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Recent Dynamics in the Global Liquefied Natural Gas Industry

Sophia Ruester

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Sophia Ruester[1]

Abstract

This paper provides a summary on recent developments in the global liquefied natural gas (LNG) industry and discusses prospects for capacity development in the mid-term future. During the early years of the industry, most of the world's LNG export infrastructure remained under state control and the industry was characterized by inflexible bilateral long-term supply agreements with take-or-pay and destination clauses. In today's LNG market, new flexibility in trading patterns comes from changes in the structure of long-term contracts. In addition, short-term agreements and spot transactions gain in importance. The first export projects without having sold total volume based on long-term contracts are moving forward. LNG suppliers and buyers increasingly integrate vertically along the whole value chain. Some companies invest in an entire portfolio of LNG export, shipping, and import positions, enabling them to conduct flexible trades and to benefit from regional price differences. In contrast, some new entrants invested in non-integrated LNG import terminals operating them as tolling facilities or speculating for short-term deliveries. However, the non-integrated players still have to prove to be successful in an industry, which a long time has been a sellers' market without major uncommitted export capacities, and in which also in the longer-term future, once, the economic crisis is overcome, importers are expected to continue to compete for global supplies.

JEL Codes: L22, L95

Keywords: Liquefied natural gas, LNG, globalization, value chain, vertical integration, self-contracting, long-term contracts

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[1] Dresden University of Technology, Department of Business and Economics, Chair of Energy Economics and Public Sector Management, D-01062 Dresden. The usual disclaimer applies.
Corresponding author: contact@sophia-ruester.de, URL: http://www.sophia-ruester.de.

1 Introduction

Natural gas accounts for about 24% of world primary energy supply. It is mainly employed for power production, for industrial uses as well as for heating and cooking in the residential sector. In 2008, 27% of the total production of 3,018 bcm have been traded internationally. LNG thereby accounted for 28% of the exported gas (BP, 2009). The International Energy Agency (IEA) forecasts that natural gas will play a key role in the global energy picture also in the future, even though the pace of demand growth will critically depend on climate policy actions. In the IEA reference scenario, global gas demand increases by an average of 1.5% per year until 2030 with the power sector remaining the largest driver of gas demand (IEA, 2009b, p. 365).[2] LNG is expected to continue to gain in importance since it enables the transportation of natural gas over long distances and often becomes the fuel of choice in cases where pipeline sources are limited (e.g., Japan or Portugal) and where supply sources and trade routes shall be diversified (e.g., Spain or Greece).

During the past decade, the LNG industry altered substantially. Traded volumes increased by an annual average of 7% from 2000 on. New players entered the market and new trading patterns evolved. On the one hand, vertical and horizontal integration have become more common with oil and gas majors investing in a portfolio of LNG export, transport, and import capacities which enables flexible trades. On the other hand, new business models of non-integration emerged. Long-term contracts with a duration of more than 20 years co-exist with short-term agreements. Recent developments of unconventional gas resources change the global supply picture. The current economic crisis entails short-term overcapacities in the global LNG export market and supports the development of a buyers' market at least for the mid-term future. The survival of incumbents and new entrants strongly depends on their ability to operate economically.

2 The LNG Industry

2.1 LNG value chain

Prior to the development of the LNG technology, the transportation of natural gas was limited to destinations that could be served by pipeline. The liquefaction of natural gas enables transport over long distances as well as between regions where the construction of pipelines is not feasible due to difficult geographic conditions. Whereas transportation of natural gas in the form of LNG requires very capital-intensive upfront investments, variable costs increase less with shipping distance than for pipelines. Break-even of offshore pipeline and LNG transport is achieved at about 2,500 km (Jensen, 2009b, p. 7).

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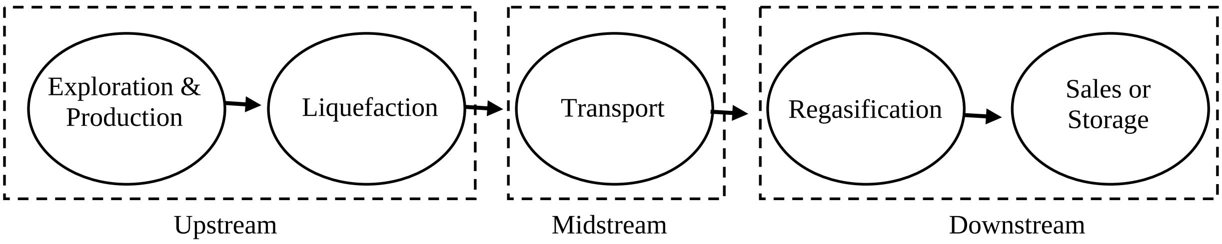
[2] This increase in natural gas demand is fostered by environmental motivations. Natural gas entails lower specific CO_2 emissions as compared to coal or oil. Improvements in the technology of combined cycle gas turbine power plants furthermore allow for natural gas being employed for mid- and base-load electricity generation. The average yearly increase in world demand for the period from 1990 to 2008 was 2.4%.

Figure 1 depicts the five stages of the LNG value chain. Following exploration and production (stage 1), the raw feed gas is transported via pipeline to liquefaction facilities. After removing impurities and separating heavier hydrocarbons, it is cooled to minus 160°C under atmospheric pressure in so called liquefaction trains and shrinks to about 1/600 of its volume (stage 2). This energy-intensive process consumes about 12% of the incoming gas. The liquefied gas is transported to the destination country using tankers equipped with a complex insulation system essential to keep the gas liquid during shipment (stage 3). Gas boiling-off throughout the journey (0.15% of the cargo volume per day) can be used to fuel the ship. Upon arrival, tankers are off-loaded to terminals that reconvert the LNG to its original state of aggregation via heat exchangers where again up to 1% of the incoming gas is used as a fuel (stage 4). Finally, the gas is fed into the destination country’s pipeline grid, traded and sold to marketers, distributors, or power producers, or stored for future demand (stage 5).

In general, the structure of export and import projects is largely predetermined by exogenous factors and therefore lies beyond the control of individual players. Exploration and production of natural gas are directly linked to the liquefaction projects whose ownership structures in many cases are determined by national oil and gas companies. On the downstream end, national infrastructure, marketing, and distribution systems are often in place before import terminal construction. Therefore, this analysis concentrates on the three successive stages of upstream, midstream, and downstream activities.

Figure 1: LNG value chain



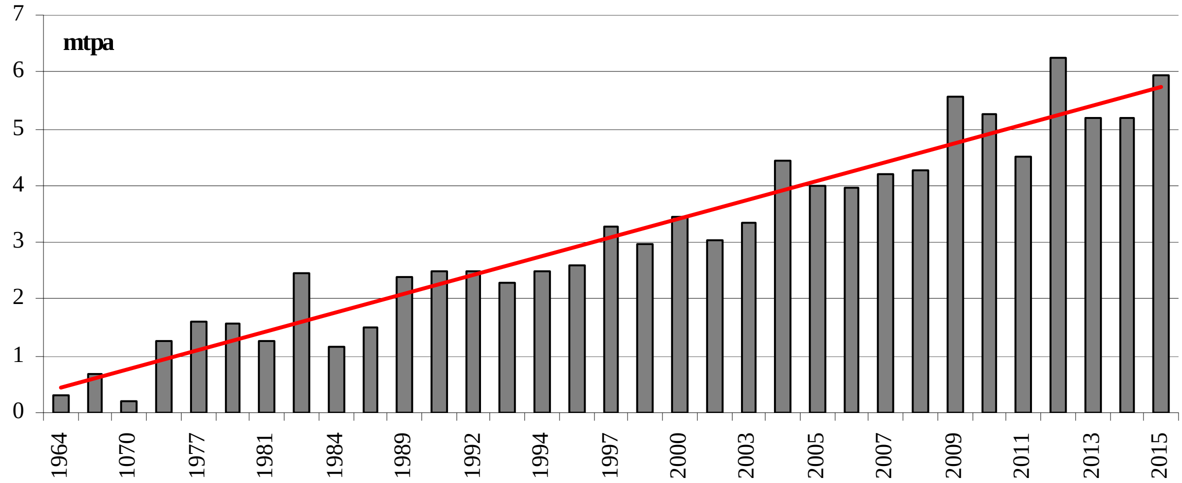
Source: Own depiction

Transportation infrastructure is a substantial element linking exporting and importing projects. In contrast to oil shipping, vessels for LNG transport are very capital-intensive and therefore traditionally have been dedicated assets for specific routes booked under extensive long-term contracts. However, an increasing number of vessels for uncommitted trade are now in the order books of shipyards and will reduce dedicated asset specificity.

Investment costs within the five stages vary significantly. Exploration and production including gas processing and transportation from the field to the liquefaction facility account for 15-20% of the total costs of the LNG value chain; liquefaction including gas treatment, cooling, loading and storage for 30-45%; shipping for 10-30%; and regasification including unloading and storage for 15-25% (EIA, 2003, p. 42).

During the period from the mid-1990s to about 2003, costs along the whole value chain were declining (see e.g., EIA, 2003) which supported the rapid expansion of the LNG sector and a general enthusiasm with respect to future growth potentials. This was mainly driven by technological advances and the realization of economies of scale in liquefaction, shipping, and storage. Fuel efficiency in liquefaction and regasification could be improved using higher-efficiency gas turbines. Overcapacities and redundancies have been reduced. Whereas the first liquefaction trains (Arzew in Algeria) had a capacity of 0.3 mtpa, today, trains with a capacity of 4 mtpa are common and Qatar recently completed its first 'mega-trains' including 7.8 mtpa units. See Figure 2 for an illustration of the development of average liquefaction train size. Economies of scale of two 4 mtpa trains reduce liquefaction cost of an 8 mtpa greenfield project with four 2 mtpa units by nearly 30%. An increase to one 7.8 mtpa unit leads to an additional 20% cost reduction (Jensen, 2003, p. 31). Average investment costs fell from about 550 USD/mtpa in the early years of the industry to 350 USD/mtpa in the 1980s, 250 USD/mtpa in the late 1990s, and 200 USD/mtpa in the early 2000s (Cornot-Gandolphe, 2005).

Figure 2: Development of average liquefaction train size by start-up year



Source: Own depiction

Tanker financing and construction schedules have benefited from new manufacturing techniques and more shipyards that can build LNG vessels. Typical vessel size today is in the range of 120,000 to 180,000 m³. Building costs for standard LNG tankers have decreased from about 280 million USD in the mid-1980s to 155 million USD in the early 2000s (EIA, 2003, p. 42). In November 2007, the first super-size tankers with a capacity above 210,000 m³ have been delivered. These ships benefit from lower average transport costs; however, there are restrictions concerning potential destination facilities since only a number of ports can handle these vessels. Small-size LNG carriers are employed in Japan, where intra-country LNG transport compensates for the lack of a nationwide transmission system.

In the mid-2000s, the trend of falling costs reversed due to rising raw material prices (such as steel or nickel) and the large demand for LNG facility construction. There are only four companies contracting for engineering, procurement and construction of LNG plants and the contractor market has become increasingly tight during the last years, when significant investments along the LNG value chain have been realized. The number of liquefaction trains simultaneously under construction increased from an average of eight during the 1990s to twelve in the early 2000s and to 16 for the period from 2005 to 2008 (IEA, 2009b, p. 451). Table 1 provides a summary of cost estimates over time.

Table 1: Development of costs along the LNG value chain

	Cost of service early 1990s [USD/MBTU]	Cost of service early 2000s [USD/MBTU]	Capex as of 2006 [bn USD]	Cost of service as of 2006 [USD/MBTU]	Capex as of 2009 [bn USD]	Cost of service as of 2009 [USD/MBTU]
Source Trade route	Cornot-Gandolphe (2005): Deliveries from Middle East to Europe		Jensen (2006): Two 4 mtpa trains, Nigeria to US Gulf coast		Jensen (2009b): Two 4 mtpa trains, Nigeria to US Gulf coast	
E&P	0.5-0.8	0.5-0.8	1.6	0.80	3.0	1.00
Liquefaction	1.3-1.4	1.0-1.1	1.6	0.94	4.3	2.15
Shipping	1.2-1.3	0.9-1.0	2.0	0.99	2.1	1.23
Regasification	0.5-0.6	0.4-0.5	0.6	0.38	1.1	0.70
Total	**3.5-4.1**	**2.8-3.4**	**5.8**	**3.11**	**10.5**	**5.08**

A number of projects have suffered from cost overruns and construction delays during the last years: e.g., for Indonesia's 7.6 mtpa Tangguh project, an 18-month delay in the final investment decision led to a cost increase from 1.4 to 1.8 billion USD. The Russian Sakhalin II and Norway's Snovhit projects have experienced huge cost overruns which might partially be caused by the Arctic environment. Snovhit furthermore suffered from technical failures and ran at only 55% of nominal capacity from its commissioning in 2007 and was shut down again in 2008 for an additional maintenance. Cost overruns and delays also have been reported for Yemen LNG and the large-scale trains at Qatargas IV and V (all still under construction).

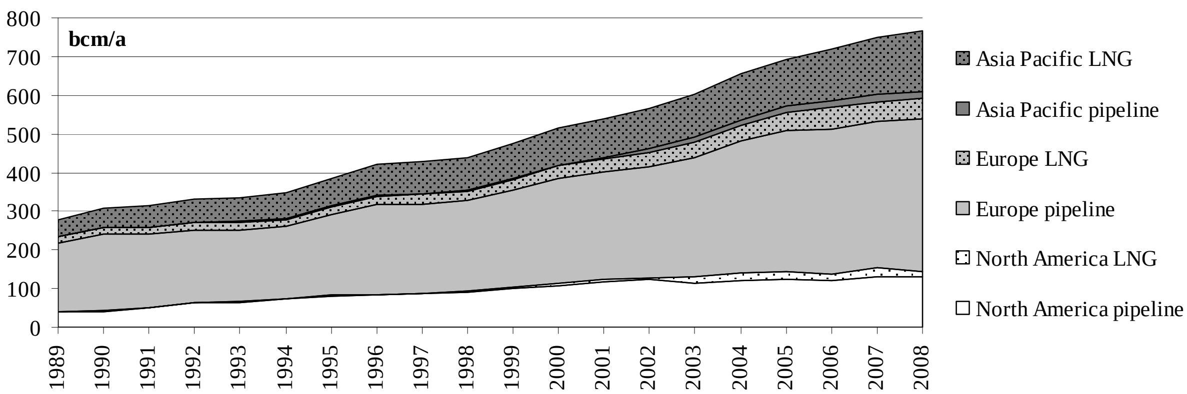
2.2 Development of the LNG industry

Converting natural gas to LNG for transportation by tanker has been utilized for more than 40 years, but the industry achieved a remarkable level of global trade only recently. Since 1964, the technology of natural gas liquefaction enables commercial transport in tankers with the first deliveries having been dedicated from Algeria to the UK.[3] Transport remained expensive and natural gas markets stayed regional in nature until the 1990s.

[3] The UK imported LNG from 1964 to 1982. With the growing natural gas production in the North Sea, however, imports had been stopped, the UK became a net exporter of natural gas and the regasification facility at Canvey Island was dismantled.

The North American market including the US, Canada and Mexico traditionally has been highly self-sufficient with substantial domestic production in all three countries and some intra-regional pipeline trade. The US opened its first LNG receiving terminal in 1971 to import additional volumes from Algeria. However, due to a surplus in domestic supplies in the mid-1980s two of the four import terminals (i.e., Elba Island and Cove Point) have been mothballed in 1985 and contracts with the Algerian Sonatrach were terminated before their official end. In Europe, indigenous natural gas supplies and imports via pipeline were available to meet demand and LNG capacities grew relatively slowly. Spain opened its first LNG import terminal in 1969, Italy and France followed in 1971 and 1972, respectively. In contrast, traditional Pacific Basin natural gas importers such as Japan, South Korea or Taiwan lack domestic supplies and are beyond the reach of any pipeline sources. They are highly dependent on imports in the form of LNG and dominated the LNG industry during its first decades (see Figure 3).

Figure 3: Development of natural gas imports of the world's major importing regions



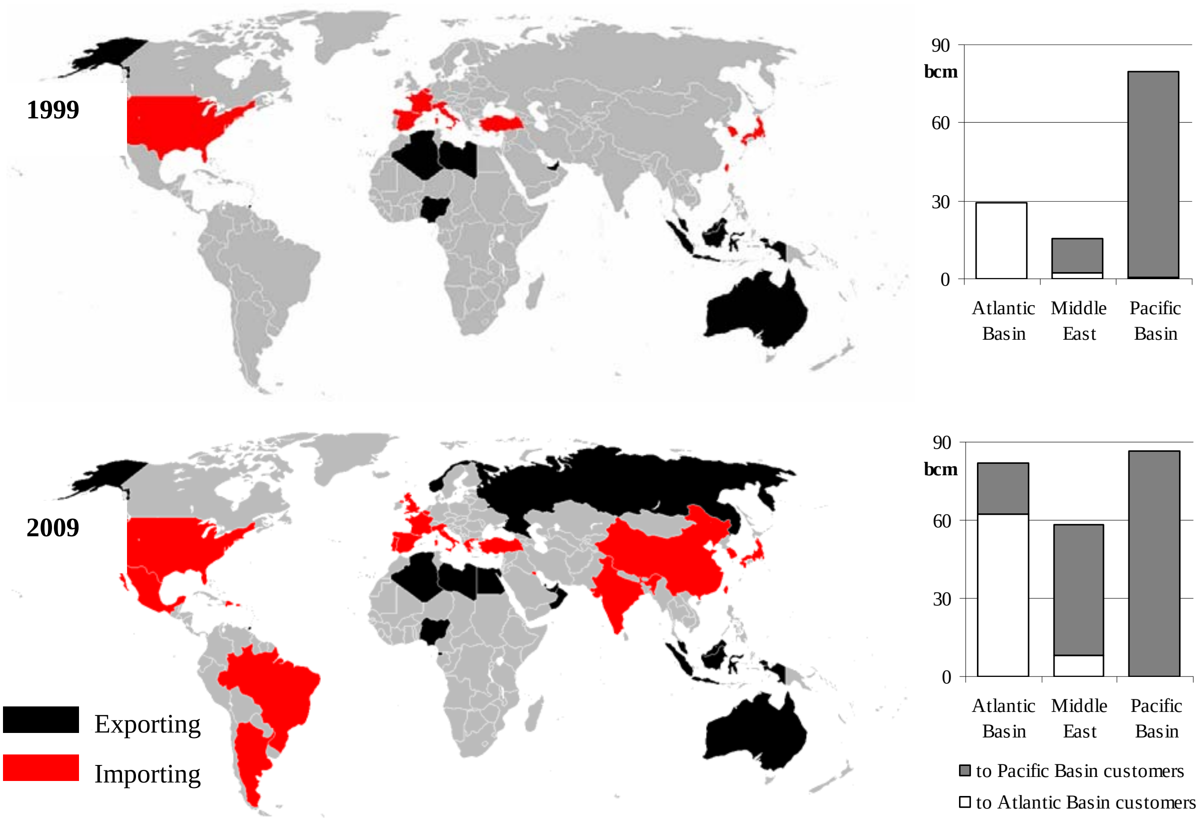
Source: Own depiction based on data from BP Statistical Reviews of World Energy (1990-2009)

During this early stage, most of the world's LNG export infrastructure remained under state control and private or foreign companies were involved only with minority shares. Inflexible bilateral long-term contracts with take-or-pay and destination clauses secured the capital-intensive infrastructure investments and reliable supplies for import-dependent buyers.

Nissen (2004) calls these early trading structures 'project-utility chain model' where the export project (typically a joint venture between a national oil and gas company (NOC) and a private oil and gas major) functions as the seller and a monopoly franchised utility or a merchant trader as the buyer. Downstream competition in most importing countries was not encouraged; e.g., buyers in South Korea and Taiwan were state entities, the Japanese natural gas sector was highly regulated without any foreign participation and Japanese utilities controlling all imports; and also in European countries such as France for example, a state-owned monopoly was responsible for all imports and natural gas transmission. Capacities along the whole value chain, including shipping, have been bilaterally committed and each supply project was linked by technical and commercial design to a specific market.

Since the 1990s, investments in LNG infrastructure grew rapidly as worldwide natural gas demand increased significantly, leading to substantial economies of scale throughout the value chain. New entrants include Turkey (1994), Greece (2000), Portugal (2003), India (2004), China, and Mexico (both 2006). The UK re-emerged as an LNG importer in 2005 to substitute for declining domestic production. Significant expansions and new investments have been realized in Spain and the US re-opened its mothballed terminals since domestic supply sources no longer appeared adequate to support the expected increase in demand. South American countries received their first LNG in mid-2008.

Figure 4: Countries participating in LNG trade and inter-regional trade volumes 1999 vs. 2009[4]



Source: Own depiction based on data from BP Statistical Reviews of World Energy (2000, 2009)

Industry experts agree that the LNG industry has altered substantially during the last decade (Iniss, 2004, p. 9; Jensen, 2004, pp. 7 ff.). Regasification capacities increased from 251 mtpa in 1999 to 462 mtpa at the end of 2009 (+84%), liquefaction capacities from 108 to 229 mtpa (+112%) during the same period and the number of operating LNG vessels augmented from 106 to 337 (+218%). Atlantic Basin LNG trade gained in importance. After nearly 20 years without any export capacity extensions, Trinidad/Tobago and Nigeria opened their first liquefaction trains in 1999, Egypt followed in 2005 and Equatorial Guinea and Norway in 2008 and 2009, respectively. The Middle East, accounting for more than 40% of worldwide proven natural gas reserves, is becoming the largest regional exporter of

[4] The figure of traded volumes in 2009 uses trade data of 2008. However, due to the economic crisis and its negative impact on natural gas demand, no increase in traded volumes is expected for 2009 (IEA, 2009b, p. 48).

LNG. With Qatar and Oman, two additional suppliers started deliveries in 1997 and 2000. The region is currently evolving to a swing producer. Deliveries to European and Asian markets and even to North America are feasible without a significant difference in transportation cost.[5] Jensen (2007a, p. 29) even argues that Qatar, the largest LNG exporter since 2005, may become the "Henry Hub of global LNG pricing".

In today's LNG market, new flexibility in trading patterns comes from i) changes in the structure of long-term contracts, ii) a small but growing short-term market, and iii) a trend of suppliers towards self-contracting with their own downstream marketing affiliates. Changing contract terms have taken several forms: average contract duration as well as contracted volume are decreasing, take-or-pay requirements are reduced, destination clauses are eliminated and buyers increasingly conclude for free-on-board agreements enabling cargo diversions. Long-term contracts are accompanied by flexible short-term agreements as well as vertical integration and strategic partnerships. Today, spot and short-term trade account for about 20% of total LNG trade. Arbitrage trade in the Atlantic Basin is increasingly linking North American and European markets.

Changes in the institutional framework, i.e., the move from monopolistic structures to competition,[6] in turn demand fundamental changes in the organizational behavior of market participants. More competition, mirrored by evolving spot markets, a gain in contract flexibility, and increasing international trade, exposes traditional players to greater pressure. Global mergers and acquisitions, integration, and strategic partnerships have become routine today and the LNG industry is dominated by a small number of large players. Global oil and natural gas producers and distributors are frequently engaged in all stages of the LNG value chain. In addition, export projects are increasingly financed and developed by private (and foreign) interests. Former downstream monopolists of natural gas are finding their traditional markets challenged by the intrusion of oil and gas majors integrating into import markets. Vertical integration in response to market deregulation features drivers including upstream producers aiming to benefit from downstream margins and from ownership of transportation capacities to exploit arbitraging possibilities. Distribution and power companies move upstream to ensure margins and supply security.

[5] Shipping costs for deliveries from North Africa account for about 0.35 USD/MBTU (to Europe), 0.95 USD/MBTU (to the US Gulf coast), and 1.8 USD/MBTU (to Japan). For deliveries from the Middle East they are in the range of 0.8, 1.0, and 1.4 USD/MBTU, respectively (Razavi, 2009, p. 14).

[6] The US natural gas industry, where restructuring already started in 1978 with the Natural Gas Policy Act deregulating wellhead prices, is a functioning and highly competitive market. See Makholm (2006; 2007) and Hirschhausen (2006, pp. 4 f.) for an overview on regulatory actions implementing vertical unbundling and competition in production and marketing. The UK followed with the privatization of British Gas in 1986 and vertical unbundling in the 1990s. In Continental Europe, the liberalization process did not start before the late 1990s with the EU directives 98/30/EC and 2003/55/EC. In Japan, deregulation of natural and electricity sectors started only recently.

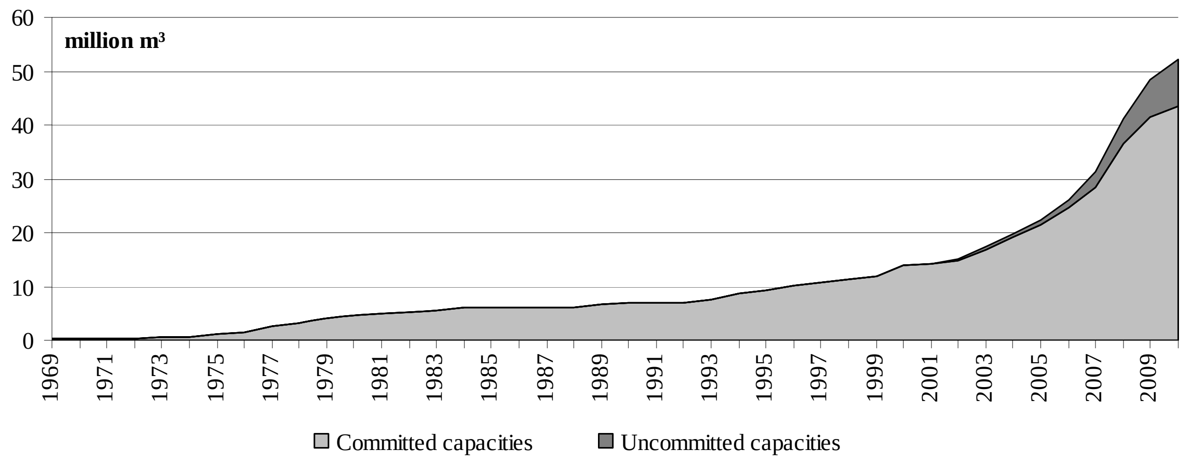
2.3 Globalization of the natural gas market

The technology of natural gas liquefaction enables inter-regional gas trade linking the historically isolated markets of North America, Europe-Eurasia and Asia-Pacific. Even though regional trading patterns prevailed a long time, today's natural gas market can be regarded as a global market in the sense that price signals are transmitted from one region to another. However, the (liquefied) natural gas market is different from global commodity markets such as the oil industry. Highly capital-intensive infrastructures make it economically difficult to hold permanent spare capacity and instead support the conclusion of long-term sales and purchase agreements. Together with high cost of transportation and a lack of liquid trading hubs and fully competitive downstream markets these conditions prevented the establishment of a global natural gas price.

Recent developments towards more flexibility within contracts and trades support the globalization of the natural gas market. The volume of uncommitted capacities along the value chain increases. The first export projects without having sold their total volume based on long-term contracts are constructed (e.g., Oman LNG, Malysian Tiga LNG, Russian Sakhalin II, expansion trains of Australia's North West Shelf Venture). Project delays of downstream regasification plants or a surplus in capacity during ramp-up periods can be used to conduct short-term deliveries (e.g., in 2002, LNG shipments from Oman and Abu Dhabi which had been destined for India's Dabhol import terminal suffering from construction delays were sold on the short-term market).

A long time, shipping has been seen as the critical bottleneck motivating oil and gas majors and export and import consortia to order a large number of vessels. As a result, the number of LNG ships has augmented significantly. Whereas in 1999, virtually all ships had been dedicated to specific trade routes, the share of uncommitted capacity increased to 14% in 2009 (49 of the 337 ships with a total capacity of 6.9 million m³; see Figure 5 for an illustration of the development of shipping capacities).

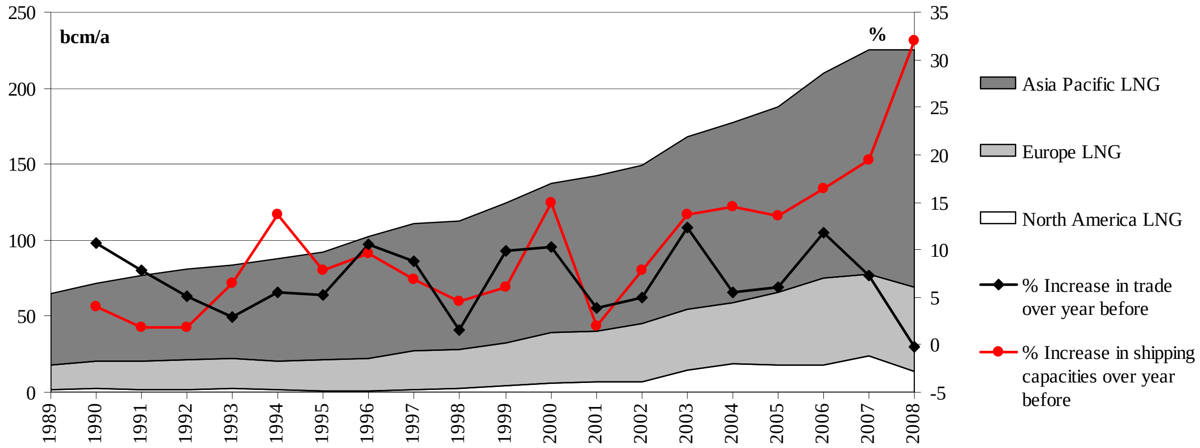
Figure 5: Development of shipping capacities



Source: Own depiction based on data from http://www.shipbuildinghistory.com

Free transport capacities are also available due to recent delays in the start-up of liquefaction projects. In addition, the current economic crisis reinforces this imbalance between LNG production and transportation capacities at least in the mid-term future. Whereas LNG trade ceased growing in 2008, the number of LNG ships still increased by 32% from 2007 to 2008; another 35 ships are currently in the shipyards' order books (see Figure 6). It is likely that this surplus will support the future expansion of the short-term and spot market. LNG vessels also could be employed as temporary floating storage and sellers thereby could take advantage of short-term and seasonal price differences.

Figure 6: Development of LNG trade and shipping capacities

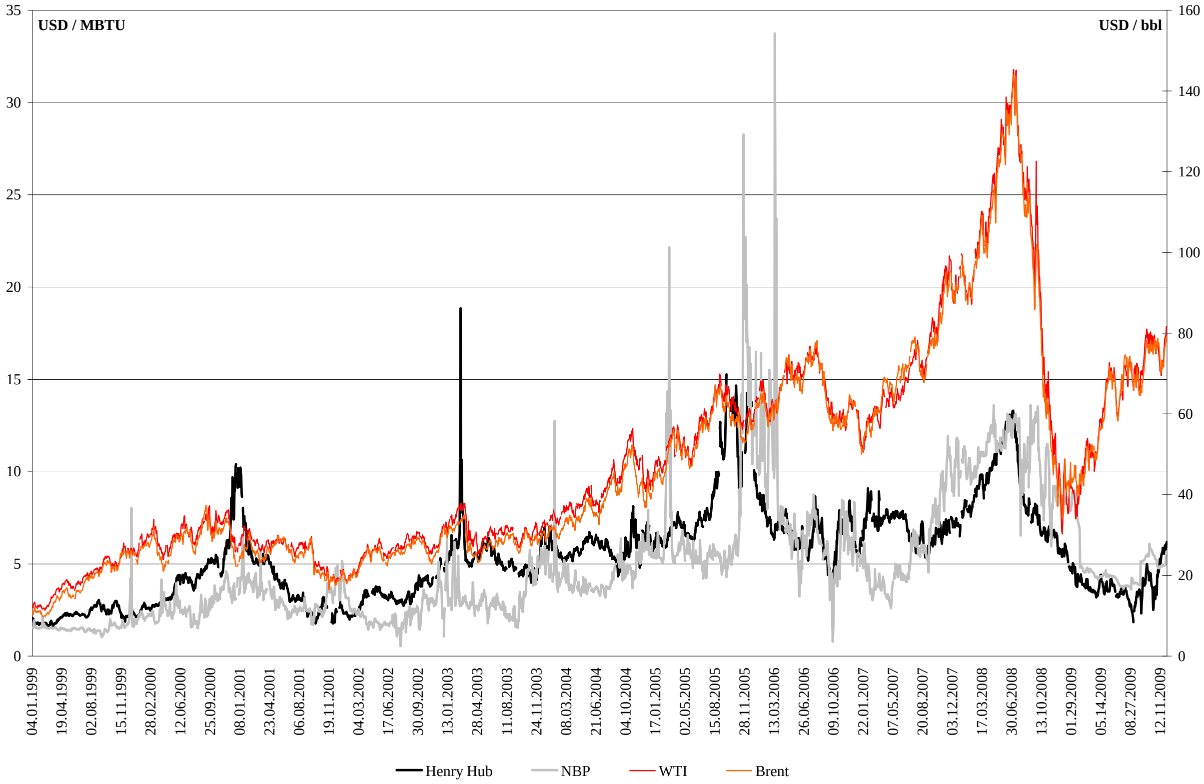


Source: Own depiction based on data from http://www.shipbuildinghistory.com and BP Statistical Reviews of World Energy

Figure 7 shows the historical natural gas and crude oil spot prices observed on both sides of the Atlantic. Whereas oil prices (i.e., the US WTI and North Sea Brent) move quite parallel reflecting a global oil price, natural gas prices (i.e., US Henry Hub and UK NBP) clearly diverge. To a major part, they reflect region-specific, instead of global, supply-demand conditions. Using spot data for the US, the UK and Continental Europe from 1999 to 2008, Neumann (2009) confirms the non-convergence of international natural gas prices. However, she shows that formerly regionally isolated markets are becoming more integrated and that convergence is higher for winter months when markets are tight and natural gas spot prices tend to be more volatile, supporting the redirection of LNG spot cargoes.

Tight supply situations in Asian importing countries regularly mirror in high prices for short-term deliveries, too, despite the absence of liquid natural gas markets and import prices being determined based on oil price indexed pricing formulas within long-term contracts. The short-term price differences between regions provide economic incentives to redirect flexible cargoes and to deliver additional spot volumes to higher value markets. In the period from 2000 to 2001, for example, the US faced higher price levels than Continental Europe which led to cargoes being redirected from Europe to North America. A similar price relationship and trade pattern was observed in 2003. During the winter of 2005/2006, a severe competition for LNG spot cargoes within the Atlantic Basin and sharp price spikes occurred. In North America, hurricanes Katrina and Rita severely affected production; in the UK, the transition from a net exporter to a net importer created additional import demand; Spain suffered from poor hydro conditions raising the demand for gas-fired power generation; and demand in Continental Europe was high due to a cold winter. In early 2008, cold weather pushed Japanese power consumption to record levels at the same time when a major share of the country's nuclear capacity was offline. Tokyo Electric Power shut down its 8.2 GW Kashiwazaki-Kariwa power plant after an earthquake in July 2007. Hence, natural gas demand from the power sector increased substantially which mirrored in prices of up to 19 USD/MBTU paid for LNG spot cargoes at a time when average import prices were in the range of 9 USD/MBTU. In April 2008, China bought an LNG spot cargo at 14 USD/MBTU. Similar prices have been paid for other spot shipments in spring 2008. RWE contracted for the delivery of eight cargoes to be delivered to the UK from December 2009 to January 2010. Due to recent price increases in the US, however, these volumes will be redirected towards the North American market.

Figure 7: Development of crude oil and natural gas prices



Source: Own depiction based on data from the EIA and ICIS Heren

Theoretical and empirical studies of arbitrage trade in the LNG industry are rare. Hayek (2007) simulates the value of the option to conduct flexible LNG trades developing a mean-reverting model to represent the stochastic evolution of gas prices in regional markets and the resulting price spreads. Obviously, larger price differences will be observed for a low correlation between regional prices. Zhuravleva (2009) provides a qualitative discussion of different arbitrage models (i.e., initial seller-arbitrageur, initial buyer-arbitrageur, and independent trader-arbitrageur).

3 Prospects for Liquefied Natural Gas

Evaluating the future development of LNG export and import capacities is a very difficult task due to a number of reasons: i) during the last decade, natural gas (and/or LNG) demand augmented rapidly in countries such as China, India, or Spain, but also in historically self-sufficient countries such as the UK or Indonesia. The recent economic crisis, however, yields a stagnation (and even reversion) of regional demand growth at least for a shorter-term perspective and has fostered the development from a sellers' to a buyers' market. The exploration of unconventional natural gas sources such as shale gas in North America may have an impact on the domestic supply of different countries; ii) oil and natural gas prices experienced a sharp increase during 2007 and the first half of 2008, followed by a rapid price decrease. The demand for LNG is inherently sensitive to natural gas price volatility and small changes in the supply-demand balance alter incentives to invest in its capital-intensive infrastructures; iii) the future treatment of greenhouse gas emissions will also have an impact on the economics of natural gas as a fuel competing with coal and oil on the one hand as well as with renewable and nuclear energy sources on the other.

This is supported by Jensen (2007b, p. 10), who argues that "[i]n this environment, it is unlikely that any forecast – no matter how well done – will get it right." The following paragraph therefore focuses on the prospects of investments in LNG export and import capacities in the mid-term future up to 2015. A dataset including all LNG facilities (i.e., operating, under construction, planned, and proposed) has been built up using data from various publicly information such as periodical reports, newsletters, industry journals, and company websites. It includes information on nominal liquefaction, regasification, and storage capacities, ownership structures, capital investments, supply sources, customer portfolios, concluded contracts as well as the LNG world fleet. The number of projects reported publicly substantially exceeds the number of projects that are likely to be commercialized; therefore, it is necessary to judge which projects are likely to go forward and when. Based on these data as well as an objective evaluation of the technically feasible and from an economic point of view reasonable realization of the projects, forecasts for capacity development have been generated.

3.1 Prospects for LNG exporters

The early LNG industry was dominated by Pacific Basin trade with supplies coming from Alaska (start-up 1969), Brunei (1972), Indonesia (1977), Malaysia (1983), and Australia (1989). In the Atlantic Basin, Algeria (1964) and Libya (1970) were early exporters and the United Arab Emirate started deliveries from the Middle East to Asian customers in 1977. At the end of 2009, there are 226 mtpa of liquefaction capacity, of which 35% are located in the Atlantic Basin, 42% in the Pacific Basin and 23% in the Middle East (see Table 2). In 2008, Qatar was the largest exporter supplying a total of 39.7 bcm of LNG to both European and Asian customers. Together with Malaysia (29.4 bcm), Indonesia (26.8 bcm), Algeria (21.8 bcm), Nigeria (20.5 bcm), Australia (20.2 bcm), and Trinidad/Tobago (17.4 bcm), these seven countries accounted for 78% of total LNG exports.

Table 2: Existing and proposed liquefaction facilities as of 2009

Country	Existing sites	Nominal capacity [mtpa]	Under construc-tion	Nominal capacity [mtpa]	Proposed	Nominal capacity [mtpa]
Atlantic Basin						
Algeria	2	20.2	1	4.5	-	-
Angola	-	-	1	5.2	-	-
Egypt	2	16.2	-	-	-	-
Equatorial Guinea	1	3.7	-	-	exp.	4.4
Libya	1	0.6	-	-	exp.	3.2
Nigeria	1	20.3	-	-	3	40
Norway	1	4.3	1	0.3	-	-
Trinidad/Tobago	1	14.8	-	-	exp.	3
Venezuela	-	-	-	-	1	4.7
Total	***9***	***80.1***	***3***	***10***	***4***	***55.3***
Pacific Basin						
Australia	2	19	1	4.3	5	37.5
Brunei	1	7.2	-	-	-	-
Indonesia	3	35.1	-	-	2	4
Malaysia	1	22.7	-	-	-	-
Peru	-	-	1	7	-	-
Russia	1	9.6	-	-	1	7.5
US	1	1.4	-	-	-	-
Total	***9***	***95***	***2***	***11.3***	***8***	***49***
Middle East						
Abu Dhabi	1	4.8	-	-	-	-
Iran	-	-	-	-	3	28.8
Oman	1	10.7	-	-	-	-
Qatar	2	35.7	exp.	31.2	exp.	7.8
Yemen	-	-	1	6.7	-	-
Total	***4***	***51.2***	***1***	***37.9***	***3***	***36.6***
Total	**22**	**226.3**	**6**	**59.2**	**15**	**140.9**

Source: Own depiction based on data from various publicly available sources

For the near term, significant expansions will be added especially within the Middle East, a region where more than 40% of world natural gas reserves are located. Major expansions are under way in Qatar and an additional greenfield project is expected to start operation in Yemen in 2010. Qatar announced to observe the behavior of the production from the North Field before making commitments about further expansions; therefore, additional export capacities beside those already under construction are not expected for the mid-term. In the Atlantic Basin, capacities will be expanded in Algeria and Libya. In Norway a small-scale LNG project for intra-regional trade is under construction and Angola is likely to enter the stage as an additional supplier. Nigeria in the longer-term has the potential to provide additional exports; domestic consumption is low and still much gas is flared during oil production. In the Pacific Basin, neither Brunei nor Malaysia are expected to expand their liquefaction capacity. The Alaska venture will reach the end of its economic life in the mid-term.

Peru is expected to open its first LNG terminal in 2010. Works on Australia's Pluto venture already started in 2007 and also the Gorgon venture is likely to be developed until 2015.

In recent years, the evolving competition between growing domestic demand and exports in traditional supply countries such as Algeria or Libya has become increasingly discussed.[7] In the absence of new gas developments, export availability will be reduced (IEA, 2009a). For example, Egypt faced continuously increasing domestic natural gas consumption over the last 20 years with an average yearly demand increase of 11% from 1998 to 2008. The government decided to prioritize the home market and introduced a moratorium on new export projects in 2008. In Iran, domestic consumption increased by an average of 8.7% during the last decade. Large volumes of produced natural gas are re-injected into oil fields in order to maintain oil production at economic levels.

Indonesia is a country showing substantial dynamics. After twenty-five years enjoying the position as a reliable supplier of LNG, the country has become a source of supply uncertainty. LNG exports peaked in 1999 at a level of 38.8 bcm and declined to 26.9 bcm in 2008. The reasons are diverse. First, domestic demand increases due to the government's efforts to reduce oil consumption via slowly reducing subsidies on domestic oil use. Second, the Arun natural gas field, which began production in 1978, is aging and production declines. Furthermore, domestic natural gas consumption is prioritized; certain volumes are delivered to a fertilizer and a pulp company. The LNG plant is already partially shut down and is expected to stop exports during the next decade. From the Bontang field, some natural gas is diverted to the domestic industry, too.

Hence, the country was not able to fulfill its long-term supply contracts. According to Global Insight, ten cargoes destined for Taiwan had to be cancelled in late 2004; the Oil and Gas Journal reported in 2007 that Indonesia already had failed to deliver 72 cargoes of LNG (4.1 mtpa) to Japanese customers. In 2007, 0.23 mtpa of scheduled LNG cargoes to South Korea had been dropped. Pertamina, the state-owned oil and gas company, negotiates with LNG buyers over the further proceeding (i.e., whether the export volume will be reduced or whether some cargoes might be rescheduled or replaced by swap arrangements). The company furthermore has purchased volumes on the spot market to fulfill its delivery commitments. Some of its older contracts with Taiwan and South Korea will expire in the coming years and Pertamina already has indicated that it will not renew these contracts at their original levels. The new Tangguh liquefaction plant which started operation in early 2009 will temporarily absorb the decline in the country's exports. However, industry experts agree that any exports from the Donggi field, as had been proposed for the mid-term future, are very unlikely due to the high domestic demand as well as lower gas reserves confirmed as expected.

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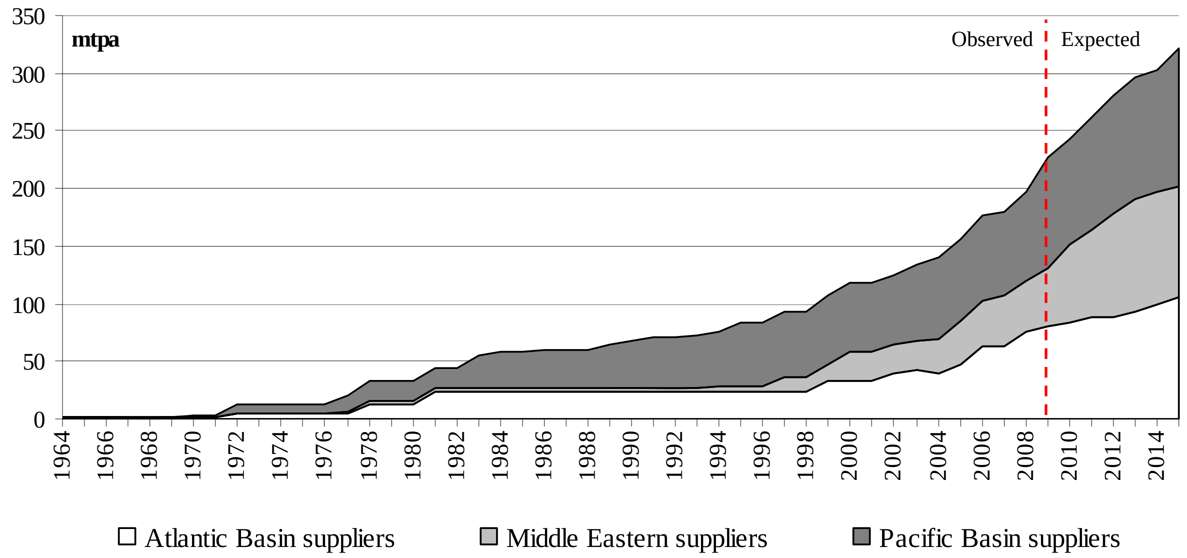
[7] Razavi (2009) discusses natural gas pricing policies in MENA countries (holding almost half of global gas reserves) where gas prices are set by the governments, often substantially below its economic cost which in turn results in a wasteful use of gas, the deployment of inefficient technologies, and a huge burden on government budgets. For example, the Egyptian government buys the gas from producers at a price of 2.65 USD/MBTU and sells it in the domestic market at an average price of 1.19 USD/MBTU resulting in a subsidy of about 7 bn USD/a. The Iranian government provides gas to the national power utility at 0.1 USD/MBTU, to the industrial sector at 0.6 USD/MBTU and to residential/commercial customers at 0.45 USD/MBTU. Similar estimates for actual price levels and much higher market values for numerous countries are provided by EIA (2009b, p. 525).

Another interesting development in Indonesia is that the country announced to study the potential of LNG *import* facilities. A pipeline network covering Sumatra and Java connects the main demand centers Java and Bali and with the predominant supply sources Natuna Island and southern Sumatra. Other supply regions such as Kalimantan and Papua are not connected to the pipeline system and LNG import terminals are considered in eastern and western Java as well as in northern Sumatra.

Taking the above discussed developments into account, world liquefaction capacity being operational in 2015 is forecasted to be 322 mtpa, with the Atlantic Basin accounting for 33%, the Pacific Basin for 37% and the Middle East augmenting its share to 30% of the installed capacities (see Figure 8). In the short-run, the current economic crisis will have a negative effect on LNG demand and on the ability to finance infrastructures along the value chain. However, the normal lag in liquefaction plant construction (on site works take about four years) makes it difficult for suppliers to respond quickly to demand variations. The delayed supply response to an earlier demand growth will start operation until 2015 and will create a surplus in supply in the mid-term future.

These forecasts go in line with the LNG demand projections developed by Jensen (2009b, p. 58) expecting between 270 and 325 bcm in 2015. Also the Energy Information Administration (EIA) in its recent World Energy Outlook projects global LNG trade to be in the range of 300 bcm in 2015 (EIA, 2009b, p. 439) with prospects for installed liquefaction capacity at a level of 295 mtpa.

Figure 8: Development of liquefaction capacities



Source: Own depiction

3.2 Prospects for LNG importers

The first LNG import facilities started operation in the UK (1964), Japan and Spain (both 1969), Italy and the US (both 1971), France (1972), and South Korea (1986). Whereas capacities in Europe and North America grew slowly or even were mothballed (i.e., UK and US) during the first decades of the industry, Pacific Basin countries, rapidly invested in additional projects. Since 2000, however, Atlantic Basin countries experience substantially higher annual growth rates with an average of 16.4% (versus 2.3% for Asian importers). This renewed interest in LNG had a number of reasons including decreasing production from conventional natural gas fields in the US and the North Sea (the UK has become a net importer of natural gas in 2006), increasing employment of gas-fired combined cycle gas turbine power plants (e.g., gas-fired generation increased from 19 TWh in 1999 to 93 TWh in 2007 in Spain), and efforts to diversify supply sources.

At the end of 2009, there are 450 mtpa of regasification capacity, of which 41% are located in the Atlantic Basin, 58% in the Pacific Basin and 1% in the Middle East (see Table 3). In 2008, Japan was the largest importer receiving a total of 92.1 bcm of LNG (41% of world LNG trade). Together with South Korea (36.6 bcm), Spain (28.7 bcm), France (12.6 bcm), and Taiwan (12.1 bcm), these five countries accounted for 80% of total LNG imports (BP, 2009). In the coming five years, significant expansions are expected especially within Asian emerging countries. Moderate expansions are projected for European countries whereas North America currently faces a supply-overhang due to the development of substantial unconventional natural gas sources. Figure 17 in the Appendix classifies LNG import countries according to their dependence on natural gas imports in the form of LNG and the level of proposed new capacities.

Table 3: Existing and proposed regasification facilities as of 2009

Country	Existing sites	Nominal capacity [mtpa]	Under construc-tion	Nominal capacity [mtpa]	Proposed	Nominal capacity [mtpa]
Atlantic Basin						
Argentina	1	2.2	-	-	-	-
Belgium	1	6.3	-	-	-	-
Brazil	1	1.6	1	3.7	2	3.6
Canada	-	-	1	3.6	5	24.1
Canaries	-	-	-	-	1	1.3
Croatia	-	-	-	-	1	7.3
Dominican Republic	1	2	-	-	-	-
France	2	10.7	1	6.1	4	19.3
Germany	-	-	-	-	2	11
Greece	1	3.3	-	-	-	-
Ireland	-	-	-	-	1	3
Israel	-	-	-	-	1	2.9
Italy	1	2.6	3	21.3	13	75
Jamaica	-	-	-	-	1	1.1
Mexico	1	3.6	-	-	-	-
Netherlands	-	-	-	-	4	24.7
Portugal	1	4	-	-	-	-
Puerto Rico	1	0.7	-	-	-	-
Spain	6	33.5	1	5	-	-
Turkey	1	4.6	-	-	1	~ 3
UK	3	20	1	4.5	3	15.7
Uruguay	-	-	-	-	1	2.6
US	8	88.7	3	29.6	25	~ 51
Total	***29***	***183.8***	***11***	***73.8***	***65***	***194.6***
Pacific Basin						
Chile	-	-	-	-	2	4
China	3	9.3	2	6	12	45
El Salvador	-	-	-	-	1	0.8
Hong Kong	-	-	-	-	1	3
India	2	8.6	1	5	7	22.5
Indonesia	-	-	-	-	4	9
Japan	23	176.3	1	3.7	5	~ 10
Mexico	1	7	1	3.8	4	20.9
Philippines	-	-	-	-	2	2.4
Singapore	-	-	1	3	-	-
South Korea	4	53.6	-	-	1	5
Taiwan	1	7.4	1	3	1	3
Thailand	-	-	1	5	-	-
Total	***34***	***262.2***	***8***	***29.5***	***40***	***115.6***
Middle East						
Dubai	-	-	-	-	1	3
Kuwait	1	3.8	-	-	-	-
Pakistan	-	-	1	3	-	-
Total	***1***	***3.8***	***1***	***3***	***1***	***3***
Total	**63**	**449.8**	**20**	**106.3**	**105**	**310.2**

Source: Own depiction based on data from various publicly available sources

3.2.1 North America

With 812 bcm of natural gas production and a consumption of 824 bcm in 2008, North America accounts for a major share of the total world natural gas industry. Thereby, the US represents the world's largest consumer (657 bcm) and the second largest producer (582 bcm). Domestic production was rather sufficient to satisfy demand during the last decades and LNG historically could not compete with cheap domestic production. It accounted for less than 1% of North American gas consumption in 1999 and was mainly used for peak-load energy needs with LNG import facilities restricted to the area of the US. Intra-regional trade included pipeline deliveries from Canada to the US as well as some minor volumes from the US to Mexico.

The EIA forecasts in its latest Annual Energy Outlook that natural gas demand in the US is expected to decline in the short-run until 2011 and will continue to grow afterwards with an average annual growth rate of 0.2% for the period from 2007 to 2030 (EIA, 2009b, p. 109). The major consuming regions are the states of Louisiana and Texas in the South (high consumption originating from the industrial and electricity sectors), the Midwest and the Northeast (mainly for heating purposes). The share of electricity generated by gas-fired power plants increased from 15% in 1999 to 22% in 2007. This equals average annual growth rates of 6.2% since 1999. In comparison, growth rates for coal, nuclear, fuel oil, and hydroelectric generation have been less than 1% over the same period (EIA, 2009c, p. 11). However, the future demand for natural gas is mainly influenced by future climate policy actions and the economics of natural gas with respect to relative costs of alternative fuels.

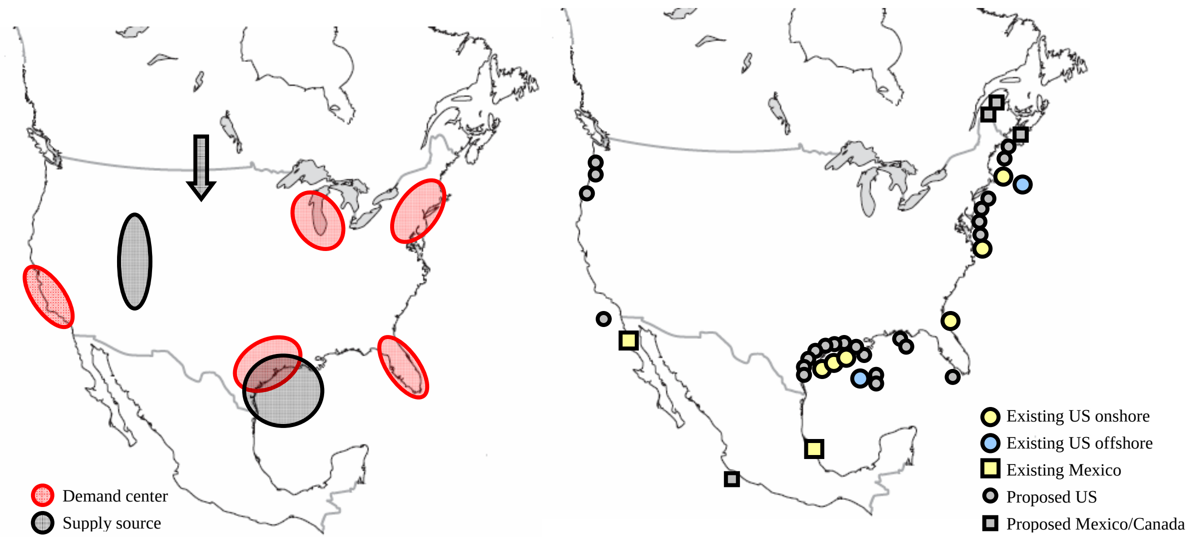
Major producing regions are Texas, Louisiana, offshore fields in the Gulf of Mexico, and Alaska. Production in the Rocky Mountains has increased steadily since 1998. The construction of new transmission capacity to consumption centers in the Northeast and Midwest and the expansion of existing pipelines to Southern California underline the importance of the mid-central region as a domestic supply source. In 2008, nearly one fifth of total US production came from unconventional sources; 55.6 bcm of coal-bed methane (mainly from Wyoming, Colorado and New Mexico) and 57.2 bcm of shale gas (mainly from Texas) were extracted.[8]

The year 2000 saw a renaissance of interest in imports in the form of LNG. Conventional natural gas production reached a peak in 2001 at the same time that demand was projected to continue to increase and forecasts claimed that US natural gas production would be unable to meet growing demand (e.g., EIA, 2004, p. 91). With the opening of the LNG export terminal in Trinidad/Tobago, furthermore, a supply source close to the North American market was emerging. Potential investors for LNG for a long time believed the biggest struggle for realizing new capacities would be to get the regulator's approval. FERC, however, sought to create an investor-friendly environment and even deviated from its initial view where LNG import capacity should be treated the same way as pipeline capacity. With the 'Hackberry Decision' in 2002, it terminated open access requirements to regasification facilities.

[8] 'Unconventional gas' is found in difficult-to-access geological formations with the rocks being hardly permeable and natural gas only flowing with great difficulty. The three main sources include gas shale, tight sands, and coal-bed methane.

This led to a rapid boost in project proposals. At present, there are 25 approved projects (including greenfield investments and expansions) in total North America.
All four LNG import terminals which have been built during the 1970s and early 1980s have revisited operation and even have undergone substantial expansions (see Ruester and Neumann, 2008, pp. 3163 f.). Gulf Gateway LNG, an offshore facility in the Gulf of Mexico operated by Excelerate, is the first new-built terminal since more than two decades and started operation in 2005. Four additional terminals came on stream recently (i.e., Freeport Texas, Sabine Pass Louisiana, and Northeast Gateway offshore Boston all commissioned in 2008; Cameron LNG Louisiana received its first shipment in July 2009). Mexico opened its Energia Costa Azul import facility in May 2008; total capacity is dedicated for re-exports via the 140-mile Baja North pipeline to California and Arizona.
It becomes apparent that all new-build and advanced proposed projects are either located in the Gulf of Mexico or feed into the US pipeline system (see Figure 9). Since September 11, 2001, the public has grown more aware of risks to national security. Chemical plants and existing and planned nuclear and LNG facilities have come under intense scrutiny. Receiving terminals on both the Atlantic and Pacific coast face a strong resistance from the local population ('not-in-my-backyard' attitude).

Figure 9: North American LNG import potential



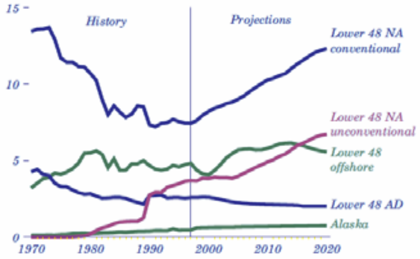
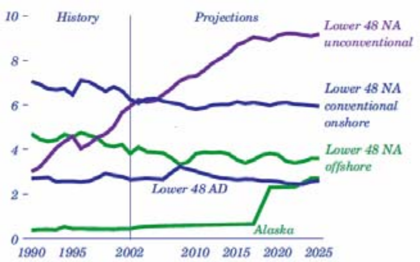
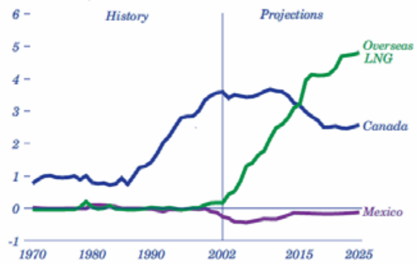
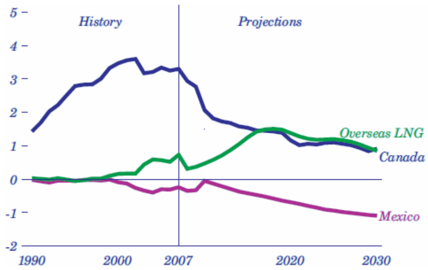
Source: Own depiction

The long-standing history of natural gas production in Texas and Louisiana has proved beneficial for all participants: local governments and population are familiar with the approval process, several large customers are nearby, and major pipelines are connecting to the Midwest and northeastern US.[9] At present, the pipelines are reserved 100% by firm customers, but there are two issues of interest: the feasibility of expansions and declining domestic production from conventional sources. Volumes in

[9] E.g., The Transco-, Texas Eastern-, and Tennessee Gas pipelines extend to the Northeast. Trunkline Gas Company and Mississippi River Transmission supply power producers and industrial users in the Midwest.

the form of imported LNG could make up such shortfalls. Beside the already completed projects, two further facilities are under construction.
It is difficult to assess the probability of success for individual US projects outside the Gulf of Mexico. Developers regularly delay or cancel proposed projects. In California and Massachusetts, for example, both states with an increasing natural gas demand, proponents face strong public resistance. Thus, investors look elsewhere. Mexico has already opened an import terminal dedicated to supply the southwestern US; another project is proposed. Canada’s Atlantic provinces deliver natural gas produced offshore near Sable Island to the northeastern US since 1999. The Canaport LNG terminal currently under construction is expected to start operation in 2010. Two further projects are under consideration.
New LNG must compete with existing facilities and expansions both within the US and in other importing regions. A barrier to entry during the first half of the 2000s was the lack of available upstream deliveries. Excelerate Energy’s Gulf Gateway import facility, for example, received only nine cargoes during its first year of operation. In contrast to market entrants, incumbent oil and natural gas majors therefore currently simultaneously construct liquefaction capacities to correspond with regasification capacities.
However, nothing has altered the North American natural gas market and its appetite for LNG as severe as the discovery and development of significant unconventional gas sources. Within a couple of years, the supply-demand balance has changed from one of continuous production declines to one of an upcoming surplus. Rising natural gas prices since 2001, easy financing and technological innovations (i.e., horizontal drilling and hydraulic fracturing) encouraged companies to invest in wells. Amongst others, large deposits were explored with the Barnett Shale and Eagle Ford plays (both in Texas) and the Haynesville Shale (Louisiana). The Potential Gas Committee states in its 2008 assessment report that the US alone might possess a total resource base of 51,200 bcm which would increase the static reserves-to-production ratio from about ten to 90 years. In Canadian British Columbia, the Horn River Shale Basin is estimated to comprise about 14,000 bcm. A pipeline to the coast and a liquefaction terminal are under consideration.
The substantial rise in unconventional gas production reversed the historical decline in US gas output reducing demand for LNG. In the early 2000s, researchers still saw North America as a major player in the future LNG market (see e.g., Chabrelie, 2003, p. 5; CIEP, 2003, p. 114). The EIA regularly adapted its annual energy production and consumption forecasts. In 1999, most domestic production was expected from conventional natural gas with unconventional sources projected to account for not more than 200 bcm in 2020 and LNG imports were forecasted to remain at marginal levels. The 2004 outlook five years later predicted unconventional production to increase to 255 bcm and LNG imports to rise to 140 bcm in 2025. In its latest outlook, future unconventional natural gas production has been adjusted further upwards (340 bcm in 2025 and 400 bcm in 2030) whereas the prospects for LNG imports with 30 bcm in 2030 are less enthusiastic (see Table 4).

Table 4: EIA Annual Energy Outlook projections over time (reference case)

Year of publication	Supply sources	Net imports	Average annual increase in demand (%)
1999 (p. 71)	 - Most production expected from conventional sources - Unconventional: ~7 tcf in 2020 (200 bcm)	 - Most imports from Canada - LNG not expected to grow on a significant scale	1% for the period 1999-2020
2004 (pp. 90-91)	 - Most production expected from unconventional sources - Unconventional: ~9 tcf in 2025 (255 bcm)	 - LNG expected to gain in importance with ~5 tcf in 2025 (140 bcm)	1.4% for the period 2002-2025
2009 (pp. 77-78)	 - Significant potential of unconventional sources forecasted - Unconventional: ~12 tcf in 2025 (340 bcm) and ~14 tcf in 2030 (400 bcm)	 - LNG prospects corrected downwards with ~1 tcf in 2030 (28 bcm)	0.2% for the period 2007-2030 (decline in the short-run for 2008-2011)

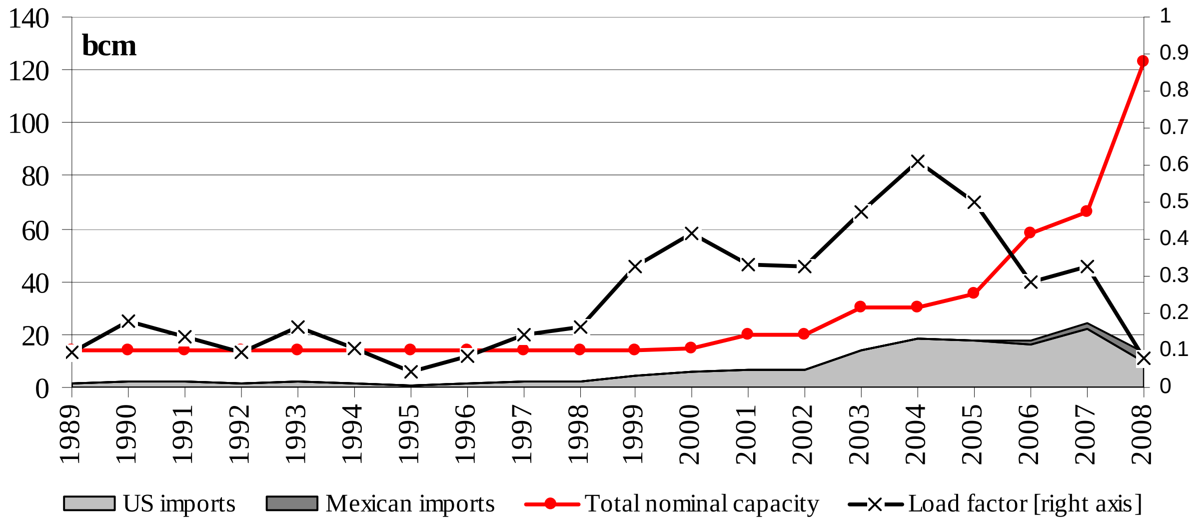
Source: Own depiction based on EIA (1999, 2004, 2009b)

The future potential for natural gas production from unconventional sources, however, will mainly be determined by the level of natural gas prices and the development of production costs. Each shale play has its individual geological characteristics; no general statement on the cost structure can be made. Dar (2009) quotes the break-even price at 3.88 USD/MBTU (Eagle Ford), 3.74 USD/MBTU

(Marcellus), 4.49 USD/MBTU (Haynesville), and 5.18 USD/MBTU (Barnett). This goes in line with Jensen (2009b) arguing that much shale gas could be developed at natural gas price levels of 4 USD/MBTU. Berman (2009), in contrast, argues that only half of the Barnett Shale wells would be economic at prices of 10 USD/MBTU and expects a drop in drilling activities as a response to the lower prices since mid-2008. Whether current production levels can be maintained at prices below 5 USD/MBTU is one of the major uncertainties for the mid-term future.

As a consequence of the increased domestic production, needs for imports declined. For the short-term, this trend is further amplified by the recent demand downturn due to the economic crisis (IEA, 2009a). US LNG imports dropped in 2008 to 9.9 bcm from 21.8 bcm in 2007. Import terminal operators suffered from idle regasification capacities. The load factor of total North American LNG import capacity fell from 61% in 2004 to 8% in 2008 (see Figure 10). It is very likely that beside the completion of projects already under construction, no significant investments in LNG capacities will be realized in the mid-term future. Some LNG terminal operators even have already sought permission from FERC to add *export* equipment to their facilities. Since North America was expected to be a major growth market for LNG, this development has a severe impact on the future global LNG demand.

Figure 10: Development of North American LNG imports and nominal import capacity



Source: Own depiction

3.2.2 South America

South America has emerged as an LNG importing region in mid-2008 with the commissioning of Argentina's Bahia Blanca offshore terminal operated by Excelerate Energy in June and Brazil's Port Pecem offshore facility operated by state-owned Petrobras in July. An additional project is already under construction offshore Rio de Janeiro and is expected to start operation in 2010. South American natural gas demand is expected to increase above world average from 127 bcm in 2007 to 229 bcm in 2030 with an average annual growth rate of 2.6% (IEA, 2009b, p. 366).

Further proposals for regasification facilities include one project each in Argentina and Uruguay and two projects each in Brazil and Chile. For the mid-term outlook, it is very likely that no substantial investments will be realized since most countries are endued with some natural gas reserves and intra-regional pipeline trade (e.g., from Bolivia to Brazil or Argentina) could be expanded. For Chile, a country without large natural gas resources, the construction of one small-scale facility until 2015 seems probable. In 2004 and 2005, Argentina reduced its deliveries to the country in order to ease its own domestic gas shortages which raised concerns about energy security.

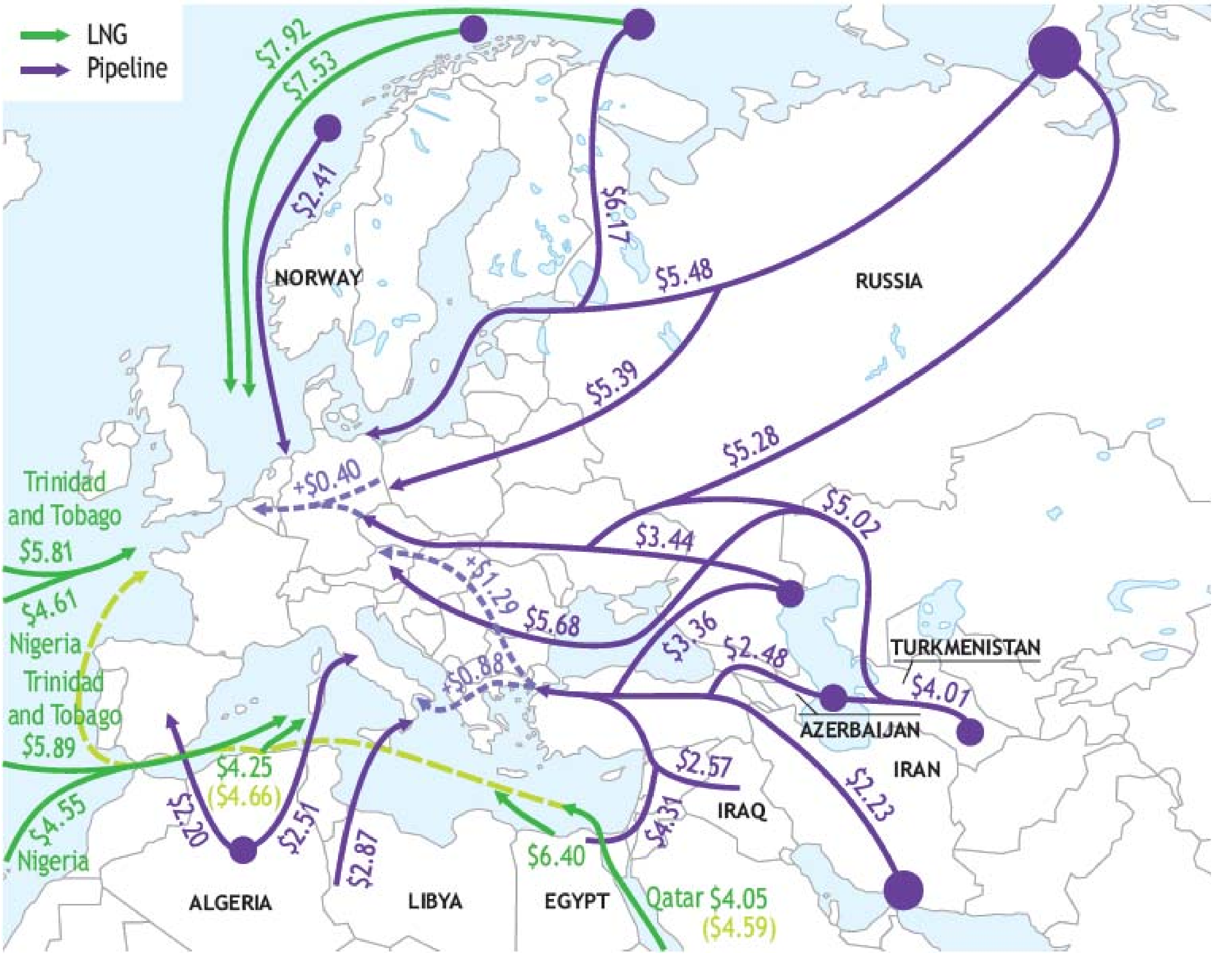
3.2.3 Europe

After a short-term decrease in natural gas demand as a consequence of the world economic crisis, the long-term upward path is projected to continue from 2010 on. The IEA forecasts an increase from 544 bcm in 2007 to 651 bcm in 2030 in the reference scenario (IEA, 2009b, p. 366) with the demand growth mainly being driven by the power sector. Modern combined-cycle gas turbine power plants benefit from lower up-front investment costs and shorter construction times than alternative mid- and base-load technologies, greenhouse gas emissions are significantly lower than for other fossil fuels, and gas-fired capacity is a suitable complement to renewable energy sources since its flexible operation is able to absorb supply fluctuations.

On the supply side, overall OECD Europe's production is expected to decline from 294 bcm in 2007 to 222 bcm in 2030, even though Norway will raise output during the coming decade increasing its production from the Ormen Lange and Snovhit fields. The Netherlands' Groningen field and UK's Continental Shelf are reaching maturity. The exploration of unconventional gas sources is still in its infancy. Shale gas resources are estimated to be in the range of 14,000 bcm but will only play a minor role on a local scale, given that public resistance in the densely populated areas can be overcome (Schulz and Horsfield, 2009). Hence, overall import needs are forecasted to move up from 250 bcm in 2007 to 428 bcm in 2030 (IEA, 2009b, p. 478).

The future composition of foreign supplies will depend on a number of factors including the comparative supply costs and natural gas availability of alternative sources, upstream investment risks and midstream transit risks of alternative supply routes, and the countries' policies with respect to diversification. Industry experts agree that increased import needs are likely to be met through additional pipeline supplies from Europe's traditional suppliers (i.e., Russia, Algeria, and Norway), new supplies from the Caspian region and potentially from the Middle East, and additional LNG imports. Thereby, Russia will experience higher supply costs in the long-term since production from its Yamburg, Urengoy and Medvezhye fields will decline and new, more expensive fields (e.g., Shtokman, Yamal Peninsular) have to be developed, which in turn improves the competitiveness of alternative supplies. Figure 11 provides an overview on supply costs of potential natural gas sources for both pipeline as well as LNG.

Figure 11: Supply costs for potential sources of gas delivered to Europe (USD/MBTU)



Source: IEA (2009b, p. 482)

Nominal European LNG import capacities augmented from 36 mtpa in 1999 to 91 mtpa at the end of 2009 with Spain accounting for about one third of the capacity increase. The country has always been highly dependent on natural gas imports receiving the first LNG deliveries in 1986. Pipeline deliveries are restricted to supplies from Algeria via Morocco and some minor volumes from Norway via France. In order to meet rapidly increasing demand and to diversify supply sources, Spain expanded its existing LNG receiving terminals and three new facilities came on stream since 2003. A seventh terminal currently is under construction.

Greece and Portugal entered the industry in 2000 and 2003, respectively. For both countries no expansions are planned for the mid-term future. Italy, in contrast, will become a more important destination for LNG imports in the next years; two terminals are under construction; numerous additional projects are proposed. The commissioning of about three import terminals until 2015 seems likely and will decrease Italy's reliance on Algerian and Russian natural gas imports. Further capacity additions are expected for France, Croatia (functioning as a transit country for deliveries to Central Europe), and the Netherlands. Proposed projects in other countries such as Albania, the Canary Islands, Germany, Ireland, or Poland are not likely to be realized until 2015.

The decline in the UK's domestic production has provided incentives to invest in LNG infrastructure. Three regasification facilities started operation during the last four years and additional capacities are under construction. Imports in the form of LNG add to supply security on the one hand and may enable the country to function as a European hub and re-export volumes via the Interconnector and BBL pipelines to the Continent if local price differences support this.

3.2.4 Asia Pacific

Within the Asia Pacific region, one has to distinguish between traditional LNG importers (Japan, South Korea, and Taiwan) and newcomers (China and India). The somewhat isolated and more developed economies in northeast Asia lack substantial energy resources and have started to use LNG and nuclear energy in order to minimize their dependence on imported oil. Natural gas consumption is forecasted to increase only moderately during the coming two decades supporting only minor investments in new LNG import capacities. Two facilities will come on stream in Japan until 2015; one new import terminal is expected for Taiwan.

The emerging economies of China and India, on the contrary, are the critical uncertainty factor within the global LNG market. Historically, the two countries have mainly used domestic coal to satisfy their energy needs. However, natural gas is increasingly becoming an important component of their primary energy mixes. The IEA forecasts an increase in natural gas consumption from 73 (39) bcm in 2007 to 242 and 132 bcm in 2030 for China and India, respectively (IEA, 2009b, p. 366), representing annual growth rates of 5.3 and 5.4%, much above world average of 1.5%.

The Chinese natural gas market has been expanding rapidly in recent years, particularly after the completion of the West-East pipeline in 2004. The government aims to expand the share of gas-fired power generation from currently 1% to about 10% in 2020 (IEA, 2009a, p. 123). Production growth cannot keep up with demand growth although new supplies from the Sichuan Province are expected to come on line in the short-term. The country could be dependent on imports for more than 30% of its consumption in 2030. These are likely to be met by pipeline imports from Turkmenistan via Kazakhstan and LNG (EIA, 2009a, p. 44). Three LNG import terminals are in operation with the Guangdong terminal (start-up in 2006) and the Fujian and Shanghai facilities commissioned in 2009. Two additional facilities are under construction, 14 terminals are proposed.

In India, natural gas plays a small role in the total energy mix, but demand has been growing rapidly, too. Much of the country's current production originates from more mature fields that are beginning to decline and India is projected to be dependent on imports for more than 30% in 2030 (EIA, 2009a, p. 44). Some new domestic production will come from the Krishna Godavari Basin. Pipelines supplying natural gas from the Middle East, Central Asia, or Myanmar have been discussed in the past; however, their realization is very unlikely in the near future. With the Dahej and Hazira facilities, two LNG import terminals are operating since 2004 and 2005. One additional terminal is already under construction, seven projects have been proposed.

For both countries, however, it is very difficult to evaluate how many projects finally will be realized and when. Unconventional gas resources are supposed to be present in China (e.g., South China, Zhungaer, Tuha, Qadam, and East China Basins) as well as in India (e.g., Gondwana and Gambay Basins) and could reduce the needs for natural gas imports. Their scope and recoverability have not yet been explored. Furthermore, cheap abundant coal reserves could affect the optimistic growth forecasts for LNG imports. Obviously, Asian emerging economies represent a substantial challenge in a carbon-constrained world given the large share of coal in their energy supply portfolios and the high growth rates in energy demand.

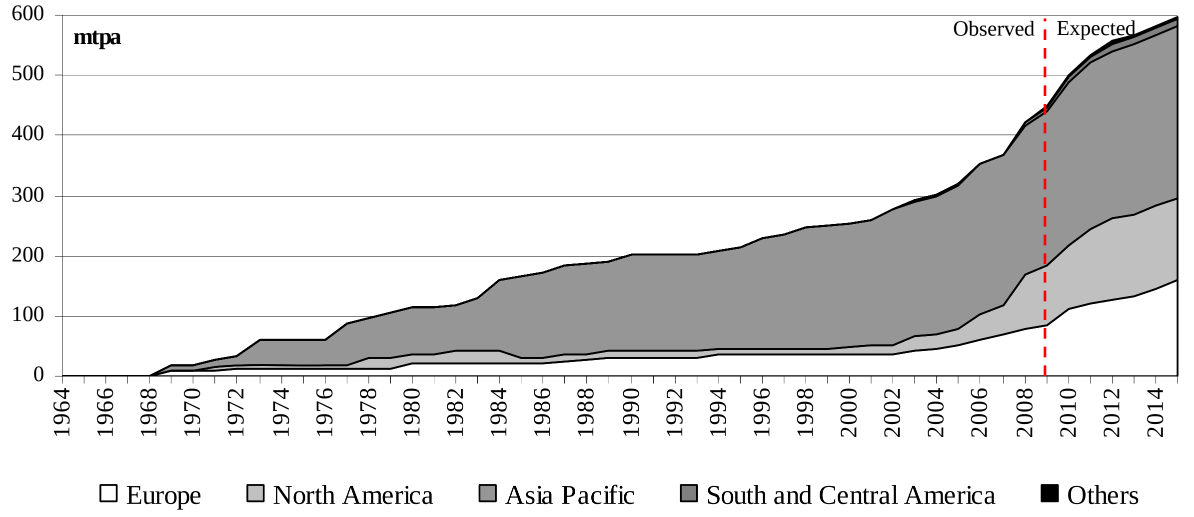
Using a model of the world natural gas market, Huppmann et al. (2009) investigate the impact of a strong demand increase in China and India on global trade patterns. Whereas domestic production levels in the two countries would increase only slightly under this positive demand scenario, imports gain in importance. Regasified volumes in 2030 would increase by 860% for China and by 450% for India as compared to the reference case. Intra-regional pipelines are constructed from Kazakhstan (2015) and Russia (2020) to China as well as from Pakistan (2020) to India, with expansions in later periods. LNG deliveries from the Middle East to Europe and North America decrease by 20% and 47% respectively; exports to Asia increase by 40% and price levels raise. This mirrors that the future development of the supply-demand balance in these emerging economies will have a substantial impact on the global (liquefied) natural gas market.

Two further countries will enter the LNG market until 2015. Singapore is constructing an import terminal in order to secure natural gas supplies. LNG shall complement the current pipeline imports from Indonesia and Malaysia which are used to generate 80% of the country's electricity supply. Gas demand also is expected to rise due to the substitution of oil-fired power plants for new-built gas-fired capacities as well as the construction of new petrochemical plants. Thailand is constructing an import terminal in order to diversify supply sources. Domestic production is declining and pipeline imports are restricted to deliveries from Myanmar.

3.2.5 Summary

Taking the above discussed developments into account, world regasification capacity being operational in 2015 is forecasted to be 596 mtpa, with Europe accounting for 27%, North America (including Mexico) for 23%, Asia for 48%, and South and Central America for 2% of the installed capacities (see Figure 12).

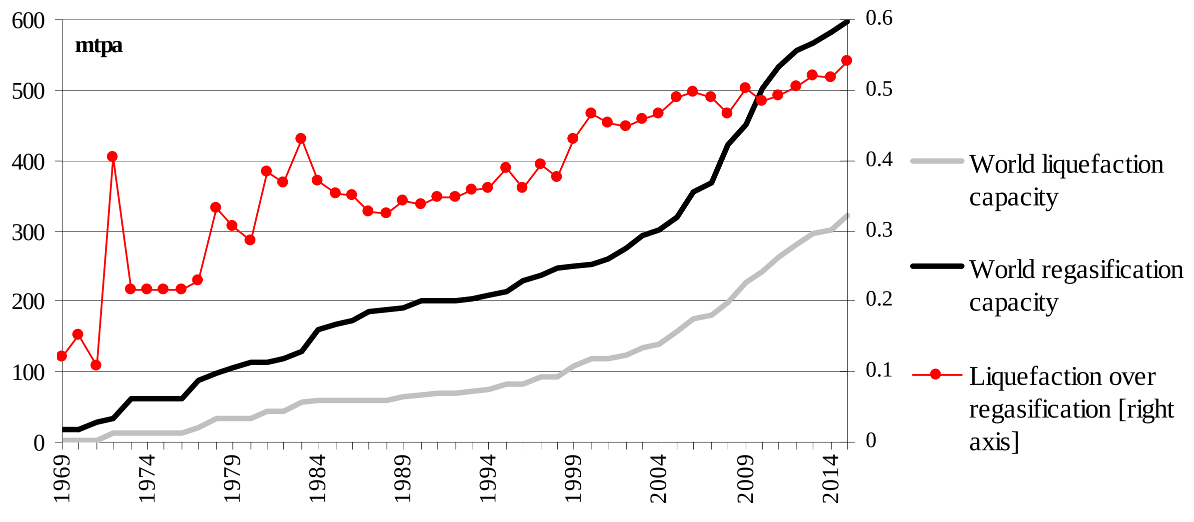
Figure 12: Development of regasification capacities



Source: Own depiction

World regasification capacity is outstripping liquefaction capacity; the ratio of total import over total export capacity approached about 0.5 during the last decades (see Figure 13). To a certain extent this is a natural development since LNG in some countries is a major source of seasonal supply. Korea Gas Corporation for example has a twenty-year long-term supply contract with Yemen LNG over the delivery of 2 million tons of LNG per year; 50% of the annual contracted volume thereby is taken off during the winter months. Other import terminals are run mainly based on short-term and spot deliveries in order to exploit favorable supply-demand situations (e.g., India's Hazira terminal operated by Shell and Total; Excelerate Energy's import facilities in the US, the UK, Argentina, and Kuwait). Moreover, a regasification facility is the cheapest part of the value chain and some players invest in an import terminal in order to enter a new market.

Figure 13: World liquefaction versus regasification capacities



Source: Own depiction

4 Vertical Structures in the LNG Industry

The development of the global LNG market from an infant towards a mature industry has been accompanied by far reaching dynamics in vertical structures within the industry. The following subsections discuss the changing role of traditional long-term contracts and the increasing relevance of short-term and spot trade. A number of oil and gas majors follows a strategy of vertical and horizontal integration investing in a portfolio of export, shipping, and import capacities at the same time that other companies choose a strategy of non-integration operating LNG terminals as 'tolling facilities'.

4.1 The changing role of long-term contracts

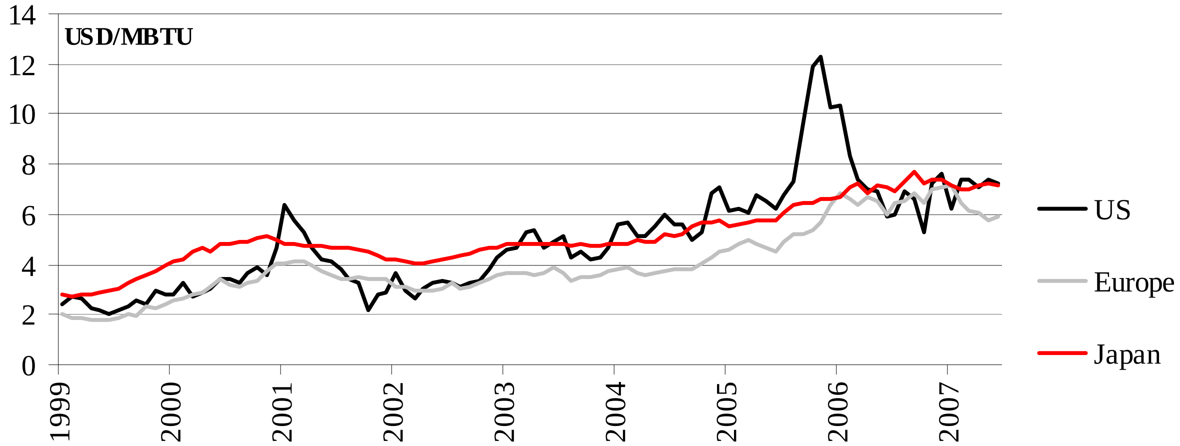
Investments in LNG infrastructure, especially in upstream exploration, production, and liquefaction, are very capital-intensive. Therefore, financing traditionally required the conclusion of long-term sales and purchase contracts before the construction process was initiated. Sellers typically have been state-owned oil and gas majors (e.g., Algerian Sonatrach, Indonesian Pertamina, Malaysian Petronas) and for a minor share joint ventures of private companies (i.e., US' Philipps and Marathon) or of private and state companies (e.g., Brunei Coldgas, a partnership between the state of Brunei, Shell, and Mitsubishi). Buyers typically have been downstream state-controlled utilities (e.g., Gaz de France, Japanese Tokyo Gas, Korea Gas Corporation, Turkish Botas, or Spanish Enagas).

The traditional contract was a rigid take-or-pay contract in which the buyer accepted to take-off a certain minimum level in the range of 90% of the nominal contracted quantities (CIEP, 2003, p. 12). The seller in turn accepted a price escalator related to some measure of competing energy prices. Hence, the buyer took the volume risk whereas the price risk was transferred to the seller. Restrictions in destination limited arbitrage trades.

Within the three importing regions, alternative contracting patterns and pricing structures established. Prices for LNG thereby are set either by price competition with domestic gas (mainly US, UK) or by the operation of pricing formulas. When the first LNG contracts were negotiated with Japanese buyers in the 1960s, Japanese power generation was heavily dependent on fuel oil. Pricing clauses therefore tied the price escalation to the Japanese Customs Clearing price, an index of Japanese crude oil import prices. This pricing scheme later was adopted for other Asian contracts, too. In the mid-1990s, the oil-linkage of LNG prices in Asian contracts was softened. So-called 'S-curve' formulas guarantee the interest of the seller if the price of the benchmark crude oil index drops below a certain threshold and protects the buyer from oil prices rising above a certain ceiling.[10] Asian importers traditionally were willing to pay a price premium of about 1 USD/MBTU as compared to LNG buyers in Europe and North America reflecting their concerns about supply security (see also Figure 14).

[10] The first 'S-curve' formula was applied within a contract concluded between the Australian North West Shelf venture and Japanese customers in 1994. The floor price was set at 16.95 USD/bbl and the ceiling price at 26.95 USD/bbl (Chabrelie, 2003, p. 7).

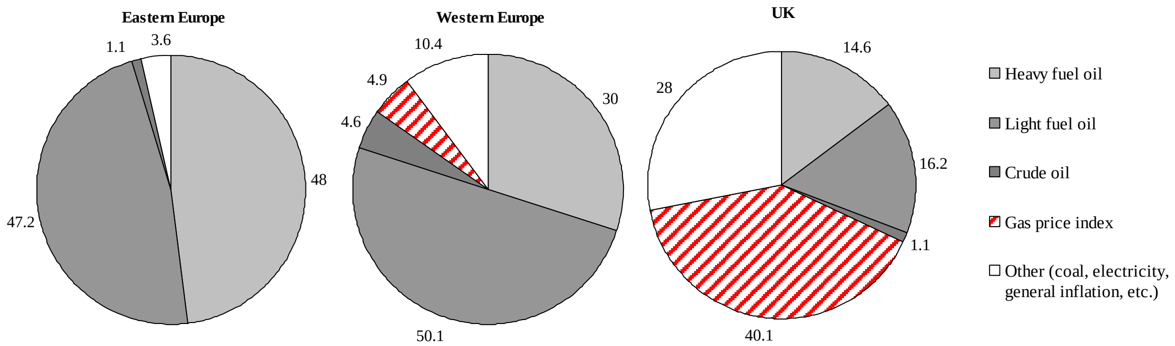
Figure 14: Average LNG import prices (monthly data)



Source: Own depiction based on data from IEA Energy Prices and Taxes

Continental European pricing structures were effectively originated by the Netherlands' pricing policies for domestic natural gas produced from the Groningen field since 1962. The natural gas price was indexed to light and heavy fuel oil. This pattern later was also adopted for export contracts. More recent (liquefied) natural gas contracts include also prices of other relevant energy sources such as coal, natural gas or electricity (see Figure 15). The improvement of gas-to-gas competition and increasing liquidity in natural gas hubs should support the establishment of gas market indicators. In contrast, North America and the UK today are characterized by a functioning gas-to-gas competition with long- and mid-term contracts being to a large extent tied to gas market indicators.

Figure 15: Oil-linkage in long-term natural gas contracts



Source: Own depiction based on data from Stern (2007, pp. 9 f.)

As the LNG industry has expanded during the past decade, terms of long-term supply contracts started to change and trade became more flexible. Average contract duration as well as contracted volumes are decreasing in both Atlantic and Pacific Basin markets (see e.g., Hirschhausen and Neumann, 2008; Ruester, 2009a). Destination clauses are eliminated (Energy Charter Secretariat, 2008, pp. 56 f.). Take-or-pay requirements are relaxed and options for additional cargoes are included in recent contracts, e.g., in a recent contract between Korea Gas Corporation and Qatar's Rasgas venture

(Chabrelie, 2003, p. 6). Whereas deliveries in the early years of the industry typically have been ex-ship sales, free-on-board (fob) agreements are becoming more common (Eng, 2006; Nissen, 2007b). For fob contracts, the buyer takes ownership of the cargo once it is loaded and has complete flexibility over a potential redirection or resale. For example, Korea Gas Corporation traditionally procured LNG ex-ship but enlarged its tanker fleet recently and now concludes for fob contracts. In 2007, Equatorial Guinea sold its entire LNG output on an fob basis to BG. In 2008, a re-loading facility was inaugurated at the Zeebrugge import terminal. Once a cargo is discharged to the storage tanks, the LNG belongs to the importing company and re-export is feasible without violating the contract. Cargoes sourced originally from Qatar already have been delivered to South Korea, India, Portugal and Spain.

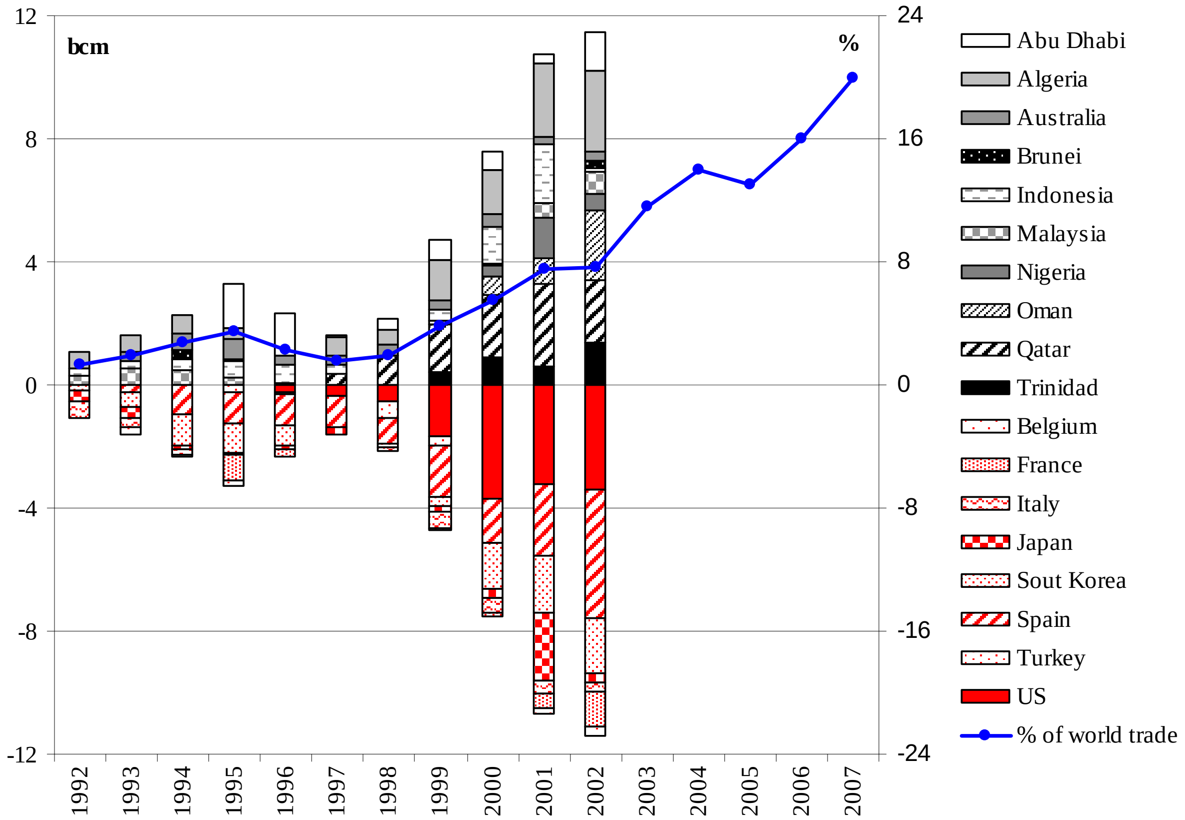
Contract flexibility has also been a major target of buyers when renegotiating existing contracts. The Japanese importers Tokyo Gas and Tokyo Electric Power for example have renegotiated a Malaysian contract to supply a part of the volume fob rather than ex-ship enabling the buyers to resale some cargoes. According to Zhuravleva (2009), it is also becoming common practice to divert contractually committed LNG volumes to third markets given a mutual agreement of both seller and buyer. This increased contract flexibility is supportive to supply security since it permits adaptations to short-term changes in the supply-demand balance. The netback value will determine the most attractive market in those cases where LNG shippers are free in the choice of destination.

Long-term supply contracts allowing the financing of new infrastructures are increasingly accompanied by short-term agreements (less than 3 years) and spot transactions balancing supply and demand in the short- to medium-term. For example, a consortium of Japanese buyers signed contracts with Malaysia to buy 0.68 mtpa for a period of 20 years and an additional 0.34 mtpa for a single year beginning in April 2004. The short-term component is updated annually. This combination of short- and long-term provisions provides much higher volume flexibility than conventional take-or-pay contracts.

The short-term market established not before the 1990s with the first arbitrage trades and swap agreements appearing in the early 2000s. Electricité de France (holding 3.3 mtpa at Zeebrugge and 0.7 mtpa at Montoir) has signed a swap agreement with the US-based Dow (3.75 mtpa at Freeport) offering each party a slot of 1 bcm per month of import capacity at the other company's import terminals.[11] The additional margin is shared among Electricité de France, Dow and the supplying company. A similar trans-Atlantic swap agreement involves Suez and ConocoPhilipps. Major short-term and spot volumes today are supplied by Qatar, Algeria, and Oman; main buyers have been the US, Spain and South Korea (see Figure 16).

[11] Electricité de France's supply for Zeebrugge from Qatar's Rasgas project is interruptible at the supplier's option, which explains why many of its Zeebrugge slots are not used.

Figure 16: Development of short-term and spot trade



Source: Own depiction based on data from EIA (2003), Cornot-Gandolphe (2005), Jensen (2009b)

However, there may be technical and economic constraints limiting arbitrage activities. First, free capacities have to be available along the value chain including liquefaction plants (sellers may utilize volumes during the ramp-up period of a contract), shipping and storage at the downstream regasification plants. Second, gas quality differs by natural gas source and import facilities constructed during the early years of the industry have been designed to receive LNG of a certain composition. However, it is technically feasible to endow import terminals with natural gas adaptation equipment allowing for a decrease (i.e., nitrogen injection; mainly necessary in the UK and the US) or increase (i.e., propane injection; mainly Asian importers) of natural gas quality in order to meet grid requirements. Third, during the loading and shipping period, typically between four days (e.g., Trinidad/Tobago to the US Gulf Coast) and two weeks (e.g., Qatar to Japan), spot prices in the destination country may change.

For the near-term future, the outlook for spot LNG trade is quite modest and will critically depend on how quickly the global economy recovers from the current recession. Many buyers that have been active in spot- and short-term trade currently can meet their gas requirements by their long-term contracts and some even have to demand downward adjustments in volume flexibility due to weak consumption levels (IEA, 2009b, p. 529). For the longer term, the outlook is more optimistic. LNG exporters increasingly dispose of uncommitted liquefaction capacities. The overhang in regasification capacities facilitates downstream market access for non-incumbents and the increasing liquidity of European trading hubs enhances price transparency.

4.2 Recent trends towards vertical and horizontal integration

Joint ventures always have been a common form of organization within the LNG industry for two main reasons. First, the large investment costs associated with upstream exploration, production and liquefaction ventures makes it difficult for one single company to develop and finance the project on its own. Joint ventures are set up in order to share the risks and financial burden. Partnerships between private oil and gas companies have formed: e.g., for Alaska LNG (ConocoPhillips and Marathon) or for the North West Shelf Venture in Australia (BHP Billiton, BP, Chevron, Mitsubishi/Mitsui, Shell, and Woodside Energy). Second, a joint venture with the incumbent NOC is likely (e.g., Abu Dhabi, Egypt, Indonesia, Nigeria, Russia or Qatar). On the one hand, NOCs seek to retain control over natural gas reserves; on the other hand, private majors contribute to the partnership technological knowledge and marketing channels. In summary, 15% of the existing nominal liquefaction capacities are owned and operated by joint ventures between private majors, the majority of 76% is controlled by partnerships between NOCs and private partners, and the remaining 9% of the capacities are operated by NOCs without any third party (i.e., Algeria, Libya).

<u>Forward integration from the upstream to the downstream sector</u> is a governance form which has become characteristic for the industry with players controlling capacities along successive stages of the value chain. Upstream producers aim to benefit from downstream margins. One recent phenomenon is the increasing employment of self-contracting. Thereby, the seller concludes for a sales-and-purchase agreement with its own marketing affiliate as has been realized at Qatar's Qatargas and Rasgas liquefaction projects (Exxon Mobil, Qatar Petroleum, and Total), in Trinidad/Tobago (BP, Repsol, and BG), or Norway (Statoil and Gaz de France). In Nigeria, the first three trains of the Bonny Island venture were dedicated to traditional long-term take-or-pay contracts concluded between the venture and European buyers. For trains 4 and 5 in contrast, Shell and Total (holding equity shares in the liquefaction plant) self-contracted certain volumes. In total, eleven companies have self-contracted for about 1,660 bcm of LNG over the period from 2009 to 2025 (IEA, 2009b, p. 527).

In one version of this commercial business model, the LNG export project is operated as a tolling facility selling the services of liquefaction, storage, and loading to the LNG merchant (see also Nissen, 2004; 2006) and natural gas producers rather than the venture become the sellers of natural gas. This structure has been adopted for example in Egypt where the BG Group and BP act as merchant traders at the Idku plant and the Spanish Union Fenosa at the Damietta facility. Alternatively, the venture's project partners buy the LNG from the project.

The unbundling of transportation assets and services from rigid export-import project relationships is a major precondition for flexible trade and the control of non-committed shipping capacities has become of strategic value in today's LNG market. Private players have invested in a significant number of vessels during the last decade: Shell controls 30 carriers through joint ventures and direct ownership. Exxon Mobil and Qatar Petroleum have a fleet of 27 ships. The BG Group owns eight vessels and recently ordered another four ships. Several other companies entered the midstream shipping stage during the 2000s (e.g., BP, Gaz de France, and Osaka Gas). As already discussed above, the number of uncommitted ships has increased from approximately zero before 2000 to 49 in 2009 (of a total of 337 ships representing 14% of total shipping capacity).

Self-contracting accompanied with investments in a portfolio of upstream and downstream positions and uncommitted ships enables the players to decide where to send LNG cargoes on a shorter-term basis and to take advantage of favorable price conditions. Three case studies shall demonstrate the successful employment of this strategy: Shell disposes of LNG export positions in Australia, Brunei, Malaysia, Nigeria, Oman, and Russia at the same time that the company holds capacity rights at import terminals in India and Mexico. It will continue its expansion within the industry and participate in projects proposed for France, Italy, and Brazil. Similarly, Total has built up a portfolio of export positions in all three exporting regions and import positions in India, Mexico, and France. Exxon Mobil and Qatar Petroleum entered a partnership in the late 1990s. In order to mitigate supply costs given the long distance from the Middle East to consuming centers, they constructed the largest liquefaction facilities (7.8 mtpa trains) and ordered the largest vessels (>210,000 m³) ever, thus realizing substantial economies of scale. At the same time, the partners secured capacity rights at import terminals on both sides of the Atlantic (South Hook in the UK, Rovigo in Italy and Golden Pass in the US).

Backward integration from the downstream to the upstream sector is observed, too. Traditional natural gas distributors increasingly participate in LNG export ventures, motivated mainly by supply security considerations: Gaz de France holds shares in Egypt's Idku project and Norway's Snovhit LNG; Union Fenosa participates in Oman's expansion train; and Tokyo Gas in Australia's Darwin project. Also electricity companies, forming part of the extended value chain including natural gas-fired power production, enter the stage. Whereas Spain's first LNG terminals were operated by Enagas, traditional electricity companies (Union Fenosa, Endesa, and Iberdrola) are now the dominant investors. AES Corporation, the operator of a 319 MW gas-fired power plant in the Dominican Republic also owns and operates the country's LNG import terminal. Electricité de France proposed a regasification facility in the Netherlands. Some Japanese power producers even integrate further upstream: Tokyo Electric Power holds a share in Australia's Darwin project and Kansai Electric will participate in the Pluto venture.

In contrast to these integrated players, there are also some new entrants into downstream LNG markets which follow a strategy of non-integration: With the upcoming enthusiasm for LNG needs within North America in the early 2000s, Cheniere Energy entered the market and applied for the construction of four onshore LNG import facilities at the Gulf coast which should be operated as tolling facilities. The Freeport LNG and Sabine Pass projects were commissioned in 2008. However, as discussed above, the US' supply-demand balance altered throughout the last years. With the development of substantial unconventional resources, increased domestic production is outstripping higher cost LNG supplies. Thus, the two terminals suffer from low utilization rates. Plans to build the additional facilities are dormant at the moment and it is very unlikely that these projects will be realized in the next decade. In fact, recent developments have resulted in liquidity problems for the company and Cheniere had to lay off more than half of its 360 employees in April 2009.

Another entrant is Excelerate Energy, founded in 1999. In 2008, the German RWE acquired a 50% stake in the company. Excelerate employs an innovative technology of offshore, onboard regasification. Five import facilities have been already been built with the Gulf Gateway (start-up 2005) and Northeast Gateway (2008) in the US, Teesside GasPort in the UK (2007), Bahía Blanca GasPort in Argentina and Mina Al-Ahmadi GasPort in Kuwait (both 2008). An additional facility is proposed for Germany offshore Wilhelmshaven. However, industry experts report that only minor deliveries took place up to today through these facilities. The non-integrated players still have to prove to be successful in an industry, which a long time has been a sellers' market without major uncommitted export capacities, and in which also in the longer-term future, once, the economic crisis is overcome, importers are expected to continue to compete for global supplies.

5 Summary and Conclusions

This paper discusses recent dynamics in the global LNG market, which developed from an infant towards a mature industry during the past decade. Capacities along all stages of the value chain more than doubled since 2000 and numerous players, countries as well as companies, entered the market. Long-term contracts gained in flexibility and are increasingly accompanied by short-term trades. Whereas the early industry typically was characterized by ex-ship take-or-pay contracts concluded between the upstream project and downstream utilities with the import terminal being part of the integrated value chain, today, explicit destination flexibility regularly is requested. LNG players increasingly invest in a portfolio of import positions and uncommitted shipping capacities enabling flexible trade. Some new import terminals are operated as merchant terminals, receiving spot cargoes and lacking any long-term supply contracts (e.g., India's Hazira facility), others are operated as tolling facilities, with the owner selling unloading, storage, and regasification services (e.g., UK's Grain LNG).

The coming five years will see expansions in export and import capacities even though the recent decrease in global energy demand, falling cash flows, and a tight credit market have led to a drop in investments in large-scale energy projects. Long lead times in the construction of LNG facilities result in a delayed supply response to the demand growth observed during the past five years and numerous projects which currently are under construction will start operation until 2015 creating an oversupply in the market for the short-term. On the supply side, the Middle East will become a major exporting region and amplifies the globalization of the natural gas market delivering LNG to both Atlantic and

Pacific Basin customers. On the demand side, emerging economies in Asia represent a major source of uncertainty concerning future LNG demand and competition for global supplies. For the longer-term, the development of LNG depends on several factors such as natural gas' relative competitiveness compared to coal in power generation, environmental policies, or the exploration and cost structure of unconventional natural gas sources.

Various governance forms co-exist in the LNG industry, including the poles of spot market transactions and vertical integration as well as numerous hybrid forms such as long- and short-term contracts, joint ventures and strategic partnerships. Frequently, the same company chooses different governance modes along alternative value chains. Furthermore, different companies follow varying strategies even though they traditionally operate in similar stages of the value chain. These observations represent a suitable base for empirical studies investigating firms' motivations to choose alternative organizational structures.

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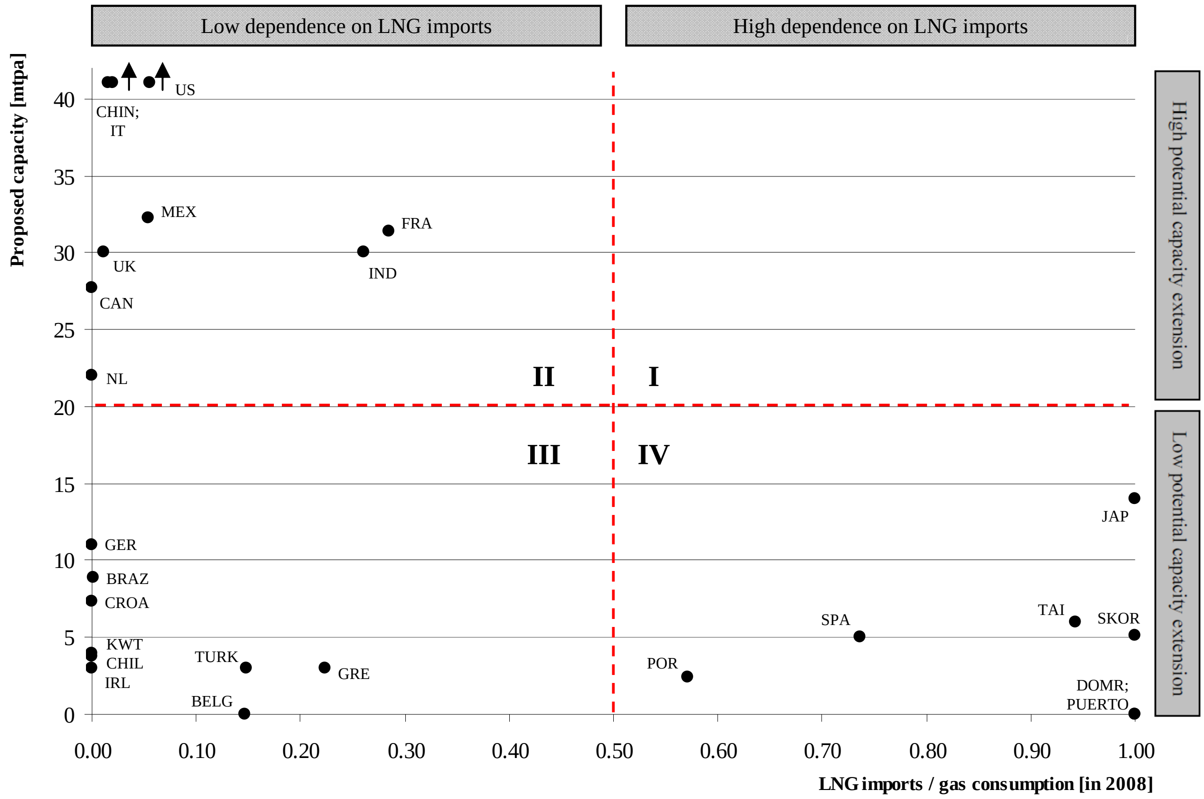
Appendix

Figure 17: Import country matrix



Source: Own depiction

Figure 17 classifies LNG import countries according to their dependence on natural gas imports in the form of LNG and the level of proposed new capacities (irrespective of the probability of realization of these capacities). Quadrant I thereby indicates countries with a high dependence on LNG imports and a high level of proposed new capacities which would indicate a low level of short-term physical supply security. No country is situated within this area. In contrast, there are many players within Quadrant II, characterized by numerous project proposals, too, but a low dependence on imports. These markets are expected to grow (e.g., China, India).[12] Diversification of energy sources and natural gas supply routes is one motivation to expand LNG capacities (e.g., France, Italy). Other countries have to come up against decreasing domestic production (e.g., UK, Netherlands) or plan to expand re-exported volumes (e.g., Mexico, Canada, UK). Quadrant III mainly represents (potential) new entrants into the LNG market (e.g., Brazil, Kuwait) and small players in the market (e.g., Greece, Turkey, Belgium). Quadrant IV includes mature markets with a high dependence on LNG imports where significant investments have been realized in the past (e.g., Japan, Spain).

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[12] The US represents an exemption due to the recent change in the domestic supply-demand balance. Projects proposed during the last decade not being under construction yet are very unlikely to be realized in the near- to mid-term.