ cubic meters per year of regasification capacity range from $4.5$ to $7.5$ million USD per year (or $1.5$ to $2.5$ million USD for 1 Bcf/month capacity). These estimates include both construction costs and fixed operations and maintenance costs, which would accrue independent of volumes delivered. A median estimate of the unit cost of regasification is plotted in figure 4.

A gas supplier considering the investment in flexible capacity will also be concerned about the probability distribution of arbitrage benefits, 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.K. market suitably attractive. Figure 5 shows the distribution of arbitrage returns from the Trinidad-US-UK example for parameter values: $\rho = 0.5$, $\sigma_{us,uk} = 1$, and $\eta_{us,uk} = 0.1$. In near one year out of every three no cargoes are delivered to the U.K. because price differentials are unattractive. However, the expected value of arbitrage gains for all years for these parameter values is 21 million USD per $1 \times 10^9$ cubic meters per year capacity (or $7$ million USD per Bcf/month capacity). In operational terms, if the option to deliver cargoes was held for 10 or 20 years, much of the value of holding the option would come from a few years where high U.K. prices and relatively low U.S. prices provide large profits.

The values shown in figure 5 are relatively insensitive assumptions for the long-term mean price. The value of arbitrage arises from price differentials between the two markets. Thus any difference in mean prices between the markets would be important. Also, the spread between the mean price and the price floor constrains the overall variance.

Based on capital costs for a new build regasification terminal of $400$ to $600$ million USD for 1 Bcf/day of peak sendout capacity and fixed operating costs estimated at $15$ million USD per year [8]. Assumes 10% return on capital investment and full coverage of fixed O&M costs.

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 [2] 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.
The results shown in figure 4 suggest significant profits to attract investment in physical arbitrage capacity in the Atlantic Basin, especially at recent levels of volatility and the currently low level of gas market integration. If there are no barriers to entry to the arbitrage business, and the high variability of returns on investment in flexible capacity can be managed in a portfolio of other risks, one would expect that investment in ships and regasification capacity would continue, driving further market integration via the transmission of prices across the Atlantic. Investment would continue until the level of price covariation drives the expected benefits of flexible 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. Natural gas markets are unlikely to approach this level of integration, 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.\footnote{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)\cite{9},\cite{3}.} For offloading, oil tankers require little more than a dock and a pump—also at a fraction of the cost of a regasification facility required to offload LNG.

In this model framework, the major question for investors in deciding whether to invest in LNG arbitrage capacity relates to the expected evolution of price fundamentals. Long-run average prices are obviously important, but it is variability in prices drives the returns to arbitrage capacity. If investors expect current high levels of volatility to continue, large investments in flexible LNG capacity would appear attractive. If these investments were realized, the result would be tightly integrated Atlantic
Basin markets, with price covariations approaching 80%. (Based on U.S. price volatility of 0.8 and U.K. volatility of 0.7 based on the 2000 to 2005 period).

More likely though, is that the movement of spot LNG cargoes will also tend to dampen volatility. The model presented here assumes no price impact of the arbitrage volumes, and thus no robust insights on the volatility effects can be directly derived from the model results. However, one would expect that the movement of 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 US and European markets, shown in figure 2, suggests that consumption spikes (and thus positive demand pressures on price) will generally not occur simultaneously in both markets. Increased supply response to non-correlated demand swings should reduce expected price volatility.

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. A return to price behavior as occurred on the Henry Hub for the 1994 to 1999 period would leave little incentive for flexible LNG supply, as shown in figure 4. At this extreme, LNG projects would return largely to the point-to-point trade model, as the profit incentives to divert cargoes would not be sufficient to support the added costs of surplus tanker and regasification capacity.

Interestingly, the results from the price simulations used in the model suggest that the arbitrage benefits from stochastic volatility outweigh gains from seasonal diversions. Preliminary future price simulations included a seasonal factor in pricing. U.K. prices (and European gas demand) tends to be higher in the winter months versus the annual average. Thus a seasonal trend in the mean price level was fit for both markets. Seasonal trends which produced a $2.11 per 10^9 joules ($2.00 per mcf) swing in UK prices, compared to a $1.06 swing per 10^9 joules ($1.00 per mcf) in January to July prices in the U.S. were tested, but yielded marginal arbitrage gains compared to the variations in the stochastic parameters ($\sigma$, $\mu$). This result did not match prior hypotheses about the value from flexible LNG trade. However, low benefits of seasonal price swings is consistent with the distribution of arbitrage values, as in figure 5. Large returns from high amplitude price swings in a relatively few years and scenarios creates the bulk of the expected mean option value.

4. 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. Effective integration of regional gas markets and prices will depend on the movement of gas supplies (LNG) to respond to price differentials in currently isolated markets. The model presented here provides a framework for evaluating the level of price integration that can be expected, based on the incentives for gas suppliers to invest in the flexible capacity needed to engage in physical arbitrage between markets. The results suggest quantitative boundaries on the level of price integration due to the high capital costs of LNG tankers and regasification facilities.

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 results are believed to be robust beyond these specific conditions.

The value of flexible LNG supply is not entirely dependent on competitive spot market pricing. Competitive gas market pricing (as exist in the U.S. and the U.K.) is in general more volatile than rigid pricing structures, such as oil-linkages that continue to dominate gas pricing in continental Europe and in Asia. As shown above, higher price volatilities create the incentive for investment in flexible supply capacity, as investors can look to high price periods to justify capacity levels in excess of average loads. The persistence of oil-linked pricing structures would effectively limit the incentives for flexible LNG supply, thus preventing a shift to tighter integration of regional gas prices.
Moreover, rigid pricing structures are not reflective of the supply-demand balance in the marketplace and thus have limited means to attract spot cargoes to respond to short-term market imbalances. Indeed, gas buyers in the oil-linked markets such as Spain have been forced to pay U.S. market prices for gas to attract LNG cargoes in recent years [10]. The expansion of this trend will make it difficult to maintain the rigid pricing structures. As these markets increasingly rely on purchases of LNG that is traded in a global market, internal prices will come under pressure to reflect the scarcity conditions for LNG cargoes in other competitive markets—as well as their own internal-supply demand balance.

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 that could result in scarcity rents accruing to holders of capacity in either segment of the chain. Effective arbitrage between markets requires that some 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 create barriers to price integration 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 options. For example, a gas supplier with access to liquefaction on the eastern side of the Atlantic 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.K. when prices there are significantly higher than in the U.S. No flexibility benefits accrue in those years when U.K. prices are low relative to the U.S. However, if the same supplier held some excess regasification capacity in the U.S. market, and also had contractual LNG supplies normally destined for the U.K. market, the structure would provide for arbitrage returns inversely correlated with U.K. flexibility benefits, potentially yielding smoother returns across the a portfolio of project supply.

Further research will examine the interaction between flexible LNG supply and the other main alternatives for response to demand and price variability. Gas storage has long been the tool for the gas business has used to meet daily, weekly, and monthly variations in gas demand. The analysis here suggests a role for LNG to act alternative to storage, particularly at monthly scales. The model results implicitly suggest that LNG is a cost-effective alternative based on the current structure of gas markets, as high price volatilities have remained in the current market, with considerable storage activity. Future work by this author will seek to explicitly address the storage-LNG tradeoff in the Atlantic Basin.
5. REFERENCES