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Dawning of a New Era: The LNG Story

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The LNG Story

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Executive Summary

Spurred on by higher natural gas prices and a growing demand for cleaner fuels, interest in new liquefied natural gas (LNG) facilities has mushroomed. At the end of 2004, over forty new receiving and regasification stations were being proposed in the United States, and another ten were seeking siting approvals in Mexico and Canada. Even if less than ten percent of these projects are approved and built, more than twenty percent of United States gas demand may be supplied by LNG facilities by 2012. On the production side, the number of countries contemplating the construction of liquefaction facilities has doubled, and existing producers are scurrying to build more and larger facilities.

A glance at the economics shows why. Since the mid 1990s the costs of every stage of the LNG chain – gas production, liquefaction, shipping, and regasification – have dropped substantially. Today LNG costs have fallen below those of domestic pipeline gas in both the United States and Europe. Actual LNG costs depend on many variables, but range from as low as $2.50 per Mcf to approximately $3.50 per Mcf (as compared with the price of pipeline gas in the United States of $7.00 per Mcf). Industry experts believe that improvements in technology, especially for tankers, could lower these costs still further.

While costs have dropped, the price paid by consumers is likely to track the price of pipeline gas. Hence, the profits from LNG trade may be considerable, given the gap between the domestic price of natural gas and the cost of importing LNG. The competition to capture these profits will be fierce, but if history is any judge, most will be retained upstream – in the hands of the producers and their host governments.

This paper addresses two important questions:

1) Will competitive pressures change the structure of today's LNG markets?

2) As more LNG is traded, will the national security concerns that have characterized oil markets over the past thirty years also begin to characterize gas markets?

Competition

In the last ten years, wholesale markets for electricity in the United States, Europe, and Japan have become highly competitive. Firms with lower fuel prices have a distinct advantage. United States domestic gas markets have deregulated, and Europe is moving in the same direction. Driven by competitive forces, both the direct and indirect purchasers of LNG are exerting strong pressure on sellers to reduce prices and increase volume flexibility. Some experts speculate that as the demand for LNG grows, buyers will transform the market from one characterized by rigid long-term contracts to one characterized by merchant sellers who rely on spot markets and arbitrage opportunities. However, the evidence suggests that while the market will become more flexible, the

basic framework under which LNG has been traded will remain, at least for the near and mid-term.

The financial risks inherent in investing in each subsidiary in the chain of companies that comprises the LNG industry are too large to be left to the vicissitudes of the marketplace. Despite the current rhetoric, most liquefaction plants, shipping fleets and regasification faculties will be anchored by long-term contracts. Fluctuations in volume are considered more risky than price volatility, and thus upstream LNG producers will attempt to lock in long-term commitments to purchase supply, while allowing prices to shadow those in the importing country's gas market.

Security

With international natural gas trade poised to increase four-fold, consuming country governments have expressed concerns about the possibility of future politically motivated disruptions in LNG supplies. Will the problems inherent in oil dependence be replicated by a new set of security problems? This paper argues that such fears are overstated for several reasons:

1) Between 2005-2030, imported LNG volumes as a percent of the total amount of gas consumed will under almost every growth scenario remain much lower than that for oil. The only exceptions will be countries such as Japan or India that have limited domestic supplies. In these countries, LNG will continue to supply large boilers and electric generating stations and thus compete with substitute fuels, such as low-sulfur diesel oil or coal.

2) The number of new liquefaction and regasification facilities and the number of LNG tankers will be significantly greater in 2012 than in 2004. While this growth by itself does not insure against disruptions, it does indicate that buyers and sellers will have more options to purchase and deliver substitute supplies. This will be especially true if the size of spot markets grows in proportion to the total amount of gas.

3) Investments in redundant facilities and more storage, the use of sharing agreements among regasification and liquefaction facilities, and the design and development of more flexible contracts will give importing countries greater flexibility to weather supply disruptions. Japan has aggressively pursued every one of these options, and its success in managing the recent curtailment of LNG deliveries from the Arun facility in Indonesia is an example of how such actions can reduce a country's vulnerability.

4) In the case of natural gas, both the country being disrupted and the country doing the disrupting face significant costs. The former may lose gas supplies, but the latter endangers its flow of hard currency, trade in other commodities, and its standing in the international community. This interdependence can be increased

through the development of creative trade and investment arrangements that would be linked, either formally or informally, to LNG contracts.

LNG markets differ from oil markets in many ways, including size, the character of the participants, the nature of the investments, and patterns of trade. While specific accidents will happen, their impact will be localized and the global market will adjust more efficiently as the number of players and the size of the market increases.

I: INTRODUCTION

The world has enormous pockets of natural gas, but they are often located thousands of miles from consumption centers. Known global reserves are in the vicinity of 5,500 trillion cubic feet (Tcf)[1] and there are some who believe that the ultimate reserve size will be close to 14,000 Tcf.[2] In 2003, world demand was only 91 Tcf,[3] a small fraction of the global resource base.

As the consumption of natural gas grows, stimulated by economic growth, concern about security of oil supplies, and environmental imperatives, countries will increasingly look outside their borders to meet their demand.

There are two principal options for moving gas over long distances: larger and longer pipelines (where land routes are possible) or liquefying the gas and moving it in cryogenic ships. Both options move large amounts of gas between points of production and points of consumption. Often the imported gas is equal to 10-25 percent of the total gas consumed in a city or region. In the case of Japan and South Korea, almost 100 percent of their gas is received in the form of imported LNG. Interruptions in the flow could have consequences that differ from disruptions in other energy systems, such as oil or electricity, where there is greater flexibility, more redundancy, and a larger menu of sources. While there are variations on the relative economics of these options, the standard rule of thumb is that a pipeline route is more expensive per unit of gas transported than LNG shipments when the pipeline has to travel more than 2000-3800 kilometers.[4]

Catalyzed both by shortages in domestic gas supplies and the desire to improve local air quality, proposals for new LNG facilities mushroomed in the beginning of this decade. In 1995, only 3.3 Tcf of gas was sold in the form of LNG[5] and most of these supplies were bought by electric utility companies in Japan, South Korea and Taiwan. By 2002, the figure had risen to 5.4 Tcf[6] and is projected to increase to over 10.5 Tcf by 2010 and 14.4 Tcf by 2020.[7] If these predictions are accurate, more than one-third of all gas moved across country borders in 2020 will be in the form of LNG.

By the end of 2004, in the United States alone, there were 40 new receiving terminals and regasification facilities seeking approval.[8] In addition, there were ten terminals proposed

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[1] United States Energy Information Agency (EIA). The Global Liquefied Natural Gas Market: Status and Outlook. Washington, DC. December 2003, pg. 4.
[2] U.S. Geological Survey (USGS). World Petroleum Assessment 2000—Description and Results (revised).
[3] BP, BP Statistical Review of World Energy. June 2004, pg. 25.
[4] US EIA, op. cit. , pg. 4. These estimates are very dependent on the topography that must be traversed. The shorter distances referrer to pipelines that are under water for a portion of their length.
[5] US EIA, World LNG Imports by Origin, Washington, DC, 1995.
[6] US EIA, The Global Liquefied Natural Gas Market: Status and Outlook. Washington, DC. December 2003, pg. 1.
[7] The Petroleum Economist. Fundamentals of the Global LNG Industry. Landon, February 2004, pg.15.
[8] CEDIGAZ, 2003 Natural Gas Year in Review, www.cedigaz.org.

in Mexico and Canada, several of which would export their gas to the United States. Three of the four existing LNG facilities in the United States were seeking permission to expand.

On the production side, there are over 60 new LNG liquefaction facilities being built or planned. Qatar is seeking to build eight more liquefaction trains and to acquire the capacity to export more than 3 Tcf by 2010. Iran, Norway, Russia, Yemen, Egypt, Venezuela, Peru, and Equatorial Guinea are all planning to join Brunei, Indonesia, Oman, Australia, Libya, Algeria, Nigeria, United Arab Emirates, and Malaysia as major exporters of LNG. Moreover, the volumes of gas allocated to LNG are on the verge of increasing dramatically. Nigeria plans to double its exports by 2008.[9] Indonesia is expanding its Bontang facility to 22.3 million tons per year and will open the Tangguh facility (seven million tons) by 2007.

This surge in LNG production capacity was catalyzed both by rapidly growing demand for gas in Asia and North America and by major technological advancements in LNG production. Historically, in countries like Qatar, Trinidad, or Nigeria, gas was of little value and in some cases was perceived as a byproduct of oil production. Since there was no local market, gas was flared or left in the ground. As new markets for gas emerged, countries saw an opportunity to extract value from these resources. Capturing this value meant developing cost-effective options for transporting gas over long distances. In many instances, this required shipping the gas in liquid form. Multinational petroleum companies spent substantial sums of money to improve LNG technologies and reduce their costs.

There have been many studies that have assessed LNG's growth potential.[10] Scenario planners at Royal Dutch/Shell believe that gas may surpass oil as the world's most important energy source by 2025.[11] Some executives forecast that the industry will invest over $100 billion in expanding LNG by 2014.[12] This paper begins by examining the economics of the LNG chain. It then explores the forces that are shaping the structure of this emerging industry and addresses the implications of this growing market to the larger issue of energy security.

[9] Petroleum Economist, op. cit., pg. 76.
[10] EIA, op. cit., or International Energy Agency, "Security of Gas Supply in Open Markets: LNG and Power at a Turning Point", Paris: OECD, 2004.
[11] "The Future's a Gas," *The Economist*, Aug 28- Sept 3, pg. 53.
[12] Ibid, pg. 53.

II. ECONOMICS OF THE LNG CHAIN

Production

Natural gas reserves are typically controlled by state-owned and/or private multinational corporations.[13] In most cases, several production platforms in a large field are dedicated to a liquefaction unit. For example, the size of Qatar's North field is over 500 Tcf and the government claims it may be as large as 900 Tcf,[14] yet current projections for its 2015 LNG exports are no more than 3 Tcf per year. The North Sakhalin fields in Russia are reported to contain over 122 Tcf,[15] Northwest Australian shelf over 104 Tcf,[16] and Nigeria has more than 159 Tcf.[17] In 2004, there were over 12 countries poised to export significant volumes of LNG and for most, domestic options for using their gas was limited. In other words, the choices were to earn no revenue from plentiful gas resources or find a way to access foreign markets.

The investment cost to establish a new gas production unit varies enormously between one field and another. It is impossible to provide an average number that is meaningful. The depth at which the gas is found, the size of the reserve, whether it is associated or non-associated, its quality, the pressure in the system, and the distance from the liquefaction plant all affect the bottom line and will differ among fields. The cost of capital, or more appropriately a company's opportunity cost, will vary from one company to the next and from one region to another.

Some gas contains large amounts of impurities, some of which can be quite corrosive. Most all gas contains some water, but the volumes will differ from one field to the next. Gas also may contain liquids and condensates that have significant value. Some fields are rich in condensates and some are not.

Most LNG trains are fed from gas produced offshore. Equipment to remove the impurities can be located offshore or onshore, with the former more expensive than the latter. The more corrosive the impurities, the more likely they will be stripped at the point of extraction, which will increase the cost of production. Wells that contain more water than others will have to invest more heavily in dehydration equipment. Hence the cost of producing in one field can be significantly higher or lower than producing in any other field.

[13] There are some isolated cases where Asian electric utility companies have a minority share of the production field, but historically these are uncommon.
[14] Petroleum Economist, op. cit., pg. 56
[15] Proven reserve figures are approximately 65 Tcf (Alfred Turner, "Japan and the Russian Far East: The Economics and Competitive Impact of Least Cost Gas Imports" Baker Institute of Public Policy, Rice University, May 2000). The USGS estimates that there are an additional 57.5 Tcf of unproven reserves (USGS Survey, *World Petroleum Assessment 2000*).
[16] 40 Tcf of proven reserves (US EIA, Australian Country Analysis Brief, updated November 2004) and 64.6 Tcf of undiscovered resources (USGS op. cit.).
[17] EIA/DOE, Country Analysis Brief for Nigeria, August 2004. If all the planned liquefaction trains are completed, Nigeria will increase its LNG exports from 392 billion Bcf to 1.1 Tcf by the end of 2007.

On the other hand, condensates and liquids can be stripped and refined into light petroleum products that have significant value. Some fields develop a revenue stream from liquids that, by itself, justifies the production of the gas flow. That is, if the return to the production field from selling the methane to an LNG facility was zero, it might still be profitable to produce the gas.

If one has the numbers, one could calculate the production and operating costs per Mcf of gas produced in any individual field. One could then subtract out the value of the condensates and liquids and derive a net cost figure. But this calculation would not tell the reader anything about the cost of the production in another field.

Further, it would not tell one much about the revenue from the sale of the methane. In most projects the revenue at the wellhead is derived once the cost and return to the liquefaction, shipping, and regasification facilities are subtracted from the wholesale price of gas in the market. Economists call this the netback price – the price once all downstream costs are netted out. For some fields this price could be very low, but the profits from the condensates alone could justify continuing to produce the gas. In others, the price of the methane might be over $1.00 per Mcf.

In my calculation, I have used a price of $0.43 per Mcf, but this is an arbitrary number that is midway between various points in a wide range. It also is a number that does not seem to give people in the business heart failure. But I would not claim that it reflects the economic and financial realities of any single field (illustrative calculation provided in the appendix).

<u>Liquefaction</u>

The methane is sold to a company or consortium, who in turn converts the gas into a liquid form, by cooling it in a liquefaction train to negative 260 F, reducing its volume by 610 times.[18] Liquefaction trains are expensive and comprise about 35-40 percent of the final cost of a unit of LNG. In 2003, the cost had dropped to approximately $200 per ton compared with $575 per ton ten years earlier.[19] Some believe that over the next few years these costs will fall still further to $150 per ton.[20] These numbers translate into a per unit cost for a new six million ton per year facility of $1.29 per Mcf of natural gas.[21] Smaller facilities have higher per unit costs.

While there have been measurable improvements in the technology, these cost improvements are driven primarily by economies of scale. Ten years ago, an LNG train liquefied between 49 Billion cubic feet (Bcf) – 97 Bcf per year. In 2003, companies were

[18] EIA, op. cit., pg. 3.
[19] In 1993 the cost was $575 per ton as compared with approximately $200 today. (EIA op. cit., pg. 43 and testimony by Ralph Alexander, British Petroleum. "Developing the US and Global LNG Markets," Washington LNG Summit, December 17-18, 2003)
[20] Alexander testimony, op. cit.
[21] Liquefied gas is measured by weight (tons), but in gas form it is measured by volume (cubic feet). To allow the reader to follow the comparisons, the paper usually uses the volume measure that would result when the liquid is regasified.

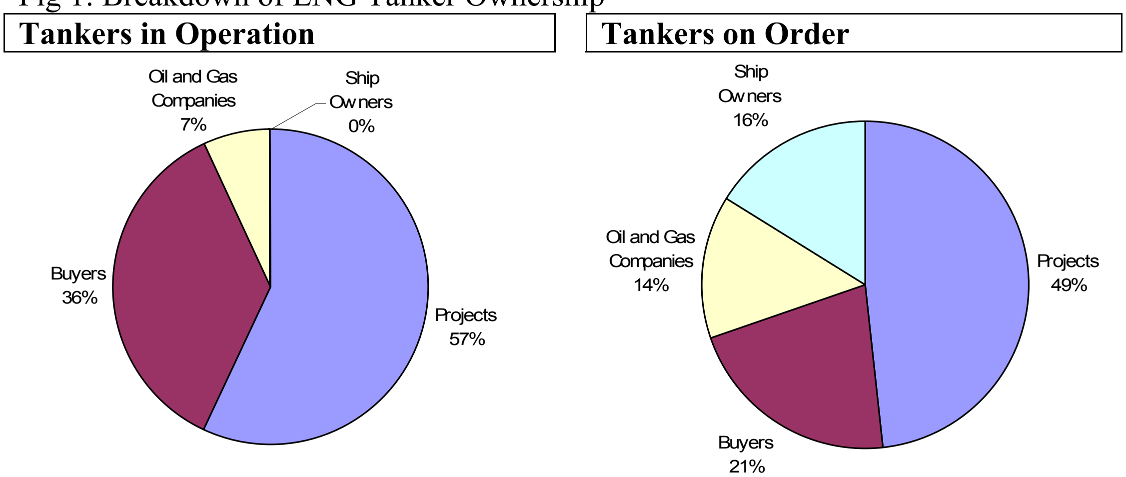
planning on building facilities that could liquefy as much as 380 Bcf per year, or three to seven times more gas.

Most liquefaction facilities are owned by the same companies that own the rights to the production – usually state-owned enterprises and/or international oil companies. Most trains are financed through partial non-recourse structures, often through public bond offerings or private sales. That is, debt holders only have recourse to revenues generated by the project, as opposed to the balance sheets of the sponsors. Hence the revenue projections for each project are closely scrutinized by the lenders and the investment banks that advise the sponsors.

Shipping

Once the gas is converted to a liquid, it is loaded onto a specially-built tanker and shipped to market. Because these cargoes must be maintained at very low temperatures and because of strict safety requirements, these tankers are very expensive. But they too have enjoyed the benefits of economies of scale. The capital cost of a new LNG tanker in 2003 was about 45 percent less than ten years before, and the number of shipyards able to build these tankers has now expanded to six.[22] Recently, investor enthusiasm has resulted in an 18-month backlog in orders for new LNG tankers, increasing their price by about 15 percent.[23]

Fig 1: Breakdown of LNG Tanker Ownership



SOURCE: CERA, "The Incoming Tide: LNG Surges into North America," January 2004.

Ownership of LNG tankers is changing. Historically these ships were dedicated to a particular project and were used exclusively to transport LNG between a production

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[22] In 2003 a new tanker cost between $150 and $170 million. The Petroleum Economist, op. cit., pg. 30.
[23] Asset Finance International, London, England, 2 May 2004.

facility to a specific receiving station.[24] It was logical for the ships to be owned by the owners of either the liquefaction unit or the receiving facilities (See Figure 1.). Of the 216 LNG ships in operation or under order at the end of 2003, only 21 were not tied to a specific combination of supply and market.[25] Spurred by changes in market dynamics, this pattern is adjusting to allow for more flexibility. Several independent LNG shipping companies are emerging. One expert predicted that by 2006 independent ship owners will have 36 percent of the LNG market.[26] If this comes to pass, it would indicate that investors believe that future markets will be significantly more flexible than in the past.

Investing in a $270 million tanker without guaranteed contracts is an inherently risky undertaking. Hence strong incentives to anchor the investment with long-term contracts will remain. Even so, when spot prices are high, or arbitrage opportunities appealing, more shippers will make themselves available to transport spot cargos.[27] Between 2003 and 2010, 34 existing large or medium sized tankers will have their contracts expire.[28] Whether or not their owners seek new contracts will be a harbinger of just how confident the industry is in the economics of merchant transactions.

Table 1: Shipping Prices to US LNG Terminals (Dollars per MMBtu)

Exporter	**Everett**	**Cove Point**	**Elba Island**	**Lake Charles**
Algeria	$0.52	$0.57	$0.60	$0.72
Nigeria	0.80	0.83	0.84	0.93
Norway	0.56	0.61	0.64	0.77
Venezuela	0.34	0.33	0.30	0.35
Trinidad & 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

Note: Based on 138,000 m^3 tanker at a charter rate of $65,000 per day.
Source: LNG Shipping Solutions published in EIA, "The Global Liquefied Natural Gas Market: Status & Outlook," December 2003, pg. 44.

Costs to the party paying for the shipping are largely determined by the number of days it takes to move the gas from its point of export to receiving and regasification stations. Typical day rates have been in the vicinity of $55,000-$65,000 per day for contracted gas

[24] Ships were restricted to moving LNG between a particular liquefaction facility and a particular receiving station for contractual as opposed to physical reasons.
[25] Wood, Mackenzie, "Prospects for a Globally Traded LNG Market", presentation at LNG 14, Dohe, Qatar. March 22, 2004.
[26] Ibid., pg. 30.
[27] The paper examines the cost to those doing the shipping, either the exporters or importers of the LNG. Hence, their costs are the price the transporters charge as opposed to the capital and operating cost of the tankers. This is different from the cost estimates for liquefaction, production, and regasification, which are the actual capital and operating costs.
[28] Morita, Koji et.al, "Study of Changes in Patterns of LNG Operation", The Institute of Energy Economics. Japan, December 2003, pg. 24.

and almost double that figure for short-term or spot LNG cargoes.[29] Table 1 shows the shipping prices between major exporters and the four United States receiving stations. Most of the shipments from Trinidad and Tobago are contracted and most of the shipments to the United States from Nigeria and Qatar have been spot sales, hence prices for the latter have been higher than the distance differentials alone would indicate.

For contracted gas, unit prices are derived from nautical distances. The more days it takes the vessel to travel to its destination, the higher the unit costs. For example, it takes twenty days or more to move a cargo from Qatar to Yokohama, Japan and only ten days to ship LNG from Port Darwin in Western Australia to Yokohama (see Appendix B). Hence the price of the former is almost twice as high as the latter (0.91 cents per MMBtu versus $0.45)[30]. Projects closer to major consuming markets will have a cost advantage over those that are more distant, since they will pay less for shipping.

Regasification

Once the LNG arrives at its destination, it can be converted into gas or stored on site. The regasification technology is not technically sophisticated, and gas companies have been using this process for many years. In fact, many distribution companies liquefy domestic pipeline gas in the summer months, store it and reinject it into the distribution system during peak winter days.

In 2002, twelve countries had working LNG receiving facilities, with the largest number in Japan, which has 23 facilities.[31] There are over 70 new LNG receiving stations now being proposed worldwide. Most of these will not be built, but even if only fifteen percent are completed, they will significantly expand the world's LNG marketplace.

The cost of building a regasification facility varies widely, depending on where the terminal is built, the desirability of redundancy, and the need for storage. Local regulations and land costs are major variables. Regasification facilities sited in densely populated areas, such as those in the northeastern United States, California, or Europe will have much higher land costs than a facility in a less densely populated area. In some instances, it will be more cost effective to locate the regasification facility in a remote location and then pipe the gas into population centers. Examples would include the proposed facility in the Bahamas to serve Florida or the facility in the Canadian Maritimes to serve the northeastern United States.

[29] US Energy Information Agency, "The Global Liquefaction Natural Gas Market: Status and Outlook," December 2003, pg. 44. And an email with Divay Goel at Drewry Shipping Consultants in United Kingdom, March 2004.
[30] BTUs are a measure of the heat value of natural gas. The Btu content of the gas will differ slightly from one field to the next depending on the amount of residual condensate. In the United States the average gas sold at the retail level contains 1.029 million Btu per Mcf gas. (US EIA, Monthly Energy Review, April 2004.) Most of the shipping and regasification data used in government studies are calculated on a Btu as opposed to a Mcf basis.
[31] US EIA, op. cit., pg. 19.

The amount of gas that is vaporized in a regasification facility is usually less than the design capacity of the facility. In other words, the facility has a capacity factor in the vicinity of 70-75 percent. To increase this capacity, the owner would have to build more storage, which would require additional money and land. When one reads that a facility is built to handle a certain volume of gas, its actual thru-put will depend on its capacity factor.

The Gas Technology Institute estimates that a new facility in the United States will cost between $200-$300 million depending on location and size.[32] This would translate into a cost per unit of between $0.30 and $0.50 per MMBtu, making it the least expensive component of the LNG chain.[33] If additional storage is required this figure would be ten to twenty percent higher.[34]

<u>Summary</u>

While there is considerable variability in the cost of any particular LNG chain, it is indisputable that the costs have fallen significantly in the last ten years and are now very competitive with the wholesale price of domestic gas. To give the reader an approximation of these numbers, I have made a rough estimate of the cost of each element in the LNG chain. My estimates are for new facilities, however most chains will consist of a combination of existing and new facilities, and the actual costs are likely to be slightly higher. Secondly, I am still referring to costs not prices, which in an unregulated market may be quite different.

Appendix A summarizes my calculations. As I mentioned earlier, any single estimate will not reflect the actual costs at any particular field. The $0.43 per Mcf figure is a rough estimate of the midpoint of a range of costs from conversations with industry officials and other studies. I am assuming a new liquefaction train that uses today's technology and built to optimal scale. The shipping distances in my calculations are quite long (28 days). Hence the liquefaction costs in the calculations are probably low and the shipping costs high.[35] I am using the mid-point of EIA's regasification cost estimates and, as I mentioned, making a rough estimate of production costs. Adding these estimates together, I derive a cost estimate of $3.20 per Mcf. If it takes only twelve days to ship the LNG, the shipping costs could be reduced to $0.54 per MMBtu and the total cost to $2.65 Mcf. At these rates, LNG moved from Trinidad to the United States or Qatar to India will be very competitive with pipeline gas, even in a scenario where United States domestic prices return to their 2002 levels. These estimates also illustrate the importance of

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32 US EIA, op. cit., pg. 46.

33 The US EIA study estimates that in the US regasification adds $0.30/MMbtu (EIA op. cit., pg. 46). Ellsworth estimates cost between $0.30 and $0.50/MMbtu. A third study by Gurcan Gulen of the University of Houston Law Center presented at the Energy Modeling Forum Workshop, Stanford University, January 29-30, 3004, echoes Ellsworth's findings.

34 Offshore regasification facilities are being considered in densely populated areas. However, there is an implicit tradeoff between the benefits of improving the public's perception of safety by siting offshore and the loss of thru-put flexibility because of reduced storage levels.

35 Some industry experts now believe that the cost of building very large LNG tankers will come down by as much as 30% over the next eight years, thus my estimates may be high.

shipping distances in determining the wholesale cost of LNG. The greater the distances, the higher the costs will be. Finally, revenue from condensates and liquids will supplement the sale of gas, and in some circumstances, these revenues alone can justify the production of the gas.

My LNG cost estimates are much lower than those in the 1980s and 1990s in the United States, and are significantly below the price of pipeline gas, which between 2001 and 2004 has averaged over $4.30 per Mcf. The difference between the cost of a new LNG chain and the price of domestic gas indicates that the rents may be significant. Who obtains these rents will depend on the structure of the industry and the market in which it functions.

III. THE CHANGING MARKET ENVIRONMENT

If the rents from LNG trade in certain markets will be larger than previously anticipated, which party – the producer, the shipper, the regasification owner, or the consumer – will capture them? As the competition intensifies, which strategies are likely to be pursued?

One strategy would be for prospective investors to own two or more of the segments in the LNG chain. The recent interest of some of the multinational oil and gas companies in developing regasification facilities is an indication that this idea has not been lost on them.[36] Investors in independent LNG shipping companies will attempt to capture a portion of these rents, by owning essential bottleneck assets – the transportation facilities – linking producers and sellers. Buyers, often pressured by regulators, aware of the favorable economics will attempt to capture these same rents by negotiating more flexible contacts at lower prices. An example is the aggressive positions taken by Japanese utilities in their negotiations for new LNG contracts. However, if one extrapolates from history, the owner of the resource should be able to extract the largest percentage of these rents. In many instances, these will be the governments in which the production and liquefaction facilities are located.

The LNG industry structure is realigning and how these changes evolve will have ramification for sellers, buyers, and governments in both exporting and importing countries.

To gain a better understanding of these market trends, it is useful to look more closely at some of the factors that are likely to affect them.

a) Project-on-Project Risk

There are certain characteristics of LNG trade that are germane. LNG is delivered in large volumes, and these volumes are likely to become even larger in the future. The day the first cargo of LNG is delivered could substantially increase the supply available in an importing market, especially if the market is small or isolated. If there is a market price for gas, as there is in the United States, the economic rents available will be the differential between the cost of delivering the LNG to a market and the marginal price of gas in that specific market. A surge of new supply with no corresponding increase in demand will lower that marginal price of gas. Thus, the profitability of many regasification facilities depends in part on the absence of other LNG receiving projects.

For example, if there are two projects, each one capable of receiving 200 billion cubic feet of gas per year and the projected market for incremental gas is only 200 billion cubic feet, the economic viability of one project depends on the absence of the other. First comers will have a major advantage, hence the fierce competition in the United States to obtain federal and local permits before one's rivals. Alternatively, investors can reduce project-on-project risk by siting their regasification plants in larger markets, especially

[36] See Shell Oil's proposal to build a large regasification facility in the United Kingdom and another on Mexico's Baja Peninsula.

major hubs used by several pipelines. These markets can absorb multiple LNG projects without significantly affecting the market clearing price.

b) The Emergence of Competitive Markets for Energy

Competitive markets for LNG are a new phenomenon. In the past, most cargos were shipped under long-term contracts, and the buyers were usually large vertically integrated monopoly utilities. The price of LNG was negotiated and indexed to a substitute fuel, often crude or residual oil. Today this situation is changing. First, the potential market is expanding rapidly to include North America, parts of Europe, and developing countries such as India and China. Second, in the North American and European markets, the ultimate buyers will primarily be gas companies that own mature distribution networks, serving a wide spectrum of customers as opposed to a few very large users.

While most gas retailers are still monopolies, they are buying their domestic supplies in competitive markets. In North America, these markets are almost fifteen years old, while European countries are still in the process of complying with the new competitive system mandated by the European Union.[37] However, the direction in both regions is clearly away from the vertical monopoly model. In a competitive market, LNG will compete with the marginal price of gas, not with oil products. There will be one gas market as opposed to separate markets for pipeline gas and LNG.

Simultaneously, the electric generators, who are the largest consumers of gas, are also facing competitive pressures in their markets. For these customers, gas is an intermediate good, and its price has a major impact on their production costs. Often, they too have lost, or confront the possibility of losing, their monopoly position, particularly in the wholesale market. Electric generating facilities are facing market pressures to decrease the cost of their power or risk losing sales and, in some cases, market share. Thus, to remain competitive they must reduce the cost of their inputs, particularly fuel. For example, in many hours of the day, electricity demand is below the available supply. During these periods, the higher cost generators are not dispatched.[38] Since fuel costs are a substantial percentage of the cost of generated power from a gas or oil fired facility, small changes in gas prices in one facility, as compared to those for another, will determine the number of hours the former is dispatched. If each day a plant is used four to five hours less than its competitor's, over a year its foregone earnings will be significant. Responding to these competitive pressures, utilities are more determined to lower their fuel prices.

As this trend toward competitive electricity markets continues, the buyers of wholesale gas will be more sensitive to price and the sellers of gas (including LNG) must mirror this concern or risk losing their customers.

[37] European Union Directives, 2003/55/EC. Also see International Energy Agency, *Security of Gas Supplies in Open Markets*, Paris: OECD, 2004, pg. 287.
[38] Most electric grids follow a least cost dispatch protocol where the facilities with the lowest operating costs are used first and as the demand increases plants are added in rank order of their costs.

c) Evolving Contract Structures

One might reasonably conclude that the development of competitive markets for gas and electricity will reduce the incentives for both buyers and sellers of LNG to enter into rigid long-term pricing arrangements. As the LNG market grows, there will be opportunities for arbitrage as well as opportunities to seek better prices in the spot and short-term markets. In 2002, eight percent of the LNG was sold in the form of short term cargos, and some pundits are predicting that this number will increase significantly over the next ten years.[39] The arbitrage market that exists in the North Atlantic will become more competitive as other suppliers, such as Norway, Russia, and Venezuela join Trinidad, Algeria and Nigeria as major LNG sellers. Because of longer shipping distances, spot markets have not emerged to the same degree in the Pacific region. This is likely to change as the number of suppliers increase and the buyers face competitive markets for their products. Price and supply flexibility will be valued, and the risk of depending on spot markets will be reduced by the sheer volume of LNG available.

Harbingers of these new market pressures are already emerging. First, buyers, including the Japanese electric utilities, are pushing to reduce the percentage of the gas that contractually must be taken and are attempting to negotiate more flexible pricing arrangements. In a competitive market, large take-or-pay requirements can be a severe financial weight on a firm's ability to meet a demand profile that is increasingly volatile. Exporters to the North American markets are resigned that they will be price takers, allowing markets to set the LNG price as opposed to negotiating fixed price contracts or pegging the LNG price to oil products. Even in Europe there are efforts to negotiate more flexible pricing arrangements. These can take the form of having different tranches of gas covered by different pricing schemes or simply reducing take-or-pay requirements and designing more flexible destination provisions.[40] In many cases, buyers will simply restructure their supply portfolios, so that they have the flexibility to purchase a percentage of their gas on the spot market.

On the supply side, there are examples of LNG suppliers withholding a portion of their gas so that they can participate as merchant suppliers in the spot market. The development of independent LNG shipping companies demonstrates that some investors are betting that a robust LNG spot market with lucrative arbitrage opportunities will emerge, and thus the option value of having spot capacity available could be significant.

d) Long-term Contracts Will Remain

In the midst of this euphoria about the prospects of growing and profitable short-term markets, there are several factors that suggest that the move to merchant LNG providers

[39] Barr, Patrick and Seth Gaurau, "Current and Future Trends", *Petroleum Economist: Fundamentals of the Global LNG Industry*. London, 2004, pg. 26-27.

[40] In older contracts, buyers were not permitted to redirect their cargoes to alternative ports, while in many of the newer contracts there is some flexibility to resell cargoes, although it is usually limited to a particular geographic area. For example, a cargo destined to Tokyo could be redirected to another city in Japan, but not to North America or China.

and flexible markets may not be as large as some pundits are suggesting. LNG projects cost billions of dollars. This means that investors, especially institutional investors, are not likely to be enthused about assuming large market risks, on top of the sovereign risks that they already bear. In many industries characterized by large fixed costs such as office buildings, airports, and power plants, developers use contracts to lock in a substantial percentage of their demand prior to initiating construction. The market risks are simply too great. For most developers, volume uncertainty is a much larger concern than price uncertainty. Hence the propensity to anchor large LNG projects with contracts.

Many of the new liquefaction projects are funded under non-recourse or partially non-recourse arrangements. These financing schemes mean that the demand risk is borne by the project itself and not by the sponsoring government or corporations. Hence both equity sponsors and lenders carefully scrutinize a project's projected revenue flows and are under intense pressure to manage demand risks. Hedges and other financial schemes can help and as the market grows they will be available at lower costs, but the pressure to cover a significant portion of the liquefaction and regasification facilities through long-term contracts will remain high. The percentage of LNG sold under contract will differ from one project to another, as investors strive to identify an optimal marketing strategy. However, it is probable that a vast majority of LNG traded in 2012 will be sold under long-term contracts; although these contracts will be more flexible than their predecessors. To obtain an understanding of how these changes in risk, contracts, and markets will affect the participants, I will briefly look at the strategic options confronting one exporter and several importing regions.

e) Market Strategies: Qatar

The logical strategy for Qatar will be different than the logical strategy for Nigeria or Australia. Qatar has four advantages that it attempts to leverage: 1) Its gas resources are huge, and in the long run it is more concerned with fluctuations in volume sold than prices. 2) Its gas is rich in condensates and even if the methane were priced at zero, the profits from the stream of condensates might cover the cost of production. 3) Its liquefaction facilities are built to capture economies of scale, and 4) it has more experience negotiating robust and sustainable long-term contracts than most of its competitors.

Qatar has one major disadvantage. It is more distant from the major Asian and North American markets than many of its competitors. The cost of shipping gas from Indonesia or Australia to Japan can be $0.50 to $0.60 per MMBtu cheaper than shipping gas from Qatar. As more large suppliers, such as Russia and Australia, come-on stream in the Pacific market, Qatar will likely push its comparative strengths more aggressively to make up for its shipping disadvantage. While it is true that gas reserves in its North Field are huge, its competitors in the Asian market also have supply revenues more than adequate to meet any demand scenario that might arise in the short and mid-term.[41] Thus Qatar can not rely solely on its supply advantage. Realizing this, it will: 1) continue to

[41] US EIA, op. cit., *The Petroleum Economist: Fundamentals of the Global LNG Industry*, 2004, pg. 67-71.

invest heavily in gas to liquids production to diversify its portfolio,[42] 2) attempt to build in advance of the market (and thus ahead of their potential competitors) while aggressively leveraging its experience in marketing and contracting for gas,[43] and, 3) strive to build the most cost-efficient liquefaction complex in the world to make up for its cost disadvantage in shipping. Qatar's only other options are to offset the swings in the market by allowing the price of the gas at the point of production to fluctuate or have the LNG equity owners (including their state-owned company) absorb the losses. Neither of these options is appealing, but as long as the cash flows from its condensates are strong, Qatar and its partners will have the financial strength to weather any short-term price volatility in the LNG market.

Qatar has been a pioneer in the emerging LNG market and recently has been enormously successful at marketing its products. In fact, Qatar announced that all its LNG capacity was fully booked through 2010.[44] There is no question that it will continue to be one of the world's largest suppliers, but it will face competitive challengers in the next decade because of its distance from many of its major markets – challenges that will mount as more producing countries enter these markets.

Market Strategies – Consuming Markets

a) Europe

Most European countries have built comprehensive gas transportation and distribution networks. LNG imports are sold to the owners of this network. Further as the European Union continues to liberalize the industry, investment in greater transmission integration will increase. The capacity to move gas from one European country to another should be much greater in 2012 than in 2004. As this transformation moves forward, European gas markets will begin to resemble those in the United States.

In 2002, Europe only imported 2.8 percent of the world's LNG, most of which was sold to three countries: France, Italy, and Spain.[45] Most European markets are served by pipeline gas from Russia, Norway, and the Netherlands. Historically, the price of the imported LNG was pegged by contract to the fuel for which it is substituted, usually low sulfur residual oil. However as the market liberalizes, gas-on-gas competition is likely to emerge. This may be troublesome for LNG suppliers and the source of their concern will be the huge gas reserves in Russia.

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[42] Natural gas can be converted into liquid petroleum products, usually middle distillates. Conversion facilities are complex and expensive, but they provide major producers with an alternative market for their gas. Gas to liquid facilities involves a process different than that used to strip, separate, and refine condensates.
[43] As of January, 2004, Qatar had 17 long-term contracts for their LNG. Several will come up for renegotiation in the next several years and Qatar is actively negotiating contracts for a significant portion of the LNG from their new projects presently under construction.
[44] Dow Jones and Reuters, "Qatar gas pauses for breath," *Global Factiva*, March 11, 2005, http://global.factiva.com
[45] Energy Information Administration, op. cit., pp. 50.

If Russia is able to attract the necessary investment and is able to economically develop, transport, and sell a greater portion of its reserves in western Siberia, especially those in new fields such as Shtokman in the Barents Sea, to European markets, it could significantly affect the clearing price. If LNG providers commit billions of dollars to build new facilities based on an expectation that European markets will face supply shortfalls and higher prices and subsequently new Russian projects, import large incremental supplies of new gas, those LNG investments could find their revenue projections under severe pressure.[46] Project-on-project risk of additional Russian exports is much higher in Northern Europe than in countries such as Spain., Portugal and Italy, which are close to and Middle East gas fields.[47] In this region, LNG will compete with pipelines from the North African fields.

b) North America

Historically, the North American market has imported small amounts of LNG and then mostly to meet seasonal demand peaks. However, with 2004-2005 gas prices at the city gate averaging more than $6.00 per Mcf and over $7.50 during high demand periods, both LNG exporters and importers are stampeding to enter this market. As of December of 2004, over 40 new LNG projects have been proposed to serve the market. However United States gas prices are uncertain and are likely to remain volatile.[48] Further, new LNG projects will impact local prices in proportion to the ratio of the imported LNG to the total gas supply in that market. As mentioned earlier, the larger the market, the less impact a LNG project will have on the price in that specific market. In other words, LNG will be a price taker not a price setter. There will be a price for natural gas, and buyers will be indifferent as to whether the supply is sourced from a tanker/regasification facility or a pipeline. For example, LNG projects located in Louisiana or Texas will be able to move the gas to markets across the entire eastern United States through Henry Hub. The potential market for these projects will be half the nation. The LNG increment will be small compared to the total amount of gas sold.

The advantage of locating receiving facilities in the Gulf is reinforced by the siting difficulties confronting new LNG receiving facilities along both the east and west coasts. Siting controversies can delay LNG projects and dramatically increase pre-construction costs. Finally, land availability will be more limited in populated regions, driving up prices and limiting the size of any new gasification unit. Hence, the per-unit costs of LNG receiving stations located in California or the Northeast will be much higher than in the Gulf of Mexico. It is not surprising that the first new LNG regasification facilities

[46] Experts are divided as to the extent of this risk. Some believe that the cost of developing many of the gas fields in Western Siberia is so high that they would not be an economic threat to LNG, while others are more bullish on the prospect of Russian gas.
[47] Russia is contemplating building one or more liquefaction facilities in its western Siberian region, but the LNG would probably be moved to either North American or Northern European markets.
[48] Some pundits argue that the volatility will be more limited because of the large amount of idle gas-fired generating capacity. As gas prices fall, an increasing percentage of this capacity becomes competitive and gas consumption will increase and so too will prices. They assure that as long as a large amount of uneconomic gas-fired electric generating capacity exists, there is a floor on gas prices below which they are unlikely to go.

permitted and under construction are all in the Gulf: Cameron LNG, Port Pelican, and the Excelente "Energy Bridge" project. The latter two are offshore facilities.[49]

Siting may not be as large an obstacle as many pundits fear. The United States has four existing LNG regasification stations – Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana,[50] which together have the capacity to regasify 2.82 billion cubic feet per day. Planned expansion at these sites will, if approved, increase capacity to 7.6 billion cubic feet. Capacity at the four new facilities recently approved will add another 4.4 billion cubic feet for a possible total in 2008 of twelve billion cubic feet. If one assumes a capacity factor of 0.8 (80%), these facilities would be able to produce gas supplies equal to fifteen percent of the 2003 average daily demand for natural gas in the United States. If only four of the remaining 36 proposed facilities are built, the United States will have a receiving capacity of over sixteen billion cubic feet per day. This would be 5.7 times more capacity than existed in 2004 and would be equal to more than twenty percent of 2003 natural gas consumption levels.

Some of the expansions may not occur, but the numbers suggest that even if 85 percent of the proposed plants are <u>not</u> built because of siting or permitting difficulties, the country will still posses significant regasification capacity by 2012.

While the United States market has become very attractive, LNG suppliers will still want to protect themselves from price volatility. As mentioned, it will be difficult to lock in LNG prices contractually and hedges can be expensive, hence there will be a strong incentive for both buyers and sellers to serve as large a market as feasible in order to avoid local perturbation and reduce their demand risk.

Suppliers close to the United States market, such as those in the Atlantic basin, will face lower shipping costs and thus will have a distinct competitive advantage selling to the United States. They will be willing to price their gas on a market basis. Suppliers from the Middle East have a cost disadvantage in the form of higher shipping costs. As of September 2004, LNG cargos from Qatar and other Middle East producers delivered to the United States have all been purchased at spot prices. In a period in which gas prices have been extremely volatile, the profit margins from such sales more than offset the disadvantage in shipping costs. However, investors are likely to question whether these very high marginal prices will continue, especially as producing countries located in proximity to the North American market increase their volumes. Hence North American markets are likely to remain less attractive to Middle East producers than European and Asian markets.

<u>Summary</u>

While the future of LNG markets looks very promising in the aggregate, investments in new projects will carry with them risk profiles that will differ according to the region of

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[49] The Energy Bridge project converts the liquefied gas to vapor onboard the ship. The other approved plant built to serve the US market is AES's facility in Ocean Bay, Bahamas that will pipe gas to Florida.
[50] I am excluding the small facility in Puerto Rico.

the world in which the projects are located. LNG producers in regions distant from consuming markets will face a cost disadvantage, in the form of higher shipping costs. This disadvantage will become magnified as: 1) significant new LNG production becomes available from countries located closer to these markets and 2) the consumers in these markets become more sensitive to pricing. For LNG exporters in the Middle East, this will create pressure to pursue gas to liquid facilities and emphasize take requirements as opposed to price guarantees in future contracts.

Historically, demand risk has always been part of the LNG business, but both buyers and sellers managed that risk by signing long-term contracts that covered both price and volume. Going forward it will be increasingly difficult to protect investments against fluctuations in gas prices. In developing countries, the demand risk will be compounded by sovereign risks as effective government institutions are only beginning to emerge.

If LNG facilities are financed as non-recourse projects and if the demand and sovereign risks remain high, lenders will require higher proportions of equity. There are few corporations who can afford to take multi-billion dollar risks, and most of those who can are large multinational energy companies or state-owned enterprises. The latter, though, will be constrained by domestic restrictions on the risk profile of allowed investments and the perception of what is deemed politically acceptable by their governments. Private companies are not so constrained. Thus the recent interest by multinational oil companies in investing in both the upstream and downstream segments of the LNG chain is not surprising and in all probability will increase in the years ahead. At the same time, smaller companies will find it difficult to raise sufficient equity to obtain favorably financing terms from the banks. Over the long-term, they will not be competitive in this market. Given these trends, the LNG industry is likely to be dominated by a limited number of large companies, some private and some state-owned.

IV. NATURAL GAS AND SECURITY RISK

Since the 1970s, western governments have been concerned about the economic consequences of disruptions in the flow of oil. Since oil is traded in a global market, disruptions, regardless of origin, will affect all oil-consuming nations. While countries can reduce this vulnerability by limiting their dependence on imported oil or can manage it by building up emergency stocks or pursuing alternative energy sources, no country can escape it. Hence oil continues to have national security implications.

While natural gas trade has had security implications for Japan and South Korea for the last two decades, it has not been a concern for the United States whose only major international source was Canada, a staunch ally and trading partner. Europe has relied heavily on Russian gas, but has retained the capacity to access additional supplies, particularly from the Netherlands, Norway, and North Africa. If the gas trade becomes increasingly global, will the security and vulnerability concerns that characterize oil markets emerge in gas markets?

Joseph Nye and Robert Keohane in their seminal work, *Power and Interdependence*, provide an excellent framework for examining the scope and dimensions of future relevance of security on LNG. First, the authors point out that there is a critical difference between the purchase of non-strategic goods and transactions that have economic and political costs or constraints associated with them.[51] In the first instance, the parties are interconnected, but changes in the pattern of trade in these "non-strategic commodities" do not carry with them any significant costs. In the second, the commodities have a strategic-value, and thus any changes in their flow will impose a cost – both economically and politically – on the importing country, and often on the exporting country. The size of this cost depends on four variables: 1) the volume being traded, 2) the magnitude of the disruption, 3) the importance of the commodity to the buyer's economy, and 4) the cost of providing subsidies. Nye and Keohane argue that the vulnerability is not dependence per se, but rather an "actor's liability to suffer costs – even after policies have been altered."[52] In other words, if the cost of providing substitutes is very costly, as measured as a percentage of GDP growth, an importing country is vulnerable because it is dependent. If the costs are manageable, then the vulnerability is small.

While the idea that a disruption in the flow of a strategic good, such as oil, may be costly to an importing country is not surprising, Nye and Keohane point out that there is interdependence between the exporter and the importer and that the former will not be unaffected by a disruption. When the cost to one party is far greater than that to the other then this interdependence is asymmetrical.[53]

[51] Nye, Joseph and Robert Keohane, *Power and Interdependence*, third edition, New York: Longman, 2001, pg. 8.
[52] Ibid, pg. 11
[53] Ibid, pg. 16

Admittedly, the total volume of natural gas traded across borders is significantly lower than the volume of oil, and even with the projected expansion of LNG facilities, gas trade will not come close to overtaking oil in the near future. I will also leave to others the issue of technical vulnerability (are liquefaction trains and LNG tankers easier to disrupt than oil production facilities) and logistical vulnerability (are the specific shipping routes for gas inherently easier to interdict). Rather, using the Keohane and Nye framework, I will focus on two questions. Will greater LNG trade increase the vulnerability of importing countries to a future disruption and the macroeconomic dislocations that go with it? And will the interdependence between producers and importers be asymmetrical?

Dependence

For dependence to be a problem, three factors would have to be present. First, the ratio of LNG to total gas consumed would have to be significant – at least above 30 percent. Second, alternative LNG supplies would not be available to replace the disrupted supplies. Third, it would be costly to access other supplies or alternative fuels.

At first glance, the volumes of LNG being traded are quite small, as a percentage of total natural gas consumed. Even if current projections come to pass, LNG will not be more than 25 percent of total gas consumption in 2020 in the United States or ten percent of gas sold in the Europe.[54] Implicit in these numbers is the assumption that gas supplies are physically fungible. LNG supplies delivered into the United States or Europe could be logistically moved anywhere in the region. Hence a loss in LNG supply at any single point would have the same impact on the market as an equal loss of domestic supplies. Prices would rise accordingly, and the market would ration the deficit across all regions. While there are no physical restrictions, there are contractual restrictions, but these are gradually being reduced and in a crisis are unlikely to restrain the flow of supply.

But the same may not hold true if the LNG was delivered to points at the end of the natural gas network, such as southern Florida or Massachusetts. While in the earlier Gulf Coast scenario the ratio of the volume of LNG to the total gas volume in the market served is small, the ratio of LNG to pipeline gas in a more localized market could be larger. If a disruption occurred, the availability of incremental pipeline gas would depend on the amount of unused capacity in the system at the time of the disruption. If LNG supplies had been serving a particular market for a long-period of time, additional pipeline capacity may not have been built to meet new demands that had emerged in the ensuing years. Further, the flow of pipeline gas throughout a regional network will, over time, reconfigure to meet changing consumption patterns. If those patterns are interrupted in one regional node because of a disruption in LNG supplies, there is no guarantee that sufficient pipeline gas can be redirected from other nodes on short notice. These constraints would be more pronounced during seasonal peaks. Hence, if an isolated LNG

[54] Spain and Portugal may receive higher percentages of the gas in the form of LNG. Further, European dependence on imports is forecasted to more than double over the next twenty years, but most of the imports are predicted to come in the form of pipeline gas from Russia, North Africa, and perhaps Iran and Caspian region.

terminal at the end of a pipeline is interrupted, the subsequent impact will be a function of the ability to redistribute pipeline gas. In some situations this ability could be limited.

Before one reaches the conclusion that the vulnerability of such locales is high, one must ask a second question. What is the probability that LNG shipments to these locations will be disrupted for a significant period of time? Is it increasing or decreasing? In a world of LNG chains in which there were only a few liquefaction centers and a few regasification facilities with specific LNG tankers dedicated to shipping product between the two, the probability may have been moderate. To reduce this risk, sites such as the facility in Everett, Massachusetts built substantial storage and only used LNG as a peaking fuel. In the future there will be many more liquefaction and regasification sites, and many tankers, a portion of which will be available to move spot cargos. If there is a disruption at one liquefaction site, or one or two tankers are put out of service, other sites and other tankers will become available. The system of the future, especially in the Atlantic basin, will be more fungible in 2010 than it was in 2000. Thus the probability of a physical disruption will be quite low.[55] The one exception would be if a regasification terminal was destroyed and pipeline gas was not available. In such a situation, redundant capacity becomes very important.

Japan and Korea lack domestic natural gas supplies and do not have a domestic pipeline network to move substantial volumes of gas between cities, yet they have managed to develop a comparatively secure LNG system.

Japan has adopted a two-pronged strategy: diversify its sources of supply internationally and build redundancy at home. Currently Japan imports from eight suppliers and ten liquefaction plants and this number will grow as the Sakhalin and Northwest Australian projects come on line. [56] For example, LNG supplies bought from Qatar are purchased from several liquefaction trains so that if an accident occurs at one, Japanese buyers have the contractual right to take supplies from another.

More players moving more LNG will enhance market flexibility and reduce the risk of a physical disruption. The value of multiple sources can be enhanced by building flexibility into LNG contracts, both in terms of price and volume. In the case of the latter, contract provisions could grant the right to take either more or less gas, at any point in time.

Japanese buyers, primarily electric utility companies, are becoming comfortable with contracting for lower volumes and having more pricing flexibility, believing that purchasing a portion of their LNG at spot prices will be advantageous.

Domestically, Japan has reduced its vulnerability by focusing on increasing the redundancy in its systems. It has done this by standardizing its port and regasification facilities so that many different ships can use these facilities. It has built significant volumes of storage, so that if there is a disruption, Japan has at least a month of supply

[55] In these scenarios, the price of substitute LNG cargo will likely be higher than the disrupted supplies.
[56] International Energy Agency, op. cit., pg. 452.

available at any given time.[57] Further, the gas and electric generating companies have entered into sharing arrangements. If one looks at Japan's regasification projects, many of them are jointly sponsored by an electric company and a gas company, as opposed to a single owner. These arrangements are supplemented by agreements to share supplies in case of disruptions. In addition, the gas and electric companies will build redundant receiving facilities; if one fails, the other is still available. There is not much pipeline interconnection between cities, but Japan is actively planning to build an interconnecting gas grid system.

Finally many of the larger gas-fired electric generating stations have dual fuel capacity, but this number is declining because of stricter air pollution requirements. These requirements are a matter of policy and could be reversed if Japan so decides.

Japan's program of diversifying supplies and building domestic flexibility provided major dividends over the last few years; first when Japan shut down Tokyo Electric's seventeen nuclear generators in 2003 and had to rely on its gas-fuel generating facilities and then again when the Arun liquefaction facility in Aceh, Indonesia was shut down because of civil unrest. Japan was able to weather both crises without significant disruptions in the flow of gas or electricity.

Europe, knowing that its reliance on gas imports will grow significantly over the next decade has been watching the Japanese experience and has embarked on a similar portfolio of actions. In December of 2003, the European Parliament approved a directive to insure an adequate level of gas supplies.[58] This directive requires member states to set standards for what constitutes adequate security and to develop action plans that include many of the same provisions adopted by the Japanese. These include storage requirements, fuel switching, redundancy levels, interconnections, and contract flexibility.

There is an emerging debate in Europe as to the efficacy of establishing a formal strategic storage program for gas, along the same dimensions of its oil storage program. Japan has such a program, but as only Japan can do, it has seen no need to label it as a formal strategic reserve. As the United States increases its reliance on LNG imports, it is only a matter of time before policy makers debate this same issue both in Congress and in international forums, such as the International Energy Agency.

The experiences in Japan and the forthcoming actions in Europe demonstrate that even in cases where supply vulnerability is a concern, this vulnerability can be substantially reduced by a policy of diversification of supplies and programs to enhance flexibility at home.

[57] International Energy Agency, op. cit., pg. 454.
[58] European Union Directive 488-2002, International Energy Agency, op. cit., pg. 292.

Asymmetry of Interdependence

The term interdependence implies that both the country being disrupted and the country doing the disrupting face costs. Let us use the example of gas imports from Russia into Western Europe. In 2003, Europe imported almost four trillion cubic feet of Russian gas.[59] Countries, such as Germany, relied on Russia for over 35 percent of their gas supplies, while Eastern Europe and Finland rely on Russia for over 80 percent of their gas.[60] As supplies from the Netherlands and the North Sea decline, this dependence will grow. A disruption in the flow of Russian gas would have serious economic ramifications for Europe. This reality has prompted the European Union to look closely at other sources of gas, including LNG, imports from North Africa, and even pipeline gas from Iran or the Caspian Basin.

While a cut-off of Russian gas to Europe would have serious consequences for the importing countries, the costs to Russia are likely to be even higher. A significant percent of Russia's hard currency comes from the sale of oil and gas to Europe – a disruption in this flow could upset Russia's ability to purchase needed imports of food, manufactured goods, and investment capital. Hence the probability of Russia deciding to disrupt the flow or unilaterally changing the terms of their sale agreements with western European countries is perceived as small. Both parties are heavily dependent on the other. The relationship is not asymmetrical – each party has the ability to provide substantial benefits and substantial costs to the other. Hence, neither feels it can unilaterally take economic or political opportunistic advantage of the other.[61]

In the case of the world oil market, the relationships are different. First, approximately 40 percent of the oil traded in the world market is controlled by a cartel – OPEC.[62] While its ability to impact the market through adjusting its production levels is stronger in some periods than others, over the long term it has significant market power. Second, one member, Saudi Arabia, has been willing to keep one to two million barrels of production capacity off the market and available to be used to move prices up or down depending on the country's economic or political concerns. This "swing" capacity gives the Saudis the ability to affect the world price of oil.

Importing country economies are sensitive to upward movements of oil prices and thus the whole market is vulnerable to OPEC and Saudi decisions on oil production.

[59] International Energy Agency, "Security of Gas Supply in Open Markets", OECD/IEA, Paris, 2004, pg. 365.
[60] Ibid, pg. 318.
[61] Some experts cite the 1978-79 disruption of Iranian gas to the USSR's Caucasus region as a counter example. In the aftermath of the Islamic Revolution, Iran suspended the delivery of gas to the USSR for several months during the winter of 1979. However, the USSR and Iran continued to cooperate and by May 1979 a significant portion of the constricted gas flow was reinstated as both countries realized that they had more to gain from cooperation than recrimination. See Jonathan Stern, *Soviet Natural Gas Development to 1990*, Lexington Books, 1980.
[62] British Petroleum, "Energy in Focus", *BP Statistical Review of World Energy*, June 2004, pg. 6.

On the other hand, the economic consequence to OPEC members is low as long as their actions do not induce a military response from the stronger importing countries. The consequences of their actions, at least in the short term, are slight. Hence in the case of oil, there is considerable asymmetry of interdependence between OPEC and its customers.

In the case of LNG markets, there is no cartel. No country is likely to have the opportunity or the interest in becoming a swing producer. There are some simple reasons that this situation is not likely to change. First, the supply of LNG is dependent not on the resource base – but on the availability of liquefaction facilities, LNG terminals, and regasification receiving stations. In the case of oil, the known resource base is located in one small part of the world, the Arabian Gulf, while gas supplies are both plentiful and geographically diversified. Furthermore, at foreseeable demand levels, no country has a resource base sufficient to allow it to assert market power (with the possible exception of Russia to Europe).

This may be true now, but what about ten years from now if the amount of LNG traded is three to four times larger? Wouldn't the major producers have the ability to exert political and economic power? For this to occur a cartel of most of the major producers would have to be formed, and it would have to be able to exert considerable discipline on its members. Second, it would have to be willing to reduce the amount of LNG produced from its existing liquefaction facilities, and it would have to control the number of new liquefaction stations built. Such a scenario seems improbable.

OPEC has had the benefit that many of its key members are located in one region and have interacted with each other for millennia. A workable cartel consisting of Norway, Iran, Russia, Qatar, Indonesia, Malaysia, Australia, Oman, Trinidad, Nigeria, and Peru would be a different entity. Furthermore, only Saudi Arabia has been willing to invest billions of dollars in oil production facilities and then not use them. Would any of the aforementioned countries volunteer to invest billions in a liquefaction facility then turn around and agree not to use it?

Most liquefaction facilities are either partnerships between state petroleum and private multinational corporations or are wholly owned by private companies. Oil production facilities in the Gulf countries are owned by their host governments. It is less difficult to get governments to bear economic costs for political gain than private investors. Having said this, it is worth noting that very few governments have been willing to assume the role of swing producers of any commodity.

In fact, the opposite situation may hold for gas. Since in a market in which many spot sellers participate, consuming countries, such as the United States and Japan, may have sufficient monopsony power to pressure producing countries. If asymmetry of interdependence does emerge in these LNG markets, it is more likely to take the form of producing countries being vulnerable to actions taken by a consortium of consuming countries than the reverse.

Terrorism

Even if LNG markets do not have the same characteristics of oil markets, LNG requires a chain of large, expensive, and discrete facilities. These facilities could become targets for terrorists and the volatility of cryogenically cooled gas is significant. The recent accident at the Skikda facility in Algeria is an example.

This paper does not purport to have any insights into the relative susceptibility of any particular LNG facility to a terrorist attack or an industrial accident. There are numerous books and papers on this topic. But certainly the impact of a single accident, or even two or three such accidents, in a world with two to three times more capacity will be smaller than it would be today. As the number of players, the percentage sold on the spot market, and the volume traded increases, the probability of a serious disruption in the global LNG market will shrink. This is not to say that such actions may not seriously affect the people in the vicinity of the accident, the investors (and insurers) of the damaged facilities and, in the case of certain stand-alone receiving facilities, the local markets.

Summary

This paper introduces some of the elements that will shape the policy debate surrounding increased LNG trade. The reductions in LNG costs, together with the high price of domestic natural gas in the United States and the liberalization of gas markets in Europe creates market opportunities for players in all parts of the LNG chain – from liquefaction to shipping to regasification. As LNG markets grow, there will be new financial risks, and those able to bear those risks will become dominant players in the marketplace.

Finally, the volumes of LNG traded will be substantially greater ten years from now, raising the concern that LNG will create some of the same national security sensitivity and asymmetrical interdependence problems that one has seen in the oil market. However when one parses the security problem, one finds that the LNG market differs from its oil counterpart in many ways, including size, the character of the participants, the nature of the investments, and the pattern of trade. The possibility of location-specific accidents exists, but the impact of such accidents will be localized and the global marketplace will be increasingly less affected as the volume traded, the number of players, and the size of the spot market increase.

Appendix A

Estimated Costs of LNG (September 2004)

Upstream Gas Production[1]

Investment	$903,000,000	
Duration	25	years
Cost Recovery Factor (CRF)	0.0977	
	$88,233,649	per year
Volumes	6,818,182	tons per year (as LNG)
	59,181,818	boe per year
	349,172,727	million Btu per year

Unit Costs

CapEx	$1.49	per boe
O&M	$1.00	per boe
TOTAL	$2.49	per boe
	$0.42	**per MMBtu or $0.43 Mcf**

Liquefaction

CAPEX	$3,640,000,000	
Duration	25	years
Cost of Capital	8.5%	
CRF	0.0977	
	$355,670,524	per year
O&M[2]	4%	fraction of capex
	$14,226,821	per year
LNG Volumes	6,000,000	tons per year
	52080000	boe per year
	307,272,000	million Btu per year
Fuel	12%	fraction of input
	720,000	tons per year
	6,249,600	boe per year
	$2.49	per boe
	$15,567,073	

Unit Costs

CapEx	$6.83	per boe
O&M	$0.27	per boe
Fuel	$0.30	per boe
TOTAL	$7.40	per boe
	$1.25	**per MMBtu or $1.29 Mcf**

Shipping

Capital	$270,000,000	per vessel
Duration	25	years
CRF	0.0977	
	$26,382,154	per vessel per year
O&M	4%	fraction of capex
O&M	$1,055,286	per vessel per year
Fuel	$90	per ton
	138	tons per day
	0.5	fuel mix
	28.0	days per voyage
	12.0	voyages
	$2,086,560	per vessel per year
LNG Volumes	10	vessels
	6,000,000	tons per year
	3%	Boil off
	4%	Cargo heel
	93%	Effective cargo
	558,720	tons per vessel per year
	4,849,690	boe per vessel per year
	28,613,169	million Btu per vessel per year

Unit Costs		
CapEx	$5.44	per boe
O&M	$0.22	per boe
Fuel	$0.43	per boe
TOTAL	$6.09	per boe
	$1.03	**per MMBtu or $1.06 per Mcf**

Regasification Costs[3]

	$0.40	**per MMBtu or $0.41 Mcf**

TOTAL	**$3.11**	**per MMBtu or $3.20 per Mcf** [4]

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[1] While the rates will vary significantly between one project and the next, host governments may collect royalty payments and taxes or both. Since these calculations are highly uncertain (see text) I have not attempted to incorporate these expenses.
[2] Does not include government taxes which are highly variable.
[3] Costs are taken from the Energy Information Agency (EIA), "The Global Liquefied Natural Gas Market: Status and Outlook," December 2003, pp. 46, and from Ellsworth, op. cit.
[4] Assumes 1.029 MMBtus per 1 Mcf.

Appendix B

Indicative Distances and Costs between Major Exporters and Importers
(All distances are round-trip in nautical miles)

East Coast North America (Lake Charles, LA)

Point of Origin	Distance	% of Distance from Qatar	Estimated Cost per MMBtu
Qatar	24,712	100.0%	$1.58
Port-of-Spain, Trinidad	4,412	17.9	0.38
Oran, Algeria	9,936	40.2	0.72
Hammerfest, Norway	11,594	46.9	0.82
Bonny, Nigeria	12,384	50.1	0.87
Port Darwin, Australia	27,094	109.6	1.78

West Cost North America (Long Beach, CA)

Point of Origin	Distance	% of Distance from Qatar	Estimated Cost per MMBtu
Qatar	22,994	100.0%	$1.53
Port Darwin, Australia	14,594	63.5	1.01
Balikpapan, Indonesia	16,346	71.1	1.12

Europe (Barcelona, Spain)

Point of Origin	Distance	% of Distance from Qatar	Estimated Cost per MMBtu
Qatar	21,050	100.0%	$1.41
Oran, Algeria	730	3.5	0.15
Bonny, Nigeria	7,848	37.3	0.59
Port-of-Spain, Trinidad	7,874	37.4	0.59
Port Darwin, Australia	23,432	111.3	1.56

East Asia (Yokohama, Japan)

Point of Origin	Distance	% of Distance from Qatar	Estimated Cost per MMBtu
Qatar	13,038	100.0%	$0.91
Balikpapan, Indonesia	5,630	43.2	0.45
Port Darwin, Australia	5,978	45.9	0.47

NOTE: The EIA data presented above was used to derive the relationship between $/MMBtu cost and distance. The equation $/MMBtu = (Distance + 1650)/16107 was found to provide a good fit to the EIA data. The constant, 1650, can be thought of as the distance equivalent of the fixed port costs.
SOURCE: Distances from National Imagery and Mapping Agency, Distances Between Ports, Bethesda, MD, 2001.

Appendix C

Frequently Used Conversions

To: / From:	Billion Cubic Meters NG	Billion Cubic Feet NG	Million Tons LNG	Trillion Btu
	MULTIPLY BY			
1 Billion Cubic Meters NG	1	35.3	0.73	38.8
1 Billion Cubic Feet NG	0.028	1	0.021	1.1
1 Million Tons LNG	1.38	48.7	1	51.9
1 Trillion Btu	0.028	0.98	0.02	1

One-to-One Conversion Table

To:	Liquid Measures			Vapor Measures		Heat Measure
From:	Metric Ton LNG	Cubic Meter LNG	Cubic Foot LNG	Cubic Meter Natural Gas	Cubic Foot Natural Gas	Btu*
Metric Ton LNG	1.00	2.19	77.47	1,335.90	47,256.70	51,982,370
Cubic Meter LNG	0.46	1.00	35.3	610.00	21,533.00	23,686,300
Cubic Foot LNG	0.012	0.028	1.00	17.08	610.00	671,000
Cubic Meter Natural Gas	0.000749	0.001639	0.058548	1.00	35.30	38,830
Cubic Foot Natural Gas	0.000021	0.000046	0.001639	0.03	1.00	1,100

*Based on Volume Conversion of 610:1 and 1,100 gross dry Btu per cubic feet of vapor.

Source: Energy Information Administration, "The Global Liquefied Natural Gas Market: Status and Outlook," December 2003, pp. 48.