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Asian Natural Gas Markets
Supply Infrastructure, and Pricing Issues

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EXECUTIVE SUMMARY

This paper discusses the supply, infrastructure, and pricing aspects of Asia's growing interest in natural gas. Because Asia has been a region of comparatively high-cost gas supply, resulting low gas market share, and costly infrastructure, it faces significant challenges as it moves forward.

Main Findings

- Asia's growing reliance on natural gas comes at a time when it must increasingly rely on more distant and costly supply sources.
- The region's oil-indexed long-term contract pricing structure is being challenged by low-priced liquefied natural gas (LNG) based on commodity competition from the restructured gas industries in the Atlantic Basin.
- Some governments subsidize local consumption. This stimulates demand for gas and inhibits local exploration with a potentially negative influence on trade balances and carbon emissions.

Policy Implications

- While full gas industry liberalization in the region is difficult to achieve because of its regional characteristics, the advantages of liberalization suggest that governments should explore its application to their individual situations.
- One major step would be to move from subsidized domestic pricing to a system based on the market value of natural gas.
- Though importing governments may have limited ability to influence the pricing terms of long-term contracts, they need to be sensitive to policy moves that would make their buyers more competitive.

This paper discusses Asian gas markets, supply, infrastructure, and pricing within the context of liberalizing international gas markets. Asia's growing dependence on interregional imports comes at a time when Asian importers remain largely dependent on oil-linked, long-term contract pricing, while the Atlantic Basin is experiencing lower-priced commodity competition from North American unconventional gas. Further, many Asian countries continue to subsidize domestic markets, a policy that could have adverse effects on trade balances and carbon emissions.

The paper focuses largely on pricing issues and discusses the evolution of liberalized international gas markets and the potential impact of this trend on Asia. The first section examines demand, supply, and trade statistics. The paper then outlines the worldwide trend toward liberalized gas markets, compares the economics of supplying gas by pipeline and liquefied natural gas (LNG), and discusses pricing and contracting practices. The next section explores a theoretical world of liberalized gas trade in order to define the economic consequences of current pricing policies. Finally, the paper concludes by discussing the policy implications for current pricing practices.

Asian Natural Gas Supply and Demand—A Snapshot

The largest energy markets in the Asia-Pacific region lack adequate natural gas resources and are difficult to supply by pipeline. As a result, gas's share of the primary energy market in the region is only 17%, whereas its share in the rest of the world is 44%. But the emergence of gas-fired combined-cycle gas turbine (CCGT) power generation and improvements in LNG transportation, which facilitate long-distance gas movement, have stimulated gas demand in the region. The demand for gas grew at a rate of 6.3% per year over the last decade, substantially exceeding that of the rest of the world, which was only 1.8% per year.

In 2009, Asia consumed 16.9% and produced 14.7% of the world's natural gas, making the region a net importer. **Table 1** shows Asia's consumption, local supply, and net imports for 2009 ranked by consumption.

TABLE 1 **Asian Consumption Balances in 2009 (bcm)**[1]

	Consumption	Local Supply [1]	Net Imports LNG	Net Imports Pipeline
China	91.2	83.6	7.6	
Japan	87.4	1.5	85.9	
India	51.9	39.3	12.6	
Thailand	39.2	30.9		8.3
Pakistan	37.9	37.9		
Indonesia	36.6	72.3	(26.0)	(9.7)
Korea	33.8	(0.5)	34.3	
Malaysia	31.5	61.0	(29.5)	0.1
Australia	25.7	49.9	(24.2)	
Bangladesh	19.7	19.7		
Taiwan	11.3	(0.5)	11.8	
Singapore	9.7	0.1		9.6
New Zealand	4.0	4.0		
Philippines	3.3	3.3		
Myanmar	2.1	10.4		(8.3)
Brunei	1.5	10.3	(8.8)	
Other Asia-				

[1] BP, *Statistical Review of World Energy*, June 2010

Pacific	9.8	9.8		
Total	496.6	432.9	63.7	0.0

[1] Taken as consumption minus net imports (equivalent to production adjusted for stock changes).

In 2009, Asian interregional gas imports were all in the form of LNG. **Table 2** shows the net trade, both within the region and with other regions. In 1996, the year before Qatar entered world LNG, the Asia-Pacific region supplied more than 90% of its own LNG requirements. But since then, local supply (Russia's Sakhalin is treated as interregional, in this analysis although Sakhalin is physically located in Asia) has not grown as rapidly as demand, and interregional LNG imports, most from the Middle East, have covered nearly 80% of the increase.

TABLE 2 **Asian Trade Balances in 2009 (bcm)**[2]

	Pipeline Shipments to Asian Markets	LNG Shipments to Asian Markets	Asian Shipments to Other Regions	Total Net Trade
INTRAREGIONAL				
Indonesia	9.67	25.92	0.08	35.67
Malaysia	1.20	29.44	9.00	30.73
Australia		24.08	0.16	24.24
Brunei		8.81		8.81
Myanmar	8.29			8.29
Asian Exporters	19.16	88.25	0.33	107.74
INTERREGIONAL				

[2] BP, *Statistical Review of World Energy*.

Middle East		47.19		49.19
West Africa		6.55		6.55
Russia (Sakhalin)		6.20		6.20
Trinidad		1.88		1.88
North Africa		1.28		1.28
U.S. (Alaska)		0.86		0.86
Belgium (Reshipment)		0.08		0.08
Non-Asian		64.04		64.04
Asian Net Trade	19.16	159.29	0.33	171.78

The International Energy Agency (IEA) expects future Asian demand to outpace demand in the rest of the world as well as the region's dependence on interregional imports to increase. In the 2010 *World Energy Outlook* the IEA expects Asian gas demand to grow at a rate of 3.1% per year between 2008 and 2030 while growth in the rest of the world is only 1.0%.[3] Since production is expected to grow at only 2.4%, Asia's dependence on interregional imports should increase at 5.7%. While earlier imports were all as LNG, pipeline trade is becoming important.

Until recently, local pipeline movements were limited to short hauls within Southeast Asia, but China has just extended its West-to-East Pipeline to Turkmenistan. Additional proposals for long-distance pipelines have been proposed from the Caspian region and West Siberia as well as from nearer Russian sources in East Siberia. This growing dependence on more distant LNG sources and on long-distance pipelines comes at a time when increasing liberalization of world gas markets poses new challenges to contracting and pricing.

[3] International Energy Agency (IEA), *World Energy Outlook 2010* (Paris: OECD/IEA, 2010), 182 191,.

Natural Gas—The Transition from Isolated Regional Markets to an International Industry

Because of the high cost of natural gas transportation, world natural gas markets have tended to develop in regional isolation from one another. And because transportation through pipeline systems exhibits strong natural monopoly characteristics, governments have commonly exerted regulatory control of natural gas transmission and distribution. In countries such the United States or Japan, governments exercised this control through rate regulation of privately owned utilities, whereas in countries such as the United Kingdom or France, control took the form of government monopoly companies.

In some cases, such as Sonatrach in Algeria or Gazprom in Russia, upstream exploration was at one time also restricted to government companies. In those countries where international oil companies were involved in exploration and production, often the government company was the sole purchaser for gas discoveries, and pricing became a contentious issue. Whereas international oil companies could argue for world oil price levels when negotiating a price for an oil discovery, there is as yet no world gas price. Companies were often at the mercy of the government in gas price negotiations, and frequently governments chose to favor their own consumers by offering very low prices to local customers.

Cross-border trade initially developed through the construction of pipeline systems linking gas-surplus and gas-deficit countries. Three major gas grids evolved over time. They were the North American grid, linking the United States, Canada, and Mexico; the European Continental grid; and the grid linking the former Soviet Union with Eastern Europe and the West. Initially, the UK was an isolated market, but with the construction of two pipelines in 1988 and 2006 across the English Channel, the UK became a part of the continental grid. Until 1983 the only cross-border pipeline trade that did not involve one of the three major pipeline grids was a movement from Bolivia to Argentina.

Trade in LNG developed much later. The first commercial shipments took place in 1964 from Algeria to the UK and France. Although the initial project was in the Atlantic Basin, the growing interest in natural gas by three gas-deficit Northeast Asian countries—Japan, Korea, and Taiwan—stimulated interest in LNG in the Pacific Basin. The first Asian shipment was from the Cook Inlet of Alaska to Japan in 1969.

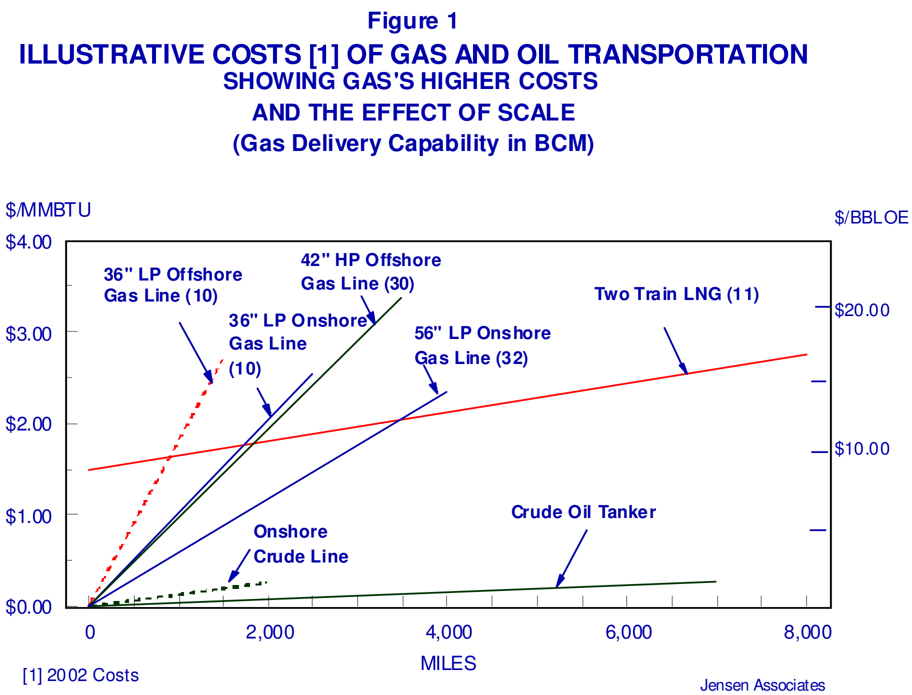
The United States first entered the market in 1972, when potential U.S. gas shortages stimulated active interest in LNG projects. The development of the early U.S. projects took place during a period of unprecedented change in world energy markets. This included the two oil price shocks, the widespread nationalization of the international oil company's concession areas within the Organization of the Petroleum Exporting Countries (OPEC), and the restructuring of the North American gas industry. While LNG imports into Europe continued to increase, the U.S. trade virtually collapsed, blunting what was expected to be a substantial growth in Atlantic Basin trade. Meanwhile, rapid growth in Northeast Asian LNG continued. As recently as 1998, 75% of the world's LNG was delivered to Japan, Korea, and Taiwan.

The Comparative Economics of Pipeline versus LNG Transportation

The low density of natural gas makes it more costly to contain and transport than either oil or coal. Because of its special processing and handling requirements, the costs of moving natural gas are significantly higher than the costs of moving oil. And the relative costs of moving gas or oil by pipeline or by tanker differ substantially, as well. This influences regional interfuel competition and thus natural gas markets. Although pipeline costs increase linearly with distance, LNG—requiring liquefaction and regasification regardless of the distance traveled—has a high threshold cost but a much lower increase in costs with distance. Thus, shorter distances tend to favor pipelining, whereas longer distances favor LNG.

Prior to the development of LNG technology, the transportation of natural gas was limited to movements that could be served by pipeline. The costs of pipelining natural gas benefit substantially from economies of scale, since large diameter pipelines are not much more expensive to lay than smaller lines but carry much greater volumes. Since the economics of long lines are so sensitive to scale, large markets are usually required to justify them. The cost relationships between LNG and pipeline transportation are illustrated in **Figure 1**.

FIGURE 1 **Illustrative Costs of Gas and Oil Transportation Showing Gas's Higher Costs and the Effect of Scale (Gas Delivery Capability in BCM)**



The North American long-distance pipeline system was built largely with pipelines whose capacity was limited to about 10 billion cubic meters (bcm) by diameter and pressure constraints. But improved steels have made it possible to utilize much higher pressures and larger diameters. A capacity of 30 bcm or more is very common today for long-distance lines. Gas is a compressible fluid, so that frictional losses not only reduce flow rates but also allow the gas to expand, thereby reducing carrying capacity, as well. As a result, a long-distance gas line requires periodic intermediate compressor stations. The earlier low-pressure lines typically required compressor stations roughly every 100 kilometers.

Offshore pipelining is usually more costly than onshore pipelining. However, in some regions where access to pipelines right of way is difficult or costly to acquire, such as in Japan, onshore lines can be costlier than offshore ones. The requirement for frequent compressor stations substantially complicates offshore pipelining since it may require expensive riser platforms to house the intermediate compressors. The development of high-pressure pipelining has significantly improved the economics of offshore lines by greatly reducing the number of compressor stations required.

A recent development is that of very high-pressure and deep marine lines. The Blue Stream Pipeline, which crosses the Black Sea from Russia to Turkey and reaches a depth of 7,000 feet (2,150 meters), pioneered this technology. Russia's proposed South Stream Pipeline across the Black Sea, designed to serve Europe and bypassing the Ukraine, is similar. While small marine lines have been built and more ambitious ones, such as the Trans-ASEAN Pipeline from Southeast Asia to Vietnam, Taiwan, and China, have been discussed, only one deepwater project has been proposed yet. That pipeline would link the Greater Sunrise gas complex on the Australian side of the Timor Gap with East Timor via a Timor trench crossing. Shell, the operator, prefers a floating LNG liquefaction plant and the project is still under negotiation. The fact that so much of Southeast Asia's gas is offshore suggests that other opportunities to utilize deepwater pipeline technology may well emerge.

LNG trade depends on the refrigeration of natural gas to cryogenic temperatures (approximately minus 260^{o}F or minus 162^{o}C) where it becomes a liquid at atmospheric pressure and occupies a volume that is 1/600th that of the fuel in its gaseous form. The product can be stored in heavily insulated tanks or moved overseas in special cryogenic tankers. But the special processing and containment requirements to transport gas as LNG come at a significant cost. An LNG project represents a chain of investments whose ultimate success is threatened by the possible failure of its weakest link. The chain consists of four (occasionally five) links: field development, in some cases a pipeline to the coast, the liquefaction facility, tanker transportation, and the receipt/regasification terminal.

The liquefaction plants consist of processing modules called trains. Train sizes tend to be limited by the size of the available compressors. Early train capacity tended to be restricted to about 2 million tons of LNG, and a greenfield facility would often require three trains to be economic. Recent improvements in compressors have made it possible to design larger trains to benefit from economies of scale. The largest conventional operating trains are less than 5 million tons, but Qatar is now commissioning six super trains with a capacity of 7.8 million tons (roughly 10 bcm).

The cryogenic tankers are much costlier than oil tankers, both because of the low density of the product and the need for insulation and low-temperature metallurgical designs. The current typical size of an LNG tanker is about 145,000 cubic meters of liquid cargo, but Qatar's new tanker designs are much larger—216,000 cubic meters for its Q-Flex class and 260,000 cubic meters for its Q-Max class.

The centers of population in many large Asian LNG-importing countries—such as Japan, Korea, and Taiwan—are coastal, which makes it easy to deliver LNG without serious concern for onward pipelining. In newer Asian markets, such as India or China, the costs of reaching the interior of the country with regasified LNG delivered by pipeline can seriously affect the competitiveness of the fuel.

How Is Natural Gas Priced?

Oil is an internationally traded commodity. Trade press pricing services regularly report prices of a number of key crude oils that serve as indicators of oil prices throughout the world. But the isolated regional nature of gas markets, coupled with heavy government intervention in gas pricing, has led to wide variations in pricing practices. There is no world gas price.

In a 2009 survey, the International Gas Union (IGU) attempted to catalog the various gas pricing systems currently in operation throughout the world.[4] It listed eight different systems:

1. *Gas-to-gas competition*. Gas is priced in open free-market trade on a spot basis or under long-term contracts.
2. *Oil price indexation*. Prices are set by formula under long-term contracts, usually of several years duration.
3. *Bilateral monopoly*. The dominant pricing mechanism in interstate gas dealings of the former Soviet Union, in Central and Eastern Europe, and in many immature gas markets with one dominant supplier facing one or two dominant buyers.

[4] International Gas Union, *Price Formation Mechanisms: 2009 Survey*, Table14.1; and IEA, *World Energy Outlook 2009*, 510.

4. *Netback from final product*. Price received by the gas seller reflects the price received by the buyer for this product.
5. *Regulation (cost of service)*. Prices are approved according to set procedures by a regulatory authority so as to cover supply costs including a reasonable return on investments.
6. *Regulation (social/political)*. Prices are set and adjusted typically on an *ad hoc* irregular basis by the government taking account of buyers' perceived ability to pay, sellers' perceived costs, and the government's revenue needs.
7. *Regulation (below cost)*. The government knowingly sets prices below the sum of production and transportation costs as a form of subsidy to the buyers and usually reimburses the seller from the state budget.
8. *No price*. The extreme form of regulation (below cost).

Based on share of consumption, the most common system was gas-to-gas competition, with a 33% share of the market. This was largely because commodity gas-to-gas competition operates in the large North American market. The second most common system with 25% of consumption was regulation below cost, where governments subsidize their own consumers. More than 90% of gas-to-gas competitive consumption takes place in the liberalized gas markets of North America and Europe, and more than 80% of oil-indexed consumption occurs in the pipeline and LNG importing markets of continental Europe and the Pacific. Two-thirds of bilateral monopoly consumption is within the former Soviet Union. Thus, international trade on the major grids and in LNG is most affected by the first three categories.

Interestingly enough, the largest proportion of below-market consumption is also within the former Soviet Union. This illustrates that, while a gas exporter may use international pricing for exports, it may still subsidize its own consumers. This is clearly the case for Russia as well as for some of the Middle East gas exporters. Furthermore, a policy of maintaining a domestic subsidy while trading in internationally priced gas is not limited to gas exporters. Argentina is an example of a country that is importing at international price levels while at the same time maintaining a domestic pricing system that is below import prices.

Table 3 shows the composition of the pricing systems, assuming that the IGU percentages apply to 2009 consumption and grouping several categories. Oil indexation and netback are treated as indexation and the last four categories are treated as less than market.

TABLE 3 **Composition of World Gas Consumption**[5]

	Gas-to-Gas	Indexation	Bilateral Monopoly	Less Than Market	Total
North America	27.2%	0.0%	0.0%	0.4%	27.6%
Europe	3.7%	12.3%	0.3%	0.7%	17.0%
Pacific	1.4%	4.5%	0.7%	2.1%	8.7%
Former Soviet Union	0.2%	0.0%	4.6%	14.2%	19.0%
Asia	0.7%	2.5%	0.4%	4.6%	8.2%
Middle East	0.0%	0.0%	0.4%	11.4%	11.8%
Africa	0.0%	0.2%	0.0%	3.0%	3.2%
Latin America	2.0%	0.6%	0.5%	3.3%	4.6%
Total World	33.4%	20.1%	6.9%	39.7%	100.0%
Asia Pacific Total	2.1%	7.1%	1.0%	6.7%	16.9%
Asia Category Share	6.3%	35.1%	15.3%	16.9%	16.9%

[5] International Gas Union, *Price Formation Mechanisms: 2009 Survey*.

The Asia-Pacific's share of world gas consumption in 2009 was 16.9%. Its proportionate share of indexed pricing was much higher (35.1%), largely reflecting the international pricing practices for LNG imports into Northeast Asia and China. The next highest share, equivalent to region's consumption share at 19.6%, was less-than-market priced consumption. These two categories represent regions of policy concern for some governments in the region. The low prices for Atlantic Basin commodity competition are a threat to oil-linked pricing in Asia, and the international community is increasingly critical of subsidized energy pricing. In the IGU survey the international goal of market liberalization—embodied in the gas-to-gas category—was by far the lowest in the region, reflecting its use primarily in Australia.

The Role of the Long-Term Contract in International Gas Marketing

Pipelines and LNG projects are highly capital-intensive. They are commonly debt-financed, and lenders require long-term contracts to guarantee debt service. The traditional long-term contract featured a carefully structured system of risk-sharing among the participants. The risk-sharing logic of the contract is embodied in the phrase "the buyer takes the volume risk and the seller takes the price risk." Hence, most contracts feature take-or-pay provisions to assure buyer offtake at some minimum level and a price escalation clause to transfer responsibility for energy price fluctuations to the seller. The early contracts viewed oil, not gas, as the competitive target and thus price risk in the indexation clauses was principally defined in oil terms.

The development of the European continental gas trade was based largely on supplies imported by pipeline and based on long-term contracts. The precedent to determine how to price gas was established by the Netherlands in its early pricing decision for the super giant Groningen gas field. It chose to set the price relative to the energy sources that gas displaced in the market—essentially oil products. As cross-border trade began to grow, this pattern of indexation to a basket of oil products became the norm for continental importers. Despite the emergence of some newer indicators such as coal or electricity, oil product indexation remains the most common.

The Northeast Asian trade was based on LNG. At the time the trade began, Japanese power generation was heavily dependent on oil firing, and early contracts chose to link LNG prices to the Japanese Customs-cleared Price for Crude Oil (JCC, or the "Japanese Crude Cocktail"). This precedent is now utilized by Korea and Taiwan as well as most Chinese contracts.

The gas industries in North America and the UK developed based on domestic gas supplies. Although long-term contracts were initially common, the fact that the governments of the United States, Canada, and the UK, at one point effectively controlled wellhead pricing meant that traditional European and Asian style price escalators were never utilized. These markets are now fully liberalized with "commodity gas-to-gas competition." Oil prices are usually irrelevant.

The Trend Toward Gas Market Liberalization

The liberalization of the North American gas industry has led to a highly competitive commodity market in which gas-to gas competition establishes the value of the fuel. Long-term contracts have largely disappeared and, with them, the concept of a contractual link between gas prices and oil prices. While the absolute level of gas prices depends on gas supply/demand balances, under certain market conditions interfuel competition between gas and either coal or oil may affect the demand for gas, causing gas to gain or lose market share. Thus, there may be at times an indirect linkage between gas prices and those of either oil or coal.

There is an active market in the physical commodity, but a liquid and transparent paper market in futures is also traded on the New York Mercantile Exchange (NYMEX) so that the market value of gas is openly reported at all times. The underlying pricing reference point is a pipeline interconnection hub at Henry, Louisiana (known as Henry Hub).

Because non-discriminatory open (third party) access is required of the transportation system, market participants can acquire capacity on downstream pipeline systems, thereby becoming competitive throughout North America. The value of the gas in downstream markets usually—though not always—reflects the cost of onward pipeline transportation, and thus a system of basis differentials to Henry Hub sets the market value in these downstream interconnection points or hubs. For example, since a delivery from Henry Hub to New York incurs a pipeline transportation charge, the basis differential for the New York City Gate reflects that transportation cost.

The UK also has a fully liberalized gas market with gas-to-gas competition. But whereas the United States uses a physical trading point as its Henry Hub marker, the UK utilizes a notional price marker called the National Balancing Point (NBP), so that gas anywhere on the system is priced the same. Because the system recovers transportation costs through an entry/exit tariff, actual transportation costs once on the system do not influence regional prices (basis differentials) in the same way as they do in the United States. Although the UK was a net gas exporter to the continent from the North Sea until 2006, it has now become a net importer. Hence UK market prices are often determined by interaction with competitive sources of supply. They tend to reflect competition with Atlantic Basin LNG markets when LNG is in surplus and prices are low, but they are more likely to be influenced by continental pricing when LNG markets are tight.

The European Commission is actively promoting market liberalization, including third-party access to the pipeline system. But acceptance of full liberalization on the continent has been slow and the dominance of long-term contract commitments has inhibited the development of an active commodity market. Perhaps the most competitive continental market region is in Northwest Europe, where pipeline now connect the UK with Belgium and the Netherlands. This exposes the low countries to UK gas-to-gas competition to the continent. Market hubs are being developed, but they are much less active than the NBP. Perhaps the most liquid and transparent is the Dutch Title Transfer Facility (TTF). The continent also uses an entry/exit approach to tariff design, so that the costs associated with increasing pipeline distances tend to be less obvious. Thus basis differentials are not utilized in European markets in the same way that they are in the U.S. However, the concept of recognizing increasing costs as a function of increasing transportation distance is still relevant in understanding the variations in the market value of natural gas in different locations.

Gas market liberalization has not proceeded to any significant extent among Asian gas-importing countries. Northeast Asia (Japan, Korea, and Taiwan) is dependent on

LNG imports with long-term contracts that are based on oil linkage. While the Northeast Asian countries have at times imported spot LNG cargo, a short-term commodity market within the countries has not really developed. Interestingly, spot cargo is a competitive trade, and thus it is possible, where pricing information is available, to compare the performance of oil-linked pricing to that of the spot LNG market.

China and India have both pipeline and LNG import options and hence theoretical flexibility to select that supply infrastructure system that minimizes the costs of imports. But geopolitical issues appear to influence decisionmaking in both markets. Other Asian countries are either beginning to import LNG, and are thus exposed to oil-linked pricing, or base their markets on domestic supplies. In many of these cases, governments price gas at levels well below what LNG markets would suggest.

The Emergence of a Flexible LNG Trade as a Means of Arbitraging Regional Gas Prices

World LNG markets developed, as did pipeline markets, based on long-term contracts. But as the trade has grown and the pressures to liberalize have developed, a substantial competition in destination-flexible LNG cargo has evolved. This includes not only short-term trading—now about 16% of world trade—but also the emergence of self-contracting, in which an LNG venture partner undertakes the long-term market commitment but is free to ship to whatever destination provides him with the best netback. Increasingly, buyers have negotiated destination flexibility so that they may divert cargo from their own markets to those that provide a better price. This increasing degree of destination flexibility has made it possible to create an international competitive market in which LNG can arbitrage prices among previously isolated regional markets.

As interest in the Atlantic Basin began to emerge in the early 2000s, LNG demand growth accelerated. Because the lead time between a decision to build a new liquefaction plant and its start-up is four or more years, LNG supply consistently lagged behind LNG demand until 2009. Markets were tight. But in 2009, supply finally caught up with expected demand just as the worldwide recession and a somewhat surprising change in the North American supply outlook blunted actual demand growth. Until quite recently, the anticipated decline in North American gas supply in the face of growing demand was expected to provide a rapidly growing market for LNG imports. But new technology to tap North America's extensive unconventional gas resources, and particularly shale gas, has sharply changed that outlook. These shale resources are very large and the cost of recovering them is lower than much of the conventional gas resource base. Atlantic Basin LNG arbitrage enabled low-priced North American gas to influence European spot markets.

During the period of relative LNG shortage, weak Atlantic Basin pricing had only a limited competitive effect on pipeline contract prices in Europe. The principal region for competition was in Northwest Europe, where pipelines from Belgium and the Netherlands potentially exposed the continent to UK gas-to-gas pricing. Germany, served by long-term contracts from the Netherlands, Norway, and Russia, is a natural battleground where competition between oil-linked contract pricing and spot gas through the Low Countries can be joined.

There have been three distinct periods of international gas market competition since late 2005. The first period, the "perfect storm," lasted from August 2005 until March 2006. It was characterized by Hurricane Katrina in the United States (which reduced production), the transition of the UK from net exporter to net importer, a hydro shortage in Spain, cold weather on the continent and tight markets in Asia. Competition for LNG cargo was severe, driving up market prices everywhere.

The second period lasted from the spring of 2006 until the middle of 2009. Atlantic Basin markets softened, but Asian markets remained very tight, as supply problems in Indonesia and a shutdown of seven nuclear plants by Tokyo Electric drove up demand in the face of short supply. Oil prices rose to record heights by the summer of 2008, dragging contract prices with them, only to collapse shortly thereafter. Asian contract prices were partially insulated from high oil prices by capping mechanisms, such as "S curves,"[6] but Asia was free to drive up spot cargo prices. In 2008, every Atlantic Basin LNG supplier but Libya shipped cargo to Japan.

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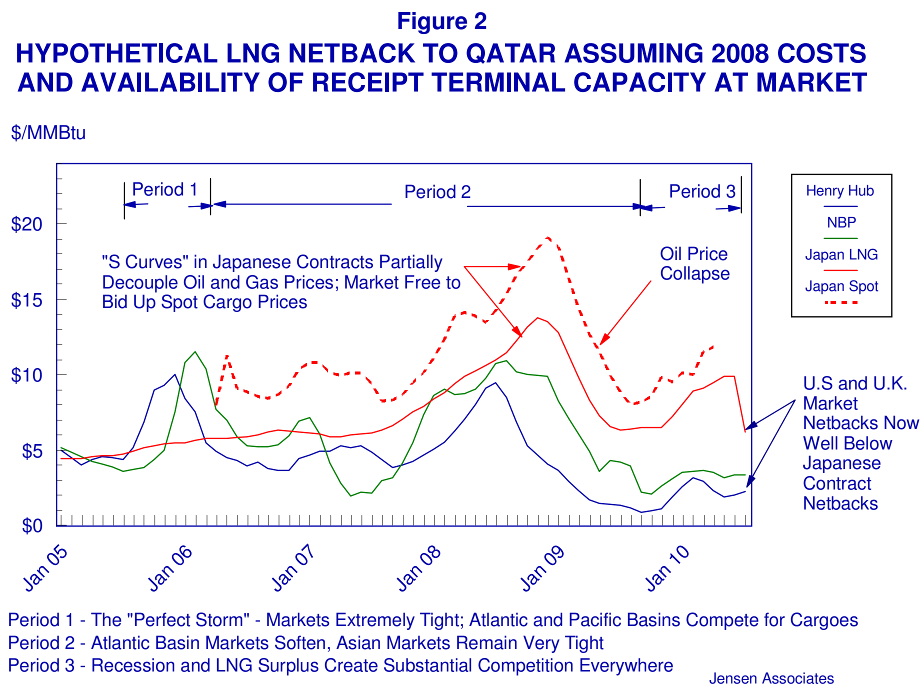
[6] S curves flatten the slope of the relationship between oil prices and gas prices at prices lower and higher than expected market conditions. They thus tend to protect buyers when oil prices are high and sellers

The third period began in mid 2009. The recession, the long awaited surge in LNG supply, and North American shale gas competition created surpluses everywhere. **Figure 2** shows the pricing consequences that these three markets experienced, which can be illustrated by looking at the hypothetical netbacks that a shipper in Qatar could have achieved in shipping LNG to the United States, the UK, and Japan.

FIGURE 2 **Hypothetical LNG Netback to Qatar Assuming 2008 Costs and Availability of Receipt Terminal Capacity at Market**



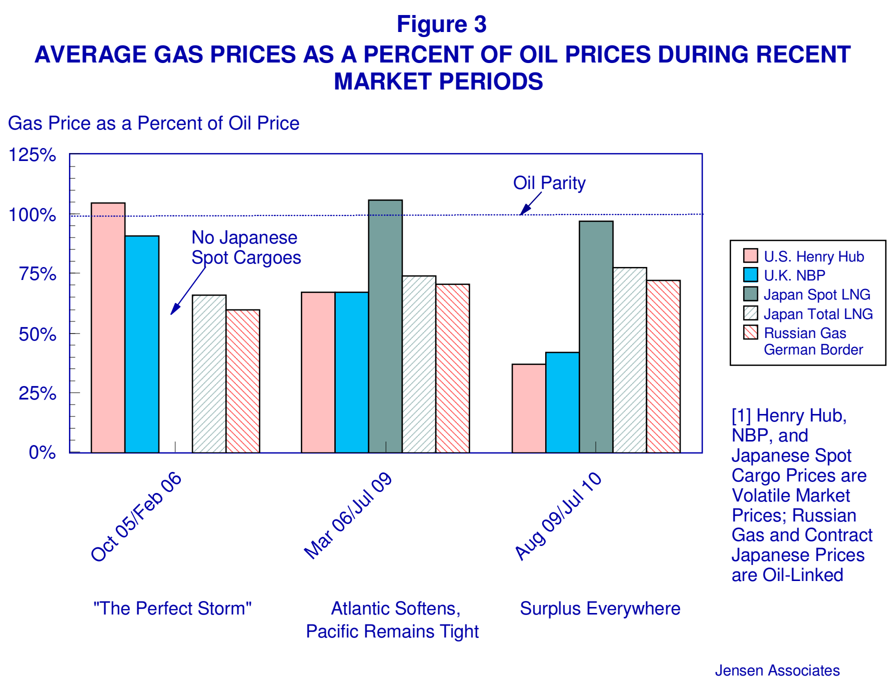
The U.S. and UK prices are market prices. The pricing of spot cargoes is also unregulated so that spot cargoes delivered to Japan are also market prices. (Japanese prices are for liquid LNG rather than gas as such.) But the prices for Japanese contract volumes are based on oil-linked pricing, which has been less volatile. The current comparative weakness of UK and U.S. commodity prices relative to Japanese contract prices is apparent. It is common to assume that oil-linkage implies oil parity. That is not the case. In Asian markets the pricing formula usually provides some discount off oil

when prices are low.

parity. Until recently, Asian contracts often had a capping mechanism—usually S curves—to insulate them from high oil prices. During the tight sellers' market in Asia during the latter part of the decade, suppliers were able to reopen many contracts to remove capping clauses. Most of these clauses are now gone. In European markets the linkage to oil products includes "pass through factors," which share some of the buyer's oil price increase with the seller. Thus, neither European nor Asian contract prices usually reach full oil parity.

For North American and UK markets, gas-to-gas competition precludes oil pricing from having a direct effect. In **Figure 3**, the prices of U.S. and UK gas, Japanese LNG, Japanese spot cargoes, and Russian gas at the German border are compared to oil price levels during the three recent market periods.

FIGURE 3 **Average Gas Prices as a Percent of Oil Prices During Recent Market Periods**



Envisioning an Idealized Global Competitive Commodity-Gas Market

The theoretical ideal of liberalized markets is to let gas-to-gas price competition set prices for commodity gas throughout the world. The mechanism for bringing world prices into this competitive equilibrium would be the flexibility of LNG shippers to direct their cargoes to those markets providing the highest netbacks. The increased competition in the higher-priced markets would thereby force prices downward at the same time that competition for supply from low-priced sources should tend to drive up prices. The resulting arbitrage would tend to drive world prices toward an international equilibrium.

The Middle East is in a unique position in world LNG trade in that it is able to arbitrage Atlantic Basin markets against Pacific Basin markets, and thus at theoretical equilibrium it should get the same netback from either region and be indifferent to which market it chooses to supply. Just how far the real world operates in disequilibrium from this theoretical ideal is illustrated by Figure 2. Had a hypothetical LNG shipper in Qatar been able to realize the prices being achieved in the various markets in April 2010, he would have netted back $7.16 more in shipping to the Japanese contract market and $1.21 to the UK than he would have in shipping to the U.S. Gulf Coast. If he were able to deliver spot cargo to Japan, the added margin would be even higher at $9.54.

This example implicitly assumes that Qatar is the point of arbitrage for world LNG markets. Just as transportation differentials tend to set basis differentials against Henry Hub in North America, the transportation differentials from the Middle East combined with the region's flexibility to ship either east or west provides an analogous set of LNG basis differentials against the Middle East. Thus, Qatar might be viewed as a theoretical Henry Hub for world LNG markets, despite the fact that it does not have the market trading activity, liquidity, or transparency of Henry Hub.

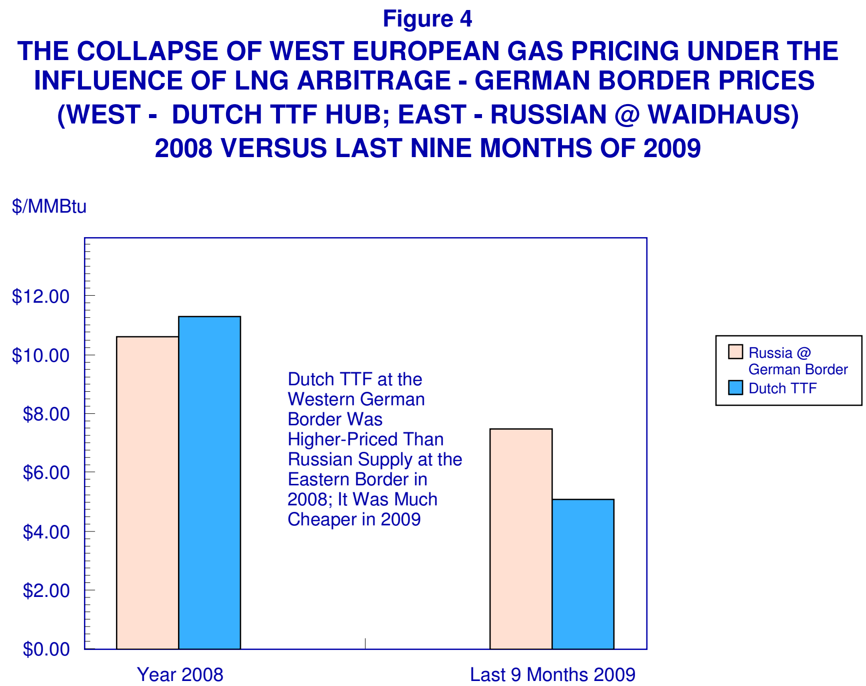
While LNG in theory might be able to set equilibrium prices in coastal LNG receipt terminals throughout the world, it is much less clear how LNG competition would establish equilibrium prices in landlocked markets such as those served by the major pipelines from Russia's West Siberian supplies to Western Europe. Until recently, there has been very little price competition between LNG and pipeline supply that might undermine the traditional oil-linkage in most long-term pipeline contracts. There are three major reasons. Before 2009, chronic shortages of LNG against market demand limited the ability of LNG to displace significant quantities of pipeline gas. Capacity bottlenecks on pipeline systems frequently limit the ability of shippers to compete in inland markets. Further, the common long-term take-or-pay obligation in pipeline contracts often limited the ability of buyers to take advantage of distressed commodity prices. While there was some competition between commodity gas and contract gas in markets such as the low countries and Spain, it was not extensive enough to provide serious erosion of continental contract pricing links.

The weak markets of 2009 significantly changed the competitive landscape. A surge of surplus LNG delivered to the UK and Belgium significantly displaced pipeline gas in Northeast Europe via the Interconnector Pipeline and Belgium's Zeebrugge LNG terminal. While LNG shipments to the UK and Belgium increased nearly fivefold between 2008 and 2009, Russian pipeline deliveries to Germany fell by 13%.[7] Prices at the German border on the west fell by 55% (as measured by the Dutch TTF quote) between 2008 and the last nine months of 2009.[8] Russian prices at the German border on the east fell also, but in line with the decline in oil prices of about 30% (see **Figure 4**). The resulting price competition forced Gazprom to renegotiate some of its contracts to make them more competitive with LNG-driven commodities. This suggests that the German market is currently the arbitrage point in competition between LNG and European pipeline supply.

[7]BP, *Statistical Review of World Energy*.

[8]ICIS, *European Gas Markets*, various issues.

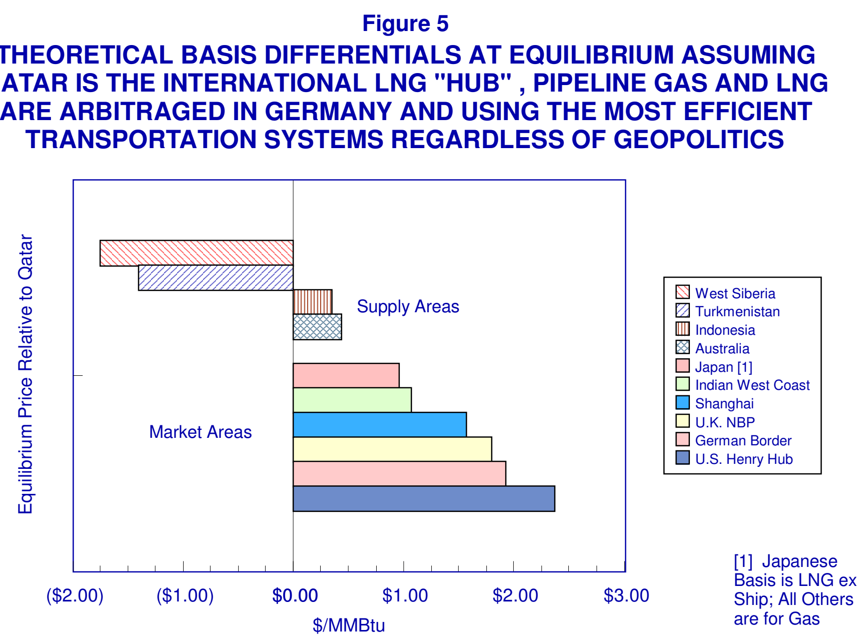
FIGURE 4 **The Collapse of West European Gas Pricing under the Influence of LNG Arbitrage**



The North American gas-to-gas competitive market works because of a large number of competitive supply offerings and open access on the pipeline system. Producers are free to compete throughout North America, and commodity competition functions very well. These conditions clearly do not apply to world gas markets, given that many supply areas lack competitive producers, pipeline system monopolies are common, and governments intervene in pricing either to subsidize their own consumers or to address geopolitical concerns. Furthermore, long-term contracts inhibit short-term commodity trading.

Still, it is possible to conceive of a theoretical world in which commodity competition sets prices worldwide. Unrealistic though it may be in real terms, such an exercise provides useful insights into the way the world's gas transportation structure might be designed and illustrates some of the economic penalties resulting from market imperfections. Such a theoretical system might use Qatar as the world's price referencing point, and thus as ground zero for establishing basis differentials for other markets and supply sources. Assuming pipeline competition with LNG takes place at the German border (east or west), the differentials for the major landlocked pipeline supplies, such as West Siberia or the Caspian (Turkmenistan), could be derived by netting back from German markets. In the theoretical case, pipeline routings assume the most direct and efficient routes regardless of their geopolitical implications. The resulting basis differentials are illustrated in **Figure 5**. For the market points shown, the basis values range from minus $1.75 for West Siberia to plus $2.37 for Henry Hub. Because of the high cost of serving the German market by long-distance pipeline, both West Siberia and the Caspian (Turkmenistan) have negative basis differentials. This is one reason for a growing interest in developing an LNG alternative outlet for the remote ice-bound Yamal Peninsula reserves in West Siberia.

FIGURE 5 **Theoretical Basis Differentials at Equilibrium Assuming Qatar is the International LNG "Hub", Pipeline Gas and LNG are Arbitraged in Germany and Using the Most Efficient Transportation Systems Regardless of Geopolitics**



Of the five major markets in Figure 5, Henry Hub has the largest basis differential, suggesting that, in a theoretical equilibrium market, its prices should be higher than that of the other major consuming markets. In fact, Henry Hub prices are now the lowest of the group, emphasizing the extent of the international price disequilibrium under the influence of low shale gas–driven commodity prices in the U.S.

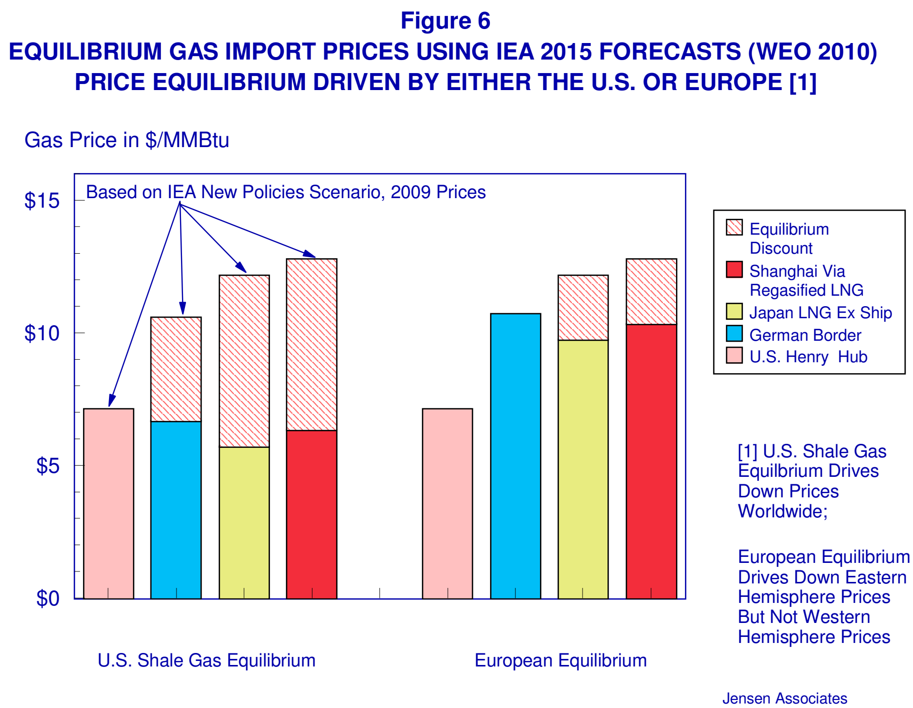
Is this disequilibrium stable? It may well be, because buyers—in the interest of supply security—are willing to accept long-term contract commitments with price indexation to other energy supplies, such as oil. Moreover, pipeline capacity constraints, coupled with many governments' influence over pipeline infrastructure and wellhead pricing, clearly constrain market competition. Certainly, the IEA in its *World Energy Outlook* foresees a continuation of such disequilibrium. In the *World Energy Outlook 2010*, the IEA predicts higher European and Japanese prices than would be the case if there were equilibrium with U.S. price projections.[9]

Disequilibrium is certainly vulnerable to the undermining of oil-linked pricing through the spread of shale-gas technology to other regions. And if the shale-gas surge were large enough to displace significant quantities of indexed contract gas, it is possible that LNG arbitrage might drive world prices toward equilibrium.

If world gas prices were driven to equilibrium by competition with low-cost shale gas in North America, the reduction in prices would be substantial. Perhaps a more likely scenario is that North America goes its own way, with Eastern Hemisphere prices being driven to equilibrium by competition in Northeast Europe. These two scenarios are illustrated in **Figure 6**, showing the effects on prices in Japan, Shanghai, the German border, and Henry Hub.

[9] International Energy Agency, *World Energy Outlook 2010.*

FIGURE 6 **Equilibrium Gas Import Prices Using IEA 2015 Forecasts (WEO 2010) Price Equilibrium Driven by Either the U.S. or Europe**



The basis differentials in Figure 5 and the delivered costs in Figure 6 for Shanghai are based on LNG deliveries from the Middle East, the lowest-cost method of delivering equilibrium gas to the east coast of China. Using the most direct routes east and west, Caspian pipeline gas is more economic than gas from West Siberia. But if Caspian basis differentials were driven down through the replacement of Russia's direct route to Europe through the Ukraine by its more costly South Stream alternative, Caspian supply would actually be cheaper than LNG in Shanghai.

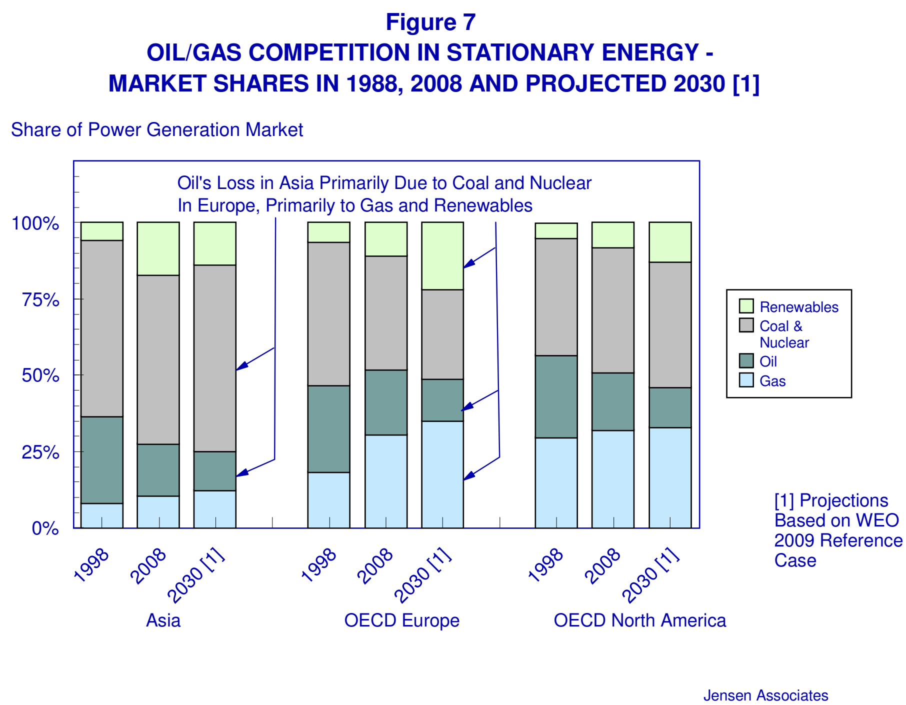
Do Short-Term Commodity Gas Prices Necessarily Determine Long-Term Contract Prices?

This discussion of gas pricing implicitly assumes that short-term commodity competition influences the equilibrium world gas price. But Asia has always been heavily reliant on long-term contracting to secure supply. This includes the traditional destination contract as well as newer secondary contracts, in which self-contractors with destination flexibility still lock in downstream customers. For example, both ExxonMobil and Shell, partners in Australia's Gorgon field, have each signed PetroChina to long-term contracts. Further, producers will argue that commodity pricing is too volatile to provide the level of revenue certainty required to justify the very large long-term investments in gas supply and infrastructure. Thus, some form of long-term pricing is a necessary part of long-term contracting.

Indeed, different short-term and long-term pricing patterns coexist in many areas of economic activity. In futures markets, the price of commodities in more distant months usually differs from prices in the near months, long-term interest rates commonly differ from short-term interest rates, and long-term tanker charter rates commonly differ from spot rates. In the latter example, short-term charter rates reflect the balance of current charter offerings relative to charter demand, while long-term charter rates usually reflect the cost of building new tankers. Thus, it is not inconsistent to foresee a different pricing regime for commodity gas than for long-term contract gas where security of supply (or demand) is important. But whereas new tanker building provides a price marker for tanker markets, it is not clear that a similar price marker exists in gas markets.

In 1969, when Japan first imported LNG, oil's share of the stationary (non-transportation) market was 61%. This was the logic of assuming that oil-to-gas competition was central to gas markets. But by 2008, oil's share was down to 33% and a third of that was for non-energy uses such as chemical feedstocks. **Figure 7** illustrates the shares of the stationary energy market for Asia, OECD Europe, and OECD North America for 1988, 2008, and (in forecast) 2030. Oil's steady loss of market share is apparent in all three regions. But whereas gas has taken the largest share of oil's market in Europe, coal and nuclear, instead of gas, have done so in Asia. Thus, it is difficult to argue that oil linkage is still the prime determinant of gas prices. However, it is also not obvious what the alternative marker should be.

FIGURE 7 **Oil/Gas Competition in Stationary Energy–Market Shares in 1998, 2008, and Projected 2030**



As commodity competition is increasingly becoming a reality in Europe, some new alternatives to oil-linked pricing are appearing. Clauses involving coal, gas market indicators (such as NBP), or electricity pool prices have appeared. But gas market indicators and electricity pool prices assume liberalized gas and electric markets, which are not yet common in Asia. Moreover, commodity gas competition remains weak in the face of the dominance of long-term contracting. Whereas an LNG surplus has set off commodity competition in continental Europe, it is not clear that this will be the case in Asia.

Competition in Asian markets is most likely to originate from competition among LNG suppliers for new contracts. This was the case in 2002 when Australia's North West Shelf, Qatar's Rasgas, and Indonesia's Tangguh projects introduced sharp price discounting in trying to compete for China's first LNG import terminal in Guandong. But the discounting took the form of modifications to the traditional oil-linked contracting terms rather than a shift to different indicators.

The most common pattern of pricing clauses in Asia is an equation in the form of P'C+A*JCC. P equals the price, C is a constant expressed in $/MMBtu, A is a fraction called a slope, and JCC is the Japanese Customs-cleared price for crude oil. By reducing the constant or the slope, it is possible to reduce the relationship between gas and oil pricing. It is also possible to introduce capping mechanisms, such as S curves. These reduce the slopes above and below selected pivot points, thereby shifting the risk relationships between buyer and seller in high or low oil-price markets. Absent some driving force that introduces new energy market indicators, it would seem that changes in the oil price linkages (a reduction in the slope or constant) are more likely when excess supply creates more competitive markets. Recently, in lieu of reducing prices, suppliers have allowed buyers to take an upstream position in production licenses. These efforts to support prices may at times create economic rents for suppliers. However, upstream integration enables buyers to share in some of the rent in profitable markets without undermining the long-term price relationships.

Policy Issues Arising from Asian Supply and Pricing Challenges

The gas policy issues facing Asian countries are far from homogeneous. Australia's large gas resource base and LNG export opportunities create a much different set of policy challenges than do China's or India's heavy reliance on coal in the face of gas-import dependence. But the way in which the world's gas pricing system evolves affects every country.

The successful North American technical breakthrough in developing unconventional sources of natural gas, and particularly shale gas, argues strongly for Asian countries to assess their own unconventional resource positions. Unconventional gas has already been a game changer in North America, and it may have that potential in some Asian countries as well. Australia has already made great strides in developing coal seam gas for LNG.

One of the most challenging issues affecting many Asian governments is subsidy pricing. In Table 3 the proportion of Asia's gas consumption that was priced below market was only slightly less than its proportion—based on Northeast Asian and Chinese long-term contracts—of indexed consumption. For the region as a whole, underpricing is clearly a significant problem. Though a politically attractive option for governments seeking to curry favor with their constituencies, protect their poorer citizens, and subsidize domestic industry, underpricing has substantial drawbacks. By overstimulating domestic demand, it inhibits supply, forfeits attractive export-revenue opportunities for exporters, and may hasten the day when imports are required. Furthermore, as global warming becomes a greater concern, underpricing fosters overuse of carbon fuels.

In its September 2009 meeting, the group of twenty (G-20) leaders singled out inefficient fossil fuel subsidies as an issue that must be addressed.[10] They pledged to "rationalize and phase out over the medium term inefficient fossil fuel subsidies that encourage wasteful consumption." They further asked the IEA, OPEC, the OECD, and the World Bank to provide an analysis and suggestions for how to proceed. The four organizations reported back at the June 2010 Toronto summit.[11] The report agreed with the policy objectives of phasing out fuel subsidies but recognized that in certain cases doing so too rapidly could be harmful. Instead, the organizations suggested a series of steps by which governments could determine when and how to implement the policy objectives. In this report, many of the world's governments—exporting as well as importing—are on record as recommending that domestic energy subsidies be phased out. It is obviously an important issue to be considered in Asia.

North America and the UK have fully implemented the competitive market model, and the European Union is aggressively championing gas and electricity liberalization on the continent. But aside from Australia, Asia has not moved very far along the path to liberalization. Liberalization has many advantages in the efficient matching of supply and demand, but the conditions that have made it possible in North America and the UK do not exist in most Asian markets. Gas-to-gas competition requires competitive supply offerings and supplier access to end users through an open transmission system. Very few Asian countries have competitive suppliers of domestic gas, either because they are

[10] See "G20 Leaders' Statement: The Pittsburgh Summit," available from the G-20 website at http://www.g20.utoronto.ca.

[11] "Analysis of the Scope of Energy Subsidies and Suggestions for the G-20 Initiative," Report, June 16, 2010, available from the OPEC website at OPEC.org/OPEC/en/1836.htm.

essentially dependent on LNG, as in Northeast Asia, or because they have a legacy of centrally planned economies, as in China. While flexible LNG trading in theory provides competitive options, individual customers rarely have the large demand required to trade in full LNG cargo, and spot cargo are often more costly than contract supply.

Each government must weigh the advantages of moving toward more liberalized markets against the challenges of implementing them in their own situations. It seems likely, however, that the indexed long-term contract will continue to dominate Asian LNG trade. For importing governments in Asia, the challenge of competing with Atlantic Basin industrial customers with low-cost supply will be significant if oil-linked pricing remains in Asia. Governments may have a more limited ability to influence long-term contract pricing, but what they can do is remain sensitive to the search for better indicators of indexed pricing clauses and facilitate their implementation where buyers' market conditions make change possible. And if the conditions suggest an opening for upstream integration during those periods, governments should recognize the value of such a move and make sure that existing policies and procedures do not unnecessarily stand in the way.