Chapter 5
Institutions and Gas Market Security

by Mark H.Hayes[1]

5.1 INTRODUCTION [2]

Increasing dependence on imports of liquefied natural gas (LNG) raises new concerns for policy makers and regulators with responsibilities for energy market security. Natural gas provides one-quarter of OECD countries' primary energy supply and plays a critical role in residential heating and electric power generation. The shift toward LNG for U.S. and European gas supply needs will interconnect these previously isolated regional markets. Policy makers and regulators will be tasked with understanding how the growing LNG trade will affect future gas supplies and prices and to design and implement regulation considering these changing market fundamentals.

Concerns about supply security have long been a central concern to energy policy makers. Since the oil crises of the 1970s most analyses have focused on the instability of imported oil supplies and the cartel behavior of OPEC.[3] In the 1980s, Europe's increased dependence on pipeline imports of natural gas also brought concerns about gas supply security to the forefront (Stern 1986). The same conceptual framework developed to manage oil import risks was extended to natural gas. Researchers suggested policies that would diversify gas import sources so as to minimize the costs of disruption (Manne, Roland et al. 1986; Hoel and Strom 1987). As in oil, strategic "stockpiles" in the form of underground gas storage were advocated as the preferred means to manage risks associated with interruptions of pipeline flows caused by technical failures or political disputes (IEA 1995).

By the analogy with earlier work on oil and pipeline gas imports, early attention to rising LNG imports is also focused on supply, e.g. the reliability of physical cargo deliveries (Burr 2005). However, the fundamental variability of natural gas demand and the flexibility provided

[2] Conversations with several analysts and industry participants informed the framework and discussion presented herein. In particular, the author thanks Ira Joseph (PIRA Energy) and Paul Carpenter (The Brattle Group).
[3] Toman (1993) provides a review of the oil security literature.

by ship-based transport of natural gas suggest a broader framework to evaluate energy security in the context of rising imports of LNG.

Natural gas demand in end-use markets has significant seasonal variability and stochastic variability (see figure 1.2 and figure 4.1, respectively). The analyses presented in chapters 2, 3 and 4 of this text suggest that the growing LNG trade is likely to respond to variable gas demand in end-use markets. Chapter 2 and 3 pointed to the likely seasonal nature of LNG flows, responding to regional differences in monthly gas demand profiles and gas storage costs. Chapter 4 discussed the embedded value of LNG transport capacity to flexibly respond to variations in natural gas prices between regional gas markets. Such price variations are, in reality, driven by the significant stochastic (unpredictable) variability in natural gas demand.

Given the complexity of the interaction of LNG imports with other segments of the gas supply, transport, and storage and delivery infrastructure – policy makers should broaden their attention to "*market security*", rather than focusing only on the physical security of gas supplies. As defined here, the concept of gas market security incorporates all segments of gas delivery infrastructure as well as natural gas demand. Market security is inclusive of supply security, including concerns about the physical availability of gas – e.g. are absolute volumes delivered, or do users have the flexibility to switch to other fuels? Market security is dually concerned with the financial aspect, e.g. what price do customers pay for gas (or alternative) energy sources consumed?

This broader conception of market security is particularly applicable to natural gas markets where demand (and price) is much more highly variable than actual gas supply. In the long-term, market security does depend on the mobilization of capital to build adequate infrastructure and delivery capacity. But in the shorter term—at daily, weekly or monthly time-scales—natural gas demand is highly variable as customers demand ready access to gas for heating needs and for other grid connected uses. Residential customers, for example, may see daily consumption swing 500% on a given day compared to annual average demand. In the short run, these variations are driven largely by factors such as temperature which are largely outside residential consumers' control.

Different countries have adopted different approaches to ensure the basic needs of customers are met. The U.S. and the U.K. have market-oriented approaches exposing larger gas buyers, such as electric power generators, to prices that reflect the supply/demand balance for gas on a daily basis. In these *competitive* gas markets, industrial users and electric power generators demonstrate a strong ability to respond to price increases by scaling production to reduce overall energy needs – or by switching to alternative fuels to reduce overall production costs. Swings in price also provide a profit incentive for private investment in storage capacity to buy gas in low price periods and sell in high price periods – resulting in an overall smoothing of prices both seasonally and on daily and weekly time scales.

Continental European and Japanese markets take a more *managed* approach to meeting variable gas demand needs, with the entire gas supply network typically under the control of quasi-state controlled, monopolistic gas companies. Gas allocation decisions are made by the monopoly service provider, entrusted by the state to build and operate the gas grid. The monopoly gas company has the responsibility to contract for gas imports in the interest of end-use consumers.

The inherent flexibility in LNG transport will interconnect regional markets with these varying institutional structures. The interactions between each of these markets will be of critical import for understanding the function of a newly global market for natural gas, and to each individual importing country and market participant. For example, a monopoly service provider in Japan may be able to easily contract for reliable deliveries of LNG, backed by a captive customer base. U.S. utilities may not be able to sign such long-term contracts under the threat of *ex-post* regulatory review. The U.S. may thus be exposed to greater variability in LNG cargo deliveries.

The discussion in this chapter will address largely the short-term aspects of market security, following on the analytical focus of the preceding chapters 2, 3 and 4. As discussed earlier in this volume, the fundamental economics supporting investment in LNG supply and import capacity are robust. The vast body of long-term energy models suggests a major role for

LNG supply over the coming decades (NPC 2003; IEA 2004b; EIA 2005b; Holz and Hirschhausen 2006). The analysis in this volume focuses on interaction of LNG cargoes at the intra-annual scale, and this chapter will focus on the institutional interactions that will affect short-term LNG deliveries and the resulting implications for gas market security.

Relatively little work has considered the fundamentals of LNG trade at the monthly scale and the implications for market security. In its report "Gas Supply Security in the Open Market" (IEA 2004a) the IEA discussed the broad implications for rising imports of LNG. Jensen (2004a) considers price formation, changing contractual structures and implications of the geographic sources of LNG supply on U.S. gas markets. To this author's knowledge, the discussion here is the first attempt to explore the implications for gas market security taking into account the important interactions between the different segments of the LNG and natural gas supply, transport and offtake chain – incorporating the fundamental economic analysis from the earlier chapters of this text.

In the remainder of this chapter, I explore institutional and regulatory issues that will shape the growing trade in LNG and create important deviations from the purely competitive market framework described in earlier chapters of this text.

First, in section 5.2, I discuss in greater detail the institutional characteristics of the major gas and LNG importers. Using some academic liberty, I group the major continental European and Japanese gas importers together, collectively describing these as the "managed" gas markets. Indeed, these markets are not completely homogenous in there characteristics. However, the key aspects of the institutions governing gas supply in these countries are consistent enough to be considered together. The institutional structures of "managed markets" are contrasted with the more open and "competitive" gas markets in the U.S. and U.K. Using these archetypes, I compare the very different approaches each takes to provide market security, with particular focus on the flexibility in gas consumption provided by the electric power sector.

In section 5.3, I discuss how the growth of LNG imports to both "managed" and "competitive" markets will impact each archetype market individually, and how the two types of markets will interact. I show how the important institutional differences between the continental European (and Japanese) markets and the U.S. (and U.K.) market will drive important structural variability in LNG flows compared to the pure competitive market assumptions used in the models considered in chapters 3 and 4.

In particular, gas companies in "managed" markets will be preferentially able to sign long-term contracts for LNG supply. Any additional cargoes they need will be purchased in the growing flexible market for LNG cargoes. The lack of a competitive wholesale market for gas and the necessity of continental European and Japanese gas companies to procure gas to meet rigid internal demand will drive variability in LNG volume deliveries largely absorbed by competitive gas markets in the U.S. and U.K.

In section 5.4 I consider several policy mechanisms, particularly for U.S. and U.K. gas consumers to mitigate the impact of supply and price volatility in a growing global market for LNG. In section 5.5, I revisit the major insights from the chapter and conclude.

5.2 Institutional Contexts for Providing Gas Market Security

"Managed" and "competitive" markets have historically taken very different approaches to providing gas market security. These differences carry over into the way that these countries buy LNG – affecting both the duration and pricing terms of LNG contracts. Moreover, to the extent that policy action is sought to mitigate concerns related to gas market security, the institutional characteristics of each market will determine the policy instruments available to address such concerns. Before considering the implications for gas market security driven by the interactions between these markets, I first describe the differing approaches to market security and LNG procurement in these archetype institutional structures.

5.2.1 "Managed" Gas Markets

In the four largest gas markets in continental Europe, incumbent national gas companies continue to supply over seventy percent of large industrial gas customers and nearly all small commercial and residential gas users in their respective national markets (European Commission

(EC) 2005). Historically, governments delegated responsibility for the management of the gas supply system to these companies – Ruhrgas (Germany), Eni (Italy), Gaz de France (France), Gasunie (Netherlands). Some were wholly state-owned enterprises, others private. Today, several are transitioning to privatized or partially privatized companies driven by a European Union directive to liberalize internal gas markets. Markets are opening slowly to competition, but for the foreseeable future these national champion companies will continue to dominate their domestic markets. In Japan, the gas market is dominated by private companies, each with *de facto* monopoly positions for their regionally isolated gas networks. In both the continental European and Japanese cases, companies hold real or *de facto* monopoly positions to procure, transport and distribute gas to domestic customers. With these monopoly service rights comes the obligation to provide the public service of a stable and secure supply of gas.

With the exception of three European producing countries – the U.K., the Netherlands and Norway – all other European countries and Japan rely on imports for the majority of their supply needs. Germany, Italy, and France – respectively the three largest gas markets in continental Europe – each import over 80% of their annual gas needs (BP 2006). Japan is totally dependent on LNG imports. To secure supplies of gas for their domestic customers, monopoly gas companies in the importing countries sign long-term contracts for gas delivery. For the continental importers, supply sources include the European producers, Russia, and Algeria. To date, LNG imports play a marginal role in continental European gas supply, providing less than 10% of total gas needs (BP).

Long-term contracts for gas imports are the backbone of gas market security for both continental European and Japanese gas importers. Monopoly gas companies sign 15-25 year contracts for gas supplies to cover the supply needs of their customers far in advance (Neumann and Hirschhausen; IEA). Contracts with gas exporters provide for a minimum take quantity, with an option to buy additional volumes based on varying demand needs. Long-term contracts support the development of the necessary upstream gas supply and transport infrastructure. Payments in these long-term contracts for gas imports are guaranteed by captive customers in respective monopoly service territories.

Managed markets largely employ an engineering solution to providing short-run gas market security. The mandate to provide gas service encourages national champion companies to contract for gas supplies and invest in whatever infrastructure is needed to meet peak gas demand needs, with total costs bundled into end-user prices. Governments have over-sight or veto-power on customer prices. In general, companies are allowed rates which provide compensation for whatever investment is agreed necessary to provide reliable gas service.

In continental Europe and Japan, prices in the long-term contracts for imported pipeline gas or LNG are determined by formula price linkages to crude oil and oil products.[4] There is thus no "market price" for gas, but rather a formula that determines prices for imports and sales. In fact, prices are even less volatile than oil prices, as formulas in long-term import contracts are typically based on a trailing average of oil prices (see figure 5.1). Customer rates are composed of long-term supply contract prices and the costs associated with building and operating domestic the gas delivery infrastructure.

[4] The formula oil price linkage was adopted so that gas would be priced competitively – usually at a discount to oil – to encourage the growth in gas market share relative to oil. Gas was encouraged to displace oil used in commercial and industrial applications, and electric power generation. Ironically, a major incentive for encouraging gas use was to balance dependence on imported oil after the OPEC crisis of the 1970s.

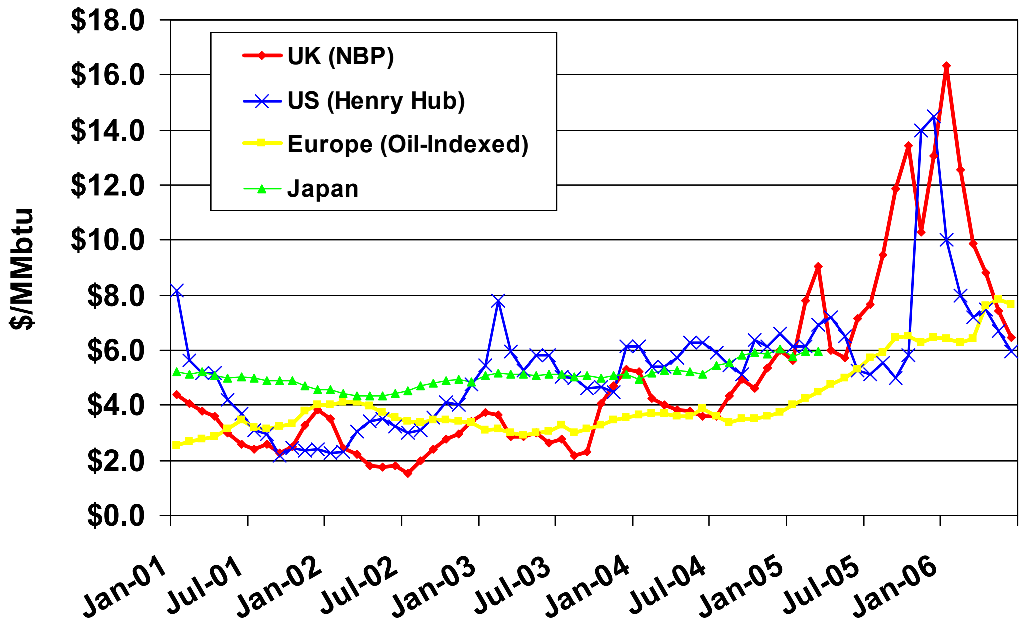

Figure 5.1. Historical monthly natural gas prices in U.S., U.K., Europe, and Japan. U.S. prices are average of daily prices at the Henry Hub quoted on the NYMEX. U.K. prices reflect the monthly average of prices at the National Balancing Point (NBP). European prices reflect the average border price for European gas imports (from Heren Ltd). Japanese prices are average LNG import prices, including regasification costs (from Gas Strategies Ltd.).

In a managed market, security is provided largely at the expense of the economic efficiency that results from competition for the wholesale supply of gas. Without a wholesale market, all customers pay prices that vary little from month-to-month and do not reflect any shortage or surplus in the availability of gas. Absent rationing, national gas companies have limited ability to induce consumers – particularly large industrial users or electric power generators – to respond to short-term capacity constraints by curtailing consumption or shifting to alternative fuels. This contrasts dramatically with the price volatility observed in U.S. or U.K. wholesale gas prices – and in turn the consumption of gas by electric power generators and large industrial consumers as they respond to price variability in these competitive wholesale markets.

Without flexible prices, national gas companies must utilize other mechanisms to manage both seasonal and unpredictable variability in gas demand. Gas storage and variations in pipeline imports are critical to meeting varying gas demand. Gas importers in managed markets are thus biased to over-contract for gas supplies to ensure that deliveries meet peak demand needs. In world without fungible trade in gas – supply and import capacities are determined by long-term contract volumes. Pipeline and LNG transport capacities are scaled to match the agreed volumes in long-term take-or-pay contracts. In a managed market structure, monopolies have assurance that any investments in delivery infrastructure will be incorporated into customer bills.

The Japanese experience provides the best example of how these monopoly gas companies participate in the global LNG market. To ensure stable supplies, Japanese LNG importers have historically demanded that LNG supply chains be engineered with redundancy and excess capacity, guarding against mechanical failure and political unrest in the supply countries, and to ensure that deliveries could meet variable consumption needs (Elass, Hashimoto et al. 2006; Shepherd and Ball 2006). In recent years it has become evident that historical Japanese contracts provided excess LNG supply capacity in each facility that has since provided spot cargoes to other LNG importers.

Through various European Commission directives, attempts are being made to open continental European markets to more competition for the wholesale supply of gas. If successful, such reforms would fundamentally alter the model that has successfully provided gas market security in these countries to date. However, progress on these reforms is halting. A 2004 report by the European Commission observed that only two of the 20 EU member countries (the U.K. and Ireland) had achieved competitive wholesale markets, and only in Spain and Ireland had more than 20% of large industrial customers switched from the monopoly suppliers (European Commission (EC) 2004) in (IEA 2004a). Progress on similar reforms in Japan has also been slow. So long as reforms are stalled in Europe and Japan, the institutional structures in these countries will drive very different gas supply and LNG import strategies compared to the competitive markets described in the next section.

5.2.2 Competitive Gas Markets

In contrast to the managed markets of continental Europe and Japan, the United States and the United Kingdom have developed open, competitive wholesale markets for natural gas. In the U.S. the move toward competitive pricing for gas began with the 1978 Natural Gas Policy Act (NGPA). The NGPA moved gas pricing more firmly under the control of the U.S. Federal Energy Regulatory Commission (FERC), and began the decade-long process of removing all controls over wellhead prices, and facilitated the move toward open access to gas pipelines.[5] In the U.K. the shift toward competitive gas markets began in the mid-1980s with the privatization and restructuring of then state-owned monopolist British Gas. In both the U.S. and the U.K., a critical step in reforms was the move to separate the transport function from gas production and sales, so that sellers and buyers could freely contract for the needed pipeline capacity to move gas from production regions to end-use markets (De Vany and Walls 1995).

Today, gas producers in the U.S. and the U.K. sell gas to wholesale buyers of gas, including electric utilities, large industrial customers, or local distribution companies (LDC's). (In many cases smaller producers actually sell to larger gas marketers, who aggregate production and then resell to the end-use consumers and LDC's). The price and duration of these transactions are freely determined by the buyer and seller.

In an open, competitive marketplace, large gas users such as electric power generators and industrial users are exposed to price swings reflecting the supply and demand balance at any given time. Markets clear on a daily basis, with daily prices considerably more volatile than the monthly average prices shown in figure 5.1. There are also financial exchanges for the trading of standardized future contracts (the NYMEX in the U.S., and the International Petroleum Exchange in the U.K.) which allow customers and producers to mitigate their exposure to price swings.

Large industrial customers and electric power generators in both the U.S. and the U.K. continue to procure gas under long-term contract – though these contracts are typically shorter

[5] For a detailed discussion of the NGPA and the shift from regulated to competitive markets in the U.S. see De Vany and Walls (1995) and for related case law see (Bosselman, Rossi et al. 2000).

than standard continental European gas import contracts. In the U.K. about 85% of gas is delivered on contracts 2-5 years in duration. In the U.S. large volume buyers procure nearly half of total deliveries on contracts ranging from 5-8 years in duration (IEA 2004b). Delivered gas prices in the U.S. and the U.K. are usually indexed to spot prices, such as the Henry Hub price in the U.S.

The existence of a fungible market for gas means that even though large buyers may have long-term contracts, each day they face a decision whether to consume their contracted quantity of gas – or to curtail consumption and sell contracted gas back into the spot market. Gas used for electric power generation is particularly flexible with respect to prices. The decisions on the dispatch of electric power plants in the U.S. and the U.K. vary gas consumption considerably both on a seasonal basis, and to respond to short-term variations in gas prices relative to other fuels. In the U.K. and some of the largest electric markets in the U.S. such as California and Texas, the decision of which units to operate is also made in a competitive market, with lowest cost units dispatched first.[6] In Box 5.A, I describe in general terms both seasonal and short-term fuel switching in the U.S. electric power market, as an example of how competitive gas and electricity markets interact.

[6] Market rules for electricity market pricing and the dispatch of electric power plants differ on a state-by-state basis in the U.S. Similar to the natural gas market reforms of the 1980s, the intent of 1990s electricity market restructuring was to move toward competitive wholesale electric power markets. A full discussion of the mixed progress on electric market restructuring is beyond the scope of this text. However, generally, electric power generation in the U.S. does face incentives to minimize fuel costs. In markets where the supply and distribution of electricity is still vertically integrated, as in the Southeast, fuel cost minimization is not necessarily the over-riding incentive. In markets where marginal cost pricing determines plant-dispatch – as in Texas and California – fuel switching based on price is more transparent.

Box 5.A. Flexible Gas Consumption in the U.S. Electric Power Sector

Gas used to fire electric power generators represents one-quarter of all gas consumed in the United States each year (EIA 2006b). In the summer months, electric power generators use over half of total gas consumption. Figure 5.2 shows U.S. monthly gas burn for electric power generation (left axis) and total electricity consumption (right axis) for the years 2001 to 2004. The chart shows the relatively predictable, seasonal switch to gas-fired generation to meet summer electric power demand. In winter months, much of that gas-fired generation sits idle while coal, nuclear and hydro units are preferentially dispatched. For the four years (2001-2004), average gas consumption by electric power generation in January was 366 Bcf, compared to 675 Bcf in August. This represents a seasonal swing of over 300 Bcf of gas consumption (10 Bcf/day, 15% of average U.S. consumption). Seasonal switching is in response to the tendency for natural gas prices to be significantly higher in winter months, reflecting the high gas demand for residential heating. Unit-level surveys by (Pyrdol and Baron 2003) confirm this seasonal switching.

The seasonal swing in gas consumption for electric power reduces overall gas delivery infrastructure requirements. Figure 5.3 plots gas consumption by U.S. residential customers and gas burn for electric power generation. Gas use for power generation is counter-cyclical to residential heating demand. The aggregation of U.S. consumption at the national level does obscure important regional variation in gas transport requirements. In general, however, the reduced winter consumption of gas in the power sector frees gas pipeline and storage capacity to meet residential consumer requirements.

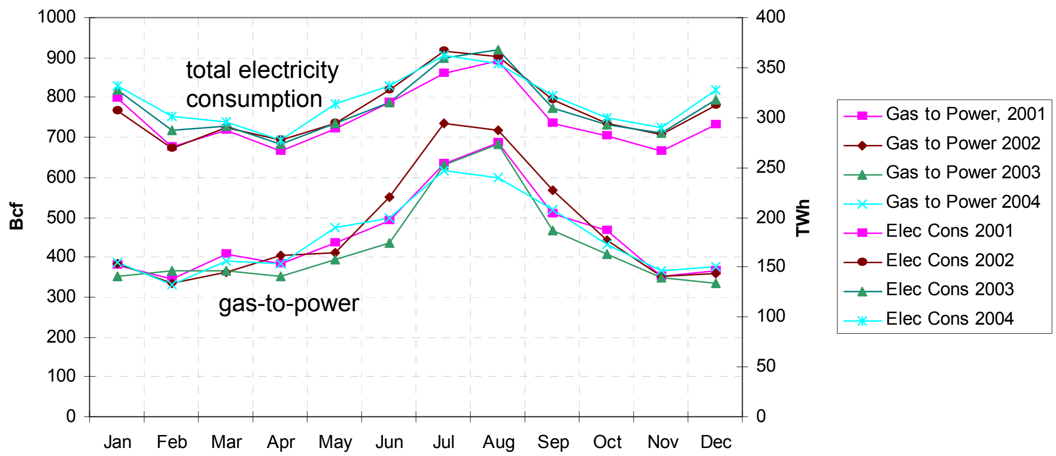

Figure 5.2. Gas role in U.S. electric power generation, 2001-2004. Natural gas consumption by electric power generators (left axis, in Bcf). Total U.S. electricity consumption by month (right axis, Terawatt-hours, TWh). *Source: (EIA 2006b).*

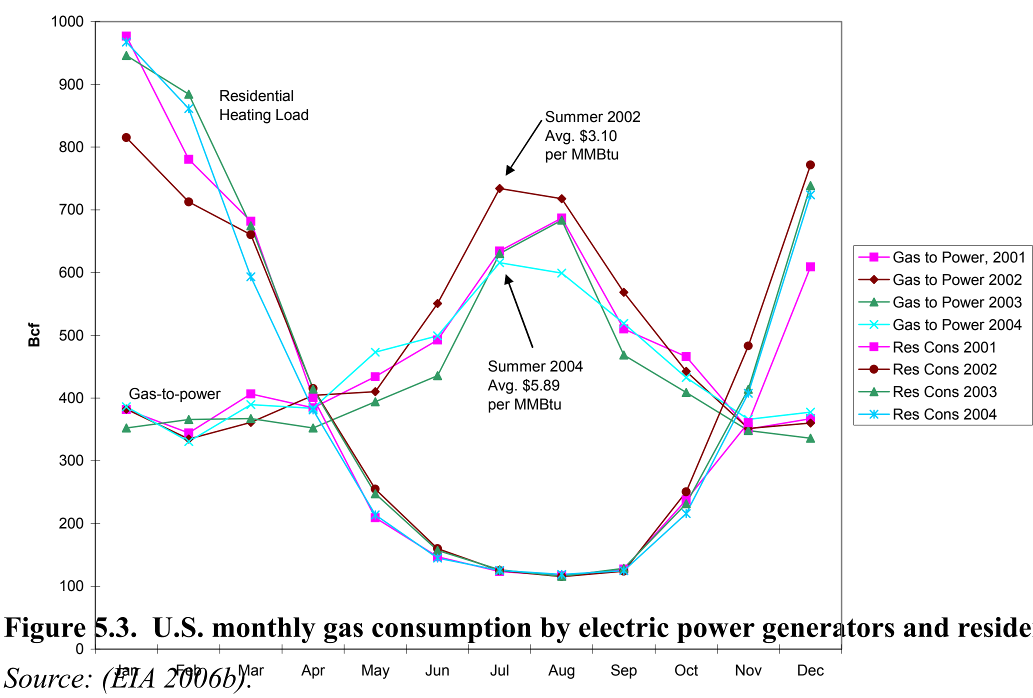

Figure 5.3. U.S. monthly gas consumption by electric power generators and residential customers. *Source: (EIA 2006b).*

Figure 5.3 also shows the response of electric power generators to less predictable, stochastic variability in gas prices relative to other fuel prices, particularly oil products. For example, U.S. gas consumption by electric power generators peaked in the summer of 2002, with consumption of nearly 734

Bcf in July of that year. As shown in figure 5.2, U.S. electric consumption was not significantly increased compared to 2001, 2003, or 2004. Instead, relatively low natural gas prices ($2.98 per MMBtu) encouraged gas-fired generation relative to alternative fuels such as residual and distillate fuel oil ($3.54 and $4.89 per MMBtu respectively for July 2002).

In July 2004, natural gas prices were considerably higher than in 2002, particularly relative to residual fuel oil. Average natural gas prices in July 2004 were $5.93, compared to $4.05 for residual fuel oil and $7.86 for distillate, each on an MMBtu basis. Higher priced gas made its use for power generation relatively less attractive, and total gas consumption for electric power generation was over 100 Bcf less in July 2004 than in July 2002 (616 Bcf compared to 734 Bcf). The shift away from gas-fired power generation was in response to the near doubling of natural gas prices in July 2004 compared to July 2002.

This analysis of aggregate gas consumption at the national level is supported by unit-level surveys conducted by (Pyrdol and Baron 2003). Pyrdol and Baron observed nearly 3 Bcf/day (roughly 90 Bcf per month) of active switching between natural gas and fuel oil depending on the relative price of each fuel.[7]

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[7] Pyrdol and Barron (2003) estimated that nearly 29 Gigawatts of power generation capacity actively switched between natural gas and fuel oil.

The U.S. electric power example demonstrates the tremendous flexibility provided by the price mechanism to induce demand response in competitive wholesale gas markets. When the supply/demand balance is tight, prices rise inducing some customers – such as electric generators – to reduce gas consumption thus increasing supplies available to other users.[8]

In the U.S. and the U.K. residential and small commercial customers are served by local distribution companies (LDC's). LDC's are granted monopoly service territories, and assume the obligation to provide gas to these customers. The LDC's are residential gas customers' proxy in this open wholesale market. In return for their right to serve these captive customers, LDC's have an obligation to supply residential customers' varying demand needs. Gas prices to small gas consumers are based on the average of the trailing procurement costs of their respective LDC – and are thus less volatile than spot wholesale prices. Thus, gas use by LDC customers is unresponsive to daily price changes and is largely determined by temperature variability that drives demand for home heating.

LDC's manage some of the variability in residential gas demand with their own storage capacity. Nearly 70% of the 3.4 Tcf total of U.S. gas storage capacity is owned by gas distribution companies (Cates 2001). This storage is usually located in proximity to the LDC service territory. Injection into storage occurs in the summer months preparing for winter peak demand. Utilities store gas taking into account the potential variability in heating needs, maintaining capacity to provide gas for a range of possible winter weather conditions. To augment storage capacity, LDC's purchase gas on the wholesale spot market to meet any additional consumption needs. The LDC then seeks to include all costs of buying gas into customer charges. Thus, even though residential gas customers are shielded from daily swings in gas prices, they are exposed to swings in gas prices that affect LDC procurement costs.

In the competitive market, security is largely measured in financial rather than physical terms. Mechanical interruptions in gas transport and distribution are concerns, as in any

[8] Gas burn for electricity generation also produces volatility in gas prices. Electricity load is itself highly variable on daily and hourly bases and – unlike gas – electricity cannot be stored. The technical characteristics of gas turbines make these units well adapted to meet variable electricity needs. Thus, gas consumption in electric power also responds to electricity demand needs, which in turn affects the market price of gas in competitive markets. For additional detail on the causal link between natural gas and regional electricity prices see Brown and Yücel (2006).

network. However, variability in gas demand and supply are continually balanced and matched by the price mechanism. On a daily basis, gas producers, traders, and major buyers participate in a liquid market, buying and selling gas to meet their variable needs and financial positions. Long-term security, measured by the adequacy of investment in gas production and transport, depends on the ability of private players to make assessments of future demand. When capacity is short, current and expected prices tend to rise, encouraging new investment.

The U.S. and U.K. gas markets have historically relied largely on domestic production and limited pipeline imports from proximate neighbors to meet their gas demand needs. The U.S. relied on neighboring Canada for about 15% of its gas needs and Canadian producers had little alternative market beyond domestic consumption. Similarly, the U.K. relied largely on production from its own North Sea fields, drawing limited imports from Norway and the Netherlands.

In isolation, both the U.S. and U.K. institutions have proven effective at providing gas market security under the competitive wholesale regime. Price volatility has been a concern in recent years, but large gas users have demonstrated the effectiveness of the price mechanism to allocate gas to its highest value use in times of short supply. The flexibility of large industrial users has allowed gas deliveries to be maintained to residential customers – those with the least ability to switch fuels or do without gas supply. Recent price increases in the U.S. and the U.K. (shown in figure 5.1) reflects the tightening of available domestic gas production in both countries. Both the U.S. and the U.K. are increasingly looking to LNG imports to meet growing gas demand needs, just as continental Europe is also looking to LNG supplies to meet growing gas demand.

5.3 LNG – Interconnecting "Managed" and "Competitive" Gas Markets

The projected growth in LNG imports to the U.S., the U.K. and Europe will inter-connect previously isolated regional gas markets. In the following section I discuss the structure of the interaction that will develop between competitive and managed markets, as both look to increased LNG imports.

5.3.1 LNG Imports for Managed Markets – Continental Europe and Japan

Monopoly gas companies in continental Europe and Japan have a guaranteed customer base, yet significant uncertainty remains about how much gas their captive industrial, electric power, and residential customers will demand in any given month. Lacking the price mechanism to induce demand response, these monopoly providers thus rely largely on shifting volume deliveries to manage variability in gas demand. Traditionally, seasonal and short-term variability in demand was managed by gas storage and varying gas pipeline imports. The growing LNG market, with its inherent flexibility in cargo movements, provides European and Japanese buyers a new and cost-effective alternative to storage and excess pipeline import capacity to meet unexpected shifts in gas demand.[9]

Two examples illustrate how players in managed markets will participate in the growing global market for LNG:

In late 2002 safety problems at a Japanese nuclear power plant forced the shutdown of five nuclear power plants owned by the Tokyo Electric Power Company (Tepco). To compensate for this massive loss of power generating capacity, Tepco increased its use of gas-fired generation which, in turn required additional LNG imports. In the six months ending September 30, 2003, Tepco purchased an additional 30 LNG cargoes (about 90 Bcf of natural gas) (IEA 2004a). Prior to the nuclear plant shutdown Tepco and other Japanese LNG buyers were selling extra cargoes to the U.S. market. However, when needed at home these cargoes were diverted back to Japan, resulting in a significant reduction in U.S. LNG imports in 2002 and 2003 (WGI 2002). Gas prices increased in the U.S. in response to loss of gas supply (though the specific

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[9] The modeling results of chapter 3 illustrate the efficiency gain for high-cost storage markets to use LNG to meet peak demand as a substitute for storage capacity investment. The model results in that chapter analyzed the benefits of seasonal LNG swing compared to storage. All else equal, LNG would also provide high cost storage markets an cost-effective means to meet less predictable variations in gas demand. Japan's storage consists primarily of tanks of liquefied gas at the regasification terminals. This storage is an order of magnitude more expensive than underground storage used to meet seasonal or daily demand swings in the U.S. or even Europe.

effect on prices is hard to measure), while wholesale natural gas prices in Japan maintained their oil-price linkage throughout the crisis.

Similarly, in 2005-2006 Spain and France experienced an extended drought that left those countries short of hydropower supplies. In response, Spanish and French power companies sought additional LNG to provide fuel for gas-fired turbines. As in the Japanese example, the incremental cargoes pulled to south-eastern Europe would have otherwise gone to the U.S. market (WGI 2006a). To attract these cargoes, Spanish and French buyers paid in excess of spot market prices in the U.S. However, since both Spain and France lack an open and competitive wholesale market internal gas prices rose only by the incremental LNG purchase costs on the average cost of delivered gas. Moreover, the additional costs of such LNG procurement enter rates slowly over time, as companies request rate increases to pass on to customers.

These two examples are representative of the interaction that will repeatedly occur between gas buyers in managed and competitive markets with the growing global trade in LNG. Figure 5.4 illustrates monthly gas supply and demand in a managed market, as it interacts with the global market for LNG.

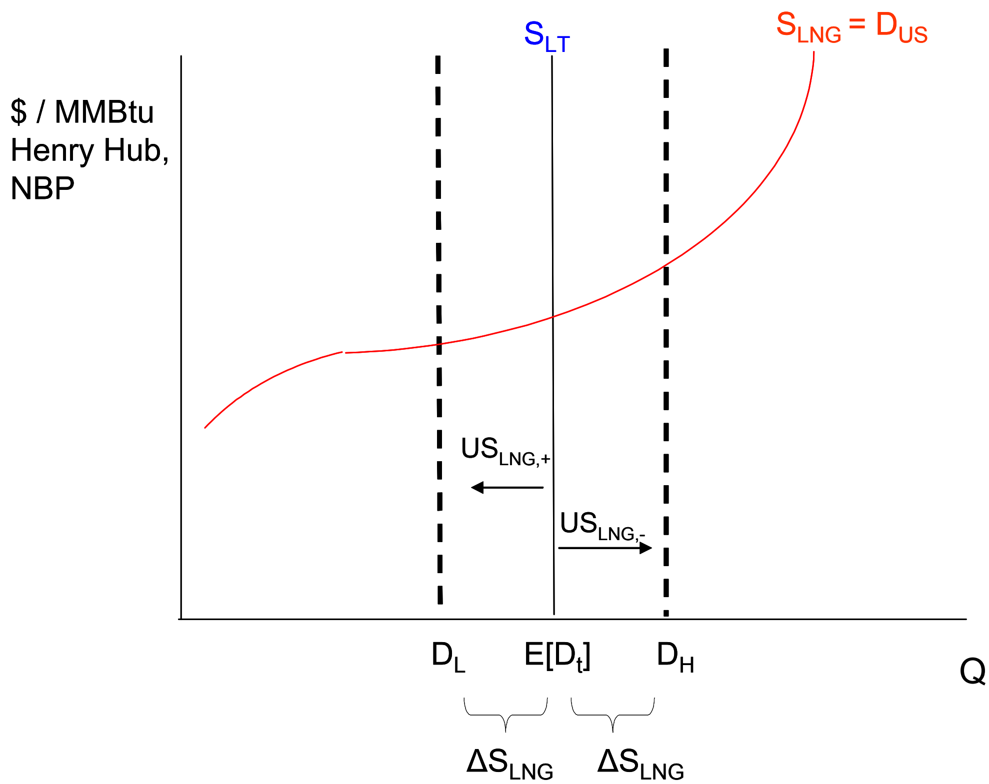

Figure 5.4. Short-term gas supply/demand balance in a managed market. The left axis indicates price levels in competitive gas markets, e.g the U.S. Henry Hub or U.K. NBP. As described in the text, without flexible internal wholesale pricing, the relevant indices for marginal LNG procurement costs for a managed market gas company are the U.S. and U.K. spot prices.

In figure 5.4 D_t shows the short-term demand for natural gas in the managed market. D_t is represented by a vertical line, as the use of gas in any given month is not influenced by world market prices. The level of gas demand will vary significantly with seasons (higher in winter, lower in summer) but will also shift stochastically, driven by weather and other unpredictable factors. In figure 5.4, two potential realizations of demand are labeled with dashed lines, D_L and D_H.

The supply of gas in the managed market is derived from two sources – reflected in figure 5.4 by (1) the long-term purchase quantity (S_{LT}) and, (2) any spot LNG purchases or sales (S_{LNG}).

The managed market gas company has both the incentive and the means to procure pipeline and LNG under long-term contract. Government policy emphasizes supply security and a captive customer base provides long-term revenue assurance – enabling managed market buyers to sign long-term contracts for their gas imports. In this context, European and Japanese companies have historically signed gas import contracts with maximum offtake volumes well in excess of average needs. The Tepco example and the recent record of long-term LNG contracts suggests that Japanese and continental European players will continue their historical tendency to sign long-term contracts as the LNG market turns global. From 2000 to 2004, 53 of 65 multi-year contracts for LNG delivery were signed by continental European or Japanese buyers [IEA 2004a].

Given these incentives, it is reasonable to assume the managed market company signed term commitments for gas supplies to at least match expected demand levels ($S_{LT} = E[D_t]$). Note, that supply in these long-term contracts is also unresponsive to the realized demand as supply is bounded by the capacity of the pipeline or LNG supply option. Thus in figure 5.4, S_{LT} is represented by a vertical line coincident with the expected demand.[10]

Historically, continental European gas companies have used a combination of long-term contracts and storage capacity to meet unpredictable gas demand. Japan, lacking cost-effective gas storage, managed most of its swing through expensive cushions in the LNG supply chain. Chapter 3 showed that even expected seasonal storage was more expensive at the margin than using LNG to meet seasonal swing in the case of Europe. We can thus expect a significant cost advantage for all managed market buyers to use spot LNG to meet 1-in-5 or 1-in-10 year swings in gas demand. The recent examples of Japan and Spain suggest the attractiveness of using LNG for flexible supply response.

When realized demand (D_H) is greater than the contracted quantity ($D_t = D_H > S_{LT}$) and the managed market gas buyer chooses to procure spot LNG, the first spot cargo bought by the continental European or Japanese buyer is pulled from cargoes that otherwise would go to the

[10] Pipeline import contracts to European markets typically contain "flex" clauses which do provide for seasonal and monthly adjustments in off-take volumes. From a capacity management perspective, such clauses require that the buyer pay full capacity charges to finance the infrastructure. Thus, whether the importer takes full pipeline quantity, customers are paying for the available pipeline capacity to meet varying demand. This is in contrast to the flexibility provided through routing of LNG tankers.

U.S. or U.K.[11] One less cargo in the competitive market increases wholesale gas prices there, that in turn, induces the least-costly incremental switch from gas to an alternative fuel source within the U.S. or U.K. (In the U.S., the reduction in gas use is likely come from a gas-fired power plant switching to residual fuel oil.) The second cargo drawn to meet demand would further reduce U.S. or U.K. supply, raise prices, causing the next least-costly switch away from gas. And so on, until the inflexible demand needs of the managed market gas buyer are met with spot LNG purchases (ΔS_{LNG}).

The cost to a managed market buyer of obtaining each cargo is determined by the wholesale price of gas in the competitive markets. To date this has been the Henry Hub in the U.S., but as U.K. LNG imports increase the NBP price could also become a benchmark for some cargo diversions. The marginal cost to managed market players of procuring cargoes will increase with the volume diverted, following the inverse of the short-term demand curve for gas in the competitive markets.

Managed market buyers will also sell LNG cargoes into competitive markets when realized domestic demand is below contracted supplies (S_{LT}). The incentive for these companies to procure gas under long-term contract suggests that these buyers may in fact have excess gas under contract more often than they are short.

From the perspective of market security under the managed regime, the expanding LNG market creates the option to procure spot cargoes to meet unexpected demand peaks more cost effectively than maintaining excess pipeline supply or gas storage. Gas market security can thus be provided more cheaply than in a world without fungible LNG markets. Fungibility in LNG supply is created by diverting supplies from the U.S. and U.K. The implications for these competitive markets are discussed in more detail in the next section.

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[11] The fungible markets in the U.S. and U.K. are the opportunity cost to which all spot cargoes are priced. A cargo could, in fact, be diverted as excess from Japan and end up in continental Europe – but the only transparently priced option to which that price is marked is the spot gas price in the U.S. or the U.K.

5.3.2. LNG Imports to "Competitive" Markets – the U.S. and the U.K.

Analysis of the institutional structures suggests that U.S. (and to some extent U.K.) flexible gas consumption, especially gas used in electric power generation, will provide the capacity for variable LNG shipments continental Europe and Japan. Experience in spot LNG trade to date supports this conclusion. In this section, I discuss the impacts of such variable LNG procurement by managed market players on competitive markets, using the U.S. gas market is as a representative example.

Figure 5.5(a) is a stylized model of U.S. monthly supply/demand balance for natural gas in the summer months. The total demand for natural gas for a given month is composed of both small, residential users ($D_{R,s}$) and larger industrial and electric power users ($D_{E,s}$). In the summer, residential demand for natural gas is small – and unresponsive to wholesale spot prices for gas (e.g. the Henry Hub price). Electric power generation constitutes nearly one-half of total gas consumption in an average June, July and August. In contrast to the managed markets in Europe or Japan, gas use in the power sector is sensitive to the price of gas. Higher gas prices, *ceteris paribus,* encourage power generators and grid operators to reduce gas consumption and switch to alternative fuel sources to meet electricity demand needs. The remainder of the summer demand for gas is composed of other large gas users, and also gas demand for storage injection for use by residential customers in winter months.

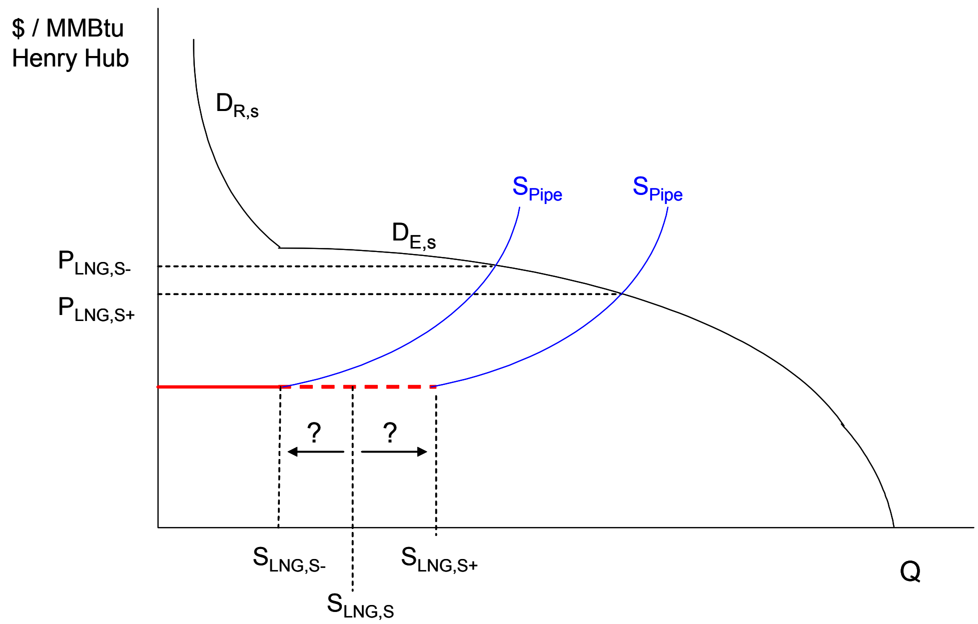

Figure 5.5(a). Short-term gas supply/demand balance for the U.S. in typical summer month.

U.S. natural gas supply is represented as two distinct segments. Most estimates, including those used in chapter 3 of this text, suggest that LNG is a low-cost supplier to the U.S. market, e.g. (IEA 2004b; EIA 2005b). However, we can also assume that LNG deliveries to the U.S. are unresponsive to Henry Hub prices following the discussion of managed markets in section 5.3.1 above. Managed market players buy or sell LNG cargoes to balance demand in their domestic markets. Even if those players wanted to divert LNG cargoes to the U.S. when Henry Hub prices are higher than their own contract purchase prices – inability to affect demand through price increases in their own markets limits a managed market gas importers' ability to adjust LNG imports in search of excess profits. The primary function of the managed market companies – under government mandate – is to provide gas services to its domestic market customers.

On a seasonal basis, expected U.S. LNG supplies are likely to be higher in summer months. Model results from Chapter 3 showed that European LNG importers will tend to be long cargoes in those months, as summer demand for gas is limited in Europe, resulting in an expected summer swing of cargoes to the U.S. In figure 5.5(a) summer LNG supplies are represented by $S_{LNG,S}$.

Uncertain demand in Europe (or Japan) makes actual, realized LNG deliveries to the U.S. dependent on spot LNG purchases (or sales) by the managed market importers. Two potential realizations of LNG supply are shown in figure 5.5(a) – one scenario where managed market importers are net over-contracted for LNG and thus diverting cargoes to the U.S. ($S_{LNG,S+}$), and one scenario where Europe and Japan are pulling more spot cargoes away from the U.S. than would have been expected ($S_{LNG, S-}$).

The remainder of gas supply in the U.S. summer is provided by domestic production delivered by pipeline. Domestic gas production is increasingly demon-strating "just in time" delivery behavior. Declining domestic well sizes and rapid depletion rates are making U.S. domestic production increasingly responsive to gas prices even on the monthly time scale (EIA 2006b; WGI 2006b). Thus, U.S. short-term domestic gas supply is represented with upward sloping curve, with supplies increasing in prices (S_{Pipe}). Unlike LNG supply, U.S. domestic production does not vary by season.[12]

In the U.S. the wholesale price of gas in a given summer month is thus determined by the intersection of the total supply curve ($S_{LNG,S} + S_{Pipe}$) with the summer demand for gas. According to this stylized model, realized U.S. gas prices for a given summer month might vary from $P_{LNG,S+}$ to $P_{LNG,S-}$, depending on the amount of LNG delivered to the U.S. market. The scale of price response in the U.S. market will depend on the volume of swing in LNG supplies and the cost of switching gas-fired power generation to alternative fuel sources to make the wholesale market clear with reduced (or increased) gas supply.

[12] The limited observed seasonality in U.S. pipeline gas supply is driven by producers' response to regular seasonal price trends.

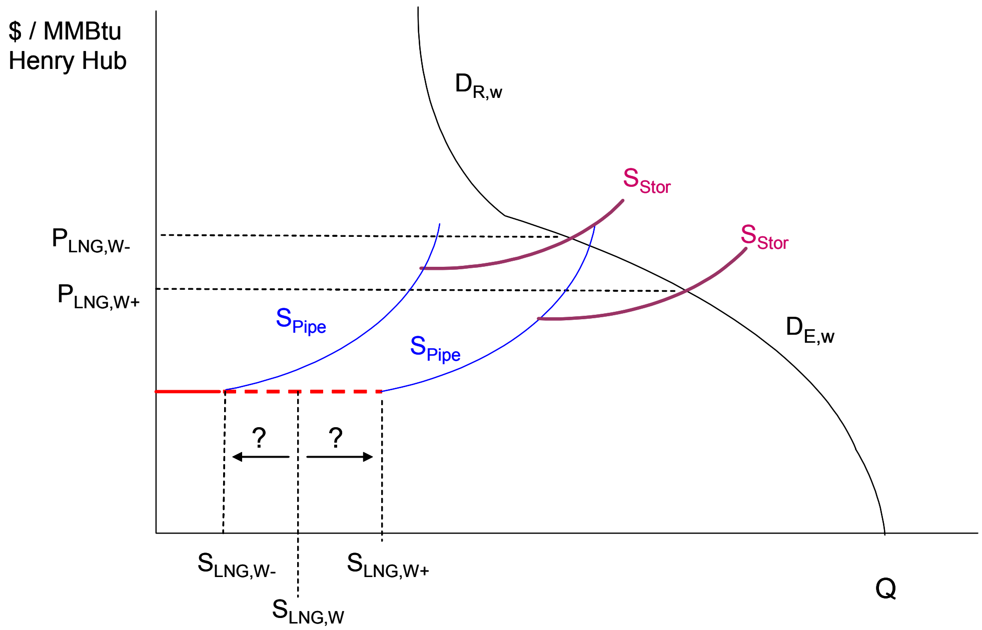

Figure 5.5(b). Short-term gas supply/demand balance for the U.S. in typical winter month.

Figure 5.5(b) shows the supply/demand balance for gas in the U.S. market for a typical winter month. Total demand for natural gas in a given month again includes residential consumers ($D_{R,w}$) and electric power and industrial users ($D_{E,w}$). Winter residential consumption is nearly a factor of ten greater than summer residential demand – and relatively unresponsive to wholesale spot prices for gas (e.g. the Henry Hub price). Gas consumption by electric power generators ($D_{E,w}$) is approximately one-half of the peak summer gas demand ($D_{E,s}$) shown in figure 5.5(a).

The supply of gas to the U.S. in the winter functions largely as in the summer months, albeit with lower expected LNG deliveries. Chapter 3 showed that higher storage costs and stronger winter demand in Europe will, on average, draw cargoes away from the U.S. in the winter, and thus $S_{LNG,W} < S_{LNG,S}$.

In figure 5.5(b), the low cost LNG supplies ($S_{LNG,W}$) still form the base of short-term U.S. gas supply. However, the potential for continental Europe and Japanese buyers (both in the Northern Hemisphere) to seek spot LNG cargoes is greater in the winter months than in the summer. Shown in figure 5.5(b) are two potential realizations of LNG supply deviating from the expected average level – one scenario where the major managed market importers are pulling spot cargoes away from the U.S. ($S_{LNG, W-}$), and a second scenario where European and Japanese importers are collectively over-contracted for LNG and thus divert excess cargoes to the U.S. ($S_{LNG,W+}$).

In addition to LNG, the remainder of winter gas delivery capacity during a winter month is provided by domestic production (S_{Pipe}) and storage withdrawals (S_{Stor}). Pipeline gas supply rises with prices due to incentives for increased drilling. Gas available from storage also increases in expected winter price levels, as higher prices create the incentive for storage operators to outbid summer electric power generators to purchase gas for injection. Thus, to the extent that storage operators have reasonable expectations about upcoming winter consumption needs, we should expect the cost of gas withdrawn from storage to reflect the summer demand curve for gas in electric power.[13]

The wholesale price of gas in a given winter month is ultimately determined by the intersection of the total supply curve ($S_{LNG,W} + S_{Pipe} + S_{Stor}$), with the winter demand for gas (D_w). According to the stylized model shown in figure 5.5(b), realized U.S. gas prices for a given winter month might vary from $P_{LNG,W+}$ to $P_{LNG,W-}$, depending on the amount of LNG delivered to the U.S. market.

The variability in LNG supply in winter months (from a low of $P_{LNG,W-}$, to $P_{LNG,W+}$) results in greater price variation than observed in summer months. Residential gas demand makes up the bulk of winter gas consumption. Home heating needs are by nature highly temperature dependent and the lack of responsiveness of residential demand to monthly

[13] Expectations about winter demand need not be perfect, but they would be an important aspect of forming the winter supply/demand balance. For a more thorough description of the economics of seasonal storage see chapter 2 of this text and Williams and Wright (1991).

wholesale spot prices makes winter wholesale prices in a competitive market like the U.S. even more sensitive to LNG supply variability.[14]

5.4 Implications for Market Security and Policy Responses

In a hypothesized world where all gas markets are open and competitive, with homogeneous seasonal demand and costs of gas storage, the growth of LNG imports would expose all markets equally to the global supply and demand variations. Policy measures adopted to manage such variability – e.g. measures to encourage additional gas storage – would benefit all markets equally. However, the continental European, U.K. and U.S. gas markets poised to import increasing amounts of LNG have very different institutional structures which create contrasting security concerns and policy measures to address those concerns.

In section 5.4.1, I discuss security implications (mostly benefits) related to the growth of the global LNG market for managed market importers. Then, in section 5.4.2, I consider how LNG supply variability will impact price volatility in a competitive gas market using the example of the U.S., and discuss the implications of such volatility for gas consumers in such a market. I then suggest four specific policy measures that will increase the ability of competitive market buyers to reap the benefits of the increasingly fungible LNG market and pass these benefits on to their customers.

5.4.1 Managed Market LNG Importers

Market Security Implications

For LNG importers in managed markets, the emergence of a global trade in LNG enhances market security simply by expanding the number of suppliers in the marketplace. Japanese or continental European buyers can much more easily diversify their geographic sources of supply, reducing the likelihood that a major fraction of imports fails due to a political or technical interruption in a particular supply country or at a particular liquefaction facility. Previously such security was provided by over-building supply capacity or expensive

[14] The reduced flexibility in the wholesale market for gas is also evident in the historically observed volatility of winter gas prices compared to summer (Graves, Coghe et al. 2002).

investments in "strategic" storage. In a growing, more fungible market for LNG, buyers will increasingly be able to attract spot cargoes to compensate for any disruptions in supply.

The growing LNG trade also creates a new, low-cost option for managed market buyers to respond to demand variability. The unpredictable nature of weather or economic conditions makes the use of gas variable on daily, monthly and even annual time scales. With a very thin market, Japanese buyers in particular were historically forced to over-contract for LNG supplies to ensure that they had sufficient capacity to cover potential demand needs. The growth of LNG trade, and the flexibility provided by U.S. and U.K. gas markets, creates an additional, cost-effective tool for continental Europe and Japan to manage variability in their gas demand.

Policy Responses

Policy makers in managed markets can further enhance the ability of LNG to provide market security by encouraging investment in "excess" regasification capacity. By allowing gas companies to build regasification capacity greater than average (or even expected seasonal peak) import needs, continental European and Japanese companies will provide those markets with a "cheap option" of obtaining additional gas supplies when domestic demand unexpectedly increases.

Long-term security in managed and competitive gas markets alike depends on growth in LNG supply to meet expected growth in gas demand. Many of the gas reserves available for LNG export projects are located in countries with less than ideal investment environments. Private investors in these markets are exposed to significant political risk. Hayes and Victor (2006) discuss a variety of measures available to investors and host country governments to better manage risks associated with investment in gas export projects. The most important factor determining successful project investment was the ability of host-country governments to credibly signal an enduring regulatory framework for a particular project. Hayes and Victor (2006) found that international organizations (such as the World Bank or export credit agencies) can increase the ability of supply country governments to make credible commitments to attract investment in export capacity.

A potential concern for all LNG importers is the possibility for the development of a gas exporters' cartel, analogous to OPEC in oil. Jaffe and Soligo (2006) argue that the potential for such a cartel to conspire to raise LNG prices is unlikely in the next decade. Capital costs for capacity to produce, liquefy, and transport natural gas are typically twice the unit costs of developing export capacity in oil, and the lead times for construction are much longer (IEA 2003). And once built, the low variable costs of liquefaction facilities make the economic incentive to produce enormously compelling.

Thus, most discussions of a gas exporters' cartel suggest that the group would cooperate to manage the development of new LNG export capacity. However, the ability of gas consumers such as electric power generators to switch to alternative fuels should invite caution to those interested in artificially constraining LNG supply in attempt to drive up prices. The recent response of power producers to look to alternative fuel sources to natural gas suggests that curtailing LNG supply will simply limit the future market for natural gas.

5.4.2 Competitive Market LNG Importers

Market Security Implications

U.S. and U.K. buyers share some of the benefits and concerns of a growing global LNG trade with their managed market counterparts. Increasing supplier diversity enhances physical security of supply. And inadequate supply investment or a cartel would potentially increase gas costs for competitive and managed market LNG importers alike.

The structure of the institutional interaction between managed markets and competitive markets also creates a set of concerns unique to competitive market gas companies and their customers. Continental European and Japanese importers have demonstrated the ability to sign long-term contracts for LNG purchase – and their captive customer base and inflexible rates provide both the means and necessity to look to spot LNG imports to match varying domestic gas demand. Recent evidence also shows that flexible cargoes are typically diverted from U.S. and U.K. markets.

While such flexibility in domestic markets reflects internal efficiency in the U.S. and U.K., such variation in LNG imports also contributes to price volatility within those markets. Large customers have the means to manage such price volatility and could in fact benefit from the fungibility created in a globalizing LNG market.[15] The implications of LNG supply variability for competitive markets residential customers are less clear.

At first glance, the liquidity of gas markets in the U.S. and the U.K. should provide LDC's the ability to use financial instruments (e.g. options) to hedge exposure to any price volatility resulting from variable LNG supplies. In theory, an LDC could design an optimized procurement portfolio to manage volatility in the market corresponding to the risk profile of its customers. However, Lyon (2003) showed that regulated utilities such as LDC's are systematically biased to under-utilize hedges or fixed-price contracts that would protect their customers from wholesale price volatility.

LDC's are less prone to manage price volatility than would be optimal for their customers because they risk not being able to pass on the costs of hedging if markets do not work in their favor. When hedging is advantageous to customers, the regulator will require that lower gas costs be passed through to consumers. However, if the spot price later turns out to be below the hedged price, then the regulator is tempted to force the utility to bear this cost, rather than allowing the full cost of hedging to be passed on to customers. (Lyon 1992) showed that the prospect of *ex post* regulatory disallowance of hedging costs biases procurement toward the spot market, which exhibits greater volatility than would be suited to the risk profile of the average residential consumer.

Surveys of U.S. LDC's confirm this bias toward over-reliance on spot market prices. A study by the U.S. General Accounting Office (GAO) found that for the winter 2000-2001, 20 percent of large utilities and 32 percent of small utilities did not hedge any of their winter gas supply for their residential customers (U.S. GAO 2002). The GAO study did show an improving

[15] The net effect on average price levels will depend on the specific actions of market participants which are less constrained by structural factors. If managed market buyers over-contract for LNG deliveries, using take-or-pay terms that cover capital costs for supply infrastructure expansion, then these European and Japanese buyers will, on average, ship more spot cargoes to the U.S. and U.K. than they attract to their markets. This would be a continuation of the historical practice – particularly for Japan.

trend over time. After the price spike of 2001, over 60 percent of large utilities and 80 percent of small utilities hedged at least one-half of their winter gas supply fro the 2001-2002 winter. Still the threat of *ex post* regulatory hindsight is real. According to the GAO study, 7 percent of U.S. gas utilities have had costs associated with gas purchases disallowed after regulatory audit (U.S. GAO 2002).

The bias toward under-contracting is evident in the fact that no U.S. gas utility has signed a multi-year LNG purchase contract to lock-up LNG deliveries [IEA 2004a]. Utilities could also sign contracts with major LNG importers and gas wholesalers that could effectively support new LNG supply chain investment and provide stable prices to LDC customers. No conclusive evidence shows that no U.S. LDC has signed such a contract. However, the GAO reports and the bias to protect against *ex post* review suggest that U.S. LDC's will be hesitant to make such commitments that would likely be in the best interests of their customers.

The biases within competitive markets – and the interaction with contractually advantaged managed market players – ensure that the U.S. and the U.K. will be both geographically and institutionally downstream of European and Japanese LNG buyers. Probably only in extreme cases of supply shortfall in the U.S. or U.K. will buyers in these markets be able to draw spot LNG cargoes away from Europe. The U.S. and U.K. experiences in the winter of 2005-2006 are perhaps best evidence of this dynamic. In December, January and February U.K. and U.S. gas prices spiked to record levels, well in excess of any quoted or oil-linked prices on the European continent (see figure 5.1). Still, Spain and continental Europe were able to pull all available spot LNG cargoes, leaving empty all U.K. regasification capacity and U.S. regasification capacity usually used for spot cargoes (WGI 2006a). Spain and Europe were also concerned about supply shortages – yet no price signals were passed on to continental European customers. Instead, the managed market buyers were well-armed with the financial security of their captive customers to buy all cargoes necessary to meet domestic gas needs.

The implications for under-contracting are likely to be worse in an integrated global gas market than when regional markets were isolated from the LNG trade. In competitive markets policies that allow and encourage LDC's to hedge price exposure may be particularly beneficial to consumers' welfare. The following section considers such polices, along with four other policy recommendations that will allow the U.S. and U.K. markets to better capture the market security benefits of low-cost LNG supplies and provide a buffer against price volatility.

Policy Responses

The simplest strategy to manage the export of gas supply and price volatility from continental Europe and Japan would be to encourage reforms that move managed markets toward more competitive models. Both the European Union and Japan have much discussed plans to open their markets to competition and reduce the dominance of state-champion monopolies. Progress on these reforms is limited, however, and not always in the direction of free and open markets.[16,17]

However, policy makers in the U.S. and the U.K. have few and relatively weak levers to affect market reforms in Europe or Japan. And regardless of progress on reforms in foreign markets, fundamental transportation and storage economics discussed in chapter 3 and 4 will continue to drive variability in LNG imports and price volatility in competitive markets. Policy makers in the U.S. and U.K. should thus pursue additional measures to ensure the benefits of cost-competitive LNG supplies are fully realized. Four specific recommendations follow:

(1) Support Term Contracting and Hedging by LDC's

Previous research and surveys suggest that utility companies are systematically biased against the types of contracting and hedging procedures that would protect their customers from price volatility (Lyon 1992; U.S. GAO 2002). LDC's will engage in longer-term contracting and hedging only if they have assurance that they will be allowed to pass these hedging costs on to customers even when the realized spot market price is below the contracted price.[18] All evidence

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[16] Note, for example, the proposed merger of Suez, the major French energy company, with Gaz de France. If successful, the combined company would entrench the combined state-owned company in the French natural gas and electric power markets (WGI 2006c).

[17] It is worth of noting that the benefits of such market liberalization would yield gains for both the reforming markets and their competitive counterparts. Competitive markets achieve allocative efficiency that managed markets cannot. Managed markets must rely on planners to determine future consumption and government has little ability to oversee state-champion monopolies without the information provided by the price discovery mechanism in an open and competitive market.

[18] In addition to concerns about "Monday morning quarterbacking" by regulators, utilities also face corporate credit issues that also bias against long-term gas purchases. In the aftermath of the U.S. electricity crises of the late 1990s

suggests that LNG can provide a low-cost supply source for U.S. domestic gas needs (NPC 2003; EIA 2005a). And the growth of a global market for gas will provide the information required by regulators to determine if long-term contract prices are truly competitive. U.S. regulators will be able to compare contracts for LNG procurement with prices paid in other competitive markets such as the U.K.

To provide regulated companies a credible signal that they will not be subject to *ex post* review based only on market outcomes, the power of the regulator itself must be constrained. In the U.S., oversight of the LDC's occurs at the state-level through public utility commissions. Thus, specific state legislation could be enacted to constrain *ex post* review of LDC gas purchase contracts, allowing hedging costs to be passed through to customers except under the appearance of anti-competitive behavior. Again, the international market for gas creates new information that can better inform regulators in this regard.

The willingness of utility companies to sign long-term financial or physical contracts would also credibly signal to potential gas suppliers the scale of future gas demand in the U.S. Historically, investment in the gas production, liquefaction, and tankers has been financed with long-term contracts. Debt financing required for massive LNG projects ($3.5 billion for an LNG train to deliver 1 Bcf/day to U.S. market) demands stable long term cash flows. The ability of U.S. buyers sign long-term contracts for LNG delivery may be critical to creating the "security of demand" to deliver robust LNG supply to the U.S. market, rather than occasional spot cargoes diverted from managed markets in Europe and Japan.[19]

(2) Encourage Siting and Construction of Regasification Capacity

Technological and economic realities suggest that abundant regasification capacity, well in excess of expected LNG import needs, would allow competitive markets like the U.S. to better

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and the meltdown of Enron, U.S. credit rating agencies adopted a policy of classifying long-term power purchase agreements as "debt equivalents" with concomitant implications for utility company creditworthiness. Similar treatment of gas procurement contracts would also raise the cost of borrowing for utilities – biasing LDC's against long-term commitments unless regulators agree to compensate for the resulting increase in interest expenses. I thank Jim Sweeny for his suggestion that these credit-rating issues also act along with the *ex post* review concerns to cause LDC interests to systematically diverge customer preferences for risk management.

[19] For further discussion about "security of demand" as a critical determinant of LNG project investment see Hayes and Victor (2006).

capture the benefits of the globalizing trade in LNG. If viewed as an option, U.S. or U.K. buyers can look to procure cargoes when the global market has excess supply. Regasification terminals represent a fraction (less than one-tenth) of the total cost of delivered LNG (see chapter 3). As shown in chapter 4, the option value provided by the ability to move (or procure) cargoes opportunistically provides value well in excess of the costs of the terminal itself. Thus, private incentives to build regasification terminals are adequate to construct excess capacity.

However, approval for terminal siting continues to be a lengthy process, particularly for facilities outside the Gulf Coast of the U.S. Further efforts to streamline cooperation between federal, state and local agencies could increase the likelihood that adequate regasification capacity exists for the U.S. (or U.K.) to capture the benefits of imported LNG.

In addition to aggregate capacity considerations, the location of LNG terminals also raises important policy questions in the U.S. Due to local community siting concerns, the bulk of new capacity is being developed in the U.S. Gulf Coast. The concentration of terminals there exposes LNG import capacity outage due to hurricanes. The location of regasification capacity closer to market area demand also creates the opportunity for these terminals to capture more of the true optionality and flexibility of LNG shipping.

For example, if protected from *ex post* regulatory scrutiny, LDC's in the Northeast of the U.S. could sign firm contracts for gas delivery in the winter months through newly sited LNG receiving terminals. Such terminals could offset incremental investment in market-area storage and to some extent provide additional flexibility to respond to regional gas delivery constraints in the U.S.

One particular option that can provide this flexibility at low cost is a technological change in LNG ships. Some new LNG ships are equipped with onboard regasification that would allow the ships to slowly vaporize their liquefied cargo and deliver it into an offshore pipeline. These tankers introduce new flexibility into the gas delivery system, and thus potentially allowing tankers to substitute for additional interstate pipeline capacity and market-area storage. Investment in these facilities could be enhanced if LDC's were encouraged to contract, over a number of years for the service provided by these LNG import infrastructures.

The policy that governs access to regasification facilities has been a particular concern. Full consideration of the proper regulatory construct – whether the facilities should be treated as supply, or whether they should be regulated as pipeline transport capacity – is beyond the scope of the discussion here. Carpenter (2005) examines the key considerations and the current policies in Europe, the U.K. and the U.S. Risks of anti-competitive behavior are minimized where there is a robust market for imports, supply and buyers – as in the Gulf Coast of the U.S. Oversight of LNG terminal access is more critical where LNG supply capacity is large relative to the local market – and especially when owners of import capacity also control gas pipelines and peak storage capacity – thus providing key tools to manipulate local natural gas prices.

(3) Encourage Additional Investment in Gas Storage Capacity

"Excess" regasification capacity will allow the U.S. and U.K. to acquire spot LNG cargoes at lower costs in times of global market surplus. However, variability in LNG supply will not smooth average price without complementary investment in gas storage capacity. For example, increased supplies in the summer months can be stored to smooth supply variability and respond to increased gas demand requirements in winter months.

However, both U.S. and U.K. storage capacities are currently constrained – with seasonal spreads in both markets in excess of $4 per MMBtu per year.[20] In the U.S. the estimated the cost of new storage capacity is estimated to be less than $1 per MMBtu per year (IEA 2003). As discussed in chapters 2 and 3, equilibrium in the storage market would imply differences between summer and winter futures prices closer to the annualized cost of storage capacity. The wide seasonal spread compared to the cost of storage is a strong indicator of the demand for additional investment in storage capacity. Increasing variability in LNG supply will continue to enhance the value of storage in both the U.K. and U.S. markets.

[20] Current estimates based on Nymex and NBP futures prices; August 11, 2006. For more discussion of the relationship of seasonal spreads to the value of storage see chapter 3, this volume, Williams and Wright (1991) or Pindyck (2001).

The institutions that govern new storage capacity will be important to determining the utility of this infrastructure to buffer LNG market volatility. Nearly 70% of current U.S. gas storage capacity is owned and operated by the regulated LDC's (Cates 2001). The primary purpose of this regulated storage is to guarantee physical availability of gas for winter residential consumption. For regulated storage operators, financial optimization is a secondary goal and subject to some of the same biases that affect LDC gas procurement. Uria and Williams (2005) studied actual storage and withdrawal behavior by both regulated and market-based facilities in California. These researchers found that the regulated entities were less responsive to market prices in their decisions – particularly on when to purchase gas for injection.

The Uria and Williams work suggests that market-based storage, free to operate independent of LDC's and charge competitive rates will better provide the balancing function increasingly valuable in a world of variable LNG imports. Flexible, market driven storage will respond to price variations, independent of the types of planning rules that typically govern LDC storage operation. Moreover, regulators may also encourage LDC's to manage their existing capacity to respond to both local and global market balances.

(4) Maintain and Enhance Flexibility in the Demand for Natural Gas

The discussion of the role of natural gas in the U.S. electric power sector highlighted the importance of fuel choice and dispatch in providing flexibility in natural gas demand. Without a fungible LNG market, the ability of power generators to switch fuels and plants provided an important tool to balance inflexible and highly unpredictable natural gas demand in the residential sector. The integration managed and competitive gas markets will place an increasing premium on electric power generators that can switch fuels or unit dispatch to respond to price variability.

Regulators can act to ensure that the benefits of fuel-switching are maintained by minimizing any factors restricting flexibility in power plant dispatch. In some cases environmental rules can create constraints that increase the cost and reduce the overall flexibility in electric power generation. The environmental benefits of these restrictions should be carefully weighed against the potential costs. The California Electricity Crisis of 2001 provides a useful example.

During the California Crisis, constraints on NOx emissions in Southern California added a significant cost to bringing on additional oil-fired power plants. This created a tremendous premium for gas-fired power—and thus providing additional support for spiking natural gas and electric power prices (Hayes and Cope 2001; Joskow 2001). The environmental restrictions were not the cause of the electricity crisis. Rather an energy shortage combined with fatally flawed regulation set the stage for market failure (Sweeney 2002). However, a temporal lifting of NOx emissions constraints in Southern California would likely have buffered the major spikes observed in gas and electric power prices during that period. A relaxation of constraints would have yielded a temporary increase in local air pollution – but the damages from that temporal increase would likely have been small compared to the many-fold increase in electric power prices during that period.

Restrictions on sulfur emissions may present similar barriers to the elastic response of gas-fired generation to price increases. Unit-level switches from natural gas to coal-fired power plants require that coal-fired generators purchase additional sulfur credits for power plant emissions. In times of severe natural gas shortage (such as the period following Hurricane Rita in 2005) temporary adjustments in emissions regulations could possibly benefit residential consumers in the form of reduced gas and power prices more than enough to offset the damages of the one-time increase in emissions. Such examples suggest an important role for informed and inter-agency regulatory policy making.

In addition to careful consideration of environmental constraints related to electric power supply, increased flexibility in the demand for electric power also offers the potential to buffer natural gas price spikes and increase overall market security. Since natural gas-fired power plants are used to flexibly respond to electricity demand variability, steps that reduce the size of demand spikes in the power market would also reduce surges in gas demand (and prices). In particular, a reform of residential electricity pricing that provides customers with the incentive to respond to the real-time marginal cost of electricity would work to buffer swings to gas-fired power generation, and in turn gas prices. In addition to reducing volatility in gas prices, the shift toward time-varying electricity rates would result in broader efficiency benefits in the electric power markets and has been studied by many analysts including Sweeney (2002).

5.5 Conclusion

Most attention to energy security focuses on the reliability of energy supplies. The highly seasonal and stochastic variability of natural gas demand suggest a broader framework for analyzing market security incorporating supply, transport, storage, and demand characteristics. The inherent flexibility of LNG transport creates both opportunities and risks to market security for countries increasingly reliant on LNG imports.

Variations in seasonal demand, storage cost, and shipping distances create important differences for each LNG importer and their interaction with the global market. As discussed in this chapter, institutional structures will likely be just as important as cost-based drivers for shaping the LNG trade. The comparative advantage of buyers in continental Europe and Japan to utilize their captive markets to in turn support long-term contracts for LNG imports will provide these importers with more reliable LNG cargo deliveries. Moreover, the lack of competitive wholesale markets for gas in continental Europe and Japan makes spot procurement of LNG cargoes an attractive means to manage domestic demand volume variability.

Spot cargo purchase (or sales) by managed market buyers will not yield price effects in those markets. However, volume shifting by continental Europe and Japan will result in supply and price effects for U.S. and U.K. markets. Such price volatility is most costly for residential consumers, who lack both the ability to respond to price increases and tend to be less protected from price swings due to regulatory market failures. Policies that both protect vulnerable residential customers from increasing price volatility – and at the same time encourage increased flexibility in gas import, storage and electric power consumption – will ensure that U.S. and U.K. markets also reap the benefits of an expanding global market for LNG.

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