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ESSAYS ON ENERGY ECONOMICS RESEARCH

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Dedication

To Andy for your unwavering faith in me.

To Mom and Dad for your never-ending love.

To my grandfather who inspired me to study Economics.

To my sons for the motivation to demonstrate to you one day that anything is possible.

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ESSAYS ON ENERGY ECONOMICS RESEARCH

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In the first chapter, I examine a variety of the factors that affect the price and demand of natural gas. Prior natural gas price research approaches utilized well-defined time series models. I have taken these historical approaches and explored an alternative approach to estimating the model- defined equilibrium market price based on the market clearing condition. Assuming that the natural gas market is a relatively efficient market, the market equilibrium price induced by the model should track the observed market price. A two-step estimation process includes - reduced formed regression estimations for each market component in the material balance equation, and solves for the market balance equation with identified coefficients and parameters for the market equilibrium price. The model results track the market price quite well, in both one period ahead forecasts and a simulated 36 months forecast case.

The second chapter in the series "The Game that Drives the LNG Train" analyzes the strategies and decisions of major oil companies' on selecting regasification terminal sites for importing liquefied natural gas (LNG) along North American coastlines and delivery of regasified gas into regional domestic markets. Each participating firm's decision is extensive and complex, involving multi-years of capital and human investments. Furthermore, fierce competition exists among firms procuring LNG cargos

and servicing the same set of demand areas, i.e. the North America market. This paper will attempt to condense the whole strategy and decision-making process into a simplified multistage model. The model will focus on exploring the strategic elements of decisions for each participant firm in the competition through a game-theory lens.

Extending from previous work on tying, the third chapter seeks a more structured result on the relationship of pre-commitment and exclusion due to tying under a Hotelling framework. A three-stage model is set up, which includes a conditional pre-commitment stage and an entry decision stage preceding the third stage of pricing competition. The paper concludes that: first, exclusion is possible even with zero fixed cost, and it is executed by conditional pre-commitment of tying upon entry. Second, conditional pre-commitment of tying only occurs if entry can be excluded, otherwise, tying is not profitable as independent pricing upon entry.

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Chapter 1: Structural Estimation of Natural Gas Price in a Rational Expectation Market Equilibrium

1.1. Introduction and Background

Academic researches and industry white papers together host a wealth of knowledge on forecasting energy prices, including natural gas prices. Most of the recorded methods share two features: first, employed a time series approach, predicting price as a function of its own lagged variables. However, the time series approaches often fail to capture sudden spikes or drops in price; second, anchored the forecasting model on the relationship between natural gas and crude oil. Traditionally natural gas and crude oil prices sustained a stable relationship: crude oil price dollar/bbl to natural gas price dollar/mmbtu is about 6 to 7:1, which is approximately the heat content equivalence between the two commodities. After reaching a peak (120 dollar/bbl for crude oil and 14 dollar/mmbtu for natural gas) in summer of 2008, prices of crude oil and natural gas dropped significantly in September 2008. However crude oil price quickly recovered back to about 80 dollars/bbl, but natural gas price has been anemic ever since then and hovering around 4 dollar/mmbtu compared to a previous 6-7 dollar/mmbtu level. Hence, the relationship between crude oil price and natural gas price in the North America market has decoupled and the correlation of the two has materially weakened since 2008, and not yet any sign that the two prices will converge back to their prior relationship.

In this paper, I investigate an alternative method, which captures shifts in market conditions by estimating the market price of natural gas based on rational expectation market equilibrium. This approach assumes the existence of a material balance in a relatively efficient market, i.e., natural gas market, although there will be small discrepancies in evidence. Compared to previous models on this topic, this approach pays more attention on the fundamental drivers in the natural gas market, in addition to its relationship to crude oil, and acknowledged and formally estimates the impact of rational expectation on market equilibrium.

1.2. Literature Review

The literature review is split into two sections. The first section reviews the underlying reasoning on relationship between natural gas and crude oil, and surveys past researches on forecasting natural gas and highlights their contributions. The second section follows the development of rational expectation market models, which is the alternative approach proposed for forecasting natural gas price in current paper.

1.2.1. A History of Modeling Natural Gas Prices

In the early stages of studying natural gas prices, the idea that natural gas price tracks closely with crude oil price evolved. To understand the origin of this idea, it is essential to understand why these two commodities are fundamentally connected in energy market.

On the demand side, natural gas and crude oil are substitutes as choices of fuels for space heating as well as electric generation. Energy Information Agency (EIA)'s 2002 Manufacturing Energy Consumption Survey (MECS) estimates about 18% of natural gas usage can be switched to petroleum products (Joutz and Villa, 2006). Based on Energy Velocity, there is about 20% of power generation capacity is dual-fired although in practice the actual utilization rate of these units are considerably less. Furthermore, fuel switching is not only limited to dual-fired units. Additional fuel switching is a result of dispatching decisions based on the relative prices of natural gas and resid oil (byproduct of crude oil) in the market. Although these percentages seem limited to the existing installed capacity in one market, the shift in marginal consumption can often have pronounced impact on prices, especially in a tight market. Therefore, an increase in crude oil prices promotes the consumption of the substitute - natural gas - versus petroleum products, which in turn increases natural gas demand and hence natural gas prices. However, it is worth noting that there has been a constant decline of oil-fueled units in Northeast of U.S., where those units are replaced with more efficient and cleaner gas units. Therefore, the relationship of fuel switching between oil and gas is expected to be increasingly limited going forward.

On supply side, the focus is the strong long-term relationship between crude oil and natural gas. Natural gas is found in two basic forms – associated gas and non-associated gas. Associated gas is natural gas that occurs in crude oil reservoirs, either as free gas or as gas in solution with crude oil. In 2004, EIA estimated that associated-dissolved gas comprised about 2.7 trillion cubic feet (Tcf) or 14% of the marketed natural gas production in the United States. When natural gas is produced from a wellhead, there are chemical products which need to be extracted prior to shipping it via a pipeline. These byproducts must be extracted to comply with natural gas purity requirements set by the pipeline owner. The natural gas chemical byproducts extracted during the refining process are referred to as liquids. Similarly petroleum byproducts as referred to as oil liquids. Natural gas liquids as byproducts of natural gas production are typically also byproducts of oil production. This results in a price linkage where natural gas liquids can be sold at oil-linked prices. In other words, there exists a linkage between the prices of gas and oil. When oil price become attractive, natural gas production with higher liquid content becomes more valuable as a result. In addition to the link between natural gas and oil in production and processing stages, crude oil and natural gas are linked together through the investment cycles of exploration and production companies. Since the two energy sources share similar channels for economic resources and capital markets for future development, exploration and drilling technique, it is common to consider the two simultaneously in investment plans. After the breakthrough in horizontal drilling which unlocked vast shale gas resources in North America, the next target was to apply the same drilling technique on oil shale. As a result, there is knowledge sharing among gas and oil production ventures. So, when oil price is much more attractive in the recent years, there is a trend for shifting focus of capital investment from gas to oil/liquid focus: producers are adjusting their production plans to reallocate rigs into production plays which produce oil or more natural gas liquids.

Therefore, crude oil and natural gas prices are related through both demand and supply sides of the market, and it is complicated to determine which linkage is dominating at any point in time. However, there is one thing which is certain: there is an underlying structural relationship between natural gas and crude oil, and that serves as a basis of past researches on natural gas prices. As the first of this series of literature, Yücel and Guo (1994) described the relationship between prices of crude oil and natural gas as: crude oil prices is determined by the world oil market conditions, while U.S. natural gas prices tend to follow. However, as mentioned earlier, there is increasing evidence of a diminishing relationship between crude oil and natural gas: although U.S. natural gas prices have followed the general upward trend with the world crude oil price, there are also distinctly independent movements. The last episode is the decoupling of the two prices since second half of 2008, and it is also the longest in its duration. There were other episodes of decoupling occurred throughout the past decade: 2000, 2002, 2003 and second half of 2005.

The decoupling phenomenon between the prices of commodities captured curiosity of researchers: Serletis and Rangel-Ruiz (2002) used the daily price of natural gas at the Henry Hub and WTI from 1991 to 2001found that although the two prices are linked, but Henry Hub and WTI do not have common price cycles as a result of deregulation. Villar and Joutz (2006) followed the same thread of research in more details, supporting the findings of Serlitis and Rangel-Ruiz (2002) that the price of WTI is weakly exogenous to the price of natural gas at the Henry Hub. Specifically, Villar and Joutz find that the price of natural gas adjusts to deviations in the long run evolving relationship, but these deviations do not affect the price of WTI. They also found that changes in natural gas prices tend to lag behind changes in crude oil prices. Hartley, Medlock and Rosthal (2006)'s paper is one of the more recent. Like Villar and Joutz, they also focuses on defining a stable co-integrating relationship between natural gas and oil prices by adding an additional variable, but they considered technology instead of a time trend. Hartley, Medlock and Rosthal have hypothesized that the increased efficiency of producing electricity with natural gas is responsible for the increasing decoupling between the two commodity prices. The latest study by Villar and Joutz (2007) extends the research down to a new direction by revealing that weekly oil and natural gas prices still have a powerful relationship. They emphasize that the relationship between the oil and gas can be described in a much more consistent way when also adding a more extensive set of exogenous variables including weather, storage and production shut-ins during hurricanes into the regression.

In comparison to the past research on natural gas prices, this paper takes a different approach by constructing a market equilibrium model, which determines the price of natural gas prices. This method has been widely used to model storable commodities, such as agriculture products, but it has not been applied to the energy commodity space. However, the storable feature as well as the lagged production decisions of natural gas makes it suitable for the type of market equilibrium models.

1.2.2. Rational Expectation Market Models

This following section provides a simple introduction to the past research on the rational expectation market model that is used this paper. I will not elaborate the long list of research performed in this field, but instead only highlight a few aspects of the literature which directly relates to my current paper. Irwin and Tharen (2011) provide a detailed review of the rational expectation market model and its applications.

Anticipation for the future values of market variables by the market participants has always played an important role in determining economic behavior. Keynes considered the role of agents' anticipation for future events in his 1936 classic *General Theory of Employment, Interest and Money.* The notion of "rational expectation" came much later. Muth (1961) formulates a definition of agents' expectations that is internally consistent with the economic model, which is defined by economists. Muth calls expectations that are consistent with the economic model as "rational". Later on, a rapidly growing literature on rational expectation modeling and testing was developed in agriculture economics. Each of agriculture markets that has been studied, is perceived by the econometricians as a basic equilibrium supply and demand system. The equilibrium is a core feature of the model structure, although there are many variations.

One of the key challenges in the rational expectation market model, is to properly model the rational expectation by market participants. There are a lot of researches, which explicitly models the rational expectation behavior of the agents, e.g., Muth, 1961; Shonkwile, 1982; Goodwin and Sheffrin, 1982; Eckstein, 1984; and Ghosh, Gilbert and Hughes-Hallet, 1987. When future contracts are introduced to the agriculture commodity markets, it is designed to be measure of forward-looking expectation that decision makers in the market are able to acting upon. The rational expectation market model is used to study the impact of the future contracts, on market equilibrium. Turnosvsky (1983) provides a theoretical approach to compare the impact of rational expectation with or without future contracts on market equilibrium, and concludes that future contracts are effective market instruments to maintain stability of the market equilibrium under uncertainty. Furthermore, Choi and Helmberger (1993) take the price of futures as a proxy for the expected price as a factor of the decision process in an empirical model, compared to the prior pure-theoretical approaches. A key feature of this empirical analysis is the estimation of an expected price function using econometrics instead of the numerical methods proposed by Lowry et al. (1987) and Miranda and Helmberger (1988). The resulting estimates appear to be plausible and the estimated system, though simple, tracks history rather well. The result suggests that econometrics might be a good substitute for the numerical methods that have been used recently to estimate expected price functions.

1.3. THEORETIC MODEL SETUP

This section establishes a simple but general theoretic model, which provides the foundation of the later empirical model used in this paper. The theoretic model setup follows the framework in Turnosvsky (1983), but the key difference is that futures market is not explicitly modeled here. Instead it is treated as a proxy of rational expectation in the empirical estimation.

A partial equilibrium market model is used to describe the natural gas market in North America. Besides demand and supply, financial trading and storage are effective means to smooth domestic prices in balancing the market with strong demand side seasonality and production side uncertainty of delivery. Since the trading component of the North America gas market does not prominently influence the market-clearing price, I have excluded it in the simple theoretic model without losing the generality of the model. I intend to treat the entire North America gas market as one integrated market: although in reality it is comprised of many individual physical market centers, a well-established pipeline system helps to effectively balance all markets. By breaking the North America market into individual and parallel market centers which are connected through pipelines, the market material balance of the structural model are the aggregation of the receipt and delivery volume of each and every market centers on the pipeline grid. However, the supply areas and demand areas are rarely synchronized in geographic sense, building the model at the level of market centers will leads to too much complexity for the scope of current research. Hence, modeling North America as one aggregated market is not only simpler but also without the loss of generality. The following structural model outlines the market characteristics of a commodity market including supply, demand and net imports and arbitrage conditions such as storage.

1.3.1. Material Balance

The available supply in period t is comprised of production (Q_t) and net imports (I_t) plus the withdrawals from carryover storage inventory ($S_t^{withdrawal}$). The market must allocate the total supply of gas among consumption (C_t) and injections for carrying over for the future storage ($S_t^{Injection}$). The resulting inter-temporal equilibrium is summarized in the following material balance equation:

Eqn1: $$Q_t + S_t^{Withdrawl} + I_t = A_t = C_t + S_t^{Injection}$$

The specification here assumes no losses in storage and internal transportation (pipeline fuel losses) and no qualitative difference between all the available commodities in the market whether it is from storage or direct production. In the natural gas market, there is a small percentage of fuel lost in the transportation and storage processes. In addition, gas extracted at wellheads contains liquids and chemicals. This type of gas is called “wet gas” and must be processed to remove any byproducts prior to shipping to any market centers.

Hence, the production at period t is the total amount of gas realized from production in period t after processing and ready for pipeline delivery, because gas delivered through pipelines is regulated in term of quality, and generally similar in term of its chemical makeup and heat content with few exceptions.

1.3.2. Production

Since gas production activity requires intensive capital and resource allocation, it takes time to plan and execute, the production realized in period t is a result of prior decisions and planning before current time. For the purpose of discussion here, I assume that there exists a time lag of *k* periods. Due to the lagged nature of production, the industry is always interested in monitoring rig counts, as that is a lead factor for production levels.

The representative firm is assumed to be perfectly competitive and to produce its output subject to a quadratic cost function. The planned production for period t formed at period t-k, $\bar{y}_{t|t-k}$, is the strategy variable and the firm's profit function is defined as:

Eqn2: $$\pi_t^f = p_t y_t - \frac{1}{2} c \bar{y}_{t|t-k}^2$$

$$\begin{aligned}
&where \\
&f: representative\ firm; \\
&p_t: spot\ price\ at\ period\ t; \\
&y_t: actual\ output\ at\ period\ t; \\
&\bar{y}_{t|t-k}: planned\ output\ at\ period\ t, decided\ ex-ante\ at\ period\ t-k;
\end{aligned}$$

Since firm makes its production decision for period t at period t-*k,* before the actual market condition at period t is known. Random fluctuations in production conditions and investment environments for the period leading to period t are assumed to be beyond the control of the firm. Actual production realized at period t is a function of the planned output plus a shock that was unobservable ex-ante and realized at period t:

Eqn3: $$y_t = \bar{y}_{t|t-k} + v_t^f$$

$$\begin{aligned} &where: \quad v_t^f = c^f + \lambda^f X_t^f + u_t^f; \\ &c^f - \text{ constant;} \\ &X_t^f - \text{ exogenous variables;} \\ &u_t^f - \text{random noise with zero mean and finite variance} \end{aligned}$$

v_t^f is a function of additional exogenous variables influencing the realized natural gas production, and a random shock u_t^f with zero mean and finite variance. Combining equation 2 and 3 yields:

Eqn4: $$\pi_t^f = p_t(\bar{y}_{t|t-k} + v_t^f) - \frac{1}{2}c\bar{y}_{t|t-k}$$

In order to keep the linearity of the model, I assume that the firm maximizes the following one period function of expected profit and its variance:

Eqn5: $$V_t^f = \pi^e(t,t-k) - \frac{1}{2}\alpha\sigma_\pi^2(t,t-k)$$

$\pi^e(t,t-k)$ is the conditional expectation of profit for period t, formed at time t-k, $\sigma_\pi^2(t,t-k)$ is the conditional variance of profit for period t, formed at time t-k. α is the coefficient describing risk attitude. Based on equation 4, the conditional expectation and variance are derived as follows:

Eqn6: $$\begin{aligned} &\pi^e(t,t-1) = E_{t-1}(\pi_t) = p_{t,t-1}^e\bar{y}_t + E_{t-1}(p_t v_t^f) - \frac{1}{2}c\bar{y}_t^2; \\ &\sigma_\pi^2(t,t-1) = E_{t-1}(\pi_t - E_{t-1}(\pi_t))^2 = \sigma_p^2(t,t-1)\bar{y}_t^2 + 2\operatorname{cov}(p_t, p_t v_t^f)\bar{y}_t + \operatorname{var}(p_t v_t^f) \end{aligned}$$

Assume that there are n identical firms, each of which contributes equally to the aggregate supply disturbance v_t:

Eqn7: $$v_t^f = \frac{v_t}{n}$$

The conditional cross moments formed at period t-k between p_t and v_t are finite and of order 1. All cross moments can be written in term of order, O(·):

Eqn8:
$$\begin{aligned}
&E_{t-k}(p_t v_t) = O(1);\\
&\sigma_p^2(t,t-k) = \mathrm{var}_{t-k}(p_t) = O(1);\\
&E_{t-k}(p_t v_t^f) = \frac{1}{n}E_{t-k}(p_t v_t) = O(\frac{1}{n})\\
&\mathrm{cov}_{t-k}(p_t, p_t v_t^f) = \frac{1}{n}\mathrm{cov}_{t-k}(p_t, p_t v_t) = O(\frac{1}{n})\\
&\mathrm{var}_{t-k}(p_t v_t^f) = \frac{1}{n^2}\mathrm{var}_{t-k}(p_t v_t) = O(\frac{1}{n^2})
\end{aligned}$$

Assuming that the number of firms is sufficiently large, the expressions, which are smaller than the first order, can be ignored without a loss of generality. The expected mean and variance of profit can be rewritten by this approximation:

Eqn9:
$$\begin{aligned}
&\pi^e(t,t-k) = p^e_{t,t\text{-}k}\bar{y}_t - \frac{1}{2}c\bar{y}_t^2;\\
&\sigma_\pi^2(t,t-k) = \sigma_p^2(t,t-k)\bar{y}_t^2
\end{aligned}$$

Substituting these two expressions into equation 5 yields the objective function: maximization of V_t^f with respect to $\bar{y}_t$. I derive the following expression for the optimal planned output:

Eqn10:
$$\begin{aligned}
&\underset{\bar{y}_t}{Max}V_t^f = p^e_{t,t\text{-}k}\bar{y}_t - \frac{1}{2}c\bar{y}_t^2 - \frac{1}{2}\alpha\sigma_p^2(t,t-1)\bar{y}_t^2\\
&\bar{y}_t^f = \frac{p^e_{t,t\text{-}k}}{c+\alpha\sigma_p^2(t,t-k)}
\end{aligned}$$

Thus, the planned output of the representative firm varies positively with the expected spot price, and inversely with its risk associated in the time lag periods for price.

1.3.3. Storage

The decision on storage of a commodity, like natural gas, is made based on maximizing the expected profit between periods by market speculators. The gas market has a unique seasonal demand pattern, while the production yields do not correlate to the same pattern leading to storage arbitrage. Storage arbitrage is common in the marketplace. Theoretically, the storage level of period t is determined based on the speculator's anticipation of price changes. Let s_{t-1}denote the net position in the commodity by a speculator entered at period t-1. If the speculator anticipates that the price of period t is higher than t-1, then the speculator holds positive stocks of the commodity, s_{t-1}>0; if the speculator anticipates a price drop in period t compared to t-1, then s_{t-1}<0 indicating that speculator is holding the commodity short. Hence, the profit of the representative speculator over the period t-1 to period t is:

Eqn11: $$\pi_t^s = s_{t-1}(p_t - p_{t-1}) - \frac{1}{2} d s_{t-1}^2$$

Where the cost associated with trading storage is in quadratic term here. These consist of storage costs if the net position is positive together with transaction and interest costs. This is a simplified way to describe the cost of storage, while keeping it in linearity of the function. In most cases, it is true and reasonable to assume that d>0 for a well-defined inventory demand function. Similar to firms, the objective function of the speculator is:

Eqn12: $$\underset{s_{t-1}}{Max} V_t^s = s_{t-1}(p_{t,t-1}^e - p_{t-1}) - \frac{1}{2} d s_{t-1}^2 - \frac{1}{2} \gamma \sigma_p^2(t,t-1) s_{t-1}^2$$

The parameter γ is the degree of risk aversion measure for speculators. Maximizing the objective function with respect to s_{t-1} yields the following storage demand function:

Eqn13: $$s_{t-1} = \frac{p_{t,t-1}^e - p_{t-1}}{d + \gamma \sigma_p^2(t,t-1)}$$

This specification asserts that risk averse speculators, when γ >0, takes a long position or short position depending on whether they expect the spot price to rise or fall over the period.

1.3.4. Consumption

Current consumption of period t is a downward sloping function of current market price of natural gas, and it is derived only at the aggregate level without deriving the underlying utility maximization for individual customers. Therefore, the aggregate demand for the commodity is:

Eqn14:
$$D_t = c_D + \lambda_D X_{D,t} - \beta_D p_t + \varepsilon_{Dt}, \qquad c, \beta > 0;$$
$$and\ E(\varepsilon_{Dt}) = 0; Var(\varepsilon_{Dt}) = \sigma_D^2$$

Where c is the constant term and β is the price elasticity of the natural gas demand. X can be a set of exogenous factors, which potentially affect demand of gas, such as the price of crude oil and weather.

1.3.5. Net Imports

Net imports are the difference between imports and exports in the market. It is a function of prices in current market and outside markets. Net imports of period t are defined at the aggregate level similar to the consumption function:

Eqn15:
$$I_t = c_I + \lambda_I X_{I,t} - \beta_I p_t + \varepsilon_{It}$$
$$and\ E(\varepsilon_{It}) = 0; Var(\varepsilon_{It}) = \sigma_I^2$$

I_t can be positive or negative, and does depend on price differentials between the two markets: the U.S. market and rest of the world. $X_{I,t}$ includes exogenous variables describing both sides of the markets, as well as prices from the rest of the world. Because the rest of the world is not the focus of the model, a simplified definition of net imports is used without elaboration on conditions in the rest of the world.

1.3.6. Aggregate Market Relationships

We can sum over the representation firms leads to the aggregate supply function and rewrite it into a reduced linear form:

Eqn16: $$Q_t = c_Q + \lambda_Q X_{Q,t} - \beta_Q p^e_{t|t\text{-}k} + \varepsilon_{Qt}, \;, \; where \;\; \beta_Q = \frac{1}{c + a\sigma_p^2(t, t-k)}$$

The aggregate storage function can also be represented in a reduced linear form with additional exogenous variables:

Eqn17: $$s_{t-1} = c_s + \lambda_s X_{s,t-1} - \beta_s \omega (p^e_{t,t\text{-}1} - p_{t-1}) + \varepsilon_{st}; \; where \;\; \beta_s = \frac{1}{d + \gamma\sigma_p^2(t, t-1)}$$

The material balance of the market can be written in terms of all three reduced form functions:

Eqn18:
$$
\begin{aligned}
& D_t + s_t = Q_t + I_t \\
\Rightarrow \\
& c_D + \lambda_D X_{D,t} - \beta_D p_t + \varepsilon_{Dt} + c_s + \lambda_s X_{s,t} - \beta_s \omega (p^e_{t+1,t} - p_t) + \varepsilon_{st} \\
= \\
& c_Q + \lambda_Q X_{Q,t} - \beta_Q p^e_{t|t\text{-}k} + \varepsilon_{Qt} + c_I + \lambda_I X_{I,t} - \beta_I p_t + \varepsilon_{It} \\
\Rightarrow \\
& (-\beta_D + \beta_S \omega + \beta_I) p_t = (c_Q + c_I - c_D) + \left[\beta_S \omega p^e_{t+1,t} - \beta_Q p^e_{t|t\text{-}k} \right] \\
& \qquad + \left[\lambda_Q X_{Q,t} + \lambda_I X_{I,t} - \lambda_D X_{D,t} - \lambda_s X_{s,t} \right] \\
& \qquad + \left[\varepsilon_{It} + \varepsilon_{Qt} - \varepsilon_{st} - \varepsilon_{Dt} \right]
\end{aligned}
$$

Therefore, for any sampling period with observed consumption, production and storage, there exists a series of spot prices that satisfy the material balance described above. That spot price describes the market clearing condition when the market equilibrium is sustained. These clearing prices are denoted as $\{\tilde{p}_t\}_{t=1....T}$.

Eqn19:
$$
\begin{aligned}
& \exists \{\tilde{p}_t\}_{t=1...T} \; solves \; this \; equation \; above \\
& \tilde{p}_t = F(X_{Dt}, X_{Qt}, X_{st}, X_{st-1}, X_{It}, p_t, \; p_{t-1}, p^e_{t+1,t}, p^e_{t,t\text{-}k} \mid \Gamma_t) \\
& \Gamma_t : all \;\; parameters
\end{aligned}
$$

A sampling distribution of the difference between $\{\tilde{p}_t\}_{t=1....T}$ and $\{p_t\}_{t=1....T}$ can be calculated based on residuals of each function defined in the market:

Eqn20: $$under\ sample\ of\ size\ of\ n:\ \delta_t = \tilde{p}_t - p_t \sim N\left(\mu, \frac{\tau^2}{n}\right)$$

The interest of the post-estimation discussion focuses on the extreme cases where the market observed price of natural gas is statistically different from the calculated equilibrium price $\widetilde{p_t}$.

1.4. DATA

This section introduces the dataset used for empirical estimation, and explores its statistic characteristics. All data used is from EIA. Appendix 1 includes a detailed description of each variable included in this paper. Although the data source dates from 1980s or earlier for some variables, only data from 1994 to 2010 is used for empirical estimation in this paper for the following reasons:

A deregulated market since 1992:

Although earlier data is available, I have chosen to focus on the post-1992 timeframe, since this is when the natural gas market was officially "deregulated". The often referred as the Final Restructuring Rule after a 20 year process of "deregulation and unbundling", the FERC order 636, issued in 1992, states that pipelines must separate their transportation and sales services. As a result, all pipeline customers can select their gas sales, transportation, and storage services from any provider and in any quantity. The deregulation granted all natural gas sells gain equal rights in the marketplace in moving natural gas from the wellhead to the end-user or LDC and allows the natural gas customer the choice of the most cost effective method of obtaining natural gas. As a result, the natural gas market becomes a much more efficient one, compared to its prior state.

Introduction of Future Contracts of Gas

Since the price of natural gas futures are used as a proxy for expected market price, it is necessary to select the time period when the natural gas future contracts are present. Future contract is designed and used as a risk management instrument in a high-volatility price environment. The natural gas futures contracts were initially introduced in 1994. The Henry Hub Natural Gas Futures (Physical) is an outright natural gas contract between a buyer and a seller.

Table 1 lists all the variables collected for the empirical analysis below.[1] Note that not all of these variables are used in the final version of the model. Apart from the statistics summary, it is important to have a visual concept of the key variables used in the model. The natural gas price and its future contract price (contract 1: RNGC1) share similar patterns with high correlation. Figure 1 depicts the historic natural gas price with its future contract 1 price. Overall, gas prices have been increasing since 1992, with a few spikes caused by major weather events, such as those in2000 and 2005. The price spikes in 2008, was driven by fast climbing energy prices at the global level. The spike was followed by a sharp decline in fall of 2008. Compare to natural gas prices, crude oil spot price and future contract 1 price shares even higher correlation, as there is less volatility in crude oil market compared to natural gas.

Figure 2 shows the historical US gas balance, namely, market consumption, production and storage, which is supposed to be bounded to a material balance for each period in the theoretical model. Consumption follows a strong seasonal pattern, where space heating shapes the peak of the demand every winter, while summer demand from electric generation forms a minor peak in July to August. The long-term consumption trend is related by general economic conditions and energy efficiency. While consumption has a prominent pattern around the year, production barely has any seasonality, as is shown in the graph. Storage helps to bridge the gap between consumption and production over time, and hence is an important part of the natural gas

[1] For details of definition and data source, see Appendix 4.1.

infrastructure. Note that production, consumption and storage rarely add up in reality, as there are always miscalculations, and other complications. As a result, each year the EIA calculates and publishes the balance items, which are the missing pieces of the material balance equation.

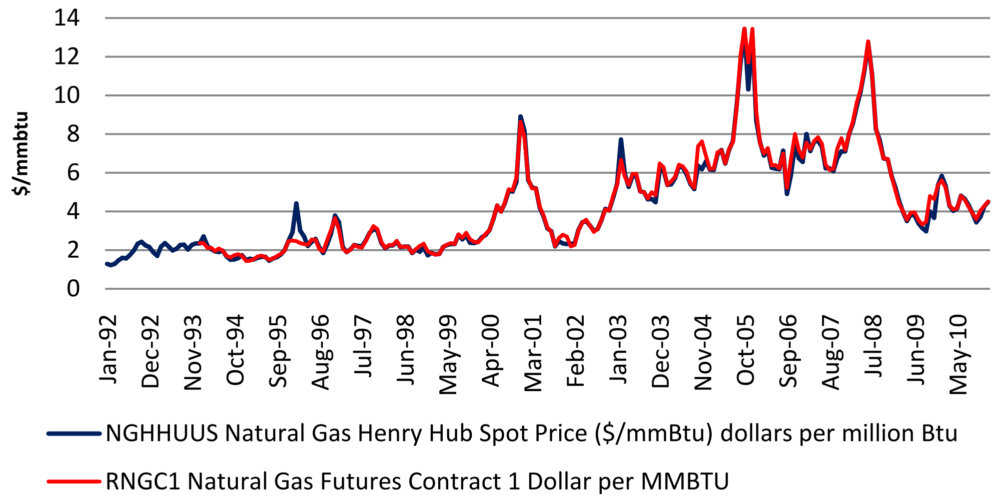


Figure 1: Natural Gas Spot Price vs. Natural Gas Future Contract Month 1

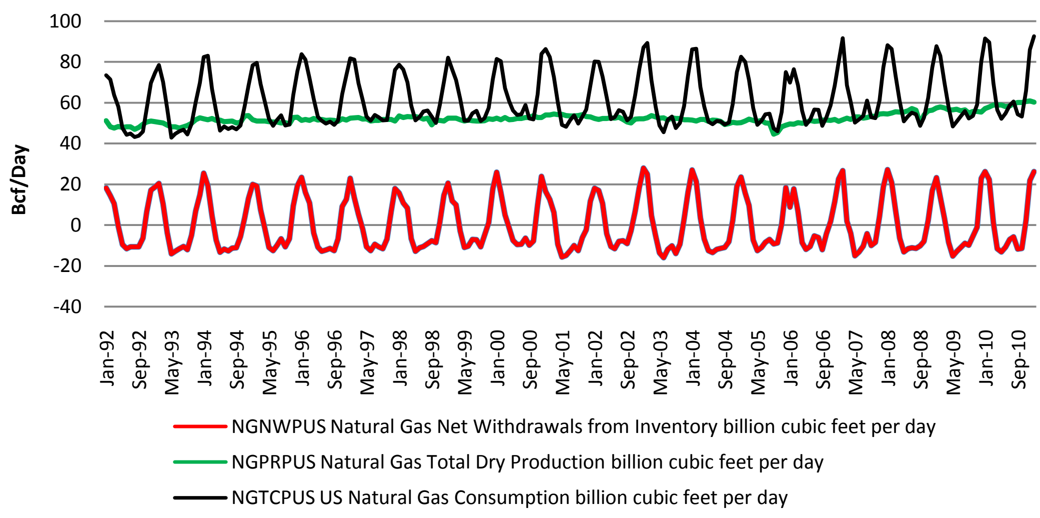


Figure 2: US Gas Balance

Variable Name	Variable Definition	Units	Mean	Variance	Std. Dev.	Skewness	Kurtosis	Median	Minimum	Maximum	Count[2]
Supply, Demand and Storage											
NGCCPUS	Natural Gas Consumption Commercial Sector U.S. Total	billion cubic feet per day	8.419	17.437	4.176	0.558	1.854	7.450	3.590	17.230	229
NGMPPUS	Natural Gas Total Marketed Production	billion cubic feet per day	55.492	7.882	2.808	0.716	4.243	54.890	46.700	63.700	169
NGNWPUS	Natural Gas Net Withdrawals from Inventory	billion cubic feet per day	0.070	162.370	12.742	0.670	2.016	-5.930	-16.070	27.840	229
NGWGPUS	Natural Gas Working Inventory U.S. Total	billion cubic feet, end-of-period	2239.12	551359.77	742.536	-0.035	2.094	2273.000	730.000	3847.000	229
BALIT	Natural Gas Balancing Item (Consumption - Supply)	billion cubic feet per day	0.509	10.175	3.190	-0.552	2.663	1.120	-8.900	6.810	229
USNETIMPORTS	Natural Gas net imports of U.S.	billion cubic feet per day	9.677	4.004	2.002	-0.309	2.210	10.166	5.311	13.759	228
Prices											
NGHHUUS	Natural Gas Henry Hub Spot Price ($/mmBtu)	dollars per million Btu	4.204	6.259	2.502	1.180	4.273	3.450	1.210	13.420	229
WTIPUUS	West Texas Intermediate Crude Oil Price	dollars per barrel	39.242	695.722	26.377	1.292	4.083	27.600	11.350	133.880	229
RNGC1	Natural Gas Futures Contract 1	Dollar per MMBTU	4.532	6.592	2.567	1.086	4.096	4.000	1.430	13.450	205
RCLC1	Crude Oil Futures Contract 1	dollars per barrel	39.253	697.828	26.416	1.288	4.068	27.620	11.310	134.020	229
Oil and Economy											
PRIMEUS	U.S. Prime Lending Rate	Percent	6.532	3.819	1.954	-0.326	1.716	6.700	3.130	9.630	229
RSPRPUS	Total Raw Steel Production	million short tons per day	0.274	0.001	0.033	-1.917	7.859	0.280	0.143	0.328	229
WPCPIUS	Producer Price Index: All Commodities	Index, 1982=1.00	1.429	0.054	0.232	0.805	2.278	1.320	1.160	2.000	229
COPRPUS	U.S. Crude Oil Production	million barrels per day	5.890	0.438	0.662	0.146	2.432	5.800	3.930	7.390	229
YD87OUS	Real Disposable Personal Income	Billion chained 2005 dollars – SAAR	8280.9	1900650.5	1378.641	-0.100	1.620	8370.000	6059.000	10359.000	229
CICPIUS	Consumer Price Index (all urban consumers)	Index, 1982-1984=1.00	1.784	0.061	0.247	0.172	1.792	1.770	1.380	2.210	229
GDPDIUS	GDP Implicit Price Deflator	Index, 2005=100	92.544	120.609	10.982	0.306	1.781	90.800	75.800	111.500	229
GDPQXUS	Real Gross Domestic Product	Billion chained 2005 dollars – SAAR	11145.1	2855013.3	1689.678	-0.271	1.688	11358.000	8128.000	13479.000	229
I87RXUS	Real Fixed Investment	Billion chained 2005 dollars – SAAR	1789.88	73722.658	271.519	-0.452	2.367	1811.000	1219.000	2206.000	193
USEXRATE	Exchange Value of U.S. Dollar: Broad Index (Weighted Ave)	Nominal, (Jan97=100)	105.946	182.824	13.521	-0.367	2.456	107.534	74.408	129.680	230
Weather											
ZWCDPUS	Cooling Degree-days U.S. Average	degree-days per month	107.825	14215.145	119.227	0.933	2.424	47.000	2.000	388.000	229
ZWHDPUS	Heating Degree-days U.S. Average	degree-days per month	367.004	100745.54	317.404	0.375	1.700	302.000	2.000	1012.000	229

Table 1: List of Variables

[2]Number of observations available starting January 1992.

1.5. ESTIMATION

In the structural model, there exists one type of variables, which describe market expectation - expected market price of time t at prior time periods, like *t-k, k>=1*. These market expectation variables appear in both production as well as storage functions, where expectations of the future influence the strategic decisions. In reality, the market expectations of future are not directly observed. Theoretically, every agent of the market has his/her own expectation of the market and acts based on those values. Fortunately, the natural gas market has an established future and option-trading place, where agents have the choice to trade standardized future contracts based on their expectations. The futures market clears every day, and the settlement prices are reported. In the estimation process of the model, the price of a natural gas future contract is used in the empirical estimation as a proxy of market expectation of future price.

The process of estimation takes the following two steps: the first step is to estimate the demand, production and storage functions based on the structural model, and identify coefficients of the reduced form functions. The second step is to solve for the market clearing price from the material balance of the market based on the coefficients obtained from the previous step assuming the material balance exists at all times. These market-clearing prices, denoted as $\{\widetilde{p_t}\}_{t=1....T}$, are compared to the observed market spot prices $\{p_t\}_{t=1....T}$. The discussion focuses on the inference drawn from the differences between the two prices.

1.5.1. Regression

This section goes through the details of the estimation of regressions for this model, including the details of tests and diagnosis of these regressions.

1.5.1.1. Definition of Regressions

The first step of the estimation process is to estimate demand, supply, storage and net imports separately.

Regression of Consumption

Eqn21:*Regression of Consumption*

$$ngtcpus_t = a_0 + a_1 * nghhuus_t + a_2 * gdpqxus_t + a_3 * zwcdpus_t + a_4 * zwhdpus_t + A * \begin{bmatrix} m_1 \\ \cdots \\ m_{11} \end{bmatrix}_t + \varepsilon_{1t}$$

$ngtcpus_t$ - U.S. Total Natural Gas Consumption at period t

$nghhuus_t$ - U.S. Henry Hub Natural Gas Price at period t

$gdpqxus_t$ - - U.S. GDP at period t

$zwcdpus_t$- U.S. Average Cooling Degree Days at period t

$zwhdpus_t$ - U.S. Average Heating Degree Days at period t

$\begin{bmatrix} m_1 \\ \cdots \\ m_{11} \end{bmatrix}_t$ - Monthly Dummies at period t

Instrumental variables and first stage regression of 2SLS for natural gas price variable, $nghhuus_t$:

Eqn22:

$$nghhuus_t = \varphi_0 + \varphi_1 * ngdrill_{t-1} + \varphi_2 * wtipuus_t + \omega_t$$

$ngdrill_{t-1}$- U.S. Natural Gas Rig Counts at period t-1

$wtipuus_t$– NYMEX Crude Oil Future Contract (Prompt Month) at period tAs discussed in the structural model, the consumption of natural gas is function of current period gas price and other exogenous variables, like weather and economic conditions. The consumption of natural gas is driven largely by weather. For example, space heating in the winter and as a fuel choice for power generation for air-conditioning in the summer. The weather variables used here are the U.S. average heating degree days and cooling degree days, which are the measurement of the number of degree above/below 65 degrees. In other words, it is a measurement of how cold/warm a location is. The higher the heating degree days, the colder a location is and hence there is a higher demand for gas for space heating. The higher the cooling degree days, the hotter a location is and hence there is a higher demand for air-conditioning. This in turn infers a greater demand for natural gas for power. Hence, the heating degree days and cooling degree days are expected to have positive coefficients for gas demand.

In addition, general economic condition is included as an exogenous variable for the regression of gas consumption. Higher economic condition drives consumption of natural gas in commercial/industrial sectors, as well as power generation, which will also influence gas demand indirectly via the fuel choice. The U.S. GDP is used as a measure of current period's economic condition, and is expected to influence gas consumption positively.[3]

The Henry Hub spot price of period t is the representation of the current gas price. This is the market price for physical transactions happening at Henry Hub in Louisiana, which is the most quoted natural gas pricing hub in North America. Since a majority of gas consumption is related to weather, residential and commercial sectors are less responsive to price changes in real time, when compared to industrial sectors and electric generation. Additional investigation can be performed to determine the price responsiveness for each sector, but it is not included for the current estimation. In this

[3] Other macroeconomic indicators like personal income and CPI are tested in the same regression with GDP. GDP has the better explanatory power for gas demand in this case.

model, the coefficient of natural gas price against gas consumption describes the price responsiveness at the aggregated level.

Regression of Production

Eqn23:

$$ngmppus_t = \beta_0 + \beta_1 * \left(\frac{1}{24}\sum_{i=1}^{24} rngc_{i|t-24}\right) + \beta_2 * \left(\frac{1}{24}\sum_{i=1}^{24} rngc_{i|t-12}\right) + \beta_3 * gdpqxus_{t-6} + \beta_4 * wtipuus_{t-3} + \beta_5 * \triangle\, primeus_t + \beta_6 * hurricane_t + \varepsilon_{2t}$$

$ngmppus_t -$ U.S. Marketed Natural Gas Production at t

$rngc_{i|t-24}$ - NYMEX Natural Gas contract i at period t-24

$rngc_{i|t-12}$- NYMEX Natural Gas contract i at period t-12

$gdpqxus_{t-6} -$ U.S.GDP at period t-6

$wtippus_{t-3} -$ U.S.WTI Crude Oil Price at period t-3

$\triangle\, primeus_t -$ Change in U.S.Prime Lending Rate at t

$hurricane_t -$ Dummy variable for Major Hurricanes in Gulf of Mexico at period t

For gas production available in period t, it is determined before period t. This has been previously discussed in the theoretical model setup. In the structural model, producers determines the production decisions for period t based on an ex-ante price expectation, which is denoted as$P^e_{t|t-k}$. The reduced form regression uses lag 24 period average natural gas future contract 1 to 24prices, $\frac{1}{24}\sum_{i=1}^{24} rngc_{i|t-24}$, as the ex-ante expectation of current period price. Despite its long name, this average price of future contract strip (multiple points along forward price) is an effective indicator of expected market condition for the following reasons:

1) Using an average of future contract prices, instead of a single future contract price, allows the production decision to focus on a general future market, instead of one specific month. The production decision made 24 months prior to the current period is the initial capital allocation and resource commitment for production about two years in the future. However, it is not intended to have an exact delivery time down to the monthly level. For example, there are other variables can also shift the production delivery timeline. Therefore, this regression includes other lagged variables indicating additional adjustment of the production plan after the initial commitment.

2) Choosing an expectation from 24 months prior to the current period has to do with the operation cycle of upstream exploration and production. Upstream operations are determined, not a month or two ahead, but approximately two years ahead of actual production.

One additional adjustment to the production plan is to the lag 12 period average natural gas future contract 1 to 24 prices, $\frac{1}{24}\sum_{i=1}^{24} rngc_{i|t-12}$. Consider the fact that producers are not making one production decision, but a series of production decisions for future periods at the same time. Producers always like to schedule more than their production delivery to the period with the highest predicted price, if they can. This adds much more complexity into the producers' decision strategy on production for each period. So intuitively taking the 24 months lead-time into consideration, producers are constantly shifting and readjusting their future production plan if they can. If the expected market conditions in 24 months are better, not only do producers naturally commit more capital and resources for the 24-month production delivery plan, but also this decision can potentially affect ex-ante plans for production delivery closer than 24 months. Due to the interest on investment in 24 months, producers can readjust their previously committed capital and resource for production delivery before the expected market boom in 24 months. In other words, producers will hold off the near term production delivery and reallocate those resources to target the expected market boom in a later period. If the dynamic allocation aspect exists when the producer making their decision, the 12-month lagged average future price strip (1-24 month contracts) is expected to have a significantly negative coefficient to current production level, as a delaying effect.

Other lagged variables are the six-month lagged U.S. GDP, and the three-month lagged crude oil price. Both of these lags have been tested and identified as the most effective choices against their alternatives. Therefore, it reveals the interesting insight of a six-month delay for gas production to reflect macroeconomic conditions, and about a three-month delay to reflect changes in the oil market. Lagged economic conditions are expected to have positive effect on gas production. In other words, the better the economy is, the higher gas production. Lagged oil prices are expected to have negative effect on gas production. Oil and gas usually have large overlaps in resource and capital. When oil prices increase, producers are more attracted to oil production and tend to shift their capital commitment away from gas. Oil and gas share similar labor and material for production activities. When oil prices increase, boosted oil production may also increase the labor and material price. That leads to higher cost and longer lead times for services and inputs on the gas production side as well.

Two variables that describe conditions in the current time period that may have an impact on gas production are the change in U.S. prime lending rate and hurricanes. Prime lending rates reflect the tightness of the capital market. An increase in the prime-lending rate puts stress on production activities, as gas production operations depend on cash flow heavily. Also extreme hurricanes that hit the Gulf of Mexico area can force the gas production operation to shut down. This is referred to as "forced majeure" in the industry, or excused non-delivery of production caused by natural disasters.

Regression of Storage

Eqn24:

$$ngnwpus_t = \gamma_0 + \gamma_1 * rngc1_{t-1} + \gamma_2 * nghhuus_t + \gamma_3 * zwcdpus_t + \gamma_4 * zwhdpus_t + \mathrm{B} * \begin{bmatrix} m_1 \\ \cdots \\ m_{11} \end{bmatrix} + \varepsilon_{3t}$$

$ngnwpus_t$- U.S. Natural Gas Net Withdrawals at period t

$nghhuus_t$ - U.S. Henry Hub Natural Gas Price at period t

$rngc1_{t-1}$– NYMEX Natural Gas Future Contract (Prompt Month) at period t-1

$zwcdpus_t$- U.S. Average Cooling Degree Days at period t

$zwhdpus_t$ - U.S. Average Heating Degree Days at period t

$\begin{bmatrix} m_1 \\ \cdots \\ m_{11} \end{bmatrix}_t$ - Monthly Dummies at period t

Instrumental variables and first stage regression of 2SLS

Eqn25:

$$nghhuus_t = \lambda_0 + \lambda_1 * wtipuus_t + \lambda_2 * crdrill_t + \lambda_3 * gdpqxus_{t-1} + \upsilon_t$$

$wtipuus_t$– NYMEX Crude Oil Future Contract (Prompt Month) at period t

$crdrill_t$ - U.S. Active Crude Oil Rig Counts at period t

$gdpqxus_{t-1}$ - U.S. GDP at period t-1

The net withdrawal of gas storage is a function of the expected price of next period and current spot price in the theoretical model. In reality, the expected price of next period is not the current future contract 1. Instead, it is more like the past period's future contract 1 like shown in the reduced form regression above. It may appear to be difficult to comprehend the choice of variable here from a theoretical point of view. However, the reason has little to do with theory, but much to do with the common practice of trading on gas storage. In most natural gas trading shops, storage deals for the current month are locked in by the end of prior month. In other words, decisions on withdrawals of natural gas from storage facilities in current month are largely determined by end of last month, using the expected price of current month (lagged 1 future contract 1 in past month). However, the decision is not final and there is still some room for correction as traders move through the current period. That part of trading is usually handled at the "Cash Desk" in a trading shop. The purpose of the "Cash Desk" is mainly to deal with weather and maintenance issues. The "cash desk" has the opportunity to adjust deals based on the realized spot price in the current month. The higher the expected future price is, the less the withdrawal from storage facilities in the current period and vice versa.

Due to the potential Endogeneity problem, the current price of gas is regressed with additional instrumental variables, such as the current oil price, current oil drilling activities and one-month lagged U.S. GDP level.

Regression of Net Imports

Eqn26:

$$netusimport_t = d_0 + d_1 * nghhuus_t + d_2 * gdpqxus_t + d_3 * zwcdpus_t + d_4 * zwhdpus_t + d_5 * wtipuus_t + d_6 * rsprpus_t + d_7 * \mathrm{wp57ius_t} + + \varepsilon_{4t}$$

$usnetimport_t$ - U.S. Net Imports of Natural Gas at period t

$nghhuus_t$ - U.S. Henry Hub Natural Gas Price at period t

$gdpqxus_t$ - - U.S. GDP at period t

$zwcdpus_t$- U.S. Average Cooling Degree Days at period t

$zwhdpus_t$ - U.S. Average Heating Degree Days at period t

$rsprpus_t$- U.S. Raw Steel Production at period t

$wp57ius_t$ - U.S. Petroleum Product Price Index at period t

Instrumental variables and first stage regression of 2SLS

Eqn27:

$$nghhuus_t = \varphi_0 + \varphi_1 * ngdrill_{t-1} + \varphi_2 * wtipuus_t + \omega_t$$

$ngdrill_{t-1}$- U.S. Natural Gas Rig Counts at period t-1

$wtipuus_t$– NYMEX Crude Oil Future Contract (Prompt Month) at period t

U.S. imports natural gas (LNG) from Canada every year. It also imported from other international destinations as liquefied natural gas. The amount of LNG is relatively small and only started after 2003. Therefore, I am going to focus on the drivers determining the net imports from Canada. Canada and U.S. exchange natural gas across borders in both directions every year though pipelines. In most years there are net positive imports to U.S.. When the price in the U.S. market, more likely hubs near the border, is more competitive, more gas is imported into U.S. market. Since only one representative market hub, Henry Hub, is included in this model, the competitive advantage from price on net imports may not be as strong as expected. The net imports from Canada are also affected by the price of crude oil. Western Canada has one of the largest oil sand deposits in the world and it takes natural gas as a form of input material. Therefore, when crude oil prices increase, the demand for oil sand production boosts the demand for natural gas in the Alberta area. That leads to fewer net imports to U.S. market.

1.5.1.2. Regression Diagnosis

It is important to examine the regression and data for potential violations against assumptions of the proposed linear regression and to treat these violations properly. This section covers the regression diagnosis on a high level.

Outliers and Influence:

The natural gas market is quite efficient. As a result, the data set exhibits no strong evidence for outliers. Most of the outliers are related to influential events, like hurricane seasons, or economic recession. In the past decade, this led to spikes in prices. However, those events carry unique information about the characteristics of the market system, and the elimination of outliers is not always the solution in those cases.

Endogeneity:

Endogeneity are treated by introducing instrumental variables (IV) to the natural gas price. The only regression that does not have any IVs is the regression of natural gas production, as it is solely determined by pre-determined variables prior to period t in this case.

Homoscedasticity

One of the main assumptions for the ordinary least square regression is the homogeneity of variance of the residuals. Violations of homoscedasticity make it difficult to gauge the true standard deviation of the forecast errors, usually resulting in confidence intervals that are either too wide or too narrow. For each regression defined in this model, I test for Homoscedasticity based on both the White test and Breusch Pagan test. The only regression leads to sufficient evidence against the null hypothesis of homogeneous variance is the regression of production and the treatment is to calculate Heteroscedasticity-consistent (HC) standard errors.

1.5.1.3. Regression Results

Table 2 presents the regression results.

	(1) Demand Ngtcpus		(2) Production ngmppus		(3) Storage ngnwpus		(4) Net Imports usnetimports	
Nghhuus	0.222**	*0.005*			4.875**	*-0.01*	0.0993**	*-0*
Gdppct	0.572	*0.993*					-28.46	*-0.14*
Zwcdpus	0.0636***	*0*			-0.00644	*-0.83*	0.00455***	*0*
zwhdpus	0.0482***	*0*			0.0108	*-0.44*	0.00155***	*0*
m1	-1.243	*-0.509*			23.21**	*-0*		
m2	5.681***	*0*			18.26***	*0*		
m3	-0.861	*-0.437*			9.262**	*-0.01*		
m5	-5.191***	*0*			-3.601*	*-0.05*		
m6	-6.810***	*0*			-1.945	*-0.59*		
m7	-9.645***	*0*			3.264	*-0.62*		
m8	-7.350**	*-0.003*			2.715	*-0.64*		
m9	-5.029***	*-0.001*			-0.584	*-0.82*		
m10	-6.632***	*0*			0.208	*-0.86*		
m11	-6.494***	*0*			10.60***	*-0*		
m12	-5.681***	*-0.001*			17.41**	*-0*		
l3.coprpus			0.408	*-0.35*				
l24.rngca24			0.728***	*0*				
l12.rngca24			-0.699***	*0*				
l3.crdrill			0.00614***	*0*				
l3.ngdrill			-0.00414***	*0*				
coprpus			4.799***	*0*				
d.primeus			-3.916***	*0*				
hurricane			-1.456**	*-0*				
l6.gdpqxus			0.00364***	*0*				
l.gdppct			-132.5***	*-0*				
l.rngc2					-4.574**	*-0.01*		
gdpqxus							0.00146***	*0*
wtipuus							-0.0690***	*0*
rsprpus							7.841***	*0*
wp57ius							1.716***	*-0*
t3b_papr_r03							0.894***	*0*
t3b_papr_r07							-1.109***	*0*
_cons	40.59***	*0*	-14.13*	*-0.01*	-10.61*	*-0.03*	-7.170***	*0*
N – Number of Obs	**203**		**180**		**184**		**227**	

adj. R^2	0.967	0.851	0.917	0.856

p-values in parentheses: $^{*}p< 0.05$, $^{**}p< 0.01$, $^{***}p< 0.001$

Table 2: Regression Results

1.5.2. Identification

Based on the linear regression estimates from the previous theoretical model setup discussion, it is easy to identify all the linear coefficients of the model. Most of the parameters can be identified directly and I will not spend time elaborating in this section.

However, the reduced form regression method cannot identify any composite coefficient, which is a nonlinear function of other theoretically defined parameters. For example, the coefficient of the expected price for period t in production regression is a function of three parameters: cost of production, risk aversion factor, and the variance of expectation.

Eqn28: $$Q_t = c_Q + \lambda_Q X_{Q,t} - \beta_Q p^e_{t|t\text{-}k} + \varepsilon_{Qt}, \ , \ where\ \beta_Q = \frac{1}{c + a\sigma^2_p(t, t-k)}$$

Those are parameters that may bring interesting insights since they can be identified under a numerical estimation regime like Maximum Likelihood. Albeit, at a higher cost of computational requirements. Also, numerical estimation can sometimes be costly yet not effective: Identification problems can still occur when the data lacks information.

A simpler way to work around this identification issue here is based on the industry knowledge. There are general assumptions on the range of cost of production and variance of expected prices which can lead to some rather insightful results, without pinning down the exact number. For example:

Eqn29:

$$
\begin{aligned}
&Given\ \beta_Q = 0.728 - based\ on\ regression\ result\\
&assume:\\
&\sigma_p^2(t,t-k) > 0\\
&c > 0\\
&then\ for\ a\ negative\ a:\\
&for\ a\sigma_p^2(t,t-k) < 0\ and\ \beta_Q = 0.728\\
&\Rightarrow\\
&c > 1.373
\end{aligned}
$$

That says in order to have a risk-averse factor (negative one), the cost of production has to be greater than $1.37. Based on the various sources for the cost of production, the cost of natural gas production is on average much higher than this threshold. The natural gas production cost is on average above three to four dollars, depending on the production area. It is therefore safe to conclude that the production agents in the market are risk-averse. Similar conclusions can be drawn for the risk aversion factor on storage agents

1.5.3. Price Estimation and Discussion

Following the theoretical model, this section compares the model one-period ahead forecasted prices defined by the material balance versus the realized natural gas spot prices in the market. This section focuses on the implications of the disequilibrium, where the observed market price is outside of the 95% confidence interval of sample distribution for the predicted prices. For each period in the sample, the one period ahead forecasted price is calculated and plotted against the realized natural gas spot price in the market in Figure 3.

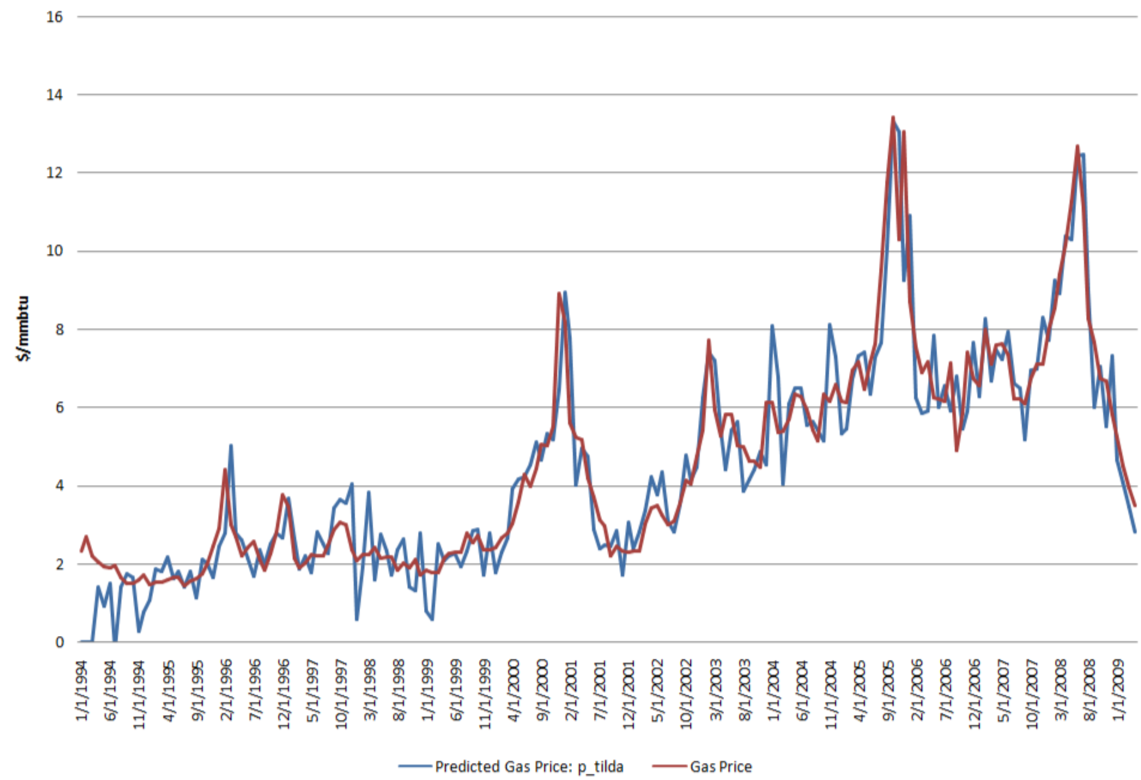


Figure 3: One Period Ahead Forecast Price vs. Observed Price

Figure 4 includes the 95% confidence interval of the sample distribution for the predicted prices, and the red dots represent periods where the observed price is outside of the 95% confidence internal of the predicted prices. In other words, the predicted prices are statistically different from the observed prices in those periods, which happens about 15% of the time during the sample period.

The following discussion is to understand the implications of these disequilibrium periods where the observed market prices are significantly different from what the model predicts. These disequilibrium periods are treated as clusters of points for the general time period, instead of individual dots in the following discussion. These time periods are being discussed and examined carefully, to justify the inconsistency presented between the market and the model. Below are my findings:

Due to the lack of a financial futures market, the predicted price is consistently spikier than the observed market price. This results in disequilibrium where the predicted market price indicates a more volatile environment when there is a disturbance in the material balance; while the observed market manages to skip or minimize the spike. That is primarily due to the fact that most market participants: consumers, producers and speculators are all active in the financial market and have already taken positions to mitigate these risks. Even though a material change in the gas balance, would lead to a spike in prices, these responses are "muted" due to the pre-cautionary measures taken in the financial market. Participants are protected to a certain degree from unexpected changes in the market. This is reflected as a milder reaction in price. Unfortunately, there is no data on the detailed hedge positions for each market participant groups. Only aggregated transaction volume data is available, which is not sufficient to tell exactly how much of resolved market volume has been hedged for each market participant group at a time in history.

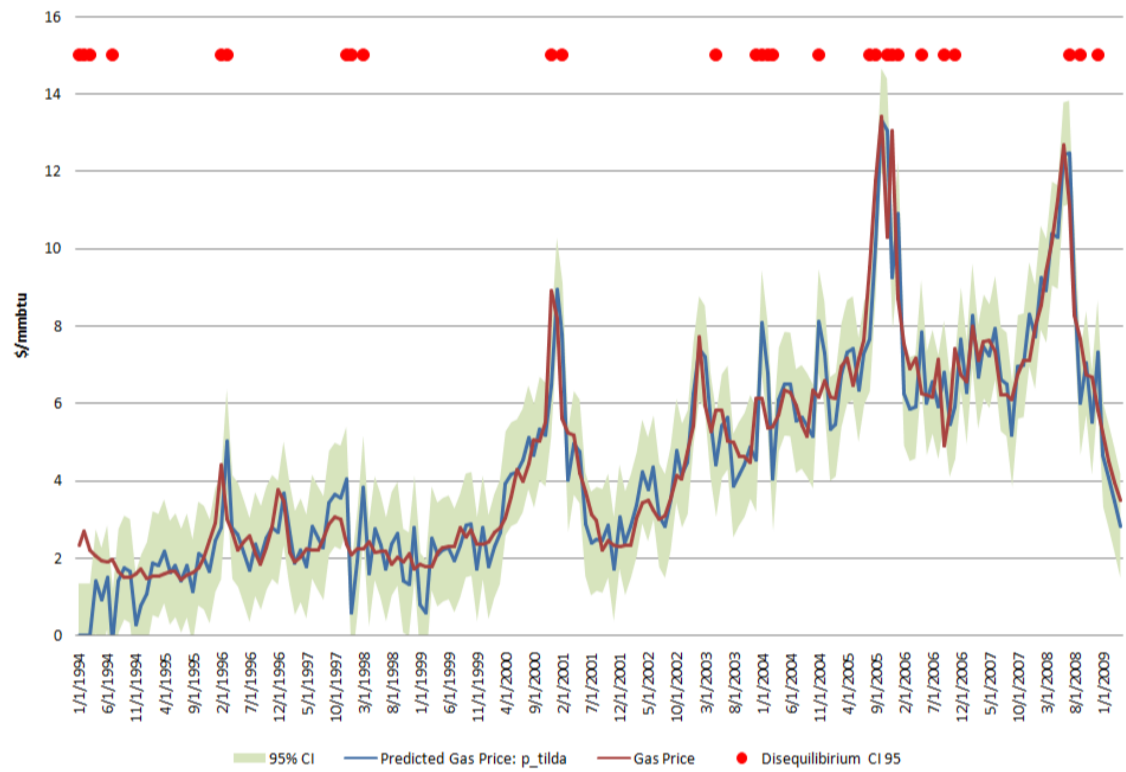
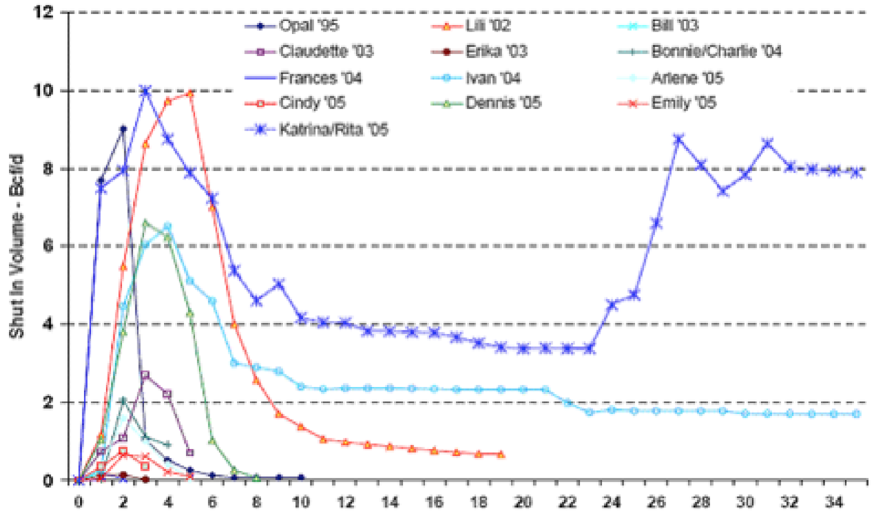


Figure 4: One Period Ahead Forecast Price vs. Observed Price with 95% CI

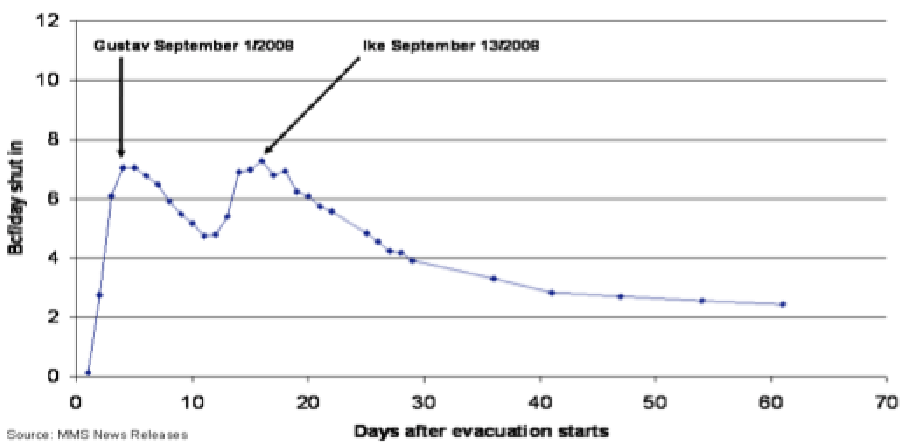
The impact of hurricanes on gas prices:

Although the regression of production takes into account of the interruptions for past hurricanes, each hurricane has different degree of impact on the gas production in the Gulf of Mexico area. The impact is dependent not only on the hurricane category, but also the specific hurricane path through the area. Figure 5 shows a 10-year history of gas production shut-ins from hurricanes up to 2005, and Figure 6 shows the shut-in impact from Hurricanes Gustav and Ike in 2008. The volumes of shut-ins vary across these observed hurricanes, as well as durations. The two past Hurricanes seasons with most shut-ins and the longest durations are Hurricane Katrina/Rita in 2005 and Hurricane Lily in 2002 according to the figures published by EIA. Hurricane Gustav and Ike in 2008's impact are just below the top two hurricanes, but the duration between these two hurricanes was much longer since they hit the Gulf of Mexico in less than two weeks apart.



Source: EIA (EES 2005)

Figure 5: Shut-ins from Hurricanes from 1995 to 2005



Source: MMS News Release

Figure 6: Shut-ins from Hurricanes after 2005

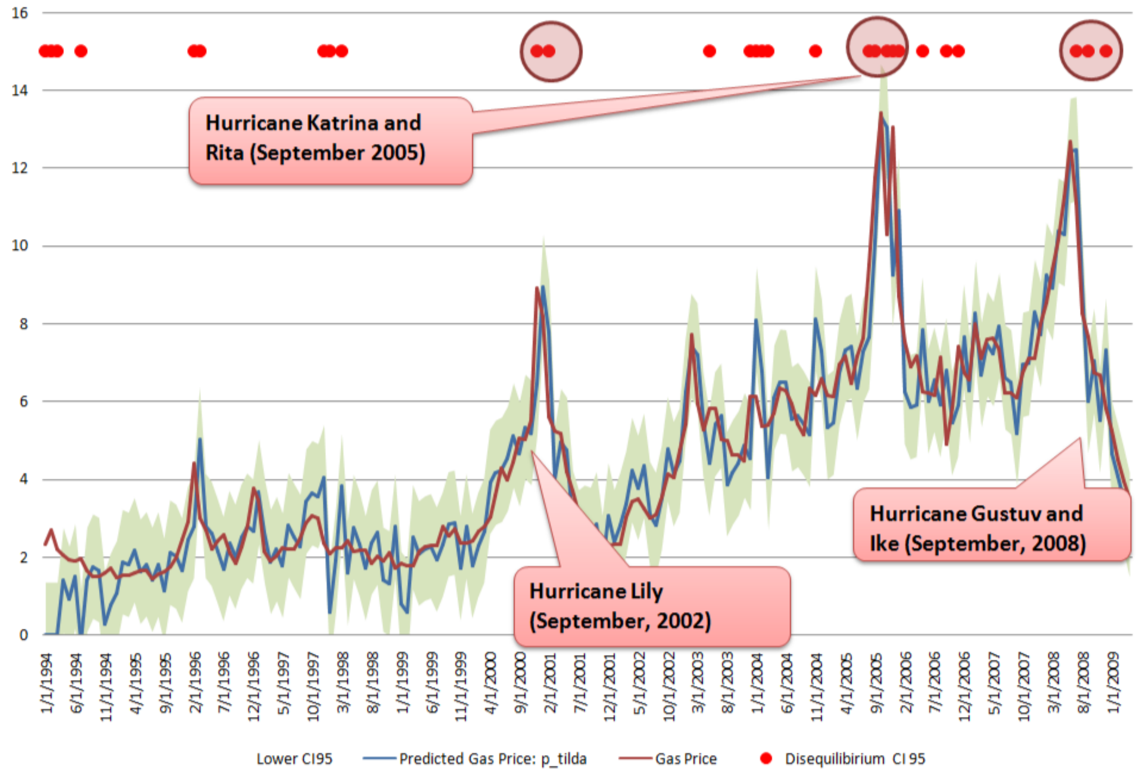


Figure 7: Disequilibrium associated with Hurricane Shut-ins

By marking those periods of hurricane seasons we see a cluster of disequilibrium in the market when comparing the predicted price with historical market realized prices. However, closer examination reveals that the predicted market prices also suggests very prominent spikes in the price and portrays a reasonable portrait of the underlying market observations. Since the price magnitudes swing within a higher range, like \$8.00 in 2002, and over \$13.00 in 2005 the difference between the spikes can easily slip out of the equilibrium confidence band. The equilibrium confidence band is not calculated based on the real-time volatility of the price, but instead a fixed value range across the whole same period. Based on careful observation, it is prudent to conclude that the model does capture the price response due to extreme weather events in the past relatively well. Some errors tend to be larger, such as when the price jumps are double or triple the market price prior to the events. Hence, these disequilibria should not be considered as a concern in specification of the model itself.

Impact of the economics of production and drilling activities on prices

Besides weather events, the rest of the disequilibria are analyzed by adding other factors onto the graph to understand the reasons for oscillations. For example, the number of gas rigs as well as the breakeven price of gas production. The following two charts analyze these oscillations in two separate time period: 1998-2004 and 2005-2009.

1998-2004 Period:

By adding the drilling rig count and breakeven price, it is easier to decipher the price movements in the history. For example, at the beginning of 1998, the price of natural gas was close to the breakeven price of production, and occasionally dipped below the breakeven point. Therefore, drilling rig count dropped since beginning of the year, and set the stage for future price increases in the next few years. Note that this is consistent with the inclusion of a lag between drilling decisions and realized market price impact, as discussed in the regression of production. Prices increased dramatically 12 months after the drilling rig count reached the bottom in middle of 1999. However, as the rig count always lags in market response, the rig count continued to increase after the price spike in 2001. The drilling activities were most likely determined prior to the price spike and bound by contracts. Rig count increased after the price spike and overcorrected the balance. The price collapsed below the breakeven point in 2002 and struggled to recover for rest of the year. For the next two years, the price of natural gas struggled to stay above the breakeven price, which was increasing due to the escalation in labor and input material costs. A very interesting and important observation starts to emerge here: when the gas price dips below or oscillates around the breakeven price, there are usually periods of disequilibria when market price is significantly different from the model predicted prices, such as in the beginning of 1998 and end of 2003 to rest of 2004. Only two disequilibria periods which have prices above the breakeven price, are during the price spike of 2001, where the predicted price was about one period lagged compared to the market observation.

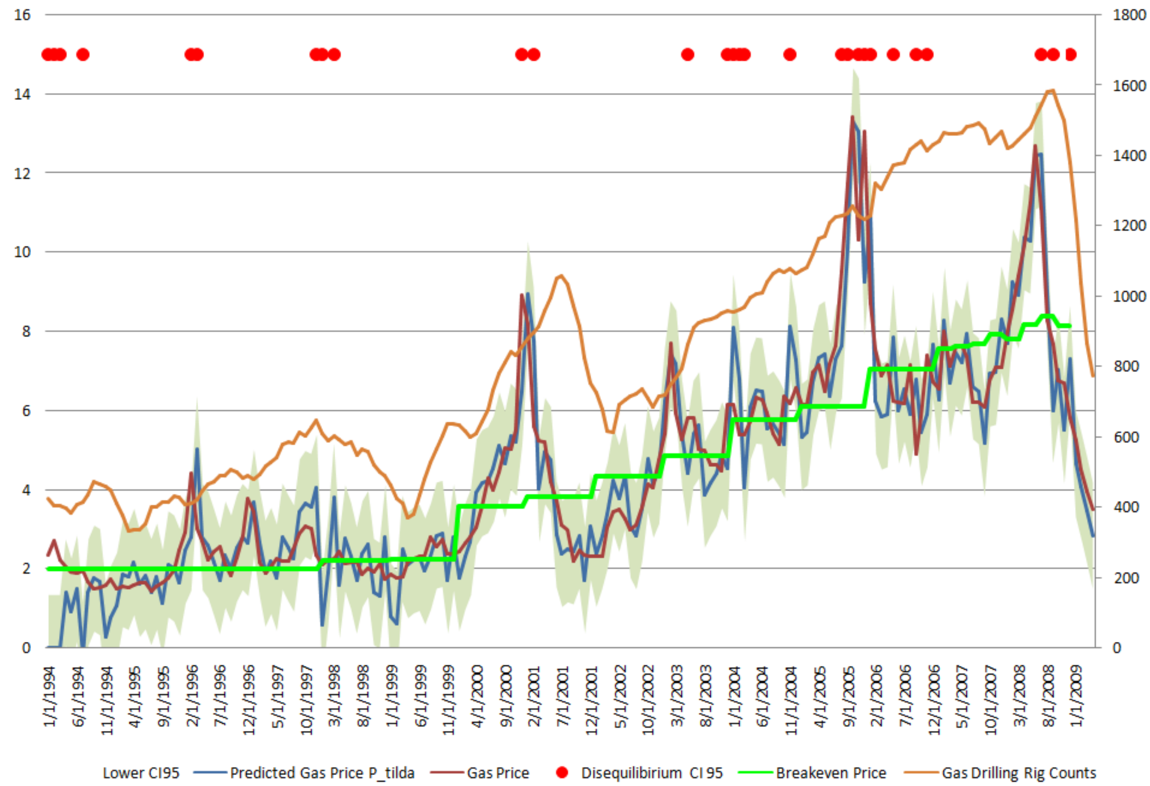


Figure 8: Disequilibrium associated with drilling rig count and breakeven cost of production

2005-2009 Period:

In the period of 2005-2009, the first year's disequilibria concentrate around the Hurricane season and the following months. Starting from 2006, the gas price dropped back to the breakeven price level and started oscillations around the breakeven point again for rest of 2005 and 2007. Similarly, in the prior period the disequilibria of the markets appeared in 2006 when market observations diverged significantly from the model predicted prices. In 2008, the gas price increased following one external factor. Crude oil price at the global level rose and crashed quickly along with the oil price when the great recession was trigged by the failure of the financial market in September 2008.

Based on observations of disequilibria occurrences during 1998-2009, it appears that the market tends to diverge away from the model defined market equilibrium more than usual when the gas price is below or crossing the breakeven price level of gas production. In the theoretically defined model, there is no optimal solution for any market participant when price is not covering the variable cost of production. Hence, the predicted market price is always supposed to be above the breakeven price. Although the breakeven price is not explicitly modeled in the current setup, it is not hard to see that the breakeven price triggers a behavior change in market price in a way that is hard to predict by the model. In other words, when market price goes below and back from the breakeven price, there can be some regime switching responses in the price mechanism, which are not captured in the current model.

Summarizing the discussions so far on the disequilibria, we conclude two occasions which have repeated evidence in the observed sample periods, when the model predicted price would be significantly different (out of the 95% confidence interval based on the sample distribution):

Under extreme weather conditions, like major hurricanes with prolonged shut-in periods, the market price tends to spike and the model is generally able to capture the event of the spikes, but not easy to identify the magnitude of the price jump. Due to the fact that the price spikes are usually about 2-3 times of the prior price level, the indication of larger predicted errors are less significant and important in that regard.

When gas price in the market dipped below the breakeven level of gas production, which is not a likely case in the theoretical model. The theoretical model tends to have difficulty predicting the movement of the price in the following months. This is probably due to a likely regime switch effect triggered when the price falls below or stay too close to the breakeven level. This switch effect leads to shift in short term market responses in prices from producers and other market participants, which are not explicitly modeled in the current setup. The price does not cover the breakeven cost and so change can modify part of the behavior of the producers immediately since the production operation is sensitive to cash flow. However, due to exactly the same dependence on cash flow, part of the production activities are hedged and bound by long-term contracts. The volume of production is determined based on real well economics and how much is bound by contracts. The responses from the market will vary time from time, and region from region.

1.6. SIMULATION

In this section, a 3-year ahead forecasted price is calculated to put the forecast capability of the underlying model to the test. The period to be simulated is from April 2006 to April 2009. The forecasted prices are generated iteratively based on the market expectation equilibrium, assuming all exogenous variables are realized in line with their observed values in the simulated time frame.

The forecasted price from the model is graphed in green in comparison to the red – the observed market price in Figure 9. The forecasted 3-year curve tracks reasonably well to the observed market price in the period, which includes some significant price movements. Although there are still sizable predicted errors during the predicted period (on average about 0.92 cents), it is key to recognize that the underlying forecast model does portray a reasonable future price movement between 2006 and 2009.

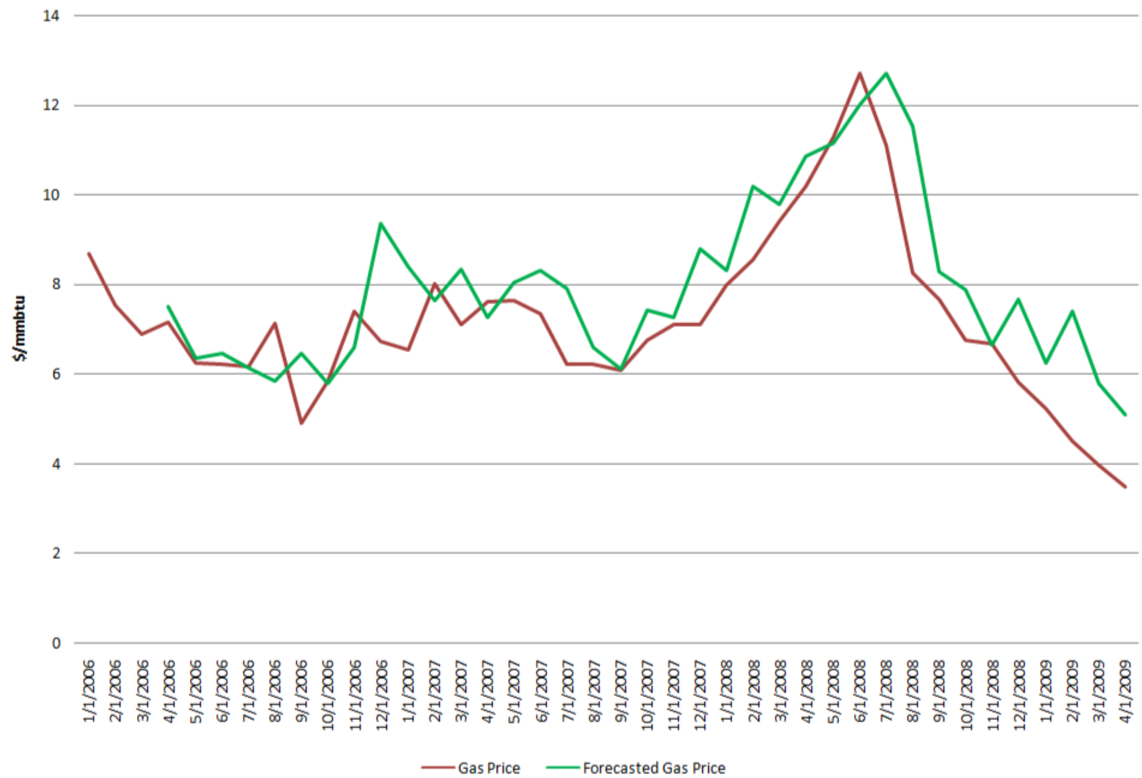


Figure 9: Forecasted Prices (Started from Apr. 2006 to Apr. 2009) vs. Observed Prices

1.7. Extension

In the following section, I have explored the polynomial regression to estimate the coefficients. By doing so, I test if there is any gain in the forecast capability of the model, when moving from the linear assumption of the price relationships with underlying observed decisions in the market to a nonlinear one.

By adding polynomial expansion terms of selected independent variables, the original linear regressions are extended to be nonlinear – order two or three or beyond – to harvest any extra explanatory power. Starting from the original linear form, a polynomial expansion of order 1, additional nonlinear terms are added for the next order of the polynomial expansion. All additional nonlinear terms are tested jointly under a hypothesis for statistic significance. This exercise of expanding the regression equations iterates until the statistic test shows jointly insignificant estimates for additional terms. Most of the linear regressions from the model tend to gain explanatory power for the polynomial expansion of order 2 and 3, and most of them have little evidence of improvement after the polynomial expansion of order 3.

By introducing nonlinear terms in to the regressions, it converts the material balance into a nonlinear equation for natural gas price. Fortunately, solving nonlinear equations for a single variable is a readily available option in many statistical packages without knowing the closed form solution of the interested variable here.

The $\widetilde{p_t}$ is calculated based on the nonlinear material balance equations shows improvement of fitting to the underlying observed price. However, the sample distribution's standard deviation is also smaller due to the smaller estimated error (the confidence interval bands are 20% narrower in the nonlinear model). Overall, in Figure 10, there is clear evidence of improvement of explanatory power in calculated $\widetilde{p_t}$ based on the polynomial expansions, while the confidence interval bandwidth shrinks due to smaller estimated errors from the regressions (from 0.67*2 to 0.42*2). There is less disequilibrium in the nonlinear case, and most of those occurrences are concurrent with the linear case. The occurrence of disequilibrium in nonlinear model is reduced to 6% during the sample period – 94% of the time the model produces statistically consistent results.

The trade-offs in the polynomial expansion are: 1) losing the identification power with some interesting theoretical model coefficients, which are not easily obtained with a closed form in this case; 2) Solving nonlinear equation can get complicated and computationally more expensive.

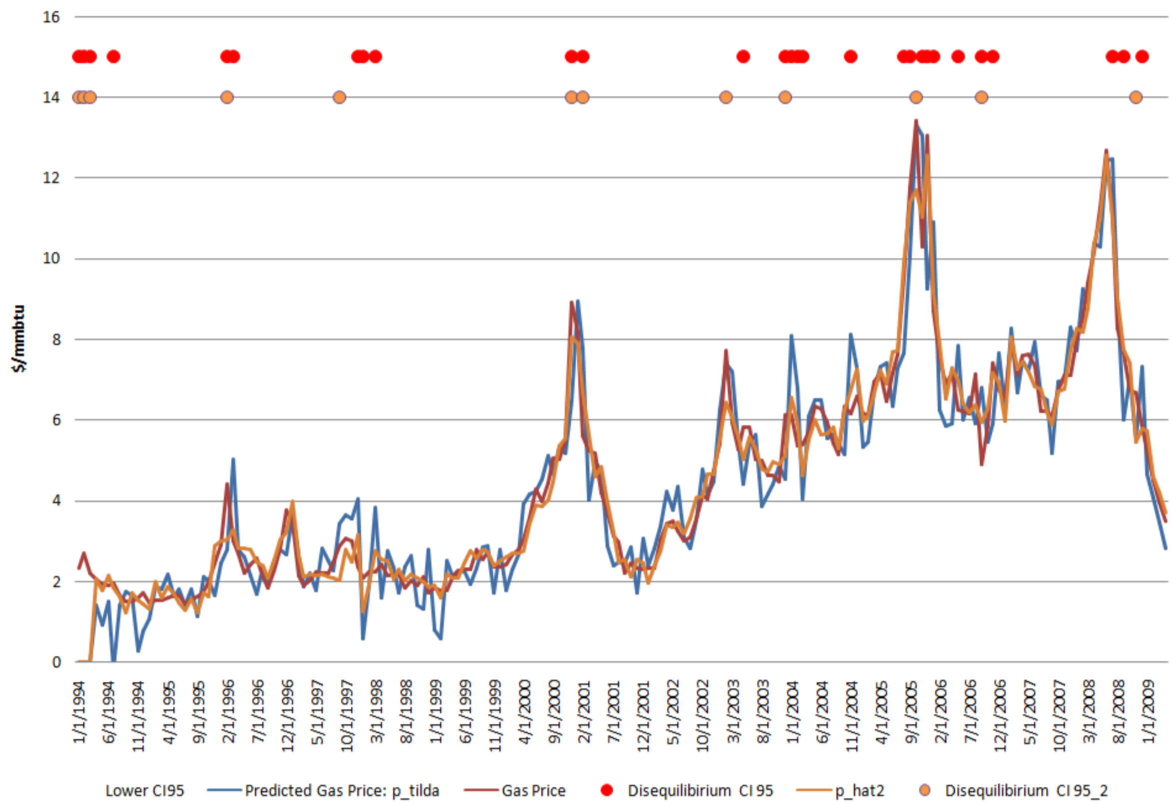


Figure 10: Disequilibrium and Forecasted Prices from Nonlinear Regression Model vs. that from Linear Regression Model

1.8. CONCLUSION

Prior natural gas price research approaches utilized well-defined time series models. The goal of this paper was to explore an alternative approach and to estimate the model defined equilibrium market price based on the market clearing condition. Assuming that natural gas market is a relatively efficient market, the market equilibrium price induced by the model should track the observed market price.

A two-step estimation process includes- reduced formed regression estimation for each market component in the material balance equation, and solving for the market balance equation with identified coefficients and parameters for the market equilibrium price. The model results track the market price quite well, in both one period ahead forecasts and a simulated 36 months forecast case. For each disequilibrium occurrences, where the market price is statistically different from the predicted model price (based on 95% confidence interval), I examine the market conditions and look for emerging patterns prior to the occurrences. It appears that there are two scenarios where the market price is more likely to diverge from the equilibrium price based on the current model: (1) extreme hurricane seasons; (2) when the price of market oscillates below/around the cost of production of gas. The second scenario indicates that the market misbehaves when the market price approaches the long term breakeven of production based on the structural model, implying a likely regime-switching story. The proximity around the breakeven level can be regarded as a trigger for the shift. This can be an extension of the current structural model.

A 36-month ahead price forecast during 2006-2009 based on the model successfully captures the major price movements during the forecasted period, which provides concrete evidence for the validity of the current approach and the consistent impact of the fundamental market drivers on prices.

The structural model is defined in linear terms for relatively easy parameter identification. However, to examine whether there is any gain on explanatory power of the model by extending to nonlinear models, I have used a polynomial expansion method to convert the original reduced form linear regression to nonlinear ones. The results show that most of the regressions result in a positive improvement in explanatory power under a order 2 to 3 polynomial expansion and the final regression residual generally shrinks about 20% compared to its linear version. As a result, the predicted equilibrium price also tracks closer to the observed market price with fewer disequilibrium occurrences. This extension implies improvement for model specification under nonlinear setting.

In conclusion, there are two findings:

First, the natural gas market moves in an effective fashion where it is possible to predict its price movement based on a structural model, such as evidence for possible regime switching behavior in certain circumstances. Nevertheless, it is proven that this complicated energy market still follows consistently with its main fundamental market forces and those impacts can be estimated.

Second, the impact of rational expectation is proven to be significant and stable in the natural gas market. It is a key factor which drives the market but is easily to be ignored or mis-specified. This paper provides evidence that a proper representation of rational market expectation can be estimated using natural gas future contracts.

Chapter 2: The Game that Drives the LNG Train

2.1 Introduction

This paper analyzes the strategies and decisions of major oil companies' on selecting regasification terminal sites for importing liquefied natural gas (LNG) along North American coastlines and delivery of regasified gas into regional domestic markets. Each participating firm's decision is extensive and complex, involving multi-years of capital and human investments. Furthermore, fierce competition exists among firms procuring LNG cargos and servicing the same set of demand areas, i.e. North America market.

This paper condenses the whole strategy and decision making process into a simplified multistage model. The model will focus on exploring the strategic elements of decisions for each participant firm in the competition through a game-theory lens.

2.2 Literature Review

The focus of the paper is spatial equilibrium under cournot competition. Spatial competition has a rich and diverse literature, which is started by the seminal work of Hotelling (1929). Without mentioning a long list of past research, I intend to outline the major branches and categories of this research topic and identify the position of my research under the existing literature classification. My review loosely follows the taxonomy proposed by Eiselt and Gaporte (1996) and other examples of papers and surveys in competitive location models are Eiselt et al. (1993) and Fresz et al. (1988).

The foremost important component of the competitive location model is the definition of the space where the customers and facilities are located. The simplest space is one-dimensional, such as a linear or circular market. In this space, all locations can be represented by a single coordinate. A logical extension from one dimensional market is a subset of n-dimensional real space, which has relatively few research results available due to its heavy computational requirements. In another perspective of extension, all space can be setup either discretely or continuously. Traditional linear and circular markets are classified as continuous space where the demand is located along the market segment with a continuous distribution. Alternatively, the space can be defined as discrete but still interesting and practical, for example, a network. The demand is defined on the nodes of the network and the markets are connected by transportation routes, but mathematically separated. Hence, the network setup provides a sense of multi dimensional space with less demanding computational requirements. Here, we choose to have a discrete network space where markets are defined as nodes or vertices on the network.

The second component of any competition location model is the definition of entry and post-entry strategy, of which literature can be described through two criteria:

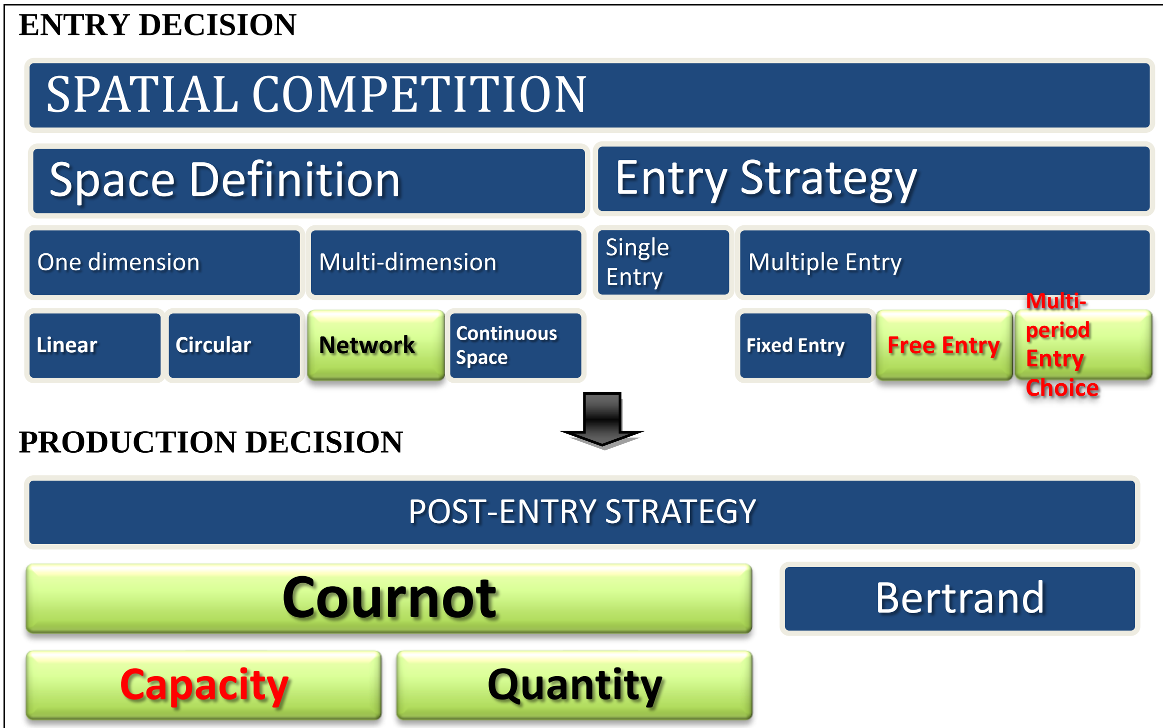
(1) the number of entrants in the entry/location game (first stage) and

(2) the consideration of strategic variables in the post entry/location game (second stage).

Depending on if there is defined cost of entry, the total number of entrants in a multiple entrant model can either be determined exogenously (fixed entry) or endogenously (free entry). In the free entry case, there are potential entrants that have the choice of not entering. There are several papers which consider a fixed number of entrants into the market, such as Hansen and Thisse (1981), Wendell and McKelvey (1981), Hakimi (1983, 1986) and Bauer et al. (1993). However, these papers focus more on the entry/location decision, but do not specify a post entry/location game. Research that considers a post entry/location game can be further classified into two sub-categories when considering the types of player strategies: location models with Bertrand competition and those with Cournot competition. Most of papers on location theory deal with models where firms compete on price. The conclusion in these papers is generally unanimous: firms never agglomerate in a location-price game, as explained in Lederer and Thisse (1990). The finding on equilibrium location is explained as coincident locations of firms offering homogenous goods will intensify price competition and drive profits to zero for all players. Each firm only can maintain a positive profit by choosing a separate location.

A relatively smaller body of literature deals with location choice under the Cournot competition spatial model. Weskamp (1989) establishes the existence of Cournot equilibrium with exogenously fixed firm locations in a network setup. Labbe and Hakimi (1991) present a duopoly model where firms make location and quantity decisions along a network connected by spatially separated markets. Examples of such markets include large urban centers connected by highways. In a duopoly with linear demand, Labbe and Hakimi (1991) show that under reasonable assumptions there exists a Subgame perfect Nash equilibrium (SPNE). Sarkar et al (1997), a Cournot oligopoly model with $n>=2$ firms is studied where firms may set up multiple facilities along the network and the demand functions may be nonlinear. As a result, Sarkar et al have shown that both agglomeration and non-agglomeration are consistent with Cournot competition, and proves that when demand is linear in each market there exist Nash location equilibria.

This paper focuses on a multiple entrant Cournot location competition model like Sarkar et al. As a point of difference from past literature, the model here has no restriction on number of entrants (free entry) for the first stage entry/location game. Furthermore, it extends the analysis to a sequential two-stage game that integrates the element of incumbent/entrant game for the second period. Knowing the identical game will occur again, firms not only face the choice of whether to enter or not in the first period, but also the choice to wait for next period and the assess the possibility of a first mover advantage. Like in the past literature, a sub-game perfect Nash equilibrium always exists in this model, although uniqueness is not in its nature.



Note: *Green boxes highlights the features of the current model in this paper*. Red font features are unique in this current paper compared to the past literature.

Figure 11: A Taxonomy of Spatial Competition Mode

Careful assessments and considerations are made in this paper to keep its theoretical path as close to its industrial applications by explaining the potential market values for each example in the context of today's North American natural gas market. The purpose of this research exercise is not only to explore academic interest on location model competition, but also to create a simplified market model mirroring key characteristics of the real industrial market and using computational simulation to reveal market insight. Hence, this paper also includes sections to cover the industrial background and constantly highlight examples related to the market source throughout the discussion. This research intends to set an example to bring the market analysis work and academic research closer together.

2.3 Industry Background

2.3.1 What is LNG?

The challenge of the natural gas market at the global level is not with the supply of natural gas. In fact, analysts predict there are vast amounts of natural gas waiting to be tapped. Based on the U.S. Energy Information Agency's annual report, there are more than 6000 trillion cubic feet of gas reserve in the world as of the beginning of 2008, which is accessible with current technology. Compare that to the total annual natural gas consumption for North America which is about 29 trillion cubic feet, and about 100-105 trillion cubic feet for the entire world. The real problem is, geographically: the energy demand and supply do not perfectly line up. In other words, gas reserves are not always located where they are consumed. For example Japan, a major high-demand energy market requiring 3.1 trillion cubic feet natural gas every year, barely produces any gas or oil domestically. Japan relies heavily on imports of oil and gas.

Figure 12 shows the balance of demand and supply of natural gas by continental market. On the left panel, the green bars show the natural gas reserves for each continental market: Africa, Middle East and Eurasia have more than 80% of the world's gas reserves. On the right panel, each market's gas production and consumption is shown. Markets which have less gas production than it consumes require extra imports of natural gas to meet its demand. Europe, North America and Asia combined make up more than 60% of the global gas consumption. When highlighting the top three gas reserve regions and the top three gas consumption markets, it is clear that there is a geographic imbalance of gas supply and demand. One solution to the problem is to transport natural gas from one continental market to another, and that is where **Liquefied natural gas** or **LNG** comes in the picture. LNG is natural gas (predominantly methane, CH_4) that has been converted into liquid form. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state, so it is convenient for long distance shipping from remote supply areas to markets. A majority of the world's LNG supply comes from countries with abundant natural gas reserves. These countries include Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, Nigeria, Oman, Qatar, and Trinidad and Tobago. There are 60 LNG receiving terminals located worldwide. These LNG importers include Japan, South Korea, the United State and a number of European Counties.

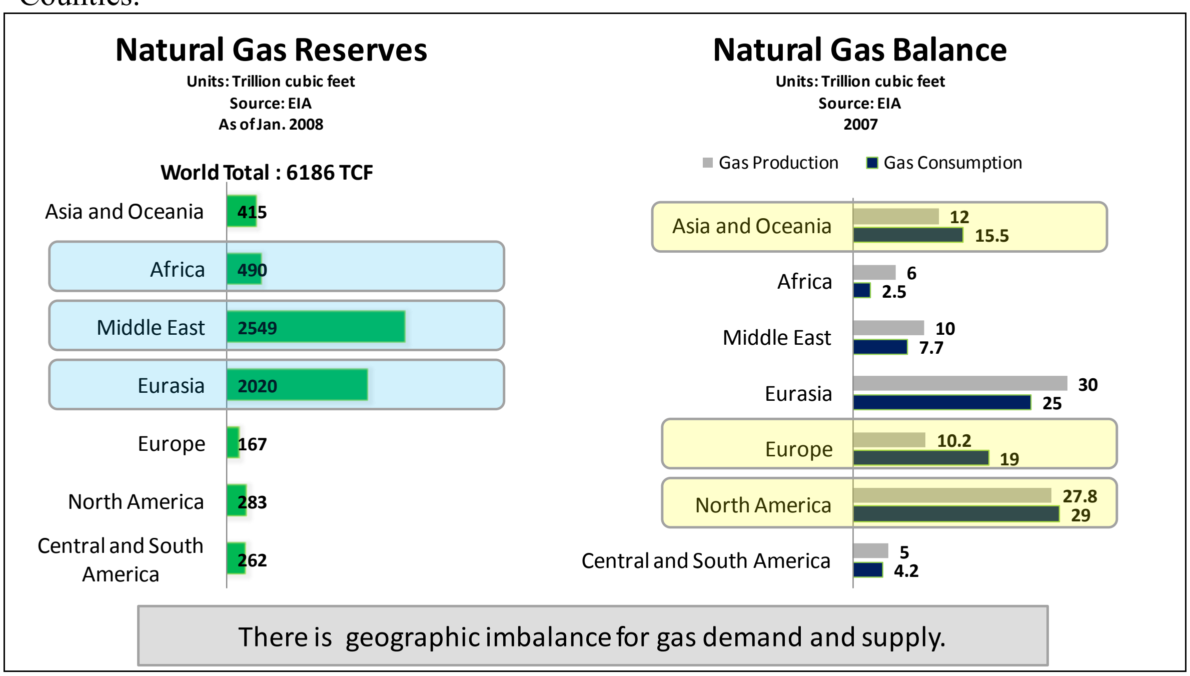


Figure 12: Natural Gas Reserves and Balance by Continent

2.3.2 The LNG Game

As LNG plays an increasingly important role in the global energy market, it is crucial to understand the game of the LNG sector. There are two major types of players: countries like Qatar, which owns the natural resources of oil and gas are LNG suppliers. The ownership of the natural resource granted the player dominant share of the LNG development project. For example, Qatar owns at least a 50% or higher share of every LNG liquefaction project developed on its soil. The owner of the resource will seek sponsors/partners, usually energy firms, who brings in capital investment and technology for the exploration and production. These sponsors/partners will often manage the related downstream operations as well. The commercial development of LNG is a style called value chain, which means LNG suppliers first confirm the downstream buyers and then sign a long term, 20–25 year, contracts with strict terms and structures for gas pricing. Only when the customers are confirmed and the development of a Greenfield project is deemed economically feasible can the sponsors of an LNG project invest in their development and operation. These energy firms usually are responsible for the marketing of LNG on different continents. They are the second type of player in the LNG game.

The upstream infrastructure needed for LNG production and transportation is an LNG plant consisting of one or more LNG trains, each of which is an independent unit for gas liquefaction. The largest LNG train in operation is now in Qatar. The Qatar gas II plant, owned by Qatar Petroleum and ExxonMobil, has a production capacity of 7.8 mmtpa for each of its two trains and was inaugurated in April 2009. LNG is loaded onto ships and delivered to a regasification terminal. Regasification terminals are usually connected to a storage and pipeline distribution network to distribute natural gas to demand markets, or a local distribution company (LDCs).

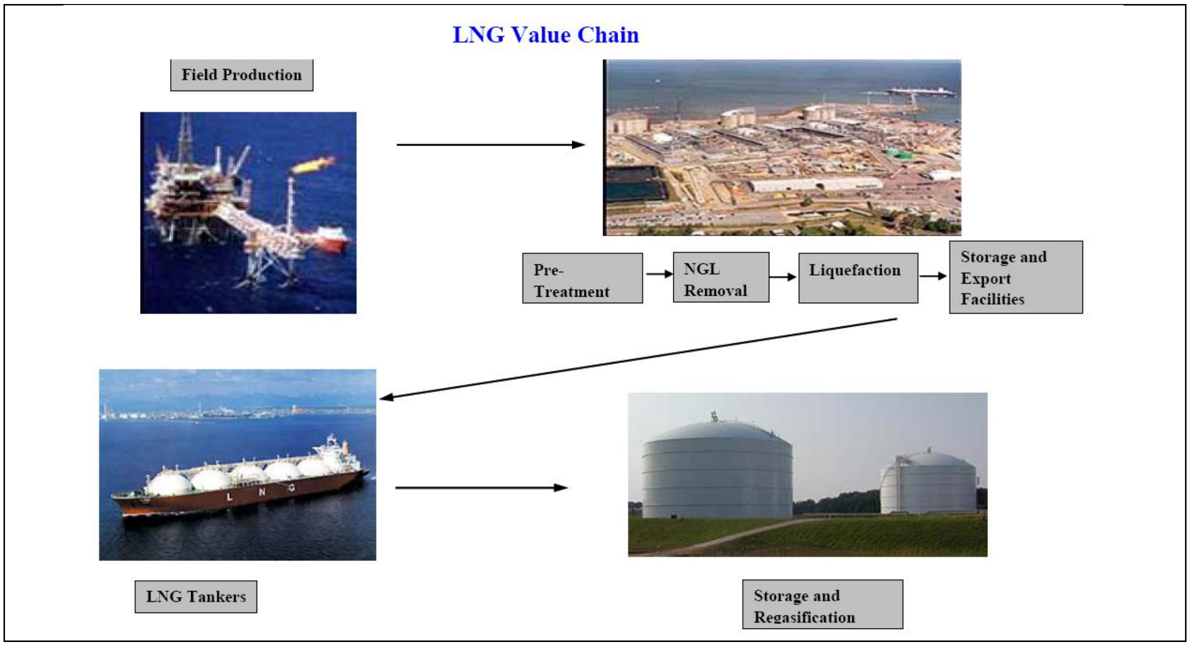
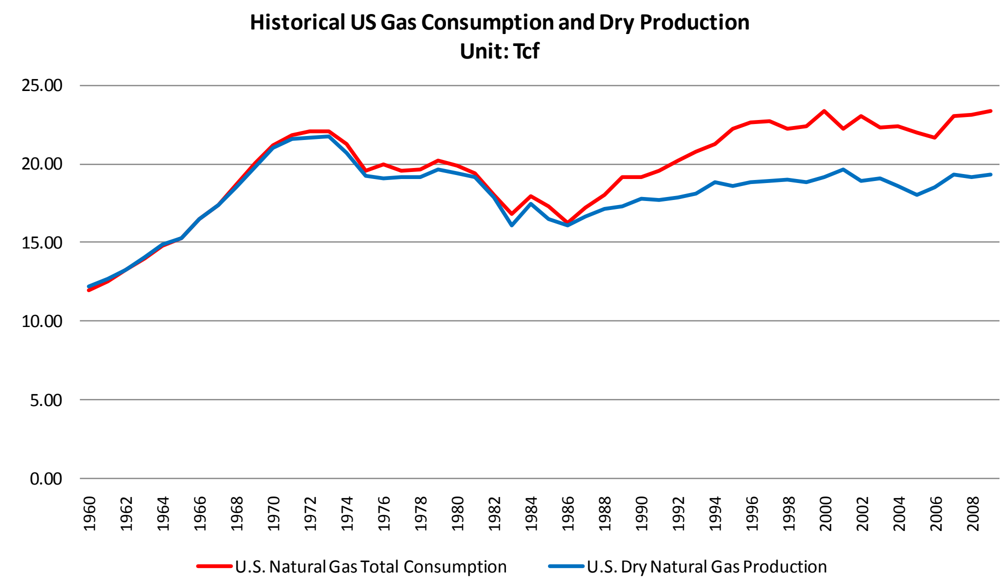


Figure 13: LNG Value Chain

2.3.3 LNG in the U.S.

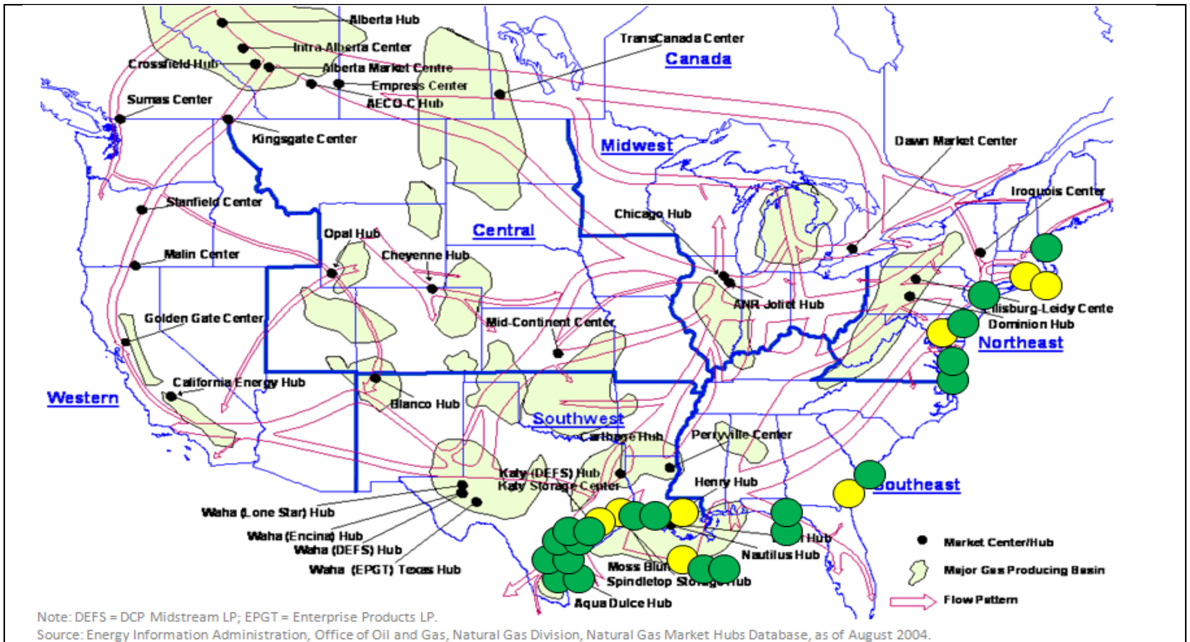
With natural gas consumption exceeding 60,000 mmcfd (Million metric cubic feet per day) and accounting for over a fifth of global demand, the U.S. is by far the largest and most developed natural gas market in the world. The U.S. is also the largest gas producer in the world. Although most of the 16% of natural gas we consume in the U.S. is delivered by pipeline from Canada, there is a growing volume of natural gas coming to the U.S. in liquid form from overseas. Following stable growth in gas demand of around 2% per annum through the 1990s, stagnant and declining production has led to price increase in year 2000-2007, as shown in Figure 14, and it was widely believed that imported liquefied natural gas would be filling up the gap between domestic supply and demand in the U.S.. As a result, there was a very active phase of investment on LNG related projects including major energy companies racing to invest heavily on liquefactions projects in overseas and to build regasification terminals to receive imports along U.S. coastline.



Source: EIA (Energy Information Agency)

Figure 14: Historical US Gas Consumption and Dry Production

The U.S. has the largest and most developed gas pipeline network in the world; the imported LNG enters the pipeline grid and flow to the demand areas. There are eight existing regasification terminals located on the East and Gulf coasts. In addition the US has indirect access to regasification capacity on the West Coast via the Coast Azul terminal in the Northern Baja California which was commissioned in 2008. Figure 15 shows the existing and proposed LNG regasification projects on the east coast of the U.S. as of 2008.



Source: EIA and FERC;

Green circles: Proposing Projects; Yellow circles: existing projects

Figure 15: Map of Existing and Proposed LNG Regasification Terminals in the U.S.

2.4 Model Setup

This paper focuses on the siting decisions for liquefied natural gas regasification terminals by energy companies in the North American market. The companies select a location for the terminal to receive their LNG cargo. Next they deliver natural gas into different markets for end-users or trading partners through pipelines. They compete in markets (one or many) through delivered quantities considering transportation cost and active competitors in the market. The price in each market is determined by the market conditions and the total quantity supplied by all participating companies. This is called Cournot competition in Economics. It is an accurate depiction of the natural gas market.

2.4.1 Baseline Model

The baseline model is a simple one-period game which describes a two-stage non-cooperative game among multiple players (can be more than 2). In the first stage of the game, firms make a simultaneous decision about where to locate a regasification facility along the coastline of North America. In the second stage of the game, firms decide on a contracted quantity to be delivered to these facilities and how much to supply to each market. The assumption is that all firms choose the location-strategy simultaneously without knowledge of the strategy chosen by the other firms. This is a simplified version compared to what occurs in reality, but the scenario is still valid. Although firms usually announce their plan to develop regasification terminals and the approved dates of proposals on these projects are also published by FERC, those dates are not necessarily good indicators of time sequences of entry decisions among participating firms. First, the time lag from the announcement of one LNG terminal to the online date is usually at least two to three years. Uncertainties around the environmental regulatory approval process and firm financial investment flows can easily derail the process. Second, it is common for proposed projects to drop out of the development process. Public announcement and FERC approvals for projects may be more of a strategic signaling tool among participants rather than an actual decision point.

The model on quantity decisions and location choice is described by the following notation: Firms are denoted by an index $i \in N = \{1, \ldots, n\}$ and markets are denoted by an index $h \in M = \{1, \ldots, m\}$, each demands a quantity of the commodity, i.e., natural gas, depending on its settled market price. The demand is fulfilled by the supply of a quantity Q_{ih} from the facility of firm i to market h. Instead of using the traditional hotelling location model assumption of continuous market space, this model assumes the existence of a finite number of markets which resembles geographically defined major metropolitan areas. The firms will choose one of the five markets to be the location of the regasification facility. The location of a market here is not the exact location of one specific terminal, but the location of the nearest market area to the terminal and there are no physical limits to number of terminals located near one market hub. An example is the cluster of regasification terminals in the Gulf of Mexico along the coastline of Texas and Louisiana. These terminals are considered to be located in the same market node. They may enter the pipeline network from different points, but they are serving one broad common market area. All terminals price their services and tariffs based one common or similar market price point. Each supply firm can open one facility at only one of the locations. This is a simplification of the reality, because companies can and actually have invested in multiple regasification terminals. For example, Shell has the Cove Point terminal and the Elba Island terminal. Conoco Phillips also has regasification access to the Freeport and Golden Pass terminals.

The market space is formalized as follows. Let $G=(V,E)$ be an undirected graph with V and E as its sets of nodes and edges, respectively, $|V|=m$. Given two nodes, $v_i, v_j \in V, d(v_i, v_j)$ is the length of a shortest (with respect to the sum of edge lengths) path on G connecting v_i and v_j . There are m markets located each at one node on the network; there are n firms that open a facility each at one node. Let $x_i \in V = \{v_1, \ldots, v_m\}$ be the location decision by firm i on the network. The quantity decision matrix Q for all firms and all markets is given by:

Eqn30:

$$\underline{Q} = \begin{pmatrix} Q_{11}...Q_{1h}...Q_{1m} \\ .... \\ Q_{i1}...Q_{ih}...Q_{im} \\ .... \\ Q_{n1}...Q_{nh}...Q_{nm} \end{pmatrix}$$

where the sum of a row is the quantity supply by firm i over all firms is $s_i = \sum_{h=1}^{m} Q_{ih}$

where the sum of a column is the total quantity supplied to market h is $q_h = \sum_{n=1}^{n} Q_{ih}$

The price $p_h(q_h)$ at market h is assumed to follow a simple linear function here: $p_h(q_h) = \max\{0, \alpha_h - \beta_h q_h\}$, $q_h \geq 0$ with price parameters $\alpha_h \geq 0$, $\beta_h > 0$.

In the first stage, firms simultaneously choose the locations of their facilities, $x_i, i = 1...n$, In the second stage, depending on the location decisions x_i, firms choose quantities Q_{ih} to be supplied to markets, which results in the quantity decision matrix Q .The profit firm i wants to maximize is denoted by $\pi_i(x_i, \underline{Q})$. A strategy for firm i at market h, $[x_i, Q_{ih}]$, comprises of a choice of x_i for stage 1 and a choice of Q_{ih} for stage 2; a strategy $[x_i, Q_{i\cdot}]$, for all markets, where $Q_{i\cdot}$ denotes the row vector of the full quantity matrix.

The game is solved backwards. First, firm i optimally chooses the vector of quantities $Q_{i\bullet} = (Q_{i1}, ..., Q_{im})$, based on what others competitors deliver and depending on the chosen location x_i:

Eqn31: $$Q_{i\bullet}^{*} = \arg\max_{Q_{i\bullet}} \pi_i(x_i, \underline{Q}^{*}(X))$$

After determining the optimal quantity supplied for each market given location choice, then going back to the first stage, where firm i chooses a location strategy x_i^{*} such that:

Eqn32: $$x_i^{*} = \arg\max_{x_i} \pi_i(x_i, \underline{Q}^{*}(X)).$$

The key drivers of difference in the behaviors among firms are their cost structures. There are three types of costs for a firm:

- Opening cost
- Transportation cost
- Supply cost including shipping cost and regasification cost plus operation cost of facility

The cost of establishing a facility by firm i at x_i is $w(x_i) \geq 0$ which is geographically specific. Given the availability of existing infrastructure and local regulatory status, the cost of constructing a regasification terminal can vary significantly. The location x_i of the facility of firm i also determines its marginal production cost $c_i(x_i)$. In addition, when LNG is received at the terminal and converted back to its gaseous state, firms have to transport the gas to markets, which includes the transportation cost: the unit transportation cost between the location x_i of the facility of firm i and location v_h of market h, is represented by $t_{ih} = T(d(x_i, v_h))$, where T is increasing and concave in the distance. In order to capture additional competition impact for these terminals, transportation cost premium is added for firms transporting gas to or passing through a market, which already has its own LNG terminals. Take for example, if firm A decides to deliver to the largest market node which is located on the other end of the network and firm B's terminal is located between A's terminal and the market. Firm A will have to pay a unit transportation cost to deliver to market, in addition to a premium on the transportation unit cost for the distance between Terminal B and market node.

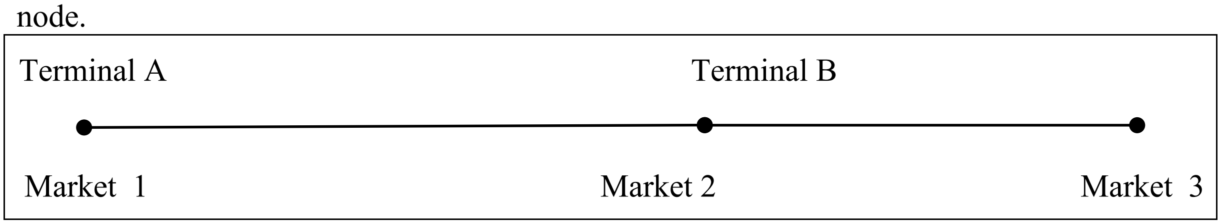


Figure 16: Demonstration of Competition Premium on the Network

The transportation cost for firm 1 to deliver gas from Terminal A to Market 3 is:

Eqn33: $$t_{13} = T(d(v_1, v_2)) + \eta * T(d(v_2, v_3))$$

where there is an extra cost for passing by the other competitors, when η>1.

The exact variable cost of receiving LNG of each firm is usually confidential to the public. It includes two parts: first is the price that the firm pays at the regasification terminal to receive the cargo. The second part of the variable cost is the regasification cost once the gas is received at the terminal. Both types of costs are represented together as a supply cost, $c_i(x_i)$. The total cost of the location and supply decision of firm i is therefore given by

Eqn34: $$\begin{aligned} TC_i(x_i, Q_{i\cdot}) &= \sum_{h=1}^{m} t_{ih} Q_{ih} + c_i(x_i) \sum_{h=1}^{m} Q_{ih} + w(x_i) \\ &= \sum_{h=1}^{m} (t_{ih} + c_i(x_i)) Q_{ih} + w(x_i) \\ &= \sum_{h=1}^{m} TCu_{ih} Q_{ih} + w(x_i) \\ \textit{where} \quad TCu_{ih} &= t_{ih} + c_i(x_i) \end{aligned}$$

Profit is denoted by i and defined as

Eqn35: $$\pi_i(x_i, \underline{Q}) = \sum_{h=1}^{m} p_h(q_h) Q_{ih} - TC_i(x_i, Q_{i\bullet})$$

Firms determine quantities for the markets to maximize profit. Substituting the inversed demand relation of the market into the profit function gives:

Eqn36: $$\pi_i(x_i, \underline{Q}) = \sum_{h=1}^{m} \max\left\{ \alpha_h - \beta_h \sum_{j=1}^{n} Q_{jh}, 0 \right\} Q_{ih} - TC_i(x_i, Q_{i\bullet})$$

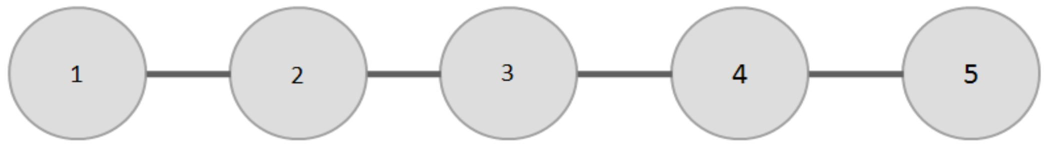
Theorem 1: Nash equilibrium quantities shipped by firm *i* to market *h* follow from the first order condition optimizing $\pi_i(x_i, \underline{Q})$:

Eqn37:
$$Q_{ih}^* = \max\left\{0, \frac{\alpha_h - \beta_h \sum_{j=1, j\neq i}^{n} Q_{jh}^* - t_{ih} - c_i(x_i)}{2\beta_h}\right\}$$

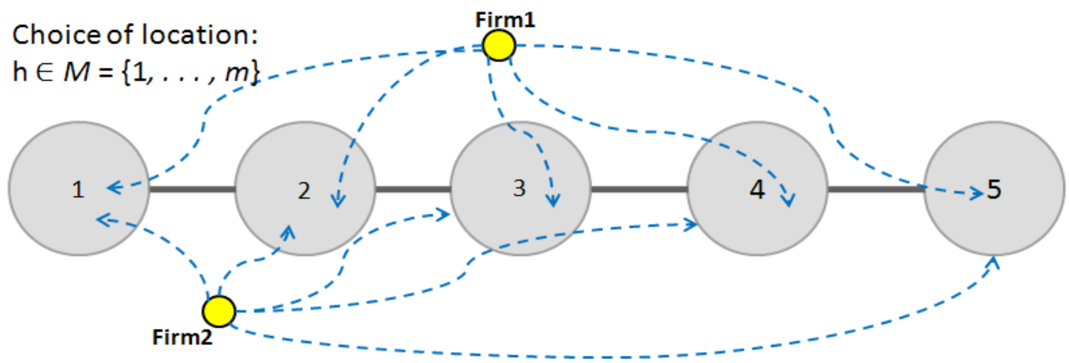
To solve for the exact quantities delivered to each market, we introduce the concept of A_h and $\overline{A}_h$, the set of firms delivering to market h, and the firms not delivering to h respectively:

Eqn38:
$$\begin{cases} Q_{ih}^* > 0 \;\; for\, i \in A_h \\ Q_{ih}^* = 0 \;\; for\, i \in \overline{A}_h \end{cases}$$

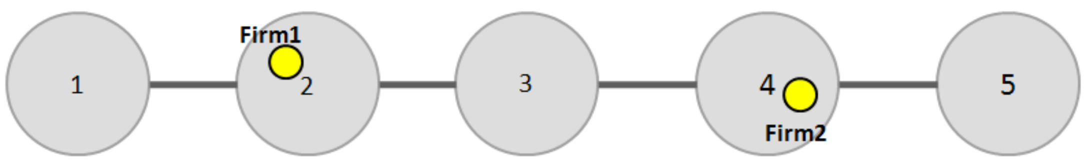
For example, there are 5 markets that the firms can choose to serve and locate the regasification terminals.



First stage: There are two firms and firms simultaneously choose locations x_i



They chose their entry locations: firm 1 chose market 2 and firm 2 chose market 4.



Second Stage: Firms simultaneously choose quantity supplied to each markets

i.e. $Q_1 = (Q_{11}, Q_{12}, Q_{13}, Q_{14}, Q_{15})$, $Q_2 = (Q_{21}, Q_{22}, Q_{23}, Q_{24}, Q_{25})$

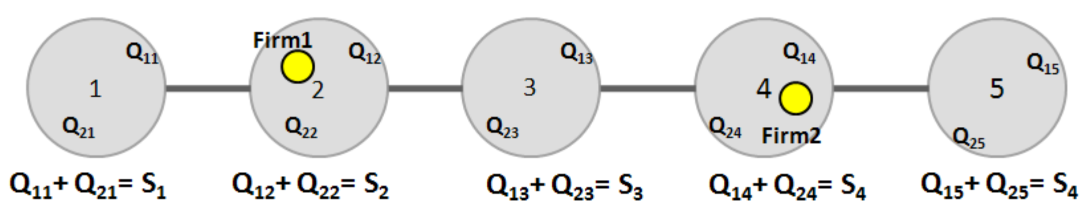


Figure 17: A step by step demonstration of the baseline model

Proposition 1

Let A_h be the set of firms which supply market h, $|A_h| = k$. The positive equilibrium quantities are given by:

Eqn39:
$$Q_{ih}^* = \frac{\alpha_h - k_h\left(t_{ih} + c_i(x_i)\right) + \sum_{j \in A_h \setminus j \neq i}\left(t_{jh} + c_j(x_j)\right)}{\left(k_h + 1\right)\beta_h}$$
$$with\ \ Q_{ih}^* > 0 \, \forall i \in A_h.$$

Q_{ih}^* depends on production and transportation cost of the active suppliers in market h.

Consequently the total quantity supplied to market h is:

Eqn40:
$$q_h^* = \sum_{j \in A_h} \frac{k_h \alpha_h - \sum_{j \in A_h}\left(t_{jh} + c_j(x_j)\right)}{\left(k_h + 1\right)\beta_h}$$

which means that higher average marginal cost and transportation costs decreases the total quantity supplied to the market. The optimal price at each market can be derived as:

Eqn41:
$$p_h^* = \frac{1}{k_h + 1}\left(\alpha_h + \sum_{j \in A_h}\left(t_{jh} + c_j(x_j)\right)\right)$$

Optimal prices at each market rise with average marginal cost and transportation cost over the firms actively supplying the market. Furthermore, equilibrium quantities are given by:

Eqn42:

$$Q_{ih}^{*} = \frac{\alpha_h - k_h\left(t_{ih} + c_i(x_i)\right) + \sum_{j \in A_h \setminus j \neq i} \left(t_{jh} + c_j(x_j)\right)}{\left(k_h + 1\right)\beta_h}$$

$$= \frac{\alpha_h - \left(k_h + 1\right) TCu_{ih} + \sum_{j \in A_h} TCu_{jh}}{\left(k_h + 1\right)\beta_h}$$

$$= \frac{\alpha_h + \sum_{j \in A_h} TCu_{jh}}{\left(k_h + 1\right)\beta_h} - \frac{\left(k_h + 1\right) TCu_{ih}}{\left(k_h + 1\right)\beta_h}$$

$$= \frac{p_h^{*}}{\beta_h} - \frac{TCu_{ih}}{\beta_h}$$

$$= \frac{p_h^{*} - TCu_{ih}}{\beta_h}$$

At equilibrium $Q_{ih}^{*} > 0 \;\; for\, i \in A_h$, $(p_h^{*} - TCu_{ih}) / \beta_h > 0$ such that $p_h^{*} > TCu_{ih}$.

Proposition 2

The relation between the firm with the highest total unit costs in the active set, $i \in A_h$, with any firm which is not entering market $j \in \overline{A}_h$, is:

Eqn43:

$$TCu_{ih} < \frac{\alpha_h + \sum_{j \in A_h} TCu_{jh}}{\left(k_h + 1\right)} \leq TCu_{jh}$$

Firms are ordered on the basis of total unit costs and they will only enter the market if the market clearing price covers their variable cost, which is the total unit cost of production plus transportation. Hence the total quantity supplied by each firm is:

Eqn44:

$$s_i = \sum_{i=1}^{n} Q_{ih}^{*} = \sum_{i=1}^{n} \frac{\alpha_h - k_h\left(t_{ih} + c_i(x_i)\right) + \sum_{j \in A_h \setminus j \neq i} \left(t_{jh} + c_j(x_j)\right)}{\left(k_h + 1\right)\beta_h}$$

Total cost for each firm is:

Eqn45:

$$TC_i = \sum_{h=1}^{m} \left(t_{ih} + c_i(x_i)\right) \frac{\alpha_h + k_h\left(t_{ih} + c_i(x_i)\right) + \sum_{j \in A_h \setminus j \neq i} \left(t_{jh} + c_j(x_j)\right)}{\left(k_h + 1\right)\beta_h} + w(x_i)$$

The final payoff for each firm given location vector X is:

Eqn46: $$\pi_i(X) = \sum_{h=1}^{m} \left(p_h^* - \left(t_{ih} + c_i(x_i)\right) Q_{ih}^* - w(x_i) \right)$$

$$= \sum_{h=1}^{m} \left(\frac{\left[\alpha_h + \sum_{j \in A_h} \left(t_{jh} + c_j(x_j)\right) - \left(k_h + 1\right)\left(t_{ih} + c_i(x_i)\right) \right]^2}{\left(k_h + 1\right)^2 \beta_h} - w(x_i) \right)$$

$$= \sum_{h=1}^{m} \left(\frac{\left[\alpha_h + \sum_{j \in A_h \setminus \{i\}} \left(t_{jh} + c_j(x_j)\right) - n\left(t_{ih} + c_i(x_i)\right) \right]^2}{\left(k_h + 1\right)^2 \beta_h} - w(x_i) \right)$$

$$\sum_{h=1}^{m} \beta_h (Q_{ih}^*)^2 - w(x_i)$$

Now return to the first stage, considering the equilibrium supply quantity in the second stage, each firm maximizes the profit function by selecting a location on the network, which has the highest optimal profit. The strategy $X^* = (x_1^*, ... x_n^*)$ is a Nash Equilibrium if for each firm i, x_i^* is the best response to the strategies specified by the n-1 other firms:

Eqn47: $$\pi_i\left(x_i^*, \underline{Q}^*(X^*)\right) \geq \pi_i\left(x_i^* \underline{Q}^*(\widehat{X})\right) \; with \; \widehat{X} = (x_1^*, ..., x_i, ..., x_n^*) \, \forall x_i$$

For every feasible strategy x_i . That is x_i^* solves:

Eqn48: $$\max \pi_i\left(x_i \, , \, \underline{Q}^*(\widehat{X})\right)$$

2.4.2 Sequential Game

Based on the results from one single period model, this section extends the game to a total of two periods. Firms have the choice to choose a location considering the current market conditions or postpone the decision to the next period. The market conditions are unknown to firms and will only be revealed at the beginning of each stage. Here, the concept of stage can be thought of as each regime change in the market. It is not constrained to a regular time period such as a month or a year. Instead, it can be thought of as a reasonably stable period of time in the market, where firms are confident about the foreseeable future. In a natural gas market, this can be a medium term of 2-4 years for a firm which is considering a business development project like a regasification terminal.

Without repeating the formulas and calculations for the extended model, the description for the baseline model in the previous section can serve as a detailed base for the discussion here. Several additional parameters are introduced for the extended model. At T =1, the current market conditions in each market are revealed to the firms:

Eqn49:
$$\alpha^{T=1} = \{\alpha_1, ...\alpha_m\}^{T=1} \; and \; \beta^{T=1} = \{\beta_1, ...\beta_m\}^{T=1}$$
$$w^{T=1} = \{w_1, ...w_m\}^{T=1}$$

Firm *i* has an expectation of the future market in the second period, which is based on firm's current knowledge of the future, denoted as κ_i and the observed market condition in current period :

Eqn50:
$$Exp\left[(\alpha, \beta, w)^{T=2} \mid \kappa_i, T=1\right] =$$
$$Exp\left[\left|\{\alpha_1, ...\alpha_m\}^{T=2}, \{\beta_1, ...\beta_m\}^{T=2}, \{w_1, ...w_m\}^{T=2}\right|(\alpha, \beta, w)^{T=1}, \kappa_i\right]$$

The firms competing for regasification terminals locations are all sophisticated players and possess comprehensive market information and knowledge. It is reasonable to assume that the firms are forward looking. Firms consider the expected outcome for next market regime when determining the current location choice. In this paper, all firms are assumed to have the same expectation of the future at the location selection time. This is reasonable for energy industry, as firms all have strong analytical teams and all have access to a few pioneering consulting firms and forecasting services. Although firms have varying modified views on many different aspects of the market, they usually come to a consensus in the industry about the general market direction.

With the introduction of multiple periods, there are additional value adjustments for the opening cost of each market, denoted as γ_h. When γ_h>1, it represents the crowding-out effect whereby the opening cost for new entrants are higher when there are incumbent firms already in the market. This can be considered as an additional entry barrier. When γ_h<1, it represents the learning benefit for the later entrants, where there is knowledge sharing of the construction and operation of the facility from the existing players. For example, to construct the first LNG regasification terminal, some challenges may include getting approval from local government and acceptance from the community. However, as a result of the first terminal, the second entrant can enjoy the established regulatory policies which were initiated by the previous terminal investor.

Since the future market conditions are unknown, firms have to decide whether or not to enter based on current market conditions and expectations of future market conditions. At first period of the sequential game, firms do not only consider location choices in current period, but also in the next period. Given the location choices of both periods, firms will estimate the expected profit for both periods. The decisions of accessing and delivering to each market are the same here as in the baseline model. Firms will then choose the best location given the associated optimal expected profit for both periods.

First, solve the first period. When T = 1, the game is solved backwards like the baseline model. Based on current observations and expectations, firms first optimally choose the vectors of quantities for both periods given a location choice:

Eqn51: $$Q_{i\cdot}^{*} = \arg\max_{Q_{i\cdot}} \pi_i(x_i, \underline{Q}^{*}(X))$$

Where

Eqn52: $$Q_{i\cdot} = \left((Q_{i1},...,Q_{im})^{T=1}, (Q_{i1},...,Q_{im})^{T=2} \middle| (\alpha,\beta,w)^{T=1}, \kappa_i \right) \text{ and}$$
$$X = \left(X^{T=1}, Exp(X^{T=2} \middle| (\alpha,\beta,w)^{T=1}, \kappa_i) \right)$$

After determining the optimal quantity supplied for each market given location choice, go back to the first stage, where firm i chooses a location strategy x_i^{*} such that:

Eqn53:
$$x_i^{*} = \arg\max_{x_i} Exp\left[\pi_i(x_i, \underline{Q}^{*}(X)) \middle| (\alpha,\beta,w)^{T=1}, \kappa_i, \gamma \right]$$
$$where$$
$$Exp\left[\pi_i(x_i, \underline{Q}^{*}(X)) \middle| (\alpha,\beta,w)^{T=1}, \kappa_i, \gamma \right]$$
$$= \pi_i^1(x_i^1, \underline{Q}^{*}(X^1)) + \delta Exp\left[\pi_i^2(x_i^2, Exp\underline{Q}^{*}(X^2)) \middle| (\alpha,\beta,w)^{T=1}, \kappa_i, \gamma \right]$$
$$\delta > 0$$
$$x_i^{*} = (x_i^{1*}, x_i^{2*})$$
$$\underline{Q}^{*}(X) = \left(\underline{Q}^{1*}(X^1, X^2), Exp\left[\underline{Q}^{2*}(X^1, X^2) \right] \right)$$

δ is the discount factor for the future. Note if discount factor is zero, firms are not forward looking and only able to observe the current market condition, the equilibrium result for the first stage of the siting game should be the same as the equilibrium resulted from the baseline model.

In order to accommodate the fact that firms can choose to enter any time in the reality for investing a LNG terminal, this model also allows second chance of entry: in second period, when nature reveals the market condition, firms that have not yet have chosen a location will be given a second chance to choose. Firms that have chosen are not given a chance to relocate. Once location choices are made, firms will again simultaneously choose the quantity supplied to each market. The game in the second stage is solved like the baseline model, except certain firms' location choices are pre-determined as they have chosen already. If there are still firms left without making a location choice from the first stage, that firm (or those firms) will have a second chance here. Firms will only enter the market whenever the market conditions in the future stages are revealed to be profitable. If the market conditions did not improve to be profitable for firms which have not chosen, these firms will never enter, as they did not at the previous stage. As firms make entry decisions depending on their cost structure of producing or delivering gas, more efficient players with lower costs will enter the market first, while others will wait until the conditions become more profitable for entering.

In reality the firms play the quantity game respectively, and it is possible to introduce a multi-stage cournot quantity game here. If the focus is not the specific quantity offered, but the location decision: the gain of a multi-stage quantity game is assessed at the beginning of every period based on firms' expectations. Multi-stage quantity game can be rewritten as one constant term in the formula given firm's expectation as follows, which demonstrates that one stage quantity game is sufficient to illustrate the purpose:

Eqn54:

$$\begin{aligned}\sum_{t=1}^{T} E\left(\Pi_{t=1}\right) &= \sum_{t=1}^{T} E\left(\Pi_{t=1} \mid p\right) \\ &= \sum_{t=1}^{T} E\left(\Pi_{t=1} \mid \left\{p_1, \ldots, p_T\right\}\right)\end{aligned}$$

2.5 Simulation Results and Numerical Illustrations

The reality only shows one story, which results from orchestrating through many fundamental drivers in the market place. It is challenging to understand the intricacy of all drivers at once. The purpose of this model is to exploit the dynamics observed in the LNG market, by providing a simplified virtual space where the researcher is able to gain a better understanding of how each variable works. Hence, the following section focuses on: 1) building a stylized scenario which mirrors industrial facts and data, and designed to simulate reality-based market behaviors; 2) introduce more model simulations to investigate the impacts of a particular market fundamental driver at a specific instance of time.

A simple algorithm is introduced here: first, the equilibrium quantities are computed for each possible location possibility. Afterwards, a Nash Equilibrium Location is chosen among all possible locations by checking whether it is better for a firm to relocate its facility given everything else remaining constant. For the extended model, the same method is used, except there are more location combinations to calculate as both periods are considered when T =1.

2.5.1 Stylized Baseline Scenario

The values of parameters in the stylized scenario are determined based on industrial facts. The following section discusses the methodology and data used to derive the stylized model simulation.

2.5.1.1 Network of Markets

A network of markets is defined as market areas located along the east coast of the United States, connected by natural gas pipelines. Figure 18 is the same map of US regasification terminals (East coast) overlaid with five market centers defined by clustering neighboring terminals based on the major demand centers along the coast line. For simplicity, the markets used in this model simulation are defined by major gas market hubs along the coastline, which are aggregated market place for natural gas deliveries and receipts. These market centers are connected by a well-defined transportation corridor, comprise of major pipelines as well as local and smaller pipelines, extending from Gulf of Mexico to major demand areas into the northeastern US, tapping supply regions in the Gulf of Mexico, Texas, Appalachia, and Canada and serving gas to markets across the Midwest and mid-Atlantic regions, including major metropolitan centers. Because these five markets are also located in five adjacent census regions, they are referred to as either markets 1 to 5, or by the names of the census regions: the South West Central (SWC), South East Central (SEC), South Atlanta (SA), Middle Atlanta (MA), and New England (NE).

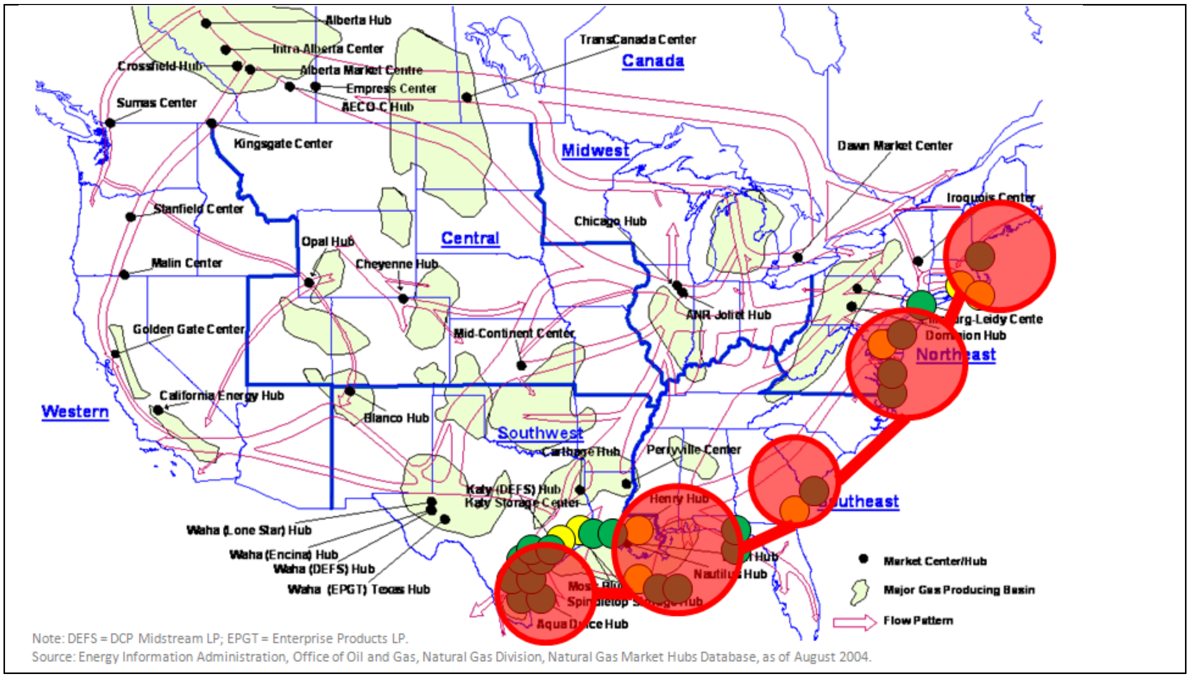


Figure 18: Map of Market Centers

2.5.1.2 Costs of Transportation

There are several options of getting from one market to another on the network via pipelines and many possible long-term contracts can be negotiated. However, the gas pipeline network is effective and liquid enough that the transportation costs between two markets are fairly consistent and close in range, it can be partially reflected by price differences between two markets. There is little concern that the contracted cost of transportation for LNG cargos is much different from the market rates. LNG cargos are usually considered and priced at the ongoing market rate when the LNG marketers decide on its quantity offered to a market.[4] Therefore, the transportation rate from one market to another is determined by a combination of tariff rates posted by major pipelines between markets

[4] LNG supply to the U.S. market has not been completely responsive to the market price in the U.S., and the supply constrains of LNG is out of the scope of this paper.

2.5.1.3 Definition of Demand Function

There are two parameters that need to be identified for each market's demand, given the linear demand assumption: α_h and β_h. α_h is a measure of the maximum price in the market where the quantity offered is zero, and β_h is a measure of price elasticity of demand. Since there are other sources of natural gas supply in the market besides LNG imports, α_h should be the marginal gas price in the market. As a result, LNG marketers use the marginal market price as an indication of the ex-ante market price before any introduction of LNG. β_h is the change in market price when incremental LNG import is supplied to the market area. Figure 19 shows the gas consumption, and production available for each market. The more demand there is, the higher the marginal gas price. On the other hand, the more local production there is, the lower the marginal gas price. The LNG players consider the balance between demand and supply in each market to determine the marginal gas price for the incremental LNG. Market 1, South West Central, represents the largest market in term of size, while there is more local gas production compared to local gas consumption in this area. Hence that leads to the fact the market price of gas observe in Market 1 is the cheapest out of the five markets. On the other hand, Market 4 and 5 are markets with little local production. Since gas is widely used for space heating in the Northeast, market 4 and 5 have little price elasticity in the winter.

2.5.1.4 Shipping Cost of LNG

Each LNG facility may have a different shipping cost schedule from each origin which is a result of specific negotiation with the LNG liquefaction project. Table 3 lists the average shipping costs to each major market area using the representative LNG regasification terminal in each area. There can be more variation of the rate, but it is not a consideration in the current model. For simplicity, the average of the shipping cost received in each representative LNG regasification terminal is used.

2.5.1.5 Construction Costs and Operation Costs

Construction costs are available from EIA and FERC announcements for selected terminals. An average of construction costs for each market area is used as part of the model. Since the quantity and price data is grouped as daily or monthly, the construction costs are recalculated into daily pay-off plus some reasonable estimate of facility operation expenses. It is much more expensive to construct a regasification terminal in northeast markets, due to the dense population and clustered metropolitan areas. Hence, the construction costs are higher in Markets 4 and 5 compared to Market 1, 2 and 3, due to additional regulatory and environmental challenges encountered when the location is In close proximity to major metropolitan areas.

2.5.1.6 Number of players

There are a handful of LNG players in the market, and the model simulates the number of players from two to four for demonstration purposes.

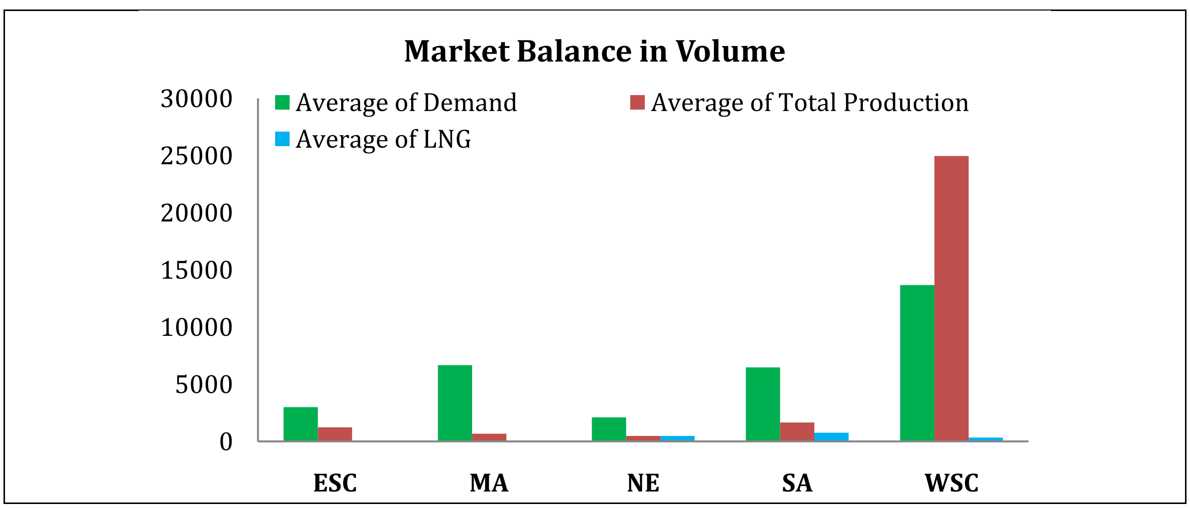


Figure 19: Natural Gas Balances for Market Areas in the model by Census Region

Representative LNG Shipping Rates:

	Middle Atlantic/New England	South Atlantic	**South West Central**	**South East Central**
Exporter / Regasification Terminals	**EVERETT**	**COVE POINT**	**ELBA ISLAND**	**LAKE CHARLES**
Algeria	0.52	0.57	0.6	0.72
Nigeria	0.8	0.83	0.84	0.93
Norway	0.56	0.61	0.64	0.77
Venezuela	0.34	0.33	0.3	0.35
Trinidad and Tobago	0.35	0.35	0.32	0.38
Qatar	1.37	1.43	1.46	1.58
Australia	1.76	1.82	1.84	1.84
Average	**0.81**	**0.85**	**0.86**	**0.94**

Source: The Global Liquefied Natural Gas Markets: Status and Outlook 2003 by EIA

Table 3: Representative LNG Shipping Rates

2.5.1.7 Model Result and comments

Table 4 includes the model parameters used for the baseline scenario. All the values of parameters are based on industrial facts and experience. The baseline scenario is designed to be a close reflection of real market in a simplified setup. Table 5 summarizes the model results, in term of equilibrium numbers and equilibrium locations, when the number of players increases from two to four.

Market Parameters ($)					
Market	Alpha	Beta	Initial Capital Cost		
South West Central	4.5	0.005	10000		
South East Central	5	0.02	10000		
South Atlanta	5.5	0.05	15000		
Middle Atlanta	7.8	0.1	45000		
New England	7.9	0.05	30000		
Tariff Matrix ($/Dth)					
Market	South West Central	South East Central	South Atlanta	Middle Atlanta	New England
South West Central	0.00	0.30	0.60	1.30	1.75
South East Central	0.30	0.00	0.30	1.00	1.45
South Atlanta	0.60	0.30	0.00	0.70	1.15
Middle Atlanta	1.30	1.00	0.70	0.00	0.45
New England	1.75	1.45	1.15	0.45	0.00
Firm Cost Structure Matrix ($)					
Cost of Gas	South West Central	South East Central	South Atlanta	Middle Atlanta	New England
Firm 1	3.9	3.9	3.85	3.8	3.8
Firm 2	3.9	3.9	3.85	3.8	3.8
Firm 3	3.9	3.9	3.85	3.8	3.8
Firm 4	3.9	3.9	3.85	3.8	3.8

Table 4: Model parameters

Number of Players			
	Two Players	**Three Players**	**Four Players**
Number of Equilibrium	**1**	**3**	**12**
Equilibrium Locations	1 1	1 1 4	1 1 4 5
		1 4 1	1 1 5 4
i.e. (x1, x2, x3, x4); Where x1 – is the location chosen by firm 1.		4 1 1	1 4 1 5
			1 4 5 1
			1 5 1 4
			1 5 4 1
			4 1 1 5
			4 1 5 1
			4 5 1 1
		5 1 1 4	
Market Locations: 1: South West Central; 2: South East Central; 3: South Atlanta; 4: Middle Atlanta; 5: New England			

Table 5: Model Result for baseline scenario

This stylized baseline scenario leads to some interesting results, which are incredibly similar to real world trends, even in a simplified model setup. When there are only two players in the market, the first choices is marked location 1, which is the South West Central – Texas part of the Gulf of Mexico. As the number of players grows, the location choices are expanded to Middle Atlanta and New England. That is a very realistic result. Market 1 is attractive with its low construction cost, and large liquid market, which makes it easy to transport gas to the Northeast market. Market 4 and 5 are attractive as they are both demand centers, but they both are expensive locations for building a terminal. As the number of players increases, even though they all have identical cost structure in the baseline scenario, the equilibrium choices indicate that firms choose to avoid additional competition and not all locate in the same markets. When the number of players is equal or larger than three, the players start to separate from each other, if possible. Table 6 shows the supply choices made by LNG players for each market in the second stage after deciding on the location of the facility. The supply choices reveal further the intention of location strategy – each LNG player chooses different markets as their focus, which reduces the competition among each other.

Number of Players = 2						
		Supply Choices				
Firm 1	Loc: 1	40.000	13.333	6.667	8.667	15.000
Firm 2	Loc: 1	40.000	13.333	6.667	8.667	15.000
		Total				
		80.000	26.667	13.333	17.333	30.000
Number of Players = 3						
		Supply Choices				
Firm 1	Loc: 1	40.000	13.333	5.000	3.000	4.250
Firm 2	Loc: 1	40.000	13.333	5.000	3.000	4.250
Firm 3	Loc: 4	0.000	0.000	5.000	17.000	32.250
		Total				
		80.000	26.667	15.000	23.000	40.750
Number of Players = 4						
		Supply Choices				
Firm 1	Loc: 1	40.000	13.333	5.000	0.500	0.000
Firm 2	Loc: 1	40.000	13.333	5.000	0.500	0.000
Firm 3	Loc: 4	0.000	0.000	5.000	14.500	21.333
Firm 4	Loc: 5	0.000	0.0000.000	10.000	30.333	
		Total				
		80.000	26.667	15.000	25.500	51.667

Table 6: Baseline Model Result of Supply Choices[5]

In reality, most of LNG facilities (existing and proposed) are located near the Gulf of Mexico (Market 1 and part of Market 2), while a few are located in Middle Atlanta and New England area (Market 4 and 5). There is only one regasification terminal located in South Atlanta (Market 3) – Elba Island terminal. This is close to what the baseline scenario has generated. That confirms the validity of the LNG game as a robust simulation of the actual strategic decisions made in locating these regasification terminals in the U.S. market.

2.5.2 Sensitivity Analysis

The advantage of modeling is the ability to measure the impact of specific market drivers, and simulate alternate scenarios, which may occur in reality. That is the focus of this section: by varying certain parameters of the model, the results reveal more meaningful variations in equilibrium location and supply choices by LNG players in the game.

2.5.2.1 Varying Transportation Tariff and Network Connectivity

Although LNG terminals are constrained to locations along the coastline for receiving cargos, gas from each terminal has to first be transported onto these pipelines for delivery to major market areas. There is capacity limitation on a pipeline, and the cost of transportation increases dramatically when the utilization rate of a pipeline approaches its capacity limit. When the pipeline network is relatively full, it is much more expensive to deliver the gas to the market. With the development of unconventional gas production newly found in Texas and Louisiana, there is an increasing challenge for the

[5] Since all equilibriums are symmetric in the baseline scenario, only one equilibrium outcome is selected here in Table 7.

displacement of LNG supplies in the future. Transportation cost is certainly a concern for firms when choosing the location of a regasification terminal. Scenario 1 investigates the effect of transportation tariff on firms' location choices, deviating from the assumptions of the baseline scenario. Two sets of sensitivity simulations are illustrated here, considering the effect of the transportation tariff:

Uniformed Change of Tariff Structure:

This is the case where all tariff structure are adjusted up or down uniformly by the same scale. In reality, that is likely to happen through a "rate case" applied by a pipeline company. When a pipeline company seeks a higher return on investment, due to market condition or economic condition, it can submit an application for a "rate case" to FERC for approval. The degree to which these rate case changes is usually uncertain to the shippers on the pipeline until the rate case is approved by FERC. The rate changes range from moderate such as a nickel up to 20-30 cents. For this reason, rate changes are always a risk for shippers on a pipeline.

The sensitivity simulation adjusts the entire transportation tariff structure up or down uniformly and the results are shown in Table 7. In this scenario, the model simulates different sets of tariff structure under a common adjustment factor, which ranges from 0.5 to 1.5 with 0.1 increments, of the original tariff in the baseline scenario. As the tariff structure moves from low to high, the location choices of regasification terminals in equilibrium change from a central agglomeration for all players to a repelled separation on each end of the network. That implies that as the transportation tariff becomes a larger part of the cost function, the need to avoid competition drives LNG players to locate further apart.

Relative Change of Tariff Structure:

This sensitivity simulation also investigates another scenario regarding tariff structure. As mentioned earlier, the congestion on the pipelines causes higher tariffs for certain market segments. This is represented by uneven increments of tariff from market to market: for example, the incremental tariff change is highest from Market 3 to Market 4, in the baseline scenario. This simulation firstly considers a hypothetical tariff structure, where there is no bottleneck on the pipeline, and all the increments of tariff change from market to market are the same, 30 cents. That is unlikely in the real market, as resolving bottlenecks on the transportation networks requires new pipelines or expansion of existing pipeline. These projects are challenging and expensive, because the congestion zones on the pipeline network are usually near major metropolitan areas. As a point of reference, there have not been any successful projects to develop long haul pipelines through populated markets, such as the Middle Atlanta area, for the past 3-4 decades. Therefore, this simulation of tariff changes ran under two existing tariff setting: symmetric tariff structure with even tariff increments versus one with uneven tariff increments.

The results demonstrate that as the tariff level increases, the equilibrium location also tends to move from a centralized location to a scatter pattern. The even tariff structure encourages more separation of locations, compared to the previous simulation where there exists more expensive and congested market segments. It is noteworthy that when the congestion is cleared on the network, market 3 becomes more attractive as a equilibrium location choice, compared to the baseline scenario: the Elba Island terminal is located in market 3, South Atlanta area. The Elba Island Terminal has faced challenges in the past of marketing LNG import gas from that area to the Northeast due to the high transportation premium that is added to the cost of LNG from market 3. While it does not have the advantage of a liquid market, its local market is rather limited and extra LNG imports into Market 3 would have faced challenges to be priced fairly, compared to its competitions which import LNG from the Gulf of Mexico (Market 1 or 2).

Note:

1. Colored block indicated a chosen location for terminals – there can be multiple terminals located in one market. There are also multiple equilibriums for each simulation case.
2. Green colored row is the location choices appeared in the baseline scenario.

Adjustment Factor/ Markets	**Uneven tariff increments**					**Even tariff increments**				
	1	2	3	4	5	1	2	3	4	5
0.50	4					4				
0.60	4					4				
0.70	2		2			2		2		
0.80	2		2			2		2		
0.90	2			2		2		1		1
1.00	2			1	1	2		1		1
1.10	2			1	1	2		1		1
1.20	2				2	1		1	1	1
1.30	2				2	1		1	1	1
1.40	2				2	1		1	1	1
1.50	2				2	1		1	1	1

Note: The number of in the market location indicates the maximum of firms chosen this market. So, it is a measurement for market agglomeration.

Table 7: Comparison of Equilibrium Locations under Even/Uneven Tariff Increments on Network

2.5.2.2 Varying Price Responsiveness in Markets

Price responsiveness in the market changes when the economic conditions change. When there is strong demand, there is plenty of liquidity in the market to support additional supply of gas and price impact from extra supply is minimal. However, on the other hand, in a market with little liquidity, any additional supply can have a significant impact on the price in the market. Assume the same network setup as in the baseline scenario and hold all market conditions the same except for the market responsiveness measure – beta. When there is higher price responsiveness in the market in general, the competition is more intense. Because there is a greater reduction in market price from every additional quantity of gas supplied to the market and firms act more cautiously with their supply decisions to markets. When the price impact is softer, firms produce significantly more.

The baseline scenario shows that the market responsiveness increases in the value of Beta from Market 1 to Market 4. This section provides two alternative sets of simulations of market responsiveness compared to the baseline scenario:

1. Simulation of a network shares the same market responsiveness for each market. Different levels of market responsiveness are tested in this simulation: from a very liquid network market to a very inflexible network market. The equilibrium location choice is stable when there is homogeneous market liquidity on the network – all location choices are centralized at market 4 from all simulated beta values. When there is no difference in market responsiveness in price, there is little motivation for avoiding competition by locating away from competitors and hence the equilibrium choices are all in the demand centers where the marginal price is high. Locating in market 1 in the baseline scenario takes advantage of the liquid market in the Gulf area, even though that advantage does not exist anymore in this simulation.
2. Simulation of a network with different market responsiveness for each market. This is similar to the baseline scenario, but with an improved market liquidity condition for markets 2 and 3. Markets 2 and 3 have a relatively less flexible market compared to market 1, as the major pipelines in these market areas are mainly passing natural gas from Gulf of Mexico to the Northeast markets (Market

4 and 5), and have less capacity to receive or delivery on this segment. It is more desirable to deliver gas as far north as possible on this corridor. Markets 2 and 3 are not a desired destination in term of profitability. So as the liquidity of market 2 and 3 increases, the beta decreases and the equilibrium location choices move from the extreme ends of the market to the middle of the network.

	Equal Price Elasticity among Markets				
Beta	1	2	3	4	5
0.000				4	
0.005				4	
0.010				4	
0.015				4	
0.020				4	
0.025				4	
0.030				4	
0.035				4	
0.040				4	
0.045				4	
0.050				4	

Table 8: Comparison of Equilibrium Locations when all markets sharing the same market responsiveness

					Changing Price Elasticity for Market 2 and 3				
					1	2	3	4	5
0.005	0.020	0.050	0.100	0.050	2			1	1
0.005	0.020	0.045	0.100	0.050	2			1	1
0.005	0.020	0.040	0.100	0.050	2		1		1
0.005	0.020	0.035	0.100	0.050	2		1		1
0.005	0.020	0.030	0.100	0.050	2		1		1
0.005	0.020	0.025	0.100	0.050	2		1		1
0.005	0.020	0.020	0.100	0.050	2		1		1
0.005	0.015	0.015	0.100	0.050	2		1		1
0.005	0.010	0.010	0.100	0.050		2	2		
0.005	0.005	0.005	0.100	0.050			4		

Table 9: Comparison of Equilibrium Locations when two markets have varying market responsiveness assumptions

2.5.2.3 Varying Cost Structures of Firms

In the baseline scenario, all firms have identical costs specific to one location of the market and hence the set of equilibria represents a symmetric set of possibilities of location choices: for example in the baseline scenario – 12 combinations for three possible locations of 4 players exist. Each player has equal possibilities to choose any of the three market locations in equilibrium, market. In reality, firms are not identical. They vary significantly in terms of their cost structures. The relative cost structure of one to other firms is a key driver to shape the business strategy of a firm under competition. In this section the focus shifts to the cost structures of firms. Instead of being equally productive, firms are configured to have different cost structures. Location choices are not only determined by the absolute value of shipping costs and regasification charges, but even more by the relativity of cost structures among firms. This section studies two sets of scenarios and presents the model results separately as follows:

Selected firms have absolute cost advantages compared to its competitors in all markets:

This simulation hypothesizes a subset of firms (one to two), which have lower supply costs compared to its competitors. This is likely if one of the players has invested in upstream liquefaction operation, compared to its competitors. In that case, that player may have special long term contract with LNG suppliers in the global market at a lower cost. That is a likely situation in real market: as mentioned in earlier sections, major oil companies which have invested in the upstream liquefaction projects have long term base-load contract which ensures a minimum delivery of LNG cargo to its designated terminals in the U.S. market without diversion rights. Therefore, these contracted cargos don't response to higher price bidders for the load; instead they are obligated to deliver at a pre-negotiated rate to a market. Therefore, the variable of cost of LNG supply is lower for these major firms, which hold long-term contracts with upstream operation.

The configuration is the cost scale between firms. For example, when the cost configuration is (1.5, 1, 1, 1), it implies that firm 2 to firm 4 have cost as the default value in the baseline scenario, and firm 1 has a higher variable cost than its competitors. As firm 1's variable cost varies from one half of, to 50% more than its rivalries, it is easy to note the changes of location choices in the equilibria: when the cost structure among firms varies significantly, due to the difference in cost structure, the strategic focus of each firms differ. The most cost-efficient players will focus on choosing the largest market area in term of liquidity as the location of its facility and all other less effective players are pushed to the other end of the network to avoid competition. As a result, a high-cost firm chooses to locate away from firm 1 and concentrate in supplying the nearby markets, 4 and 5. There is more market segmentation observed with more sparsely distributed cost structure among firms. When the difference of firms cost structure gets narrower, competition increases and pulls the equilibrium location choices closer together.

Variable Cost Scale (4 x 1)				**Firm 1 has a different variable cost**					Number of Equilibriums
Firm1	Firm2	Firm3	Firm4	1	2	3	4	5	
0.5	1.0	1.0	1.0	**Firm 1**				3	1
0.6	1.0	1.0	1.0	**Firm 1**				3	1
0.7	1.0	1.0	1.0	**Firm 1**				3	1
0.8	1.0	1.0	1.0	**Firm 1**				3	1
0.9	1.0	1.0	1.0	**Firm 1**				3	1
1.0	1.0	1.0	1.0	2			1	1	12
1.1	1.0	1.0	1.0	2			1	**Firm 1**	3
1.2	1.0	1.0	1.0	2			1	**Firm 1**	3
1.3	1.0	1.0	1.0	2			1	**Firm 1**	3
1.4	1.0	1.0	1.0	1				**Firm 1+2**	3
1.5	1.0	1.0	1.0	1				**Firm 1+2**	3

Table 10: Comparison of Equilibrium Locations when selected firm has cost (dis)advantages compared

<u>Uniformed change in variable cost structure for all firms:</u>

In addition, if there was an external shock to the LNG supplies, how would that change the game of location? This is more of a theoretic question than a practical one. When all the costs are adjusted downward from the baseline scenario together, all firms choose market 1 as the location for terminal. As the cost of opening a facility becomes more significant, market 1's fixed costs proportionally decreases. In term of supply choices, firms deliver to all markets, however, firms will deliver a higher quantity in market 1, where the liquidity is highest, and secondly in market 5.

On the other hand, when all the costs are adjusted upward from the baseline scenario together, all firms "migrated" to the other extreme of the network, market 5, where fixed cost portion is most expensive. That implies that when there is a significant increase in the variable cost, the focus of strategy shifts to locate to a market that minimizes the transportation cost and maximize marginal price. Supply choices have also shifted from delivering to all markets, to only delivering to market 5 or 4 (only delivery to market 4 when the cost scale is less than 1.4), as the variable costs become more formidably expensive for all players. Overall, this scenario shows that if the cost of LNG becomes relatively more expensive to the U.S. market, the LNG market shrinks quickly and this result helps to identify the "last resort" for LNG import, New England market.

Variable Cost Scale (4 x 1)				**Uniformed change in costs for All Firms**					Number of Equilibriums
Firm1	Firm2	Firm3	Firm4	1	2	3	4	5	
0.5	0.5	0.5	0.5	4					1
0.6	0.6	0.6	0.6	4					1
0.7	0.7	0.7	0.7	4					1
0.8	0.8	0.8	0.8	4					1
0.9	0.9	0.9	0.9	4					1
1.0	1.0	1.0	1.0	2			1	1	12
1.1	1.1	1.1	1.1	2				2	4
1.2	1.2	1.2	1.2	2				2	4
1.3	1.3	1.3	1.3					4	1
1.4	1.4	1.4	1.4					4	1
1.5	1.5	1.5	1.5					4	1

Table 11: Comparison of Equilibrium Locations under uniformed change in variable cost structure:

2.5.2.4 Market Outlook

From here onwards, the scenarios extend to the two-period game. Global energy markets are changing constantly, and there are even occasional seismic-sized shifts. However, with the great challenge of trying to predict a recession, business plans are designed with the Business-As-Usual mindset. One important assumption here is that future realization aligns with the firms' expectation. Since firms are making a decision on location choices for both periods at beginning of time, if the expectation becomes reality, the firms will simply carry out the original plan. This is just a simplification for the purpose of this paper, or pure good faith in fundamental forecasting. The focus of interest is to understand the impact of forward-looking vision on the location choices at the beginning of the first period compared to decisions made when knowing there is no second chance.

All firms have long-term market outlooks; defined as the expectation of market conditions and price movements in the future. For a capital-intensive project like an LNG regasification terminal with 30-year LNG contracts, the fundamental market outlook is crucial. When there are two periods in the game, firms have incentive to evaluate the expected profit given current choice based on their market outlooks. When there is a bullish outlook for the economy, there is incentive to enter the market and secure a competitive position. Firms will enter even the entry bears a negative profit at beginning. However, when there is a pessimistic outlook for the economy, there is a fear to invest. In the past five years, there was strong growth in energy market. There were many proposed LNG regasification terminals, although only a few were built in the end. At the turn of recession, the freeze-up in credit market and softer global demand for energy will deter future investments in regasification terminals.

This scenario presents an example that different market expectation can change firms' behavior. Suppose that the firms would have known about the recession in 2008-2009, and would have been able to predict accurately the natural gas price drop to the $4.00 level. If the second time period has a much weaker market condition, how would this outlook change the location decision made by firms at beginning of period 1? Table 12 shows a hypothesized market outlook of market conditions (alpha and beta), based on the realized market price after the gas price dropped from the peak to about 4 dollars since. As a result, the equilibrium choice changes to only market 5 in both periods, and no firms would have entered markets 1 or 4, if this were the market outlook available to all LNG players. This reveals an important insight on LNG location strategy: as LNG has not grown to a major source of gas supply in the U.S. market, the strategy of LNG siting is somewhat risky and vulnerable, as it depends much on the domestic market condition. In this simple simulation, if all firms had ex-ante knowledge of the market condition in 2008-2010, the locations of the LNG regasification terminals along the coastline will be more in New England market, rather than clustering around Gulf of Mexico. This echoes with the fact that since the natural gas price drops, the number of U.S. market LNG cargos into most of the terminals in Gulf of Mexico has sharply declined; even terminals under long term contract have not been receiving the "base load". Most of the cargos were diverted to European and Asian markets where gas price is maintained at a higher price level by linking directly to crude oil price.

Market Condition and Outlook (T = 1 and T = 2)

Market Parameters ($)		T = 1		T = 2
Market	Alpha	Beta	Alpha	Beta
South West Central	4.5	0.005	3.8	0.01
South East Central	5	0.02	3.9	0.025
South Atlanta	5.5	0.05	4.2	0.08
Middle Atlanta	7.8	0.1	4.5	0.12
New England	7.9	0.05	4.7	0.08

Table 12: Market Parameters for two-period Game

T = 1					T = 2				
1	2	3	4	5	1	2	3	4	5
2			1	1					4

Table 13: Comparison of Equilibrium Locations between one and two periods models

2.6 CONCLUSION

In order to describe the siting game for LNG regasification terminals, this paper sets up a competitive location and quantity "a la Cournot" game to study the oligopolistic competition between n (≥2) heterogeneous firms. Firms first decide where to locate a facility and then decide on how much to supply to all or some of *m*(>2) spatially separated markets from these facilities. Furthermore, the model is also extended into t=2 periods, where firms decide to enter in the first or second period, which allows forward looking vision impact firm's marginal behavior.

By designing a stylized baseline model, which reflects industrial facts and knowledge, this model is able to capture important market dynamics in natural gas market in a simple setting. The simulated model result from the stylized baseline model provides insightful comparison to the reality. The equilibrium location choices in the baseline model are either in the Texas area on the Gulf of Mexico or in Northeast market areas (Mid-Atlantic market and New England). Those are actual locations presumed by the industry in reality. All the existing LNG terminals built so far except one are locating in the same market areas indicated in the model. The only outliner terminal is located in Alabama, and there is evidence of its struggles on securing reasonable margins in the market space with its LNG supply.

Furthermore, the paper focuses on industry implications by using numerical examples to illustrate impacts of parameters on equilibrium locations and quantities. These impacts are hard to predict or quantify in reality, but it is possible through stylized theoretic model simulations. Through numerical illustration, it implies that market fundamental drivers, like market price responsiveness, long term market outlook, and transportation tariff changes, which all have material influence on the strategic decision of locating regasification terminals. Since the interest of this study is more on the location choice. Hence each scenario simulation focuses more on the impact of the fundamental driver on equilibrium locations of the terminals. It is interesting to observe gradual migration of the location pattern when the variable in study changes from one end of the value range to the other. It reveals the sensitivity and responses in term of terminal location choices for the LNG players in the market.

- When there are uneven tariff increments reflecting market congestion on the pipeline network, firms tend to locate away from congested zones to avoid paying high premium on the transportation, while when there is even tariff increments in a hypothetical setting, the equilibrium locations of terminals are more scattered along the network as firms put more priority to avoid competition from each other.
- When the market responsiveness of incremental supply is identical, in other words, all markets are equally competitive for incremental supply, firms tend to choose to all stay in the market with the highest margin and there is central agglomeration in the equilibrium choice. However, the greater difference in market responsiveness in incremental supply, the greater separation of location choices. That creates two types of approach in choosing locations among players: firms go for the highest margin realized in the market, or firms go for the lowest

costs. In the stylized model here, the two types of approaches leads the firms to locate in two clusters on the network, either near demand centers where the marginal price is highest, or near the production area with lowest operation cost and liquid market.

- When there is difference in cost structure, the firm with a significant cost advantage tends to "crowd out" its rivalry out of the same market location. That firm tends to stay in the market with the largest size, as it optimizes its strategy by supplying much more LNG to the market compared to its competitors and it needs to be in a market with deep liquidity.
- Identical cost structure to the firms cannot guarantee centralized of location choices in equilibrium.
- Outlook of the future market can influence the choice of location as well. When anticipating a much weaker economy and market in medium and long term, firms tend to concentrate to the demand center with the highest margin while abandoning other markets, compared to the stylized baseline model. Interesting, this is what the natural gas market is experiencing since 2008. The gas price has been depressed and the long term outlook of gas has been adjusted down repeatedly, the LNG terminals which are located further from the markets have been struggling in even getting LNG cargos and many of them have been almost empty for months. The only terminals, which make reasonable deliveries, are those located near New England market, supplying gas to New York and Boston, when there is congestion on the pipe originating from the Gulf of Mexico.

This paper aims to create synergy between industrial knowledge and academic research. Although game theory approach has been common in academic research and a lot of other industrial applications, it is refreshing to analyze firm behavior in energy space.

This is not only a game theory model, but also a market analysis research closely relates to the real market. This is a first step to introducing the game theory approach to market analysis work in energy space, and there are many avenues for extension and future researches. One related topic of this LNG citing game is the decision of LNG cargo delivery: when the LNG cargo leaves its liquefaction facility, it does not always end up in its originally contracted destination; instead it may divert to a different location and country when there is a higher bid. The diversion of LNG cargos has been usually studied as a response to arbitrage of market prices between continents. However, it is interesting to look at the diversion decision as a game played by major LNG players in the world, in response to market prices and their future outlooks. Because, including in this paper, we have been assuming the major energy firms are just price takers in the market. This is more realistic in North America market than in European and Asian markets, where the LNG diversions usually happen. So, what if the players do have more strategic intentions of moving their cargos than just simply responding to market demand. That is another example of game theory application in real market issues.

Chapter 3: Tying and Exclusion

3.1. Introduction

Much of the interest in tying arrangements comes from the prominent place that tying law has in antitrust law. Tying arrangements have long been suspect in antitrust courts due to the intuitive potential that they seem to have for foreclosure. For decades, ties have been challenged on some version of a theory that competition in the tied market must be reduced, since those who buy both the tied and the tying products are not available as customers to single product sellers in the tied market.

With the early work of Bowman, lawyers and economists gained a better understanding of why it is that businesses use ties. He pointed out several roles for tying that appear to solve straightforward business problems without involving a foreclosure motive at all. For example, in cases where customers have heterogeneous demands for the tying product, a tying arrangement can be a means of metering usage and engaging in profitable price discrimination. Another example is in quality assurance: by tying service and replacement parts to the initial sale of an item (often by means of warranty requirements) a seller can ensure that the purchaser does not use incompetent service personnel or defective replacement parts.

None of this, however, provides a way of understanding how tying can foreclose competition. Indeed, the so-called Chicago School of law and economics provided a simple demonstration that appeared to show that tying could never foreclose, the famous One Monopoly Rent theorem. Briefly, the theorem assumes that there is a monopolist in the market for a product called A, which also competes as one of many perfect competitors in the market for another product, B. In the A market, all consumers have the same willingness to pay for a unit of A; call it v_A. Under independent pricing of A and B, the monopolist sets the prices of A at v_A and prices at marginal cost in the B market.

Consumer surplus is limited to what can be earned on the B product, since it is fully extracted from A.

If the monopolist (call it Firm 1) ties the sale of B to the purchase of A, consumers still have the option of buying no A and consuming only B. Rationally, Firm 1 will extract enough consumer surplus to keep consumers just indifferent between buying A and B at the tied prices and buying only B, but at a marginal cost price. But this is just the situation that held with independent pricing, so Firm 1 has not gained anything by tying. This is the result of the 1MR: there is no gain to tying. Hence, if tying is observed, it must be for one of the benevolent reasons pointed out by Bowman.

A series of post-Chicago papers by Whinston (1990), Carabajo (1990) and Mathews and Winter (1998) set out conditions under which tying can led to either foreclosure of B market competitors or to a reduction in consumer surplus for consumers who buy both products. Perhaps the most famous of the three is the paper by Whinston. Whinston assumes that the B market is a differentiated products duopoly, and that Firm 1 is one of the duopolists. For my purposes, Whinston's man results are the following. First, Whinston shows that unless Firm 1 can precommit to a tie, tying is never profitable compared to independent pricing. However, if Firm 1 can precommit, it can foreclose competition. This would occur because the tie reduces scale for the single product firm (call it Firm 2), so that it may not be able to cover fixed costs, therefore either exiting the B market or not entering in the first place. The tie would not be profitable, absent exit by Firm2. Carabjo et al obtain a similar result in the case where the B market is Cournot. Matthews and Winter assume that the B market is perfectly competitive with and without the tie. They do not have a result on foreclosure, but are concerned about the consumer effects of tying. They showed that if consumer tastes for A and B are stochastically positively correlated, then tying can be a way of extracting consumer surplus in the A market that Firm 1 cannot otherwise extract, even with two part tariffs. In their setting, tying is profitable.

My model contains elements of both Whinston and Mathewson and Winter. Like Whinston, I assume a duopoly in the B market. Like Mathewson and Winter, I assume that there are some consumers of B who also have a strong preference for A; I assume this group of consumers to be a fraction θ of the total number of B consumers[6]. I assume also that the A and B market have independent demands. This is a simplification, but deserves a word of comment. Many tying situations involves A and B products that are complements, such as a copying machine and ink or paper. Indeed, most of the landmark antitrust cases involving tying are of the type' See for example, *A.B.Dick*[7]and *Jefferson Parish*[8]. However, there are also significant cases in which the tied and tying products had independent demands, such as *Times-Picayune* and *Leow's*[9].To isolate the pure effect of the conditional sale of two product, I will assume that A and B have independent demands.

My goal is to explore some of the issues raised by Whiston regarding pre-commitment and exclusion due to tying. By using a Hotelling framework, I impose much more structure on the problem that does Whiston, who deals with product differentiation at a much more general level. I analyze these issues.

First, what does it mean to say that firm 1 pre-commits to a tie? Does this mean it will charge a particular tied price whether or not firm 2 enters? Or does it mean that it

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[6]*This is a simplification of the Mathewson and Winter, since I do not assume any stochastic elements at the level of individual demands, but it is in the same spirit and gets to the same result if the B market is perfectly competitive.*

[7]*Henry v. A.B.Dick Co*., 224 U.S. 1 (1912)

[8]*Jefferson Parish Hospital District No.2 v. Hyde.*466 U.S. 2 (1984),

[9] See *Times-Picayune Pub'g Co. v. United States* 345 U.S. 594 (1953); *United States v. Loew's, Inc*. 371 U.S. 38 (1962).

will charge a tied price if firm 2 enters, but not otherwise? I will refer to the first type as "unconditional" pre-commitment and the second as "conditional" pre-commitment.

Second, will firm 1 choose one of the other type of pre-commitment? Whiston (1990) asserts that if firm 1 pre-commits to a tying arrangement, it can cause exit or deter entry by firm 2. He does not spell out the conditions under which firm 1 will find optimal to pre-commit.

3.2. MODEL SETUP

3.2.1. Stage Game

Consider the markets for two products - A and B. Assume that A and B have independent demands.

In the market of A, there is a monopoly, firm 1. Firm 1 produces A at a marginal cost of c_A per unit, and charges a two part tariff(E_A, p_A), where E_A is a per customer entry fee in addition to the unit usage price p_A. The market for B is a duopoly – Firm 1 competes with firm 2 and both firms have the same marginal cost of production,c_B. In the absence of tying, each firm charges a two part tariff in the B market at (E_1, p_1) and (E_2, p_2) respectively.

The demand side of market B follows the Hotelling setup: customers are heterogeneous, marked by their location, $t \in [0,1]$, and are uniformly distributed along the unit interval. Without loss of generality, Firm 1 is located at point 0, while Firm 2 is located at point 1. For a customer at location t, there is a disutility of kt when he purchases B from firm 1, and $k(1-t)$ from firm 2, where k is the disutility parameter of not buying of not buying a product that fits the consumer's taste perfectly. Consumer surplus for B is given by $v_B(p)$ and the demand curve for B satisfies $q_B(p) = -v_B^{'}(p)$.

Of the unitary population of customers in market B, there is a $\theta \in (0,1]$ proportion that also values A, with a weakly positive utility $v_A(p)$ and demand curve $q_A(p)$. Similarly, customer demand for A is defined as $q_A(p) = -v_A'(p)$.

3.2.2. Timing

The model proceeds in three stages. In stage 1, firm 1 announces whether or not it will pre-commit to tying, either in the conditional or unconditional sense as defined above. In stage 2, each firm announces whether or not it will enter the B market. In stage 3, entry occurs and firms price accordingly.

This is a game of complete information. Hence, when firm 2 decides whether or not to enter, it has heard firm 1's announcement either to pre-commit or not. At the time each firm sets its price, it knows if the other will enter.

3.2.3. Independent Pricing Regime

3.2.3.1. Third Stage –Profit Maximization

In the B market, firm 1 and 2 are competing according to the duopoly Hotelling model. A customer of type t $\in$ [0,1] who purchases B from firm 1 receives utility $v_B(p_1) - E_1 - kt$. If he purchases from firm 2, his utility is $v_B(p_2) - E_2 - k(1-t)$. A marginal customer is defined as when he is indifferent between the two firms. This customer type is denoted t_0, and his location is given by:

Eqn55:
$$v_B(p_1) - E_1 - kt_0 = v_B(p_2) - E_2 - k(1-t_0)$$
$$t_0 = \frac{1}{2} + \frac{1}{2k}(v_B(p_1) - v_B(p_2) - E_1 + E_2)$$

Firm 1 in market B earns its profit from selling product B to the segment of market zero to the marginal customer t_0, given the two part tariff (p_1, E_1):

Eqn56:
$$\pi_{1B} = \left[(p_1 - c_B)q_B(p_1) + E_1\right]t_0$$

And firm 2's in market B is defined by selling product B to the rest of the market from marginal customer t_0 to 1:

Eqn57: $$\pi_2 = [(p_2 - c_B)q_B(p_2) + E_2](1 - t_0)$$

For market A, given θportion of customers in B market also values product A. Assuming that such customers are uniformly distributed on [0, 1], firm 1's monopolistic profit under independent pricing regime is:

Eqn58: $$\pi_{1A} = \theta \cdot [(p_A - c_A) \cdot q_A(p_A) + E_A]$$

Therefore, the goal of firm 1 is to maximize the sum of profits from both market A and B:

Eqn59: $$\underset{E_A, p_A, E_1, p_1}{\text{Max}} \; [(p_A - c_A)q_A(p_A) + E_A] \cdot \theta + [(p_1 - c_B)q_B(p_1) + E_1] \cdot t_0$$
$$s.t. v_A(p_A) - E_A \geq 0$$

Firm 2 maximizes its B market profits

Eqn60: $$\underset{E_2, p_2}{\text{Max}} [(p_2 - c_B)q_B(p_2) + E_2] \cdot (1 - t_0)$$

<u>Theorem 1</u>

The optimal tariffs for firm 1 and 2 in the B market under independent pricing are symmetric and defined as:

firm 1: $\left(E_1^*, p_1^*\right) = \left(k, c_B\right)$

firm 2: $\left(E_2^*, p_2^*\right) = \left(k, c_B\right)$

The marginal consumer t_0 in market B is always $\frac{1}{2}$:

Eqn61: $$t_0 = \frac{1}{2} + \frac{1}{2k}\left(v_B(c_B) - E_1 - v_B(c_B) + E_2\right) = \frac{1}{2}$$

The firm 1 gains the maximum profit from each customer in market A as the monopoly:

Eqn62: $$\left(E_A^*, p_A^*\right) = \left(v_A(c_A), c_A\right)$$

For the detailed algebra, please refer to the Appendix 1.

3.2.3.2. The Second Stage- Entry Decision

The entry decision is determined by the expected equilibrium profits in the last stage. From Theorem 1, the third stage Nash equilibrium profits for both firms under independent pricing are:

Eqn63: $$\begin{aligned}\pi_1(c_A, v_A(c_A), c_B, k) &= \left[(c_A - c_A)q_A(c_A) + v_A(c_A)\right]\cdot\theta + \left[(c_B - c_B)q_B(c_B) + k\right]\cdot\frac{1}{2} \\ &= v_A(c_A)\cdot\theta + \frac{k}{2}\end{aligned}$$

The profit for firm 2 under independent pricing is:

Eqn64: $$\pi_2(c_B, k) = \left[(c_B - c_B)q_B(c_B) + k\right]\cdot(1 - \frac{1}{2}) = \frac{k}{2}$$

Assume that k is large enough here that the profit for both firms are at least as big as the sunk entry costs, both firms always choose to enter in the second stage, and play the Nash equilibrium outcome in the third stage. Therefore, under independent pricing regime this is the unique Subgame Perfect Nash Equilibrium (SPNE).

3.2.4. Tied Pricing

3.2.4.1. Third Stage – Equilibrium Prices

At the third stage upon entry, under tied pricing, consider the two types of customers: the ones who value A, and the others who do not. In the 1-θ share of the population which does value A, the marginal customer is defined the same way as in independent pricing case, and is denoted t_0:

Eqn65:
$$\begin{aligned} & v_B(p_1)-E_1-kt_0=v_B(p_2)-E_2-k(1-t_0) \\ & \Rightarrow t_0=\frac{1}{2}+\frac{1}{2k}\left(v_B(p_1)-v_B(p_2)-E_1+E_2\right) \end{aligned}$$

In the θ share of the population which values A, the marginal customer, denoted t_1, is defined as being indifferent between purchasing both A and B from firm 1 and purchasing only B from firm 2:

Eqn66:
$$\begin{aligned} & v_B(p_1)+v_A(p_A)-E_1-kt_1=v_B(p_2)-E_2-k(1-t_1) \\ & \Rightarrow t_1=\frac{1}{2}+\frac{1}{2k}\left(v_B(p_1)+v_A(p_A)-v_B(p_2)-E_1+E_2\right) \end{aligned}$$

There are two scenarios for customers who purchase from firm 1: one who values both A and B and chooses to purchase from firm 1 for both A and B, with market share of θt_1; and others who only value B and still choose to purchase only product B from firm 1, with market share of $(1-\theta)t_0$.

Hence, the profit for firm 1 is defined under tied pricing:

Eqn67:

$$\underset{p_A,E_1,p_1}{\text{Max}}\left[(p_A-c_A)q_A(p_A)+(p_1-c_B)q_B(p_1)+E_1\right]\cdot\theta t_1+\left[(p_1-c_B)q_B(p_1)+E_1\right](1-\theta)t_0$$

Similarly, there are two scenarios for customers who purchase from firm 2: ones who value both A and B, but choose to give up product A and purchase only B from firm 2, defined as $\theta(1-t_1)$; and others who only value B, and choose to purchase B from firm 2, defined as $(1-\theta)\cdot(1-t_0)$. So, profit for firm 2 is defined as:

Eqn68: $$\underset{E_2,p_2}{\text{Max}}\left[(p_2-c_B)q_B(p_2)+E_2\right]\cdot\left(\theta(1-t_1)+(1-\theta)(1-t_0)\right)$$

Initially, assume that $(t_0,t_1)\in(0,1)$, i.e., that neither marginal consumers can be at a boundary of the unit interval.

The only closed form solution here are $p_1^* = p_2^* = c_B$. For θ<1, there is no closed solution for price of p_A^*. p_A^* satisfies the following condition[10]:

Eqn69: $$q_A(p_A^*)\cdot\frac{\theta}{2k}\left[(p_A^*-c_A)q_A(p_A)+E_1(p_A^*)\right]=\theta t_1(p_A^*)\left[(p_A^*-c_A)q'_A(p_A^*)+q_A(p_A^*)\right]$$

The entry fees can be written in fairly simple functions of p_A^*

Eqn70: $$\begin{cases} E_1 = k+\frac{\theta}{3}v_A(p_A)-\frac{2}{3}\theta(p_A-c_A)q_A(p_A) \\ E_2 = k-\frac{\theta}{3}v_A(p_A)-\frac{1}{3}\theta(p_A-c_A)q_A(p_A) \end{cases}$$

From the definitions of $t_0$and t_1, firm 1's total market share for product B can be written as:

Eqn71:

$$\begin{aligned}\theta t_1+(1-\theta)t_0 &= \theta\left\{\frac{1}{2}+\frac{1}{2k}\left(v_B(p_1)+v_A(p_A)-v_B(p_2)-E_1+E_2\right)\right\}+(1-\theta)\left\{\frac{1}{2}-\frac{1}{2k}\left(v_B(p_1)-v_B(p_2)-\right.\right. \\ &= \frac{1}{2}+\frac{1}{2k}(E_2-E_1)+\frac{\theta v_A(p_A)}{2k}\end{aligned}$$

$$q_A(p_A^*)\cdot\frac{\theta}{2k}\left[(p_A^*-c_A)q_A(p_A)+E_1(p_A^*)\right]=\theta t_1(p_A^*)\left[(p_A^*-c_A)q'_A(p_A^*)+q_A(p_A^*)\right]$$

$t_0$andt_1 can be written as:

---

[10]When θ=1, it implies $p_A^* = c_A$.

Eqn72:
$$t_1 = \frac{1}{2} + \frac{1}{2k}\left[v_A(p_A)\left(1 - \frac{2}{3}\theta\right) + \frac{\theta}{3}(p_A - c_A)q_A(p_A) \right]$$
$$t_0 = \frac{1}{2} + \frac{1}{2k}\left[-\frac{2}{3}\theta v_A(p_A) + \frac{\theta}{3}(p_A - c_A)q_A(p_A) \right]$$
$$t_1 - t_0 = \frac{1}{2k} v_A(p_A)$$

Note that so far, I have assumed $(t_0, t_1) \in (0,1)$. However, there may be binding boundary constraints on these endogenous variables. In particular I have the following possibilities: Either t_0 or t_1 or both could be at the end points of $[0,1]$.

3.2.4.2. Special Case: $t_1 = 1$

If the marginal consumer for the population that prefers both A and B is bounded at 1, this implies:

Eqn73:
$$t_1 = \frac{1}{2} + \frac{1}{2k}\left[v_A(p_A)\left(1 - \frac{2}{3}\theta\right) + \frac{\theta}{3}(p_A - c_A)q_A(p_A) \right] \geq 1$$

The function of t_1 is at or outside of the boundary value of 1. Therefore the actual marginal customer will be constrained. Denote the constrained value of t_1 by $\bar{t}_1 = 1$. Given the constraint $\bar{t}_1 = 1$, firm 1 must still choose two part tariffs. These variables are denoted as $p_{A,\bar{t}_1}, p_{1,\bar{t}_1}, E_{1,\bar{t}_1}$; while $E_{2,\bar{t}_1}, p_{2,\bar{t}_1}$ denotes the decision variable for firm 2 in this bounded scenario. Hence, the profit optimization problem for both firms becomes:

Eqn74:
$$\underset{p_{A,\bar{t}_1}, E_{1,\bar{t}_1}, p_{1,\bar{t}_1}}{\text{Max}} \left[(p_{A,\bar{t}_1} - c_A)q_A(p_{A,\bar{t}_1}) + (p_{1,\bar{t}_1} - c_B)q_B(p_{1,\bar{t}_1}) + E_{1,\bar{t}_1} \right] \cdot \theta$$
$$+ \left[(p_{1,\bar{t}_1} - c_B)q_B(p_{1,\bar{t}_1}) + E_{1,\bar{t}_1} \right](1-\theta)t_{0,\bar{t}_1}$$

$$\underset{E_{2,\bar{t}_1}, p_{2,\bar{t}_1}}{\text{Max}} \left[(p_{2,\bar{t}_1} - c_B)q_B(p_{2,\bar{t}_1}) + E_{2,\bar{t}_1} \right] \cdot \left(\theta + (1-\theta)(1 - t_{0,\bar{t}_1}) \right)$$

The optimal solutions for this profit optimization are:

Eqn75: $$p_{1,\bar{t}} = p_{2,\bar{t}} = c_B;$$
$$E_{1,\bar{t}} = k + \frac{4k}{3}\frac{\theta}{1-\theta}; E_{2,\bar{t}} = k + \frac{2k}{3}\frac{\theta}{1-\theta}$$
$$p_{A,\bar{t}} : (p_{A,\bar{t}} - c_A) q'_A(p_{A,\bar{t}}) + q_A(p_{A,\bar{t}}) = 0$$

In this case, since $\bar{t}_1 = 1$, that implies all consumers who values both A and B, purchases from firm 1. Given that condition, it turns out that the marginal consumer for population which only values B will be:

Eqn76: $$t_{0,\bar{t}_1} = \frac{1}{2} - \frac{\theta}{3(1-\theta)}$$

Since $t_{0,\bar{t}_1}$ has to be greater or equal to zero, so as long as $\theta < \frac{3}{5}$, the marginal consumer $t_{0,\bar{t}_1}$ is valid. When $\theta \geq \frac{3}{5}$, there is no PSE outcome.

3.2.4.3. Special Case: $t_0 = 0$

This is another special case, when the B-only marginal consumer for the population is zero or negative. In this case, the value of function of t_0 is zero or below, given the solved price of A:

Eqn77: $$t_0 = \frac{1}{2} + \frac{1}{2k}\left[-\frac{2}{3}\theta v_A(p_A) + \frac{\theta}{3}(p_A - c_A)q_A(p_A)\right] \leq 0$$

Denote by $\underline{t_0} = 0$, the constrained value of t_0. In this case, the population which values only B only buys only from firm 2.

Given $\underline{t_0} = 0$, firm 1 and firm 2's optimization problems are written as:

Eqn78: $$\underset{p_{A,\underline{t_0}}, E_{1,\underline{t_0}}, p_{1\underline{t_0}}}{\text{Max}} \left[(p_{A,\underline{t_0}} - c_A) q_A(p_{A,\underline{t_0}}) + (p_{1,\underline{t_0}} - c_B) q_B(p_{1,\underline{t_0}}) + E_{1,\underline{t_0}}\right] \cdot \theta t_{1,\underline{t_0}}$$

Eqn79: $$\underset{E_{2,\underline{t}_0},p_{2,\underline{t}_0}}{\text{Max}}\left[(p_{2,\underline{t}_0}-c_B)q_B(p_{2,\underline{t}_0})+E_{2,\underline{t}_0}\right]\cdot\left(\theta t_{1,\underline{t}_0}+(1-\theta)\right)$$

The optimal solutions for the usage charges are:

Eqn80: $$p_{1,\underline{t}_0}=p_{2,\underline{t}_0}=c_B;\ p_{A,\underline{t}_0}=c_A$$

The marginal consumer, for population which values A and B under this case is solved as below, which leads to a value greater than 1 in all cases:

Eqn81: $$t_{1,\underline{t}_0}=\frac{3}{2}+\frac{\theta}{1-\theta}+\frac{1}{2k}v_A(c_A)>1$$

Therefore for $\underline{t}_0=0$, it is necessary that t_1 is bounded at 1. This, however, is impossible. Because when both marginal consumers are constrained at their boundary values, $\underline{t}_0=0$ and $\bar{t}_1=1$, the profit maximization problems for both firms become:

Eqn82: $$\underset{p_{A,\underline{t}_0,\bar{t}_1},E_{1,\underline{t}_0,\bar{t}_1},p_{1,\underline{t}_0,\bar{t}_1}}{\text{Max}}\left[(p_{A,\underline{t}_0,\bar{t}_1}-c_A)q_A(p_{A,\underline{t}_0,\bar{t}_1})+(p_{1,\underline{t}_0,\bar{t}_1}-c_B)q_B(p_{1,\underline{t}_0,\bar{t}_1})+E_{1,\underline{t}_0,\bar{t}_1}\right]\cdot\theta$$

Eqn83: $$\underset{E_{2,\underline{t}_0,\bar{t}_1},p_{2,\underline{t}_0,\bar{t}_1}}{\text{Max}}\left[(p_{2,\underline{t}_0,\bar{t}_1}-c_B)q_B(p_{2,\underline{t}_0,\bar{t}_1})+E_{2,\underline{t}_0,\bar{t}_1}\right]\cdot(1-\theta)$$

From the first order condition with respect to E_1:

Eqn84: $$\frac{\partial\pi_1}{\partial E_{1,\underline{t}_0,\bar{t}_1}}=\theta>0$$

Which is inconsistent with a PSE. Therefore, $\underline{t}_0=0$ cannot occur in a PSE.

3.2.4.4. A Special Case:θ = 1

If θ= 1, the third stage equilibrium has a particularly simple form. Every customer in market B values A too, and chooses either purchasing both A and B from firm 1, or purchasing only B (giving up product A) from firm 2. In other words, Firm 1's profit becomes:

Eqn85: $$\max_{E_A, p_A, E_1, p_1} \left[(p_A - c_A)q_A(p_A) + (p_1 - c_B)q_B(p_1) + E_1\right]t_1$$

Firm 2's profit becomes:

Eqn86: $$\max_{E_2, p_2} \left[(p_2 - c_B)q_B(p_2) + E_2\right]\cdot(1 - t_1)$$

There are closed solutions for this special case:

Eqn87: $$p_1^* = p_2^* = c_B$$
$$E_1^* = k + \frac{v_A(c_A)}{3};\ E_2^* = k - \frac{v_A(c_A)}{3}$$
$$p_A^* = c_A$$

These equilibrium prices have the interesting implication that firm 2 can be forced out of business even if it has zero fixed costs. From E_2^*, the profit for firm 2 from one consumer is $E_2^* = k - \frac{v_A(c_A)}{3}$. Hence if $k < \frac{v_A(c_A)}{3}$, firm 2 makes a negative profit. Intuitively, each consumer gets a surplus of $\frac{2}{3}\left(\frac{v_A(c_A)}{3}\right)$ if he or she buys from firm 1 and consumes A. To attract the marginal consumer, firm 2 must compensate for the loss of utility from A. Hence, E_2^* must be lower than E_1^* by the amount of the loss consumer surplus from A, namely $\frac{2}{3}\left(\frac{v_A(c_A)}{3}\right)$. Therefore, if $E_1^* = k + \frac{v_A(c_A)}{3}$, E_2^* must be $k - \frac{v_A(c_A)}{3}$.

3.2.4.5. Second Stage – Entry Decision

It is easy to calculate equilibrium profits in closed form when $\theta = 1$, but not for other cases, because there is no closed form solution for the unit price of product A. However, it is possible to show that firm 1 will always earn positive profit under a tied pricing regime. So, in the second stage, firm 1 will always choose to enter. For firm 2, as discussed in the third stage competition, when entry fee of firm 2 is positive, firm 2 will choose to enter in second stage. However, when firm 2's entry fee is negative under tied pricing regime in equilibrium, firm 2 will have negative profit. Hence, it is rational for firm 2 to choose to not enter in the second stage.

3.2.4.6. No Entry by Firm 2

Under the tied pricing in the third stage, when the entry fee of firm 2 becomes negative, firm 2 chooses to stay out of the last stage of the game completely. If firm 1 has made a conditional pre-commitment in stage 1 and if E_2^*<0 in third stage, entry is deterred, and this leaves firm 1 as monopoly in both A and B markets. Then, firm 1 will set separate two part tariff for both markets. Profit maximization of market A is done independently of B, and extracts $v_A(c_A)$ fully, while firm 1 gets to choose whether serves the whole market B or not:

Eqn88:
$$\begin{aligned}&\underset{\tilde{t}_1,\tilde{E}_1,\tilde{p}_1}{\text{Max}}\left[(\tilde{p}_1-c_B)q_B(\tilde{p}_1)+\tilde{E}_1\right]\theta\tilde{t}_1\\&s.t.\,v_B(\tilde{p}_1)-\tilde{E}_1-k\tilde{t}_1\ge 0\\&\quad\tilde{t}_1\le 1\end{aligned}$$

With the participation constrain for consumers in market B, as well as the constrain on the marginal consumer in market B, the profit maximization for firm 1 in market B can be written as a Lagrangian:

Eqn89:
$$L=\left[(\tilde{p}_1-c_B)q_B(\tilde{p}_1)+\tilde{E}_1\right]\theta\tilde{t}_1+\lambda\left[v_B(\tilde{p}_1)-\tilde{E}_1-k\tilde{t}_1\right]+\mu\left(1-\tilde{t}_1\right)$$

Once again, firm charges a per unit price at the marginal cost:

Eqn90: $\tilde{p}_1 = c_B$

And the marginal customer in market B is:

Eqn91: $\tilde{t}_1 = \dfrac{v_B(\tilde{p}_1) - \tilde{E}_1}{k}$

There are two cases from this point, firm 1 has two choices: if it is serving less than all of market B, then optimal entry fee is:

Eqn92: $\tilde{E}_1 = \dfrac{1}{2} v_B(c_B)$

This allows us to write $\tilde{t}_1$ as:

Eqn93: $\tilde{t}_1 = \dfrac{v_B(\tilde{p}_1) - \tilde{E}_1}{k} = \dfrac{v_B(c_B) - \frac{1}{2} v_B(c_B)}{k} = \dfrac{1}{2k} v_B(c_B)$

When $\dfrac{1}{2k} v_B(c_B) < 1$, the case exists. Note that consumers of B makes positive consumer surplus in this case. Otherwise, it contradicts with $\tilde{t}_1 < 1$.

The other case is when firm chooses $\tilde{t}_1 = 1$, and that implies that the entry fee for firm 1 is:

Eqn94: $\tilde{E}_1 = v_B(c_B) - k$

In the market A, firm 1 will charge the monopoly pricing, as it did under independent pricing, charging $p_A^* = c_A$ and $E_A^* = v_A(c_A)$.

3.2.4.7. Summary of Stage 3 Equilibrium Results under Tied Pricing

Given the discussion on tied pricing regimes with several boundary scenarios, I have concluded all the possible cases. The results are summarized below:

Theorem 2

Case 1. $t_1 \in (0,1)$ and $t_0 \in (0,1)$:

The optimal strategies are defined as:

$$p_1^* = p_2^* = c_B;$$

$$\begin{cases} E_1 = k + \frac{\theta}{3} v_A(p_A) - \frac{2}{3}\theta(p_A - c_A) q_A(p_A) \\ E_2 = k - \frac{\theta}{3} v_A(p_A) - \frac{1}{3}\theta(p_A - c_A) q_A(p_A) \end{cases}$$

$$t_1 = \frac{1}{2} + \frac{1}{2k}\left[v_A(p_A^*)\left(1 - \frac{2}{3}\theta\right) + \frac{\theta}{3}(p_A^* - c_A) q_A(p_A^*) \right]$$

$$t_0 = \frac{1}{2} + \frac{1}{2k}\left[-\frac{2}{3}\theta v_A(p_A^*) + \frac{\theta}{3}(p_A^* - c_A) q_A(p_A^*) \right]$$

If θ<1, price of A has no closed form and defined by the following equation:

$$q_A(p_A^*) \cdot \frac{\theta}{2k}\left[(p_A^* - c_A) q_A(p_A^*) + E_1(p_A^*) \right] = \theta t_1(p_A^*)\left[(p_A^* - c_A) q'_A(p_A^*) + q_A(p_A^*) \right]$$

If θ = 1, then $p_A = c_A$;

$$p_1^* = p_2^* = c_B$$

$$E_1^* = k + \frac{v_A(c_A)}{3};\ E_2^* = k - \frac{v_A(c_A)}{3}$$

$$p_A^* = c_A$$

1.1. When θ = 1 and k≥$\frac{v_A(c_A)}{3}$, both firms choose to enter and third stage they compete and reach the equilibrium as defined above.

1.2. When $\theta = 1$ and $k<\frac{v_A(c_A)}{3}$, then firm 2 will be earning negative profit in the third stage game. Therefore, in second stage, only firm 1 chooses to enter. Firm 1 becomes a monopoly in both markets in third stage, and will choose to serve either the whole market of B or part of B, depending on the underlying parameters.

1.3. When $\theta<1$, there is no closed form for third stage competition, and the entry decision of firm 2 depends on the endogenous variable E2. When $E_2 \geq 0$, both firms choose to enter and compete. When $E_2<0$, then firm 2 will choose not to enter and firm 1 becomes a monopoly in both markets in third stage.

Case 2. $t_1 = 1$:

2.1 .When $\theta < \frac{3}{5}$:

$$p_{1,\bar{t}} = p_{2,\bar{t}} = c_B;$$

$$E_{1,\bar{t}} = k + \frac{4k}{3}\frac{\theta}{1-\theta}; E_{2,\bar{t}} = k + \frac{2k}{3}\frac{\theta}{1-\theta}$$

$$p_{A,\bar{t}} \text{ solves } (p_{A,\bar{t}} - c_A)q'_A(p_{A,\bar{t}}) + q_A(p_{A,\bar{t}}) = 0$$

$$t_{0,\bar{t}} = \frac{1}{2} - \frac{\theta}{3(1-\theta)}$$

2.1 .When $\theta \geq \frac{3}{5}$: There exists no PSEs in the third stage.

Case 3. $t_0 = 0$:

There exists no PSEs in the third stage, as t_1 >1 always.

Since most of these conditions are defined by endogenous functions of multiple parameters, it is hard to visualize when different types of SPNEs exists. Next, I use

Matlab to construct the space for the existence of different type of SPNEs in order for a better visualization to describe the results from theorem 2.

There are three conditions which determine the equilibrium outcomes jointly:

Eqn95:

$$t_1 \leq 1$$
$$\Rightarrow f_1 : \frac{1}{2} - \frac{1}{2k}\left[v_A(p_A^*)\left(1 - \frac{2}{3}\theta\right) + \frac{\theta}{3}(p_A^* - c_A)q_A(p_A^*) \right] \geq 0$$
$$t_0 \geq 0$$
$$\Rightarrow f_2 : \frac{1}{2} + \frac{1}{2k}\left[-\frac{2}{3}\theta v_A(p_A^*) + \frac{\theta}{3}(p_A^* - c_A)q_A(p_A^*) \right] \geq 0$$
$$E_2 \geq 0$$
$$\Rightarrow f_3 :\ k - \frac{\theta}{3} v_A(p_A^*) - \frac{1}{3}\theta(p_A^* - c_A)q_A(p_A^*)$$

Note that it is true for all cases (including boundary scenarios) that firm 1 and 2 are going to charge at the marginal cost of product B as unit price in market B, and all three endogenous conditions above are independent of the demand parameters of product B and production cost of B. Instead they depend on the demand and production parameters of product A, as well as the transportation cost k and the share θ of the population that values A and B.

So, I will proceed through an example. Suppose demand of A and B, as well as marginal cost of B are defined as follows:

Eqn96:

$$q_A(p) = 24 - 5p$$
$$q_B(p) = 25 - 4p$$
$$c_B = 2$$

Then I narrow the varying parameters down to $\theta, k and c_A$. For each given θ, all three functions are defined as contour curves in the space of (c_A, k), and the existence and characteristics of PSEs can be described as some type of intersection of these conditions.

Here I have listed five consecutive charts which displace the contour curves for the following three functions as θ varies from 0.2 to 1.

The areas that have PSEs are colored and different color represents different type of PSEs, described in Theorem 2.

1. Firm 2 not enter and firm 1 behaves as a monopoly (Blue)
2. Firm 2 enters, and PSEs exists for non-boundary values of marginal customers (Yellow)
3. Firm 2 enters, and PSE exists for only when $t_1 = 1$ and $t_0 > 0$ (Green – only occurs$When\theta < \frac{3}{5}$)
4. Firm 2 enters and no PSE exists (Purple)

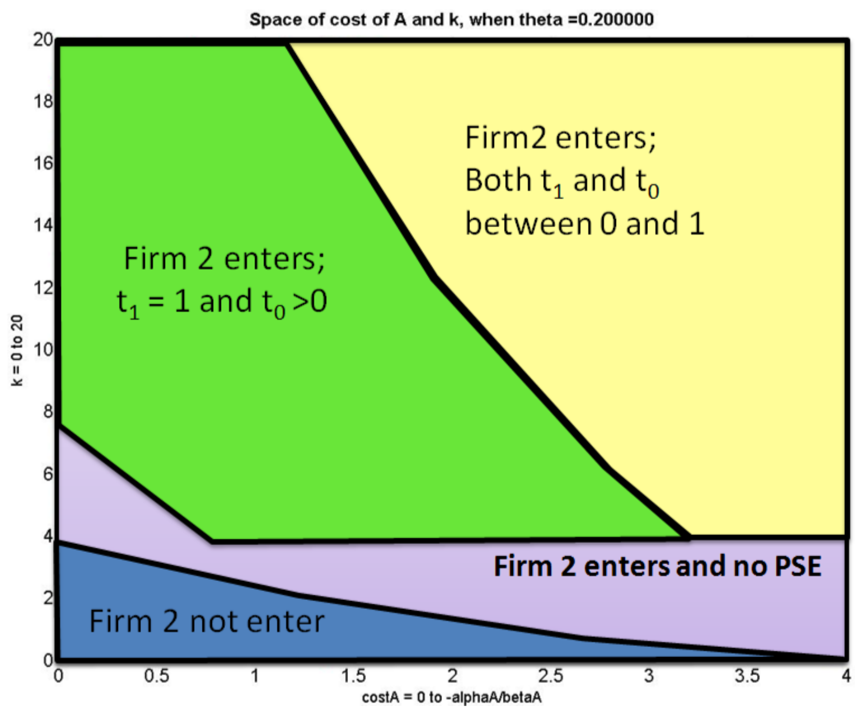

Figure 20: Equilibrium Space when θ = 0.2

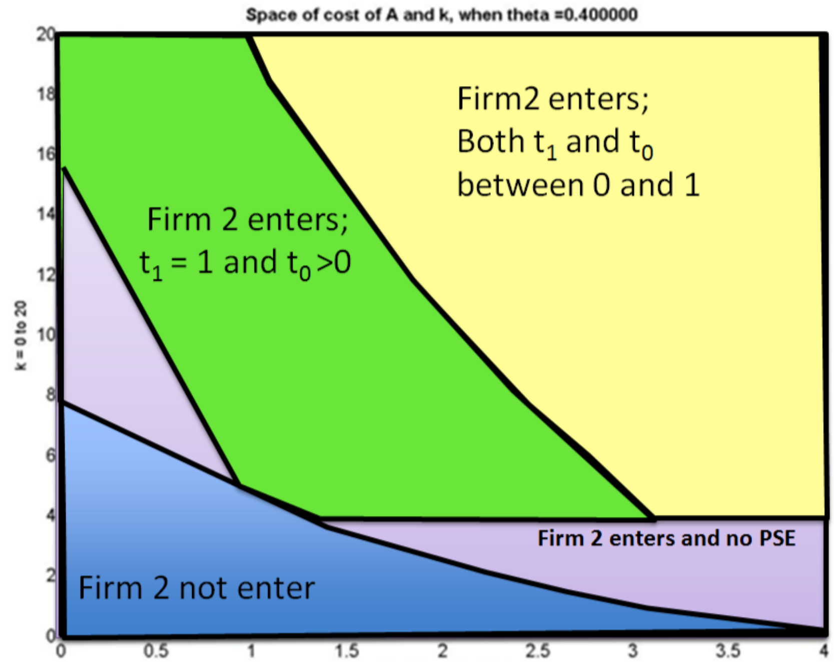

Figure 21: Equilibrium Space when θ = 0.4

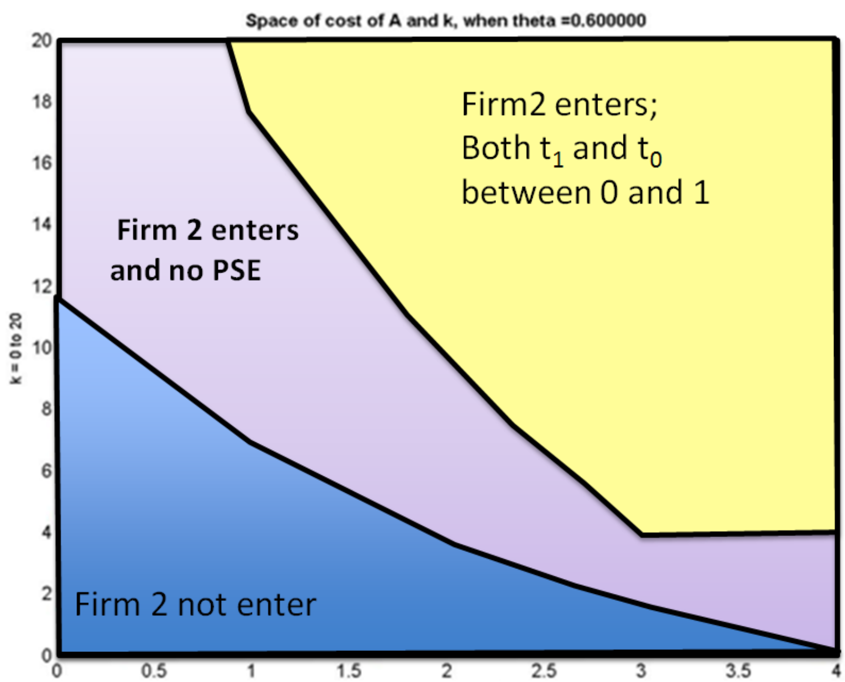

Figure 22: Equilibrium Space when θ = 0.6

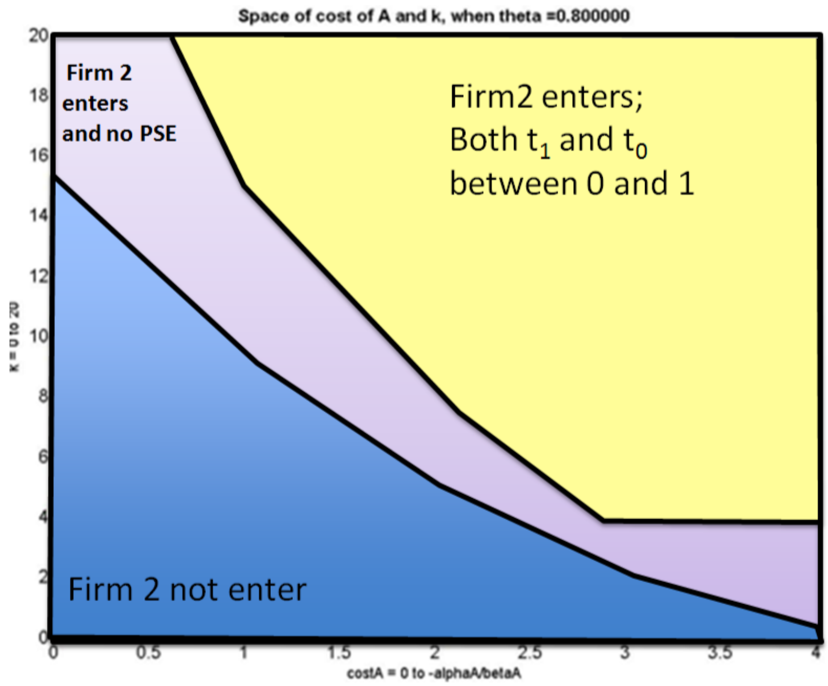

Figure 23: Equilibrium Space when $\theta = 0.8$

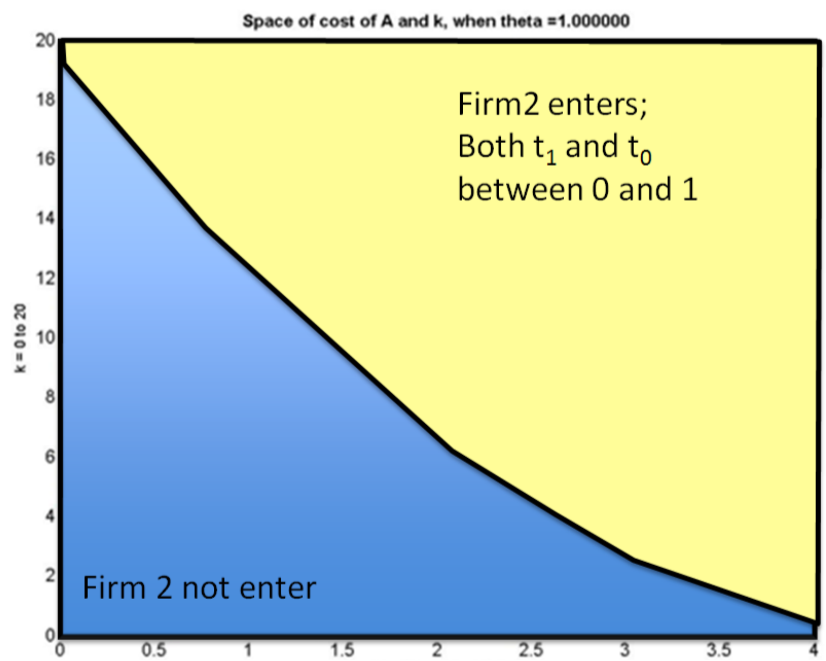

Figure 24: Equilibrium Space when $\theta = 1$

I conclude from this that the possiblity of tied pricing can deter entry even without the positive fixed costs, as emphasized by Whiston. If entry does occur, firm 1 may still monopolize the market for consumers who values both A and B.

3.2.5. Comparison of Independent and Tied Pricing Regimes

The Nash equilibrium profits for both firms under independent pricing are:

Eqn97:

$$\pi_1(p_A^*, E_A^*, p_1^*, E_1^*) = \pi_1(c_A, v_A(c_A), c_B, k) = \left[(c_A - c_A)q_A(c_A) + v_A(c_A)\right]\cdot\theta + \left[(c_B - c_B)q_B(c_B) + k\right]\cdot\frac{1}{2}$$

$$= v_A(c_A)\cdot\theta + \frac{k}{2}$$

The profit for firm 2 under independent pricing is:

Eqn98: $$\pi_2(p_2^*, E_2^*) = \pi_2(c_B, k) = \left[(c_B - c_B)q_B(c_B) + k\right]\cdot(1 - \frac{1}{2}) = \frac{k}{2}$$

For the profit under tied pricing, it is easy to calculate the closed form expression when $\theta = 1$:

Eqn99: $$\pi_1(p_A^*, p_1^*, E_1^*) = \left[(p_A^* - c_A)q_A(p_A^*) + (p_1^* - c_B)q_1(p_1^*) + E_1^*\right]\cdot t_1$$

$$= \left[(c_A - c_A)q_A(c_A) + (c_B - c_B)q_1(c_B) + k + \frac{1}{3}v_A(c_A)\right]\cdot\left[\frac{1}{2} + \frac{\frac{1}{3}v_A(c_A)}{2k}\right]$$

$$= \frac{\left[k + \frac{1}{3}v_A(c_A)\right]^2}{2k}$$

Eqn100:

$$\pi_2(p_2^*, E_2^*) = \left[(p_2^* - c_2)q_2(p_2^*) + E_2^*\right] \cdot (1 - t_1)$$

$$if\ k \le \frac{1}{3}v_A(c_A)$$

$$E_2^* \le 0\ and\ \pi_2(p_2^*, E_2^*) \le 0$$

$$if\ k > \frac{1}{3}v_A(c_A)$$

$$= \left[(c_B - c_B)q_2(c_B) + k - \frac{1}{3}v_A(c_A)\right] \cdot \left[\frac{1}{2} - \frac{\frac{1}{3}v_A(c_A)}{2k}\right]$$

$$= \frac{\left[k - \frac{1}{3}v_A(c_A)\right]^2}{2k}$$

For θ<1, there is no closed form solution. Therefore, I use Matlab to calculate the numeric value of equilibrium strategies and profits when there exists a pure strategy equilibrium, based on the discussion in previous section.

However, for θ=1, it is easy to show that profit under independent pricing for firm 1 exceeds that under tying.

Eqn101:

$$\pi_1(p_A^*, E_A^*, p_1^*, E_1^*) - \pi_1(p_A^*, p_1^*, E_1^*)$$

$$= v_A(c_A) + \frac{k}{2} - \frac{\left[k + \frac{1}{3}v_A(c_A)\right]^2}{2k}$$

$$= v_A(c_A)\left(\frac{2}{3} - \frac{v_A(c_A)}{18k}\right)$$

Since tying only occurs when firm 2 enters, it implies $k > \frac{1}{3}v_A(c_A)$. When $k > \frac{1}{3}v_A(c_A)$, $\frac{2}{3} - \frac{v_A(c_A)}{18k}$>0 and tying is less profitable compared to independent pricing.

3.3. Simulation Examples

Assume a set of parameters for both markets:

$$q_A(p) = 24 - 5p$$
$$q_B(p) = 25 - 4p$$
$$c_A = 3$$
$$c_B = 2$$

Then, in order to learn about the characteristics of the equilibria, I calculate equilibrium prices under both independent and tied pricing regimes based on varying k and θ. The following chart shows the change in profit of firm 1 from both A and B markets when switching from independent pricing to tied pricing.

Here, I am going to focus on the general case (case 1.1.) where the PSE exists: where both marginal consumers t_1 and t_0 are both less than 1 and greater than zero, and the entry fee for firm 2 is greater than zero. Note that all points plotted in the following charts represent the cases with existence of PSEs. All scenarios that lie beyond the conditions of general case PSE (described in case 1.1.), are omitted here.

First, the optimal price of p_A appears to be a nonlinear function of k and θ. The smaller θ is, the farther p_A is from the marginal cost, but closer to the monopolistic price of A (if there is no entry fee of A under independent pricing). With smaller θ, firm 1 has a lower entry fees and tries to increase the profit in market A mainly through its unit price p_A. With larger θ, firm 1 takes advantage of its leverage with larger A-and-B population, so it translates the increased leverage mainly through its entry fee under tied pricing, while keeping the marginal price level lower.

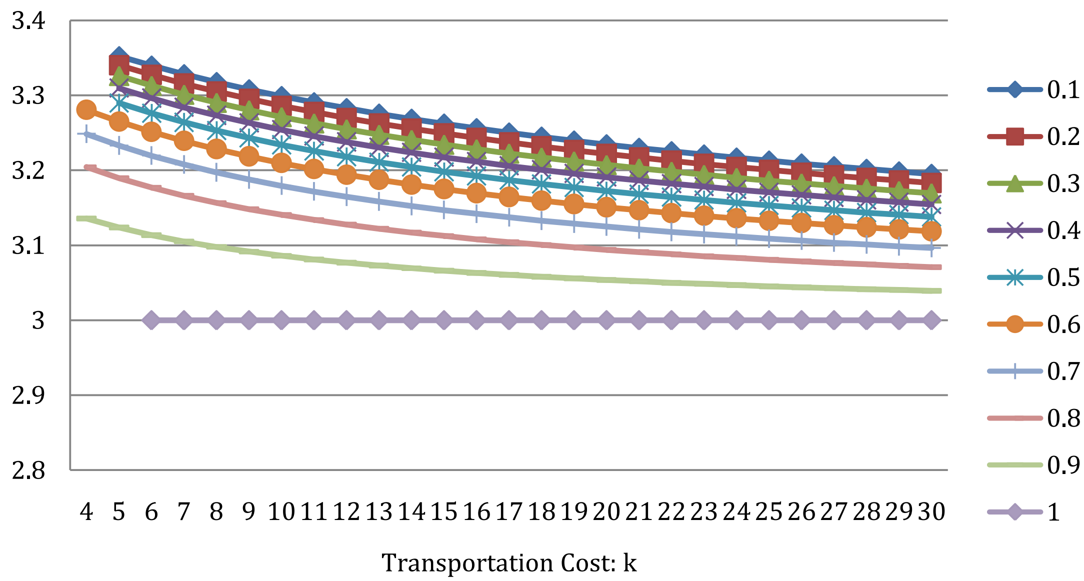

Figure 25: Equilibrium Price of A

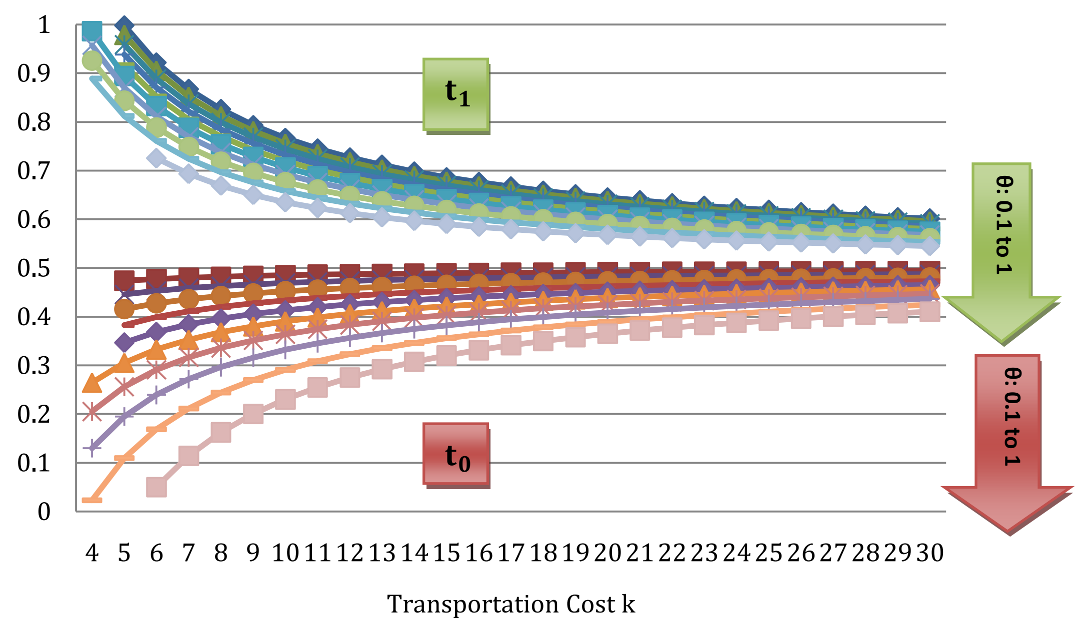

Figure 26: Equilibrium Values for Marginal Consumers t_0 and t_1

For a profit comparison, the following chart reveals an interesting observation: tied pricing is not as profitable as independent pricing in all these scenarios, when there are PSEs.

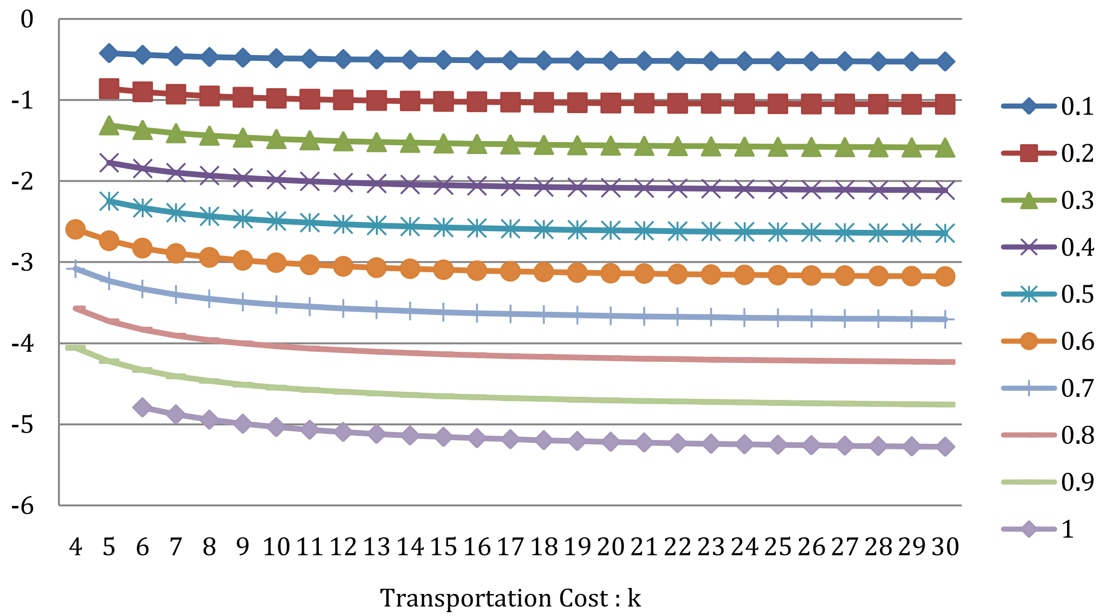

Figure 27: Change in Firm 1's profit under tying compared to independent pricing

3.4. Subgame Equilibrium Path

From the discussion above, firm 1 makes positive profits in all Subgame of stage 3, so it will certainly choose to enter in stage 2. In stage 2, firm 2 will not enter, given a conditional tying pre-commitment by firm 1, only if its optimal entry fee in the last stage is negative. Otherwise, firm 2 enters, regardless of any stage 1 announcement by firm 1. If the equilibrium entry fee for firm 2 is going to be positive under tying, firm 1 will never pre-commit to tying because it is pointless. Given that firm 2 will enter no matter what, firm 1 does better with independent pricing in stage 3. If the equilibrium entry fee for firm 2 is negative under tying, a conditional pre-commitment to tying conditional on firm 2's entry will effectively deter entry, leaving firm 1 to act as a monopolist over A and B.

A moment's thought shows firm 1 will never pre-commit unconditionally if it can pre-commit conditionally. Therefore the Subgame perfect equilibrium path of the 3 stage game is as follows:

1. If θ = 1 and k≥$\frac{v_A(c_A)}{3}$, there is no pre-commitment by firm 1. Entry occurs by both firms and firm 1 prices independently for A and B.
2. If θ = 1 and k<$\frac{v_A(c_A)}{3}$, firm 1 conditionally pre-commits to tying upon firm 2' s entry. Entry is deterred and firm 1 prices as a monopolist in A and B.
3. If θ <1 , there is no closed form for equilibrium entry fee of firm 2 in the third stage. The PSE equilibria are described by the equilibrium maps.

3.5. CONCLUSION

Whinston's classic paper on tying showed economists, one way of reconciling the possibility of exclusionary tying with the one monopoly rent theorem. In this essay, I specified Whinston's differentiated products model to the Hotelling case and then obtain sharper results on the relationship between pre-commitment to tying and the exclusion of a single product firm.

My principal results are:

- The firm 2 can be excluded even if it has zero fixed costs
- If θ = 1 and k≥$\frac{v_A(c_A)}{3}$, pre-commitment to tying by firm 1 is pointless, since it does better by independent pricing than by tying; if θ = 1 and k<$\frac{v_A(c_A)}{3}$, firm 2 can be excluded by a pre-commitment to tying.

- However, firm 1 will only choose conditional pre-commitment in order to exclude.

My results extend those of Whiston, but do not alter the main policy implications of tying that it can be exclusionary.

Appendices

A.1. Definitions of variables and notes on data source

Source: EIA and CME

Category:	*Supply and Demand*
Balancing Item	*Represents the difference between the sum of the components of natural gas supply and the sum of the components of natural gas disposition. These differences may be due to quantities lost or to the effects of data reporting problems. Reporting problems include differences due to the net result of conversions of flow data metered at varying temperature and pressure bases and converted to a standard temperature and pressure base; the effect of variations in company accounting and billing practices; differences between billing cycle and calendar period time frames; and imbalances resulting from the merger of data reporting systems which vary in scope, format, definitions, and type of respondents.*
Consumption	*The use of natural gas as a source of heat or power or as a raw material input to a manufacturing process.*
Dry Production	*The process of producing consumer-grade natural gas. Natural gas withdrawn from reservoirs is reduced by volumes used at the production (lease) site and by processing losses. Volumes used at the production site include (1) the volume returned to reservoirs in cycling, repressuring of oil reservoirs, and conservation operations; and (2) gas vented and flared. Processing losses include (1) nonhydrocarbon gases (e.g., water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen) removed from the gas stream; and (2) gas converted to liquid form, such as lease condensate and plant liquids. Volumes of dry gas withdrawn from gas storage reservoirs are not considered part of production. Dry natural gas production equals marketed production less extraction loss.*
Extraction Loss	*The reduction in volume of natural gas due to the removal of natural gas liquid constituents such as ethane, propane, and butane at natural gas processing plants.*
Gross Withdrawals	*Full well-stream volume, including all natural gas plant liquids and all nonhydrocarbon gases, but excluding lease condensate. Also includes amounts delivered as royalty payments or consumed in field operations.*
Marketed Production	*Gross withdrawals less gas used for repressuring, quantities vented and flared, and nonhydrocarbon gases removed in treating or processing operations. Includes all quantities*

	of gas used in field and processing plant operations.

Category:	**Prices**
Futures Price	The price quoted for delivering a specified quantity of a commodity at a specified time and place in the future.
Spot Price	The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.
Henry Hub Spot Price	Natural Gas spot price reported at Henry Hub, Louisiana
Henry Hub Natural Gas Future Price	Henry Hub Natural Gas Futures (Physical) are an outright natural gas contract between a buyer and a seller that offers opportunities for risk management of the highly volatile pricing of natural gas. The contract: Is widely used as a national benchmark price for natural gas, which accounts for almost a quarter of United States energy Reflects a vigorous basis market based on the pricing relationships between Henry Hub and other important natural gas market centers in the continental United States and Canada Is the second-highest volume futures contract in the world based on a physical commodity Unit of trading is 10,000 million British thermal units (mmBtu).
WTI Spot Price	West Texas Intermediate (WTI – Cushing) is a crude stream produced in Texas and southern Oklahoma which serves as a reference or "marker" for pricing a number of other crude streams and which is traded in the domestic spot market at Cushing, Oklahoma.
Light Sweet Crude Oil Future Prices	An outright crude oil contract between a buyer and seller. The contracts also serve as a key international pricing benchmark. Crude oil is the world's most actively traded commodity. Light, sweet crudes are preferred by refiners because of their low sulfur content and relatively high yields of high-value products such as gasoline, diesel fuel, heating oil, and jet fuel. Unit of trading is 1,000 barrels Delivery point is Cushing, Oklahoma, which is also accessible to the international spot markets via pipelines Delivery provided for several grades of domestic and internationally traded foreign crudes Six types of options: American style, calendar spread, crack spreads, average price, European style and daily
Contract 1	A futures contract specifying the earliest delivery date. Natural gas contracts expire three business days prior to the first calendar day of the delivery month. Thus, the delivery month for Contract 1 is the calendar month following the trade date. For crude oil, each contract expires on the third business day prior to the 25th calendar day of the month preceding the delivery month. If the 25th calendar day of the month is a non-business day, trading ceases on the third business day prior to the business day preceding the 25th calendar day. After a contract expires, Contract 1 for the remainder of that calendar month is the second following month.

Category:	**Storage**
Base (cushion) Gas	The volume of gas needed as a permanent inventory to maintain adequate reservoir pressures and deliverability rates throughout the withdrawal season. All native gas is included in the base gas volume.
Net Withdrawals	The amount by which storage withdrawals exceed storage injections.
Underground Gas Storage	The use of sub-surface facilities for storing gas that has been transferred from its original location. The facilities are usually hollowed-out salt domes, natural geological reservoirs (depleted oil or gas fields) or water-bearing sands topped by an impermeable cap rock

	(aquifer).
Underground Storage Withdrawals	Gas removed from underground storage reservoirs.
Working(top storage) Gas	The volume of gas in the reservoir that is in addition to the cushion or base gas. It may or may not be completely withdrawn

Category:	**Weather**
Cooling Degree Days (CDD)	A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree-days are summed to create a cooling degree-day measure for a specified reference period. Cooling degree-days are used in energy analysis as an indicator of air conditioning energy requirements or use.
Heating degree-days (HDD)	A measure of how cold a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the average of the day's high and low temperatures from the base temperature (65 degrees), with negative values set equal to zero. Each day's Heating degree-days are summed to create a Heating degree-day measure for a specified reference period. Heating degree-days are used in energy analysis as an indicator of space Heating energy requirements or use.
NOAA	National Oceanic and Atmospheric Administration.
Normal Weather	The National Oceanic and Atmospheric Administration (NOAA)'S 30-year average for heating and cooling degree-days as a benchmark for normal weather

A.2. NOTES ON DATA SOURCE

Source: EIA and CME

Dry Production: Form EIA-895, "Monthly and Annual Quantity and Value of Natural Gas Production Report".

Consumption: 1973-1975: Bureau of Mines, Minerals Yearbook, "Natural Gas" chapter. 1976-1978: EIA, Energy Data Reports, Natural Gas Annual. 1979: EIA, Natural Gas Production and Consumption, 1979. 1980-1989: Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition" and Form EIA-759, "Monthly Power Plant Report" . 1990: Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition" ,Form EIA-759, "Monthly Power Plant Report" and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids

Production" . 1991-1995: Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition" ,Form EIA-759, "Monthly Power Plant Report" Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production" and EIA-627, "Annual Quantity and Value of Natural Gas Report." 1996-2000: Form EIA-895, "Monthly and Annual Quantity and Value of Natural Gas Production Report" ,Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers" , Form EIA-759, "Monthly Power Plant Report" , EIA computations, and Natural Gas Annual 2000. 2001-current Form EIA-895, "Monthly and Annual Quantity and Value of Natural Gas Production Report" , Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers" and Form EIA-759, "Monthly Power Plant Report" .

Spot Price: Thomson Reuters

Future Prices: New York Mercantile Exchange (NYMEX)

Storage: 1979 and prior data from the American Gas Association, Committee on Underground Storage, The Storage of Gas in the United States and Canada. 1980 to current data from Form EIA-191M, "Monthly Underground Gas Storage Report" ; Form EIA-191A, "Annual Underground Gas Storage Report" ; Form EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition".

A.3. APPENDIX FOR SOLVING INDEPENDENT PRICING AND TIED PRICING MODELS

A.3.1. Solving for profit maximization of firm 1 when firm 2 does not enter:

Firm 1 will set separate two part tariff for both markets. Profit maximization of market A is identical to independent pricing case, while firm 1 gets to choose whether serves the whole market B or not:

$$\underset{\tilde{t}_1,\tilde{E}_1,\tilde{p}_1}{\text{Max}}\left[(\tilde{p}_1-c_B)q_B(\tilde{p}_1)+\tilde{E}_1\right]\theta\tilde{t}_1$$
$$s.t. v_B(\tilde{p}_1)-\tilde{E}_1-k\tilde{t}_1\geq 0$$
$$\tilde{t}_1\leq 1$$

Eqn 102

With the participation constrain for consumers in market B, as well as the constrain on the marginal consumer in market B, the profit maximization for firm 1 in market B can be written as a Lagrangian:

Eqn 103

$$L=\left[(\tilde{p}_1-c_B)q_B(\tilde{p}_1)+\tilde{E}_1\right]\theta\tilde{t}_1+\lambda\left[v_B(\tilde{p}_1)-\tilde{E}_1-k\tilde{t}_1\right]+\mu\left(1-\tilde{t}_1\right)$$

Profit maximization requires:

$$\frac{\partial L}{\partial\tilde{p}_1}=\left[(\tilde{p}_1-c_B)q'_B(\tilde{p}_1)+q_B(\tilde{p}_1)\right]\theta\tilde{t}_1-\lambda q_B(\tilde{p}_1)=0$$
$$\frac{\partial L}{\partial\tilde{E}_1}=\theta\tilde{t}_1-\lambda=0$$
$$\frac{\partial L}{\partial\tilde{t}_1}=\left[(\tilde{p}_1-c_B)q_B(\tilde{p}_1)+\tilde{E}_1\right]\theta-\lambda k-\mu=0$$
$$\lambda\left[v_B(\tilde{p}_1)-\tilde{E}_1-k\tilde{t}_1\right]=0$$
$$\mu\left(1-\tilde{t}_1\right)=0$$

From $\frac{\partial L}{\partial \tilde{E}_1}$, the marginal consumer can be written as : $\tilde{t}_1 = \frac{\lambda}{\theta}$. The firm earns zero profit if $\tilde{t}_1$=0, as it can always earn positive profit by choosing a $\tilde{t}_1$>0. Therefore, for $\tilde{t}_1$>0, it implies that λ>0, then the participation constraint binds:

$$\text{for } \lambda > 0, \text{ and } \lambda\left[v_B(\tilde{p}_1) - \tilde{E}_1 - k\tilde{t}_1\right] = 0$$
$$\Rightarrow v_B(\tilde{p}_1) - \tilde{E}_1 - k\tilde{t}_1 = 0$$
$$\Rightarrow \tilde{t}_1 = \frac{v_B(\tilde{p}_1) - \tilde{E}_1}{k}$$

With $\tilde{t}_1 = \frac{\lambda}{\theta}$ from $\frac{\partial L}{\partial \tilde{p}_1}$:

$$\left[(\tilde{p}_1 - c_B)q'_B(\tilde{p}_1) + q_B(\tilde{p}_1)\right]\theta\frac{\lambda}{\theta} - \lambda q_B(\tilde{p}_1) = 0$$
$$(\tilde{p}_1 - c_B)q'_B(\tilde{p}_1) = 0$$
$$\Rightarrow \tilde{p}_1 = c_B$$

Once again, firm charges a per unit price at the marginal cost. There are two cases from this point, firm 1 has two choices: either choose $\tilde{t}_1 = \frac{\lambda}{\theta}$<1 , that implies $\mu = 0$, and $\frac{\partial L}{\partial \tilde{t}_1}$ becomes:

$$\left[(c_B - c_B)q_B(c_B) + \tilde{E}_1\right]\theta - \lambda k = 0$$
$$\lambda = \frac{\left[(c_B - c_B)q_B(c_B) + \tilde{E}_1\right]\theta}{k}$$
$$\lambda = \frac{\tilde{E}_1\theta}{k}$$

Using $\tilde{t}_1 = \frac{\lambda}{\theta}$, substitute $\lambda = \theta\tilde{t}_1 = \theta\frac{v_B(\tilde{p}_1) - \tilde{E}_1}{k}$,

$$\theta\frac{v_B(\tilde{p}_1)-\tilde{E}_1}{k}=\frac{\tilde{E}_1\theta}{k}$$

$$\tilde{E}_1=\frac{1}{2}v_B(\tilde{p}_1)$$

$$\Rightarrow \tilde{E}_1=\frac{1}{2}v_B(c_B)$$

And, the firm chooses to sell to a fraction of the B market as the marginal consumer is given by

$$\tilde{t}_1=\frac{v_B(\tilde{p}_1)-\tilde{E}_1}{k}=\frac{v_B(c_B)-\frac{1}{2}v_B(c_B)}{k}=\frac{1}{2k}v_B(c_B)$$

When $\frac{1}{2k}v_B(c_B)<1$, the case exists. Otherwise, it contradicts with $\tilde{t}_1<1$.

The other case is when firm chooses $\tilde{t}_1=1$, and that implies that the entry fee for firm 1 charges is:

$$\tilde{t}_1=1=\frac{v_B(\tilde{p}_1)-\tilde{E}_1}{k}$$

$$\tilde{E}_1=v_B(\tilde{p}_1)-k$$

$$\Rightarrow \tilde{E}_1=v_B(c_B)-k$$

A.3.2. Solving for tied pricing profit maximization when θ=1:

Firm 1's profit becomes:

Eqn 104 $$\underset{E_A,p_A,E_1,p_1}{\text{Max}}\left[(p_A-c_A)q_A(p_A)+(p_1-c_B)q_B(p_1)+E_1\right]t_1$$

Firm 2's profit becomes:

Eqn 105 $$\underset{E_2,p_2}{\text{Max}}\left[(p_2-c_B)q_B(p_2)+E_2\right]\cdot(1-t_1)$$

The first order conditions for firm 1 are simplified:

With respect to E_1:

Eqn 106 $\frac{\partial \pi_1}{\partial E_1} = -\frac{1}{2k}\left[(p_A - c_A)q_A(p_A) + (p_1 - c_B)q_B(p_1) + E_1\right] + t_1$

With respect to p_1:

Eqn 107 $\frac{\partial \pi_1}{\partial p_1} = t_1\left[(p_1 - c_B)q'_B(p_1) + q_B(p_1)\right] - \frac{q_B(p_1)}{2k}\left[(p_A - c_A)q_A(p_A) + (p_1 - c_B)q_B(p_1) + E_1\right]$

With respect to p_A:

Eqn 108

$$\frac{\partial \pi_1}{\partial p_A} = -\frac{q_A(p_A)}{2k}\left[(p_A - c_A)q_A(p_A) + (p_1 - c_B)q_B(p_1) + E_1\right] + t_1\left[(p_A - c_A)q'_A(p_A) + q_A(p_A)\right]$$

The first order conditions for firm 2 are:

With respect to E_2:

Eqn 109 $\frac{\partial \pi_2}{\partial E_2} = -\frac{1}{2k}\left[(p_2 - c_B)q_B(p_2) + E_2\right] + (1 - t_1)$

With respect to p_2:

Eqn 110 $\frac{\partial \pi_2}{\partial p_2} = (1 - t_1)\left[(p_2 - c_B)q'_B(p_2) + q_B(p_2)\right] - \frac{q_B(p_2)}{2k}\left[(p_2 - c_B)q_B(p_2) + E_2\right]$

First, take from $\frac{\partial \pi_1}{\partial E_1}$, we can get the following substitution:

Eqn 111 $t_1 = \frac{1}{2k}\left[(p_A - c_A)q_A(p_A) + (p_1 - c_B)q_B(p_1) + E_1\right]$

Then $\frac{\partial \pi_1}{\partial p_1}$ becomes:

$$\frac{\partial \pi_1}{\partial p_1} = t_1\left[(p_1 - c_B)q'_B(p_1) + q_B(p_1)\right] - q_B(p_1)t_1 = 0$$

Eqn 112 $$\left[(p_1 - c_B)q'_B(p_1) + q_B(p_1)\right] - q_B(p_1) = 0$$

$$(p_1 - c_B)q'_B(p_1) = 0$$

$$\Rightarrow \quad p_1 = c_B$$

Similarly, from $\frac{\partial \pi_1}{\partial p_A}$:

$$-q_A(p_A)t_1 + t_1\left[(p_A - c_A)q'_A(p_A) + q_A(p_A)\right] = 0$$

Eqn 113 $$-q_A(p_A) + (p_A - c_A)q'_A(p_A) + q_A(p_A) = 0$$

$$(p_A - c_A)q'_A(p_A) = 0$$

$$\Rightarrow \quad p_A = c_A$$

Second, take from $\frac{\partial \pi_2}{\partial E_2}$, $1 - t_1$ can also be written as a substitution:

Eqn 114 $$1 - t_1 = \frac{1}{2k}\left[(p_2 - c_B)q_B(p_2) + E_2\right]$$

Taking this substitution into $\frac{\partial \pi_2}{\partial p_2}$, the first order condition solves for p_2:

$$(1 - t_1)\left[(p_2 - c_B)q'_B(p_2) + q_B(p_2)\right] - \left(1 - t_1\right)q_B(p_2) = 0$$

Eqn 115 $$(p_2 - c_B)q'_B(p_2) = 0$$

$$\Rightarrow \quad p_2 = c_B$$

With prices are all solved at their marginal costs, the first order condition with respect to E_1 becomes:

Eqn 116

$$-\frac{1}{2k}\left[(c_A - c_A)q_A(c_A) + (c_B - c_B)q_B(c_B) + E_1\right] + \frac{1}{2} + \frac{1}{2k}\left(v_B(c_B) + v_A(c_A) - v_B(c_B) - E_1 + E_2\right) = 0$$

$$E_1 = \frac{1}{2}\left(k + v_A(c_A) + E_2\right)$$

And the first order condition with respect to E_2 leads to:

Eqn 117

$$-\frac{1}{2k}\left[(c_B\ \ -c_B)q_B(c_B)+E_2\right]+1-\frac{1}{2k}\left(v_B(c_B)+v_A(c_A)-v_B(c_B)-E_1+E_2\right)=0$$

$$E_2=\frac{1}{2}\left(k-v_A(c_A)+E_1\right)$$

Then substitute E_1 in the function of E_2

Eqn 118

$$E_2=\frac{1}{2}\left(k-v_A(c_A)+\frac{1}{2}\left(k+v_A(c_A)+E_2\right)\right)$$

$$\Rightarrow E_2=k-\frac{v_A(c_A)}{3}$$

Therefore, E_1becomes:

Eqn 119 $$\Rightarrow E_1=k+\frac{v_A(c_A)}{3}$$

A.3.3. Profit maximization of firm 1 when firm 2 does not enter and θ=1

Firm 1 no longer needs to do tying pricing. Instead, it can set two part tariff for each market, as a monopoly in both. In market B, it can choose whether to sell to the entire B market or not:

$$\underset{\tilde{t}_1,\tilde{E}_1,\tilde{p}_1}{\text{Max}}\left[(\tilde{p}_1-c_B)q_B(\tilde{p}_1)+\tilde{E}_1\right]\cdot\tilde{t}_1$$

$$s.t. v_B(\tilde{p}_1)-\tilde{E}_1-k\tilde{t}_1\geq 0$$

$$\tilde{t}_1\leq 1$$

So, given the assumption of firm 2 staying out of the market as $k<\frac{v_A(c_A)}{3}$, there are two possible solutions, depending on the parameters of the model:

1) **A chooses to serve the whole market of B when** $\frac{3v_B(c_B)}{2v_A(c_A)}<1$

Firm 1 will be able to choose serve less than the entire market B, if $\frac{3v_B(c_B)}{2v_A(c_A)} < 1$. If so, firm 1 will have the following strategy

$$p_1^* = c_B,\ \tilde{t}_1^* = \frac{v_B(c_B)}{2k} < 1, E_1^* = \frac{v_A(c_B)}{2}$$

Under this scenario, given $k < \frac{v_A(c_A)}{3}$ and $\frac{3v_B(c_B)}{2v_A(c_A)} < 1$, if firm chooses to serve the entire B market, it will be charging per unit price $p_1 = c_B$ and entry fee $E_1 = v_B(c_B) - k$. However, serving the market not whole is definitely is at least as profitable as serving the entire market, because:

$$\pi_{1,B}(p_1, \tilde{t}_1 < 1, E_1) = \frac{v_B^2(c_B)}{4k}$$

$$\pi_{1,B}(p_1, \tilde{t}_1 = 1, E_1) = v_B(c_B) - k$$

$$\pi_{1,B}(p_1, \tilde{t}_1 < 1, E_1) - \pi_{1,B}(p_1, \tilde{t}_1 = 1, E_1) = \frac{v_B^2(c_B)}{4k} - v_B(c_B) + k$$

$$= \left(\frac{v_B(c_B)}{2\sqrt{k}} - \sqrt{k}\right)^2 \geq 0$$

$$\text{if} \quad k = 0 \text{ or } v_B(c_B) = \frac{1}{2}$$

$$\pi_{1,B}(p_1, \tilde{t}_1 < 1, E_1) = \pi_{1,B}(p_1, \tilde{t}_1 = 1, E_1)$$

Otherwise

$$\pi_{1,B}(p_1, \tilde{t}_1 < 1, E_1) > \pi_{1,B}(p_1, \tilde{t}_1 = 1, E_1)$$

2) A chooses to serve the whole market of B when $\frac{3v_B(c_B)}{2v_A(c_A)} \geq 1$

There is another possible outcome if $\frac{3v_B(c_B)}{2v_A(c_A)} \geq 1$ when $k < \frac{v_A(c_A)}{3}$, then firm only has one choice, which is to serve the entire B market because $\frac{v_B(c_B)}{2k} > \frac{3v_B(c_B)}{2v_A(c_A)} \geq 1$, and its strategies are:

$$p_1^* = c_B,\ \tilde{t}_1^* = 1, E_1^* = v_B(c_B) - k$$

In the market A, firm 1 will charge the monopoly pricing, as it did under independent pricing, charging $p_A^* = c_A$ and $E_A^* = v_A(c_A)$.

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