Valuing the Risks and Returns to the Spot LNG Trading

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Hiroaki Suenaga*
School of Economics and Finance
Curtin University of Technology

ABSTRACT

A recent increase in the level and volatility of regional natural gas prices has followed an extensive discussion on potential returns from short-term LNG trading and potentially fostering integration of geographically sparse regional gas markets. This paper examines the stochastic properties of US natural gas and crude oil prices and considers their implications for the risks and returns to spot LNG trading, as opposed to a conventional practice of trading under long-term supply/purchase arrangement, in the Asia-pacific region. The model of commodity price dynamics estimated for the daily spot prices of Henry Hub natural gas and crude oil (Brent) indicates strong seasonal pattern in mean and volatility of natural gas price whereas the crude oil price exhibits almost no seasonal variation in its level and volatility. After controlling for such seasonality, the two prices exhibit only moderate correlation. The simulation model constructed around the depicted price dynamics implies positive expected returns from arbitraging spatial price differences between Asia and the US whereas the volatility of revenue is only moderately higher for short-term trading than for forward contracting. Besides, while the option to choose from multiple regional markets increases the overall volatility of revenue from short-tem trading, it reduces the downside risk substantially, with the revenue exceeding the level under forward trading more than 90% of time. A positive return from the short-term LNG trading with reasonably low risk will provide an incentive to LNG producers in Asia-Pacific region to shift from conventional long-term supply arrangement to short-term trading.

* Correspondence to: Hiroaki Suenaga, Research Fellow, School of Economics and Finance, Curtin University of Technology, GPO Box U1987, Perth, WA 6845, Australia. Phone: +61-8-9266-4480, Fax: +61-8-9266-3026, email: hiroaki.suenaga@cbs.curtin.edu.au.

INTRODUCTION

Two major changes in the world natural gas market have been emphasized in the last decade. First, the level and volatility of regional natural gas prices, in particular, the US and Europe, have increased dramatically. Second, costs for liquefaction, shipping, and regasification of liquefied natural gas (LNG) have decreased substantially. These observations have followed an extensive discussion on potential gains from short-term LNG trading and resulting integration of geographically sparse regional gas markets. It has been often reported that the amount of spot LNG transaction has been increasing gradually and more flexible contractual arrangements have been more common among LNG traders (EIA, 2003, IEA 2005).

While recent changes and future prospects of the world gas market have been discussed extensively, there has been a little attempt to elucidate analytically how observed changes in world gas market affect a practice of LNG trading and lead traders to shift from conventional long-term supply/purchase arrangements into short-term trading. Naturally, whether a firm, either seller or buyer, trades forward or in spot markets depends on the relative magnitudes of returns and risks associated with each of the two trading strategies. This paper aims to examine the stochastic properties of the US natural gas and crude oil prices and consider their implications for the risks and returns from the short-term LNG trading in Asia-pacific region.

Within a premature literature on the world LNG market, Hayes (2006) has examined the values of flexible LNG supply in Atlantic regions. In particular, he has analyzed the gains to an LNG producer who has a supply commitment to the US market at a predetermined price but diverts its shipment to the European market when the spot price is higher in the latter than in the former market. This value is calculated as the sum, over a certain period, of the spot price differentials between the two markets. He obtains the distribution of the gains from spatial arbitrage in two steps: first, to estimate mean-reversion models of the US and European gas prices, and second, to generate the simulated price series from the estimated mean-reversion models and obtain the Monte Carlo distribution of the gains from arbitraging price difference between the US and European market.

In this paper, I follow the same two step approach as in Hayes (2006) in evaluating the gains from short-term trading in Asia-Pacific region. However, unlike Hayes (2006), I evaluate the gains from short-term trading as opposed to a conventional practice of long-term supply/purchase arrangement. This value differs from the values of flexible LNG supply examined by Hayes (2006). A trading strategy considered in Hayes (2006) requires the presence of well-developed spot gas market because the LNG producer, when it deviates from its forward supply commitment, needs to replace the reduced gas delivery to the US with the pipeline gas purchased in the US spot market. The strategy is impracticable in Japan or any other markets in Asia, due to the absence of well-developed spot gas markets in the region. Therefore, this paper considers the case where an LNG producer cannot divert from its forward supply commitment. In such circumstance, the firm's decision to shift from a conventional long-term supply/purchase arrangement to short-term trading depends on the relative magnitude of the revenue from these two trading strategies. The analysis in this paper evaluates the revenues under the two trading scenarios. This comparison is in line with a recent discussion about potential benefit from short-term trading, in the context of LNG producers located in Asia-Pacific region.

Evaluation of the revenues from two trading strategies is also complicated because the forward LNG price is stochastic at the time of forward trading, as it is often linked to the spot price of an alternative fuel. This forward price risk can be mitigated by cross-hedging with the futures markets of an alternative fuel to which the forward price is linked under forward contract. This strategy, though not discussed previously in the context of LNG trading, is possible because futures contracts for an alternative fuel, such as crude oil, are actively traded through an organized exchange, for example, NYMEX.[1] Such hedging strategy also reduces, albeit partially, the spot price risk to the extent that the regional gas price is correlated with the spot price of an alternative fuel. I evaluate the revenue from the two trading strategies (spot or forward) under each of the two scenarios—with or without cross-hedging with futures markets.

The rest of the paper is structured as follows. Section 2 examines the revenue stream to a hypothetical LNG producer under each of two trading strategies; short-term trading and forward trading. For each of the two strategies, I also consider the case where the producer hedges its price risk with the futures markets of an alternative fuel. Section 3 describes the model that simulates the revenue to a hypothetical LNG producer located in North West Shelf (NWS), Australia. The section starts with the estimation of the model of spot price dynamics for the Henry Hub natural gas and Brent crude oil. The estimated models are then used to generate the simulated gas and oil price data. The distribution of the revenue under each trading strategies is then obtained based on the simulated price data. Section 4 concludes the paper.

[1] Hedging with futures contracts for natural gas is even more straightforward for an LNG producer supplying into the US market.

2. RISKS AND RETURNS TO SPATIAL ARBITRAGE THROUGH SPOT TRADING

The analysis presented in this paper compares the revenue to an LNG producer under two trading strategies; short-term trading and long-term forward trading. It also considers the case where the producer hedges its price risk, either spot or forward, with futures market of an alternative fuel to which the forward LNG price is linked. Suppose that an LNG producer has the capacity to produce Q units of LNG per period. If the producer operates at its full capacity, its revenue under each of the two trading strategies is,

(1) $TR_F = F_{LNG}\, Q$

(2) $TR_S = P_{max}\, Q$

where TR_i is the revenue to the producer with subscript $i = F$ (S) representing that the producer supplies under forward contracting (short-term trading). F_{LNG} is the forward price of LNG, linked to the spot price of an alternative fuel. $P_{max} = \max\{P_{LNG,j}\}$ is the maximum of the spot gas prices in J regional markets and $P_{LNG,j}$ is the spot LNG price in market j ($j = 1, \ldots, J$), net of transportation cost. One of J regional markets, market 1, is the market to which the producer supplies under forward contract.

The spot price in (2) can be decomposed into,

(2′) $TR_S = TR_{S1} + TR_{S2} = (P_{max} - P_{LNG,1})\, Q + P_{LNG,1}\, Q$

where TR_{S1} and TR_{S2} represent, respectively, the gains from arbitraging the spot price differentials and the revenue, had the producer supplied only to the market 1 in spot market. TR_{S1} is non-negative while TR_{S2} is above or below the revenue from forward sales and depends on the realizations of demand, supply, and other market conditions as they determine the two prices, F_{LNG} and $P_{LNG,1}$. The two prices can differ even on average if the LNG pricing formula is not specified to represent the expectation of regional gas market conditions.

The forward price, F_{LNG}, is stochastic at the time of forward trading since the spot price of an alternative fuel, say crude oil, is not observable. However, it tends to be less volatile than the spot gas price in market 1 for two reasons. First, the spot price of an alternative fuel, say crude oil, is less volatile than the spot gas price as it is traded in much bigger market than any regional gas markets. Second, the LNG pricing formula is usually defined so that the LNG prices are insensitive to the variations in crude oil price.

The forward price risk can be mitigated through cross-hedging with futures markets for an alternative fuel to which the LNG forward price is linked. The size of futures position depending on the conversion factor used in the LNG pricing formula. For example, suppose that the LNG forward price is linked to the spot crude oil price through a linear function, $F_{LNG} = a + bP_{CO}$ where P_{CO} is the spot price of crude oil in the period of physical delivery of LNG.[2] In period 0, when the producer signs a forward contract, the producer can take a short position, in the amount b per unit of its LNG supply, in the crude oil futures contract maturing in period 1, when the physical delivery of LNG takes place. It then clears its position as the contract approaches its maturity. Let $f_{CO,s}$ denote the futures price, as in period s, of crude oil maturing in period 1. The total revenue to the LNG producer becomes,

$$(3) \qquad TR_{FC} = b(P_{CO} - f_{CO,1})\, Q + (a + b\, f_{CO,0})\, Q$$

The last term in the right hand size of (3) is deterministic at the time of forward contracting. $P_{CO} - f_{CO,1}$ is the difference between the spot and futures price of crude oil in period 1, which is zero theoretically because, if the market is efficient, the futures price converges to the spot price as it approaches the maturity.

The strategy reduces the volatility of the future revenue dramatically. The expected values and variance of the total revenue, when the LNG producer enters into a long-term supply arrangement, are, without cross-hedging,

$$(4) \qquad \mathrm{E}[TR_F] = \mathrm{E}[F_{LNG}]\, Q = (a + b\mathrm{E}[P_{CO}])\, Q$$
$$\mathrm{V}[TR_F] = \mathrm{V}[F_{LNG}]\, Q^2 = (b\, Q)^2\, \mathrm{V}[P_{CO}]$$

and with cross-hedging,

$$(5) \qquad \mathrm{E}[TR_{FC}] = b\, Q\, \mathrm{E}[P_{CO} - f_{CO,1}] + (a + b\, f_{CO,0})\, Q = (a + b\, f_{CO,0})\, Q$$
$$\mathrm{V}[TR_{FC}] = (b\, Q)^2\, \mathrm{V}[P_{CO} - f_{CO,1}] = 0$$

where the last equalities in (5) hold when $\mathrm{E}[P_{CO} - f_{CO,1}] = \mathrm{V}[P_{CO} - f_{CO,1}] = 0$. The expected revenue is also identical if the futures price of crude oil is equal to the period 0 expectation of crude oil price.

[2] The strategy eliminates the spot price risk completely as long as the slope coefficient in the LNG pricing formula is constant over the level of crude oil price.

The same cross-hedging strategy can be employed when the LNG producer supplies under short-term trading.[3] With cross-hedging, the firm's revenue becomes,[4]

(6) $TR_{SC} = (P_{max} - b\, f_{CO,1})\, Q + b\, f_{CO,0}\, Q$

which can be decomposed into,

(6′) $TR_{SC} = TR_{SC1} + TR_{SC2} + TR_{SC3} = (P_{max} - P_{LNG,1})\, Q + (P_{LNG,1} - a - b\, f_{CO,1})\, Q + (a + b\, f_{CO,0})\, Q$

where the three components represent: (i) gains from arbitraging spatial price differentials, (ii) gains from supplying into market 1 through short-term trading as opposed to forward contracting, and (iii) the revenue from futures trading, respectively.

The expected value and variance of the revenue to the producer are, with cross-hedging,

(7) $E[TR_{SC}] = E[P_{max} - b\, f_{CO,1}]Q + b\, f_{CO,0}\, Q$

$V[TR_{SC}] = V[P_{max} - b\, f_{CO,1}]Q^2$

and without cross-hedging,

(8) $E[TR_S] = E[P_{max}]Q$

$V[TR_S] = V[P_{max}]Q^2$

In (7), $V[P_{max} - b\, f_{CO,1}] < V[P_{max}]$ if crude oil price and regional gas prices are correlated and $V[P_{max} - b\, f_{CO,1}]$ decreases with the correlation between two prices.

A major benefit from short-term trading originates in the profit from arbitraging spatial price differentials among regional gas markets, which appears as $(P_{max} - P_{LNG,1})\, Q$ in (2′) and (6′). On the other hand, a producer is, in general, exposed to a greater price risk than under long-term forward contracting. Moreover, the option to choose its supply destination from multiple regional markets can either increase or decrease the spot price risk. The maximum of J regional prices can be less volatile than the spot price in one particular market because an

[3] A similar strategy can be constructed also for a buyer of LNG.

[4] The optimal position in the futures market, b, depends on the extent of the correlation between the crude oil futures price and regional gas prices. To find analytically the optimal futures position requires one to presume some forms of utility function for an LNG producer and is difficult due to the absence of analytical expressions for the distribution of P_{max}. However, an economic intuition suggests that the optimal position increase with the correlation of the crude oil futures and regional gas prices.

extremely low price in any of J markets is discarded from the calculation of maximum price unless all regional prices are similarly low. It can be also more volatile than a single price because a chance of experiencing extremely high price is higher over multiple markets than in a single market.

In terms of expression (2'), the second component of the firm's revenue, $P_{LNG,1}\ Q$, is almost surely more volatile than the revenue from the forward sales, $F_{LNG}\ Q$, because the spot gas price in market 1 tends to be more volatile than the forward LNG price for the reason previously discussed. However, the additional revenue from spatial arbitrage, TR_{S1}, tends to be negatively correlated with the revenue from the spot sales in market 1—the first and second revenue components tend to be high (low or zero) and low (high), respectively, when the regional spot price in market 1 is low (high). Similarly, the first two components in (6'), when the firm cross-hedges the spot price risk, are stochastic and negatively correlated. For both cases, the two components of the spot price risk are most likely net positive—the firm's revenue from spot sales is more volatile than its revenue from forward sales. Whether the firm shifts from long-term forward trading to short-term trading depends on the relative size of these benefits and costs associated with such transition.

Two remarks are worth emphasizing. First, the above comparison of the revenue from short-term LNG trading with the revenue from forward contracting signifies the difference between the valuations to be provided in this study and that provided by Hayes (2006). The value of flexible LNG supply Hayes reported corresponds to the first components in (2') and (6'), $(P_{max} - P_{LNG,1})\ Q$. The second term in (2'), the revenue from spot sales in market 1, is almost surely more volatile that the volatility of forward revenue. Similarly, the second term in (6'), representing the gains from supplying to the market 1 through short-term trading as opposed to long-term forward trading, is non-zero and stochastic because the nearby futures price of crude oil price, converted into LNG term through the forward pricing formula, does not converge to the spot LNG price. These incremental revenue risks are the cost to LNG producers to gain the arbitrage profit through short-term trading, in the absence of well developed spot and futures markets for natural gas in Asia.

Second, the firm's revenue has been compared between the two extreme cases in the above; either full hedge or no hedge at all in both forward and futures market. Full forward cover has been conventionally a dominant strategy among many LNG producers. A more realistic strategy would be a partial forward cover and partial hedging. Suenaga (2007) considers such partial hedging strategy in the context of LNG industry and illustrates taht an optimal positions of LNG producer in forward and futures markets depend on the distributions of spot LNG prices in regional markets and spot and futures prices of an alternative fuels. The simulation model in the subsequent section aims to examine the distributional properties of these prices, using sensible parameter estimates from the observed data.

3. SIMULATION ANALYSIS OF RISKS AND RETURNS FROM SPOT LNG TRADING

This section describes the model to evaluate the distribution of the revenue to a hypothetical producer from supplying LNG under each of four trading strategies examined in Section 2. In particular, the model considers an LNG producer located in the North West Shelf (NWS), Australia, who has finalized its decision to invest on an LNG production project, including development of natural gas reserves and facilities necessary to liquefy gas and load onto LNG cargos. On its sales side, the producer can either commit to supply under a long-term supply/purchase arrangement or to sell its product entirely through short-term trading.[5,6] In the former case, it supplies all its production capacity to Japan at the price determined by the spot price of crude oil according to the pricing formula. In the latter case, the firm can choose from multiple regional gas markets and supply its product to the market where the price, net of transportation cost, is the highest of all the possible destinations. For simplicity, I consider only two such destinations, a hypothetical spot market in Japan and the US west coast. The model can be easily extended into the case with more than two regional markets. In addition, under each of the two scenarios, the firm can cross-hedge its price risk with crude oil futures. The firm's revenue is compared across these trading strategies to make inference about the firm's incentive to move from a conventional trading practice of long-tern supply arrangement to short-term trading.

Section 2 has illustrated that the firm's revenue from short-term trading and forward contracting, depends on the distributions of three prices; (i) the spot gas prices in Japan and the US market, (ii) the spot price of crude oil as it determines the forward price of LNG supplied to Japan, and (iii) the futures price of crude oil if the firm cross-hedges. Although it is desirable to evaluate the distributions of firm's revenue based on the empirical

[5] 1 metric ton of LNG is equivalent to 52 MBTu, so the production capacity of this hypothetical producer is Q/52 metric tons of LNG.
[6] Of course, a partial hedging—supply only part of its production capacity under long-term forward contract and keeps remaining capacity for spot sales—is certainly possible and more realistic. However,

distributions of these three prices, an issue is the absence of reliable spot gas price data for Japan or any other regions in Asia.[7] Therefore, I evaluate the risks and returns from short-term LNG trading by a simulation method, which involves the following two steps. First, I estimate the models of stochastic dynamics of crude oil and HH natural gas prices using the historical data. Second, I derive the simulated data on the three prices from the estimates of these models and obtain the distributions of revenues to an LNG producer for each of the four trading strategies.

3.1 A model of commodity price dynamics

The stochastic properties of HH natural gas and crude oil spot price are depicted by estimating the following model of commodity price dynamics,

$$P_{i,t} = f_i(t) + g_i(t)\, e_{i,t} \tag{9}$$

where $P_{i,t}$ is the spot price of commodity i (i = 1 for CO, =2 for NG). The model (9) decomposes the daily spot price of commodity i into two components; the deterministic or seasonal variation as captured by $f_i(t)$, and the stochastic component, $g_i(t)\, e_{i,t}$, specified as the product of $g_i(t)$ representing seasonal variation in the variance of the deviation from the seasonal mean price, and the error term, $e_{i,t}$, with $\mathrm{E}[e_{i,t}] = 0$ and $\mathrm{V}[e_{i,t}] = 1$ for all t and i.

I specify the stochastic term, $e_{i,t}$, to follow an AR(1) process,

$$e_{i,t} = \rho_i\, e_{i,t-1} + u_{i,t} \tag{10}$$

and the innovation, $u_{i,t}$, to follow bivariate GARCH(1,1) process with constant conditional correlation of Bollerslev (1990). That is, for $\mathbf{u}_t = (u_{1,t}, u_{2,t})'$,

$$\begin{aligned} &\mathrm{E}[\mathbf{u}_t\mathbf{u}_t' \mid \Im^{t-1}] = \mathbf{H}_t = \mathbf{D}_t\, \mathbf{R}\, \mathbf{D}_t \\ &\mathbf{D}_t = diag(h_{11,t}^{1/2}, h_{22,t}^{1/2}) \end{aligned} \tag{11}$$

I do not consider such partial hedging strategy here because to find an optimal forward cover requires a development of a micro economic model taking into account the risk preference of the producer.

[7] This is simply because, unlike for crude oil and the US natural gas, well-developed gas markets are absent in the region. The best available data, to the extent of my knowledge, is the price induced from the trade statistics from the Japan Customs office. However, these prices, derived as the ratio of import value to import volume, merely represent the average of spot and forward price because the volume and value data do not distinguish between LNG imports under long-term forward contract and that imported on a temporal basis (spot trade). These average prices also exhibit large cross-sectional variations among the origins, reflecting the heterogeneity of LNG pricing formulas.

$h_{ii,t} = \gamma_{i,0} + \gamma_{i,1}\, h_{ii,t-1} + \gamma_{i,2}\, (u_{i,t-1})^2$

where $\mathbf{R} = (r_{ij})$ is a symmetric positive definite matrix with $r_{ii} = 1$ and $r_{ij} = \rho_{ji}$ for $i \neq j$, and $\gamma_{i,0} = (1 - \rho_i^{\,2})(1 - \gamma_{i,1} - \gamma_{i,2})$ for $V[e_{i,t}] = 1$.

The two functions, $f_i(t)$ and $g_i(t)$, are specified by the following trigonometric functions,

(12) $$f_i(t) = a_{i,0} + a_{i,1}t + \sum_{j=1}^{5}\left(a_{i,2j}\sin\left(\frac{2j\pi\tau_t}{365}\right) + a_{i,2j+1}\cos\left(\frac{2j\pi\tau_t}{365}\right)\right)$$

(13) $$g_i(t) = b_{i,0} + \sum_{j=1}^{5}\left(b_{i,2j}\sin\left(\frac{2j\pi\tau_t}{365}\right) + b_{i,2j+1}\cos\left(\frac{2j\pi\tau_t}{365}\right)\right)$$

where τ_t is the day in year of observation t.

The above specification allows the model to capture three important features about the co-movements of the prices of the two commodities. First, the difference in the expected prices of the two commodities exhibit seasonal variations as determined by $f_i(t)$. Second, the variance and covariance of the deviations from these expected prices exhibit seasonal variations as determined by relative magnitudes of $g_i(t)$. Third, the correlation between the two prices is time-variant because of the seasonal variations in mean and variance as well as the GARCH (1,1) process specified separately for the two commodities.

The model defined in (9) through (13) is estimated with the data on daily spot prices of Henry Hub (HH) natural gas price and Brent crude oil, for the period between November 1, 1993 and March 23, 2007.[8] The two prices are quoted in US dollar per barrel for crude oil and US dollar per million British Thermal Unit (MBTu) for Henry Hub natural gas.[9] They are transformed into log-price in estimating the model.

Table 1 summarizes the descriptive statistics of the price data used in the analysis. In the table, two prices exhibit a wide variation. HH natural gas price has ranged from US$1.035 to $19/MBTu whereas the Brent crude oil has ranged from US$9.65 through $78.74/bbl. These wide variations translate into large standard errors, approximately 60% and 55% of mean price, respectively, for HH natural gas and Brent crude oil. Two prices are also skewed positive, primarily due to recently observed dramatic increase of the two prices as shown in **Figure 1**.

[8] I also estimated the model with the spot oil price from the West Texas Intermediate. However, the use of different oil price data does not alter qualitatively the model estimates or its implications for risk and returns to spot trading presented in subsequent sections.

Table 2 summarizes the results of estimating the model defined in (9) through (13) by the maximum likelihood.[10] In the table, the coefficient estimate of ρ is 0.9834 and 0.9925 for natural gas and crude oil, respectively. They are both significantly less than unity, indicating that the deviation from seasonal mean price is highly persistent yet stationary. The conditional variance of the deviation from the seasonal mean, standardized by the estimated seasonal variance function, $g_i(t)$, is also highly persistent with the estimates of the two GARCH coefficients sum to 0.9051 for natural gas and 0.9517 for crude oil, indicating that the conditional variance is highly persistent but stationary.

Figures 2 and **3** plot the estimated mean price and seasonal volatility against the day of the year. In **Figure 2**, the natural gas price indicates the strong seasonality with mean price substantially higher during winter high-demand season (November through February). Slight decrease in the mean price over the spring through summer months is rather unexpected and possibly capturing gradual adjustment after unusually high prices in winter 2000-01 and 2002-03. In contrast, the estimated mean price of crude oil is almost constant throughout the year with no noticeable variations across seasons. The estimated functions, $f_i(t)$, account for reasonably large share of spot price variation for both commodities—approximately 69.4% and 71.7% for natural and crude oil, respectively. Similarly, in **Figure 3**, the volatility of spot natural gas price exhibits strong seasonal pattern whereas the volatility of spot crude oil price is almost flat throughout the year. The depicted seasonality for natural gas is expected from seasonal pattern of the US natural gas demand. The volatility is highest in the beginning of the year, during which high residential demand for space heating exceeds the contemporaneous supply capacity and, hence, demand or supply shocks of even a small magnitude can cause large price swings. The volatility is low in spring and summer months because gas demand is well below contemporaneous supply capacity. Demand and supply shocks can be accommodated by adjusting production and/or amount injected into the underground storage for the use in the subsequent winter peak-demand season. These seasonal patterns imply potential arbitrage opportunity, particularly during the winter months.

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[9] Difference in measurement does not affect the estimation result since the log-transformation only adds a constant to all observations.

[10] I estimated the model in two steps. First, I estimated the model defined in (9) through (13) individually for crude oil and natural gas, ignoring the cross-sectional correlation coefficient, r_{12}. The cross-sectional correlation is then estimated as the sample correlation of the standardized residuals from the estimates to the two models. This two-step method yields consistent estimates of all model parameters (Bollerslev, 1990).

Table 3 compares different correlation measures calculated for the two prices. In the table, a correlation coefficient for two prices is 0.8593 before controlling for seasonality. The correlation drops to 0.5237 once seasonal variation in mean price is controlled for, and further down to 0.1290 once autoregressive process is controlled for. That is, given the information available as of today, the movements in two prices on a subsequent day are only 13% correlated.

3.2 Simulation Model

The simulated data on the US spot natural gas price are derived directly from the model estimated in Section 3.1. These prices, for delivery at the HH, are then transformed into the FOB price effective to the producer located in NWS by subtracting the transportation and regasification cost. For the transportation cost, the EIA's estimate for shipping from Australia to Everett, Massachusetts is US$1.76 per MBTu equivalent of LNG (EIA, 2003). As of 2007, an LNG receiving terminal is under construction in Costa Azul, Baja, Mexico, which is expected to receive LNG from Asian producers (EIA, 2007). The cost to ship Costa Azul from the NWS is, hence, estimated as US$1.18/MBTu by multiplying the cost to Everett by the ratio of the distance to these two receiving terminals in nautical miles (7,955/11,874). For the regassification cost, the EIA's estimate of US$0.30 per MBTu equivalent of LNG is used (EIA, 2003).

The simulated data on crude oil spot price are also directly derived from the models of natural gas and crude oil price dynamics estimated in Section 3.1. The resulting price needs to be transformed into the forward price of LNG price. While exact pricing formulas are not available to the public, three types of formulas have been commonly used (Chabrelie, 2003). The simplest one defines the LNG price to be a fixed proportion of the crude oil price, that is, $P_{LNG} = bP_{JCC}$. The second formula adds a positive constant to the first formula, $P_{LNG} = a + bP_{JCC}$. Naturally, the slope coefficient is set smaller for the second than for the first so the LNG price is less responsive to the volatility of crude oil price. The third formula, called an *S*-curve, adds compensation factors to the second formula so that the LNG price is even less responsive to the crude oil price when the crude oil price takes the values below or above the predetermined threshold levels. Chabrelie (2003) reports that a formula in the first type is getting more common. Therefore, I use the following affine formula to convert the spot crude oil price into the forward LNG price,[11]

[11] Chabrelie (2003) introduces the two formula; $F_{LNG} = 0.8966 + 0.1485\ P_{JCC}$, and $F_{LNG} = 0.1515\ P_{JCC}$, where P_{JCC} is the Japanese custom cleared price of a basket of crude oil. The first formula applies to the LNG

(15) $F_{LNG,t} = 0.1500\ P_{JCC,t}$

where the slope coefficient of 0.1500 corresponds to the conversion factor of 6.667MBTu/bbl of oil. The resulting price represents the FOB price to export to Japan, which is comparable to the HH spot natural gas price, net of the transportation cost from the NWS to the Costa Azul.

The LNG price in a hypothetical spot market in Japan is simulated around the forward LNG price. In the base case, the spot price is set equal to the forward LNG price as provided by equations (15). This represents the case where Japanese importers purchase LNG supplied under short-term trade at the price applicable to the LNG imports under long-term supply arrangement. In the other scenarios, I allow the spot LNG price to deviate from the forward LNG price according to the following stochastic process,

(16) $$\ln P_{LNG,t} = \ln F_{LNG,t} - \frac{1}{2}\ln(1+\sigma_{LNG}^2) + e_{LNG,t}$$

$$e_{LNG,t} = \rho_{LNG} e_{LNG,t-1} + u_t$$

$$u_t \sim N(0, \ln(1+\sigma_{LNG}^2)(1-\rho_{LNG}^2))$$

In (16), the stochastic term, $e_{LNG,t}$, represents the proportional deviation of the spot LNG price from the forward LNG price, $F_{LNG,t}$. The LNG spot price in Japan is likely to be more volatile than the crude oil price (or its linear function) as it is much smaller market than the crude oil market. $e_{LNG,t}$, intends to capture this additional volatility of regional gas price. It is assumed to follow an AR(1) process because the short-term fluctuation in gas market is likely to be serially correlated, as observed in the US market. $e_{LNG,t}$ has unconditional distribution $N(0, \ln(1+\sigma_{LNG}^2))$. Thus, the expected value and variance of $P_{LNG,t}$ are, conditional on $F_{LNG,t}$,

(18) $$E[P_{LNG,t}] = F_{LNG,t}$$

$$V[P_{LNG,t}] = F_{LNG,t}^2 \sigma_{LNG}^2$$

The presumption in the above specification is that the spot price in a hypothetical LNG market in Japan has the unconditional mean of the forward LNG price. The assumption is

sales between Qatar and Japan and it converts the JCC price into the c.i.f. price with the intercept representing transportation cost. The second formula applies to the LNG sales between Oman and reasonable if the prevailing LNG pricing formula is chosen so that the resulting LNG price represents an unbiased forecast of the future relationships between spot crude oil and spot LNG price in Japan. Values of two parameters are set as σ_{LNG} = 0.20 and ρ_{LNG} = 0.90 in the base case. A range of values are considered in simulation, σ_{LNG} ranging from 0 to 0.50 and ρ_{LNG} ranging from 0 to 0.90.

3.3 Simulation Results

In the simulation, I generate one year of daily simulated data in the three prices, P_{JP}, P_{US}, and F_{LNG}, and calculate annual revenue to the LNG producer under the four different trading strategies. In calculating the firm's revenue from short-term trading, I assume that the arbitraging decision as well as processing and shipping of LNG are instantaneous. That is, the LNG producer can costlessly and instantaneously find a trading partner who agrees to pay the currently prevailing spot price for a delivery in a subsequent date. The simulation also assumes that the futures price of crude oil is an unbiased forecast of the spot price at the delivery date. Another assumption is that the LNG produce has the same forecast as the futures price of crude oil about spot price of crude oil in the subsequent period. The Monte Carlo distributions of the three prices as well as the firm's annual revenues are obtained through 1,000 replications.

Figure 4 illustrates one realization, out of 1000 replications, of one-year of simulated price series. In panel (a) of the figure, the simulated crude oil price is declining, which is purely a random outcome. The spot natural gas price in panel (b) exhibits no downward trend because its deviation from the long-run mean price exhibits almost no correlation from the deviation of the spot crude oil price from its seasonal mean. The simulated forward LNG price, on the other hand, follows the same movement as observed for the crude oil, as it is a linear function of the crude oil price. The simulated spot gas price in Japan moves around the simulated forward LNG price. The deviation from forward LNG price is reasonably large in the base case scenario and increases with the values of the variance parameter σ_{LNG} while its persistence increases with the AR(1) parameter ρ_{LNG} assumed in the data generating process.

Table 4 provides a summary statistics of the simulated price series. These numbers are the average of 1,000 values, each of which is calculated for one realization of one-year data. In the first two columns of **Table 4**, the annual mean of the simulated crude oil and HH natural gas prices, net of transportation cost, are US$59.249/bbl and US$6.706/MBTu, respectively. The annual mean price of the forward LNG price is US$8.887/MBTu, which is

Japan and provides the FOB price. Other studies (Bartsch, 1998; Fujime, 2002) also report the similar approximately 33% higher than the HH natural gas price due to the high crude oil price as well as the transportation cost from the NWS to the west coast US. The standard deviation is 7.131, 2.231, and 1.070, respectively, for crude oil, HH natural gas, and the LNG forward price. These numbers correspond to 12.0, 33.3, and 12.0% of the respective mean price, signifying high volatility of HH natural gas price as compared to the other two prices. The minimum and maximum price observed in 1,000 realizations of one-year sample are, respectively, \$28.634 and \$119.667/bbl for crude oil and \$1.077 and \$96.505/MBTu for HH natural gas (not presented in **Table 4**). These price ranges are wider than price variations observed in the past, yet, are plausible considering that 1,000 replications correspond to 1,000 years worth of observations.

In columns 4 though 6 of **Table 4**, the average of LNG price in the hypothetical Japanese market is approximately equal to the forward LNG price for any sets of values considered for two parameters characterizing the stochastic process of the spot LNG price (σ_{LNG} and ρ_{LNG}). On the other hand, the standard deviation increases with σ_{LNG} as expected, while it decreases slightly with ρ_{LNG} which is due to a non-linearity of the specified data generating process. The spot LNG price exhibits roughly the same level of volatility as the HH natural gas price in the base parameter values.

The last three columns of **Table 4** provide the same descriptive statistics for the maximum of the spot LNG price and the HH natural gas price. They show that the average of the maximum of the two prices is substantially higher than the average spot price in either of the two regional markets. It also increases with the variance of the spot LNG price in Japan while it is not very sensitive to the serial dependence of the spot LNG price. In other words, the expected return from the spatial arbitrage is higher when LNG price in the hypothetical Japanese spot market is more volatile. The standard deviation of the maximum of two prices increases with the value of σ_{LNG}, yet the sensitivity is much weaker than that observed for a single LNG price. In other words, the maximum of the two prices is more volatile than each of the two regional prices when the two regional prices are not very volatile whereas it is less volatile than the two regional prices when the two regional prices are very volatile. These sensitivities imply that a recent increase in the US natural gas price has raised an expected arbitrage profit while reduced the volatility of gains from spatial arbitrage.

Table 5 summarizes the annual revenue to the LNG producer per MBTu of daily production capacity.[12] Of the four trading strategies considered, a conventional forward

formula for the LNG export to Japan and other Asian countries.

[12] Annual revenues reported in this section are the sum of the effective prices over one year. In reality, shipment does not take place everyday. These values can be converted into a revenue per cargo per

trading without cross-hedging generates the expected annual revenue of US$3,244 per MBTu production capacity. The standard deviation of this annual revenue is US$375 or 11.6% of the expected revenue. These numbers indicate that an LNG producer is exposed to a high price risk even under a current business practice of committing all production capacity under long-term supply arrangement. The producer can mitigate this price risk by cross-hedging with the crude oil futures while maintaining the same expected revenue as in the case without cross-hedging, if the futures market is unbiased as a forecast of future spot price.

Columns 2 though 4 of **Table 5** show the mean and standard deviation of the sum over one year of the maximum of the two spot gas prices; LNG price in Japan and HH natural gas price. These numbers represent the mean and standard deviation of annual revenue to the LNG producer who supplies its product to either of the US and Japanese spot market, the one where the price is higher than in the other market on daily basis. In the base case scenario, the mean revenue is 5.9% (or US$192.24) above the level when the firm does not arbitrage spatial price differentials. This expected benefit from spatial arbitrage increases with the volatility of the spot LNG price in a hypothetical Japanese market whereas it is insensitive to the serial correlation of the spot LNG price in the Japanese market.

In the bottom half of the table, the standard deviation of annual revenue, in the base case, is approximately 7.6% higher than in the case where the firm supplies under the long-term forward contract. This increase in the firm's revenue volatility attributes to two factors. First, the firm is exposed to high volatility of regional spot gas prices even in the absence of spatial arbitrage. Second, as discussed in Section 2, the maximum of two regional prices can be less or more volatile than each of the two spot gas prices. In the base case, the maximum of the two prices is more volatile than the two regional prices as shown in **Table 4**. That is, the option to choose from the two markets exposes the firm to even greater revenue risk than the case without spatial arbitrage. This effect of spatial arbitrage on the volatility of the firm's revenue reverses as the volatility of the spot LNG price in a hypothetical Japanese market increases (i.e., high σ_{LNG}). We previously observed in **Table 4** that the maximum of the two regional prices is less volatile than the spot LNG price in a hypothetical Japanese market when σ_{LNG} is high. In **Table 5**, the volatility of the firm's revenue increases with the values of the two parameters characterizing the stochastic process of the spot LNG price in Japan. The revenue volatility increases with σ_{LNG} simply because the firm is exposed to greater price risk. It increases with ρ_{LNG} because high ρ_{LNG} means that extremely low or high spot LNG prices are

year by multiplying the size of an LNG cargo, usually 138,000 cubic meters and dividing by 60, the days that it takes for a roundtrip between the NWS to the US west coast.

more likely to be observed in consecutive days. The sensitivity to the values of two parameters can be compared with the sensitivity of the volatility of the revenue to the firm supplying through short-term trading but only to the Japanese market (columns 5 through 7 of **Table 5**). The revenue volatility under this trading strategy also increases with the values of the two parameters, but by magnitude much greater than the case where the firm arbitrage spatial price differentials. For the range of values considered for the two parameters, the revenue volatility is lower with the spatial arbitrage than with the spatial arbitrage when both parameters are very high ($\sigma_{LNG} \geq 0.4$ and $\rho_{LNG} = 0.9$).

Columns 8 through 10 of **Table 5** present the mean and standard deviation of the annual sum of the difference between the maximum of the two spot gas prices and the forward LNG price. These numbers represent the expected value and volatility of the revenue to the LNG producer who supplies to regional spot gas markets through short-term trading and, at the same time, hedges its spot price risk with crude oil futures. The total revenue to the firm is this spot revenue plus the revenue from taking a short position in crude oil futures, which is equal to the average forward price of LNG (US$3244 annually). The numbers shown in the top half of **Table 5** are roughly same as the difference between the annual revenue to the producer who supplies through short-term trading (columns 2 through 4) and the revenue to the producer who supplies entirely through forward contract (column 1). What is interesting here is the standard deviation—they are much smaller than the volatility of the revenue to the firm who supplies to the regional spot markets and does not cross-hedge its spot price risk (columns 2 through 4). The difference, representing the revenue volatility reduced by cross-hedging, is US$191.59 in the base case, which is 47.5% reduction from the case without cross-hedging. In other words, almost half of the revenue volatility is mitigated through cross-hedging with crude oil futures. As for the case without cross-hedging, the revenue volatility increases with the values of two parameters characterizing the stochastic properties of the spot LNG price in Japan. However, it is much more sensitive to the values of the two parameters than the sensitivity observed previously.

Figure 5 illustrates the distribution of the annual revenue under three of the four trading strategies considered. For the fourth strategy, if the producer supplies under forward contract and cross-hedges its forward price risk, its annual revenue is deterministic at US$3,244 per MBTu capacity. In panel (a) of **Figure 5**, annual revenue to the producer supplying under forward contract without cross-hedging has the expected revenue of US$3,244 and standard deviation of US$375. The firm's revenue is also slightly skewed positive, due primarily to the positively skewed distribution of the spot crude oil price. Panel

(b) shows that the revenue to the firm supplying through short-term trading has both mean and volatility higher than the revenue to the firm supplying under forward contract. The revenue is also more positively skewed, primarily because the distribution of the maximum of the two spot prices is skewed positive.

In panel (c) of **Figure 5**, substantial reduction in the volatility of firm's revenue through cross-hedging results in the distribution of annual revenue to be concentrated around the mean revenue around the same mean value (US$3,436). The difference in the expected revenue from the case where firm supplies under forward contracting and hedges the forward price risk is US$192. Therefore, the trade-off is between this increment in the expected annual revenue per unit production capacity and US$212 of uncertainty in the revenue to the firm supplying through short-term trade. Besides, the firm's revenue from supplying through short-term trading and cross-hedging is highly positively skewed. This positive skewness attributes to that of the maximum of the regional gas prices—option to supply one of the two prices mitigates the downside price risk more than upside price risk. Out of 1,000 replications, the annual revenue is below US$3,436 only in 91 realizations, that is, only 9% probability that the firm's revenue is below the mean. As for the sensitivity to the values of the two parameters characterizing the stochastic process of the spot LNG price in Japan, the probability that the revenue from short-term trading is below the revenue from forward trading decreases further from 9% with the volatility of hypothetical spot LNG price while increases with its persistence.

Figure 7 illustrates the frequency of the firm supplying into the US market and its sensitivity to the values of two parameters characterizing the stochastic properties of the spot LNG price in Japan. In the base case, the firm supplies to the US market frequently during the winter peak-demand periods—more than 40% of time in December and January—whereas it supplies to the US market only occasionally during off-peak demand season. Frequent delivery during the winter peak demand season is due to high average price and high price volatility in the US market. Panel (b) illustrates that the frequency of US delivery increases, particularly for off-peak demand seasons, with the volatility of the spot LNG price in Japan while it is not sensitive to the persistence of the shocks to the hypothetical spot LNG market in Japan.

CONCLUSION

Unlike for the case in the Atlantic region considered by Hayes, spot gas markets are not well developed in Japan and other countries in Asia. The absence of liquid spot market prevents the strategy considered by Hayes (2006)—to arbitrage spatial price differentials while securing its price under long-term supply arrangement. Another feature common to current LNG trading practice is that the forward price of LNG is stochastic as it is linked to the spot price of an alternative fuel. The analysis in this study has incorporated these features and examined the risks and returns to short-term LNG trading as opposed to a conventional practice of supplying under long-term bilateral supply/purchase arrangement in Asia-Pacific region.

The models of spot price dynamics estimated in this study have depicted strong seasonal variation in mean and variance of the spot natural gas price at Henry Hub. In contrast, Brent crude oil, as an alternative fuel to which the forward LNG price is linked, exhibits virtually no seasonal pattern in mean and variance. The depicted price dynamics implies a potential for a positive expected returns from arbitraging a spatial price difference between Asia and the US through short-term trading.

The simulation model constructed around the estimated price dynamics illustrates that an increase in the firm's revenue from short-term trading is about 6% of the expected revenue from forward contracting. However, the volatility of the revenue from short-term trading is also high with standard deviation about 12% of mean annual revenue. Nonetheless, the LNG producers supplying under forward trading also faces with high forward price risk due to high volatility of forward LNG price, reflecting that of the spot crude oil price. An increment in revenue volatility is not large enough to reject the possibility of LNG producers shifting from conventional practice of long-term forward contracting to short-term trading.

The simulation also is also considered for the case where an LNG producer cross-hedges its price risk with the futures markets for the commodity to which the forward LNG price is linked. Such cross-hedging strategy signifies the gains from short-term LNG trading as opposed to forward contracting. The expected incremental revenue from short-term trading is about 6% of the revenue from forward contracting while the revenue volatility is less than 7% of the mean revenue. The most noticeable difference, from the case where the firm does not cross-hedge is that the firm's revenue from short-term trading is highly positively skewed—the revenue from the spot sales exceeds the revenue from forward sales more than 90% of time. Revenue below the mean is realized only 9% of time out of 1,000 replications. This low downside risk for short-term LNG trading is attributable to the option to choose from multiple regional markets to which the producer supplies in the spot market.

These results indicate that the historical prices of the US natural gas and crude oil imply a positive return from the short-term LNG trading with reasonably low risk, even in the absence of well-developed regional gas markets in Asia. However, whether LNG producers actually shift to short-term trade also depends on other factors. Among these, the quantity risk will be an important factor, as reflected in a common discussion that spot LNG trading will become more active as more liquefaction facilities recover the initial investment costs in near future. Quantity risk and cost associated with finding trading partners through short-term trade will remain high in the absence of well-developed gas market in Asia and discourage LNG producers from shifting to short-term trading from a conventional practice of trading under long-term supply arrangements.

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Table 1 Descriptive statistics of natural gas and crude oil daily spot prices

Sample: Nov. 1, 1993 - Mar. 23, 2007

	Natural Gas	Crude Oil
Mean	4.022	28.845
Std. Dev.	2.463	15.841
Skewness	1.504	1.292
Kurtosis	5.984	3.644
Minmum	1.035	9.65
Maximum	19	78.74

Table 2 Maximum Likelihood estimation of the spot price dynamics of crude oil and natural gas

Sample: Nov. 1, 1993 - Mar. 23, 2007

	NG				CO			
	Coefficient	Std. Err.	*t* -ratio		Coefficient	Std. Err.	*t* -ratio	
Mean price function								
Constant	0.2166	0.0622	3.482		2.4455	0.0500	48.900	
Time trend**	1.7840	0.1057	16.874		1.5839	0.1215	13.037	
s1	-0.0229	0.0308	-0.746		-0.0130	0.0190	-0.683	
c1	0.0543	0.0404	1.343		-0.0315	0.0180	-1.757	
s2	-0.0476	0.0213	-2.232		-0.0066	0.0092	-0.712	
c2	0.0576	0.0217	2.652		0.0041	0.0093	0.437	
s3	-0.0001	0.0134	-0.007		0.0079	0.0063	1.248	
c3	0.0389	0.0151	2.580		0.0023	0.0059	0.393	
s4	0.0182	0.0109	1.678		0.0055	0.0046	1.213	
c4	0.0222	0.0099	2.255		0.0002	0.0048	0.050	
s5	0.0099	0.0083	1.195		-0.0008	0.0038	-0.199	
c5	0.0027	0.0067	0.406		-0.0026	0.0036	-0.720	
Variance function								
Constant	0.2697	0.0295	9.157		0.1704	0.0174	9.765	
s1	-0.0219	0.0249	-0.881		0.0066	0.0069	0.956	
c1	0.1286	0.0380	3.379		0.0028	0.0065	0.429	
s2	0.0345	0.0256	1.346		0.0012	0.0043	0.284	
c2	0.0494	0.0283	1.747		-0.0062	0.0053	-1.153	
s3	0.0294	0.0162	1.811		-0.0018	0.0037	-0.476	
c3	0.0259	0.0254	1.021		0.0021	0.0035	0.613	
s4	0.0007	0.0105	0.062		-0.0031	0.0029	-1.066	
c4	0.0200	0.0181	1.105		0.0040	0.0032	1.244	
s5	-0.0017	0.0073	-0.229		0.0006	0.0026	0.218	
c5	0.0031	0.0106	0.291		-0.0006	0.0023	-0.247	
AR(1) and GARCH								
ρ_i	0.9834	0.0000	1560.719	*	0.9925	0.0000	4124.765	*
$\gamma_{1,i}$	0.6989	0.0024	293.115		0.8844	0.0020	448.765	
$\gamma_{2,i}$	0.2062	0.0016	125.811		0.0673	0.0004	184.831	
$\gamma_{1,i} + \gamma_{1,i}$	0.9051			*	0.9517			*
Cross-commodity correlation								
r_{12}	0.1170							

* *t* -ratio is calculated with respect to one .

** Variable takes a value zero for initial observation and one for the last observation in sampling period (Nov. 1, 1993 - Mar. 23, 2007). The estimated coefficient of 1.7840 (1.5839) implies that natural gas (crude oil) price increase by approximately 13% (12%) every year.

Table 3 Cross-commodity price correlation with and without controlling for known variations

Sample: Nov. 1, 1993 - Mar. 23, 2007

Symbol as in Eqns. (1)-(5)	Description	Sample correlation
Pt	Price	0.8593
$f(t)$	Predicted seasonal mean price	0.9841
$Pt - f(t)$	Deviation from seasonal mean	0.5237
$et / g(t)$	Deviation standardized by seasonal volatility	0.5238
ut	Innovation	0.1290
ht	Conditional variance	0.1794
ut / ht	Innovation standardized by conditional variance	0.1170

Table 4 Descriptive statistics of the simulated price series

	(1)	(2)	(3)		(4)	(5)	(6)	(7)	(8)	(9)
Symbol	P_{CO}	P_{HH}	F_{LNG}		P_{LNG}			P_{MAX}		
Description	Spot crude oil price	Spot HH gas price	Forward LNG price		LNG price in hypotherical Japanese spot market			Maximum spot natural gas prices of US and Japanese Market		
					ρ_{LNG} = 0	0.5	0.9	ρ_{LNG} = 0	0.5	0.9
Mean										
	59.249	6.706	8.887	σ_{LNG} = 0	8.887			9.311		
				0.1	8.888	8.888	8.889	9.337	9.338	9.338
				0.2	8.888	8.888	8.889	9.415	9.415	9.414
				0.3	8.889	8.889	8.888	9.537	9.537	9.533
				0.4	8.890	8.889	8.886	9.690	9.689	9.681
				0.5	8.890	8.890	8.885	9.859	9.858	9.846
SD										
	7.131	2.231	1.070	σ_{LNG} = 0	1.070			1.600		
				0.1	1.412	1.409	1.386	1.830	1.828	1.811
				0.2	2.107	2.100	2.043	2.333	2.328	2.286
				0.3	2.908	2.899	2.806	2.941	2.935	2.863
				0.4	3.749	3.738	3.605	3.605	3.598	3.490
				0.5	4.606	4.595	4.415	4.308	4.302	4.148

Table 5 Mean and standard deviation of annual revenue to a hypothetical LNG producer

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Symbol	F_{LNG}	P_{MAX}			P_{LNG}			$P_{MAX} - F_{LNG}$		
Description	Forward LNG price	Maximum spot natural gas prices of US and Japanese Market			LNG price in hypotherical Japanese spot market			Annual gain from spot trading with spatial arbitrage as opposed to forward trading		
	flng	ρ_{LNG} = 0	0.5	0.9	ρ_{LNG} = 0	0.5	0.9	ρ_{LNG} = 0	0.5	0.9
Mean										
σ_{LNG} = 0	3243.89	3398.50			3243.89			154.62		
0.1		3408.14	3408.21	3408.51	3244.03	3244.07	3244.30	164.26	164.32	164.62
0.2		3436.48	3436.48	3436.26	3244.22	3244.24	3244.35	192.59	192.60	192.38
0.3		3481.08	3480.83	3479.55	3244.43	3244.42	3244.07	237.19	236.95	235.67
0.4		3536.81	3536.38	3533.65	3244.67	3244.63	3243.57	292.92	292.50	289.76
0.5		3598.37	3598.02	3593.71	3244.91	3244.88	3242.93	354.48	354.13	349.83
SD										
σ_{LNG} = 0	374.89	402.31			374.89			199.13		
0.1		401.75	402.69	408.03	375.93	377.20	384.78	201.20	202.35	210.55
0.2		400.31	403.35	421.83	377.71	381.75	407.42	207.43	211.76	241.59
0.3		400.21	406.25	443.36	380.22	388.39	440.44	216.81	225.54	282.86
0.4		402.73	412.48	472.00	383.47	396.95	481.18	228.00	241.75	328.93
0.5		407.53	421.69	506.45	387.43	407.22	527.30	239.99	259.37	377.51

Figure 1 Observed and predicted natural gas and crude oil price

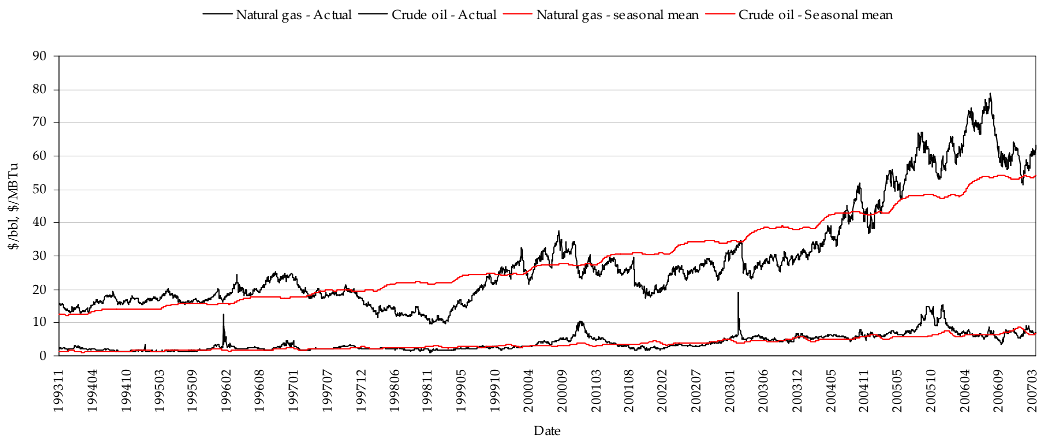


Figure 2 Estimates of seasonal mean price

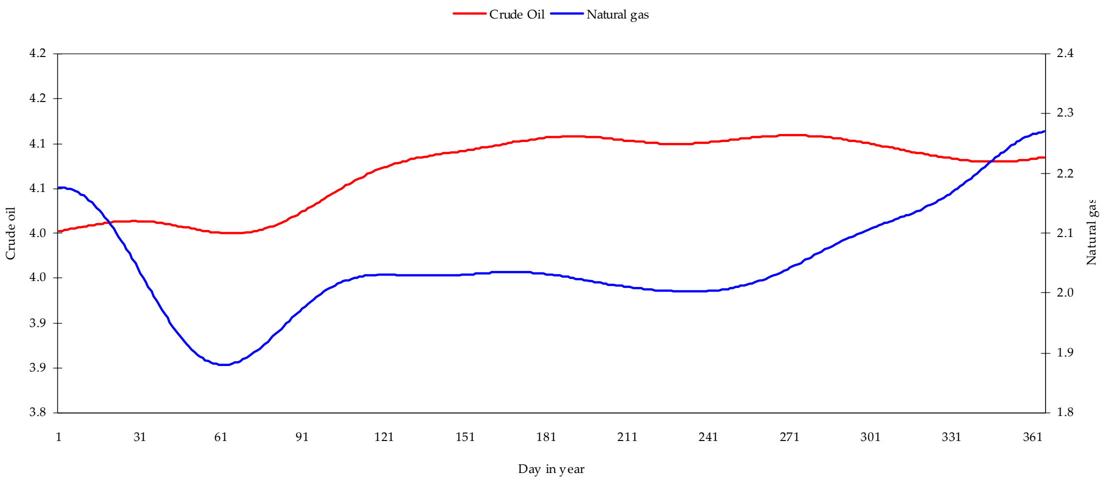


Figure 3 Estimates of seasonality in variance

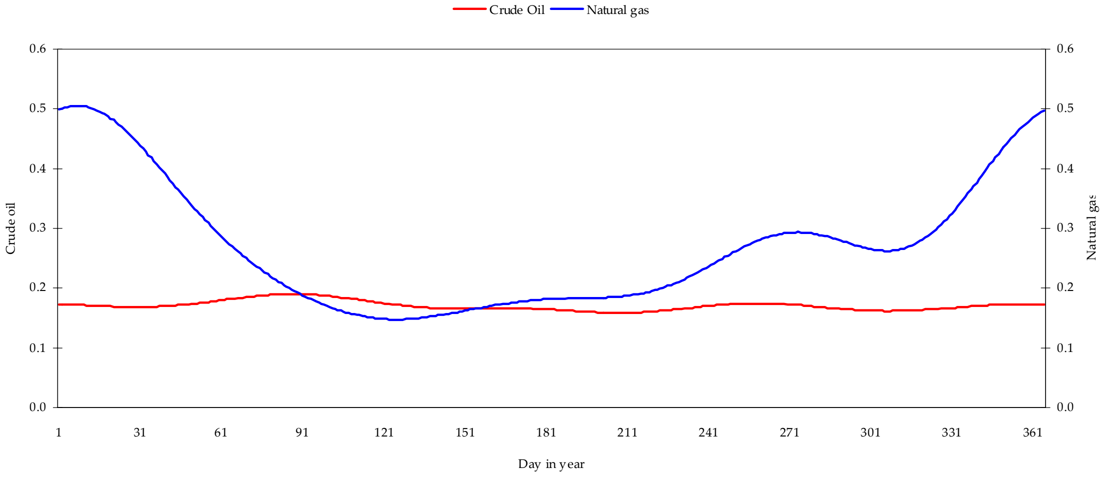
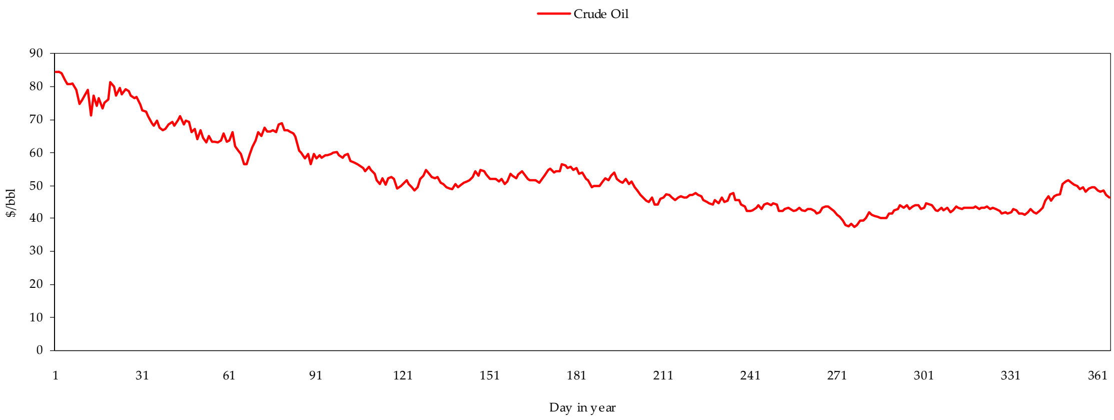


Figure 4 One realization of simulated price series

(a) Crude oil



(b) Natural gas and LNG

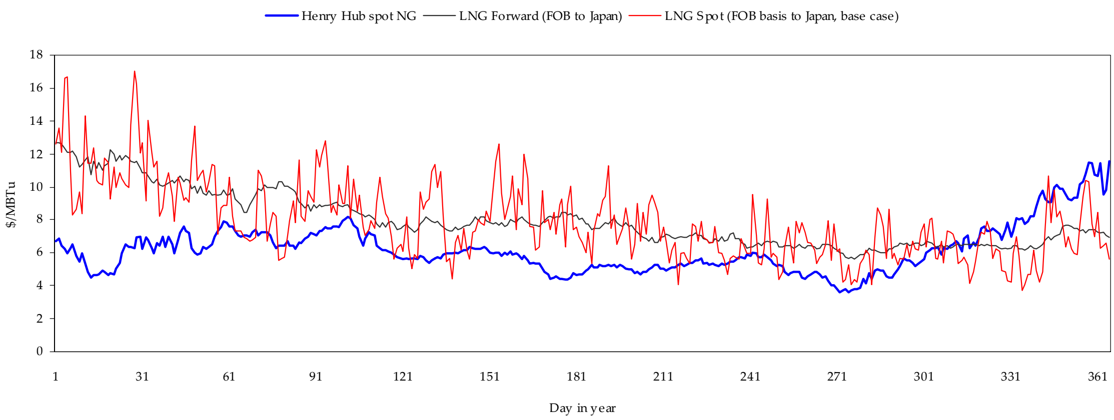
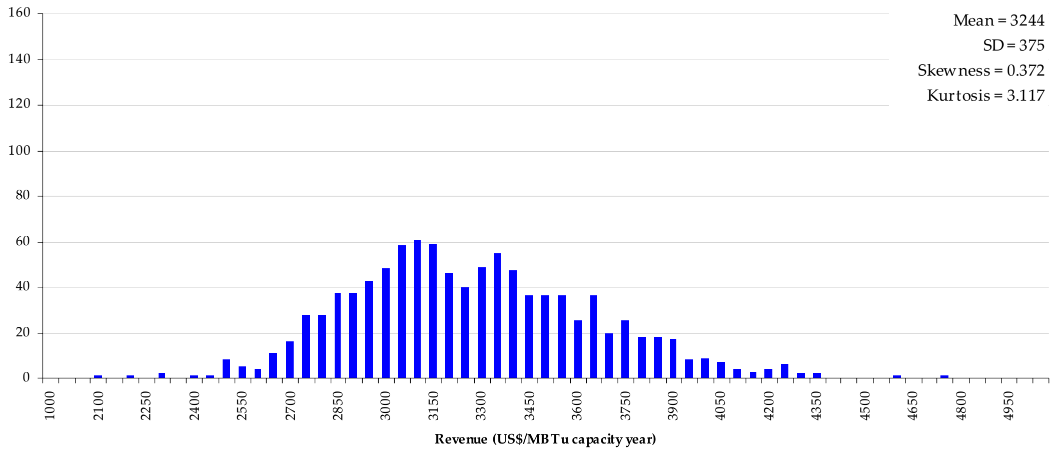
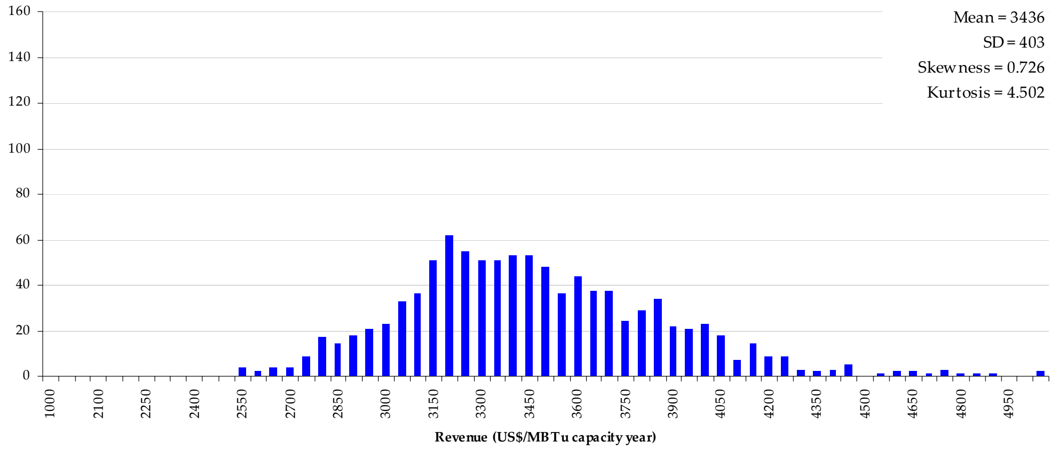


Figure 5 Monte Carlo distribution of the annual revenue to a hypothetical LNG producer—Base case (σ_{LNG} =0.2, ρ_{LNG}=0.5)

(a) Forward trading without cross-hedge (F_{LNG})



(b) Spot trading with spatial arbitrage, no cross-hedge



(c) Spot trading with spatial arbitrage, with cross-hedge

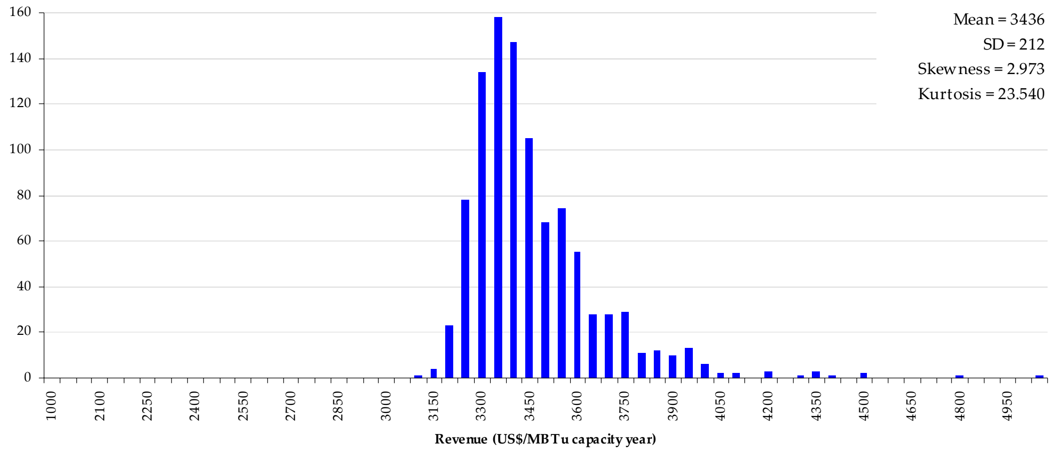


Figure 6 Seasonality in the frequency of diversion to the US delivery and its sensitivity to the parameters characterizing the stochastic process of a hypothetical spot LNG spot market in Japan