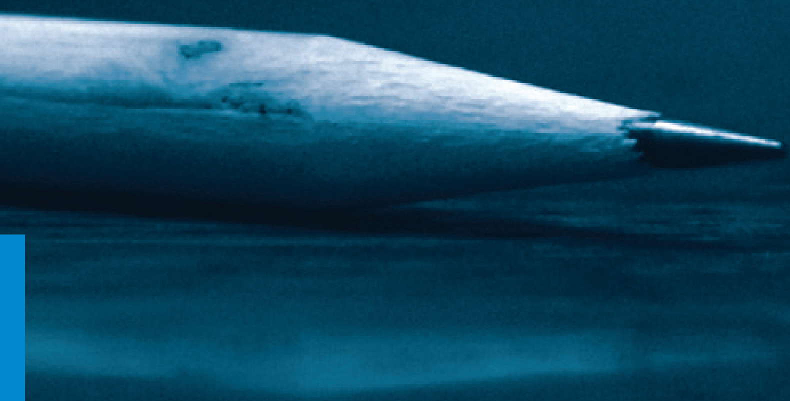
The future of gas pricing in long-term contracts in Central Eastern Europe.

Global market trends versus regional particularities

Robert Zajdler



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Abbreviations and units

ACER – the Agency for the Cooperation of Energy Regulators
CEE region – unless otherwise indicated the Report, the CEE region comprises Bulgaria, Croatia, the Czech Republic, Estonia, Lithuania, Latvia, Hungary, Poland, Romania and Slovakia, Slovenia.
bcm – billion cubic metres
BEMIP – Baltic Energy Market Interconnection Plan
EU – the European Union
FERC – Federal Energy Regulatory Commission
HFO - heavy fuel oil
HH – the Henry Hub
IGU – International Gas Union
JCC – Japanese Crude Cocktail
LFO – light fuel oil
LTCs – long-term gas supply contracts
mcm – million cubic metres
MMbtu – million British thermal units
MMcf/d – million cubic feet per day
Mtoe – million tonnes of oil equivalent
mtpa – million metric tonnes per annum
Mt/year – million tonnes per year
NGPA – Natural Gas Policy Act
NRA – the National Regulatory Authority
NYMEX – New York Mercantile Exchange
OTC – over-the-counter
tcm – trillion cubic metres
thcm – thousand cubic meters
US – the United States of America
Visegrád Group (V4) - comprises of the Czech Republic, Hungary, Poland and Slovakia.

Executive summary

Countries in Central Eastern Europe (CEE), due to similar history and their geographical proximity, have similar problems related to the development of their gas markets. Gas infrastructure was developed to transport gas from the former Soviet Union to CEE countries and Western Europe. Intra-regional gas infrastructure was not perceived as necessary. Demand was covered to a high extent by supplies from the former Soviet Union. Prices for gas were based on bilateral monopoly which in time took into account netback values. Integration or closer cooperation of CEE countries with the European Union resulted in a need to diversify supply routes and implement market-oriented changes integrating further the EU gas market. However, insufficient development of gas infrastructure and lack of effective gas market mechanisms makes CEE countries more vulnerable to producers' (exporters') market power than it is the case of the EU 15 member states in the West. It particularly concerns the way gas is priced in LTCs.

The way natural gas is priced varies across the globe but certain similarities are noticeable within the three main regional gas markets of North America, Europe, and Asia-Pacific. Differences are due to regional factors such as: market-oriented regulation, development of diversified gas infrastructure, existence and transparency of gas hubs, a degree of market opening. The main identifiable gas pricing mechanisms in LTCs include: gas-to-gas competition, oil price escalation, bilateral monopoly, netback, and regulation. CEE countries rely on oil price escalation in LTCs, close to the primary model of oil price escalation, which does not take into account recent developments in consumption patterns.

While different pricing mechanisms have coexisted for many decades, it is rather unlikely that the situation will remain the same in the near future. Significant gaps between the prices set by oil indexation in Asia-Pacific and continental Europe on the one hand and the prices set by gas-to-gas indexation in the United States, the United Kingdom and to the same extend in continental Europe on the other hand, that have opened recently. It reopened LTCs' price negotiations in the EU. The problems of contrasting price models effectively incited an important debate about the best pricing manners, and whether the use of varying methods leading to such huge differences in prices is even sustainable.

The trend to make LTCs more flexible is observed throughout the EU. Due to stronger negotiating powers the Northwestern EU countries have received concessions from producers, while CEE region still tries to follow the market. Gas-to-gas indexation higher than 15% is one of the elements negotiated to make LTCs more flexible and in line with market trends. Other concerns such as base price change, volume reduction, destination clause flexibility, minimum bill change or re-opener clause flexibility reduce contractual risks of EU suppliers. CEE suppliers seem to follow this trend, but reaching an agreement with exporters (producers) appears to be far more difficult than for suppliers in Northwestern Europe.

There are several factors which influence the change in a regional gas pricing model, such as hub expansion, LNG development, investments in storage facilities and exploration of unconventional gas sources. They influence, directly or indirectly, gas pricing in LTCs in CEE.

1) There is no single hub which dictates gas prices in the EU in a way similar to the Henry Hub in the US. A range of services offered by hubs in the EU differs from that in the US but is more uniform within the whole EU. The prices set by hubs in the EU still do not dictate the price of natural gas on the EU natural gas market. This is due to the importance of LTCs in Continental Europe. Nonetheless, it is important to note that prices at different hubs across the EU are similar. Price deviation at hubs in the EU is between 1-4% with extremes reaching only 7%. Therefore, hubs in the EU may be regarded as the benchmark for the EU region. Price deviation between hubs on national markets does not underestimate the credibility of the whole mechanism. Additionally, the most developed virtual hub in Continental Europe, the Dutch TTF, in terms of prices does not differ from the British NBP, which is considered to be the only hub close to hubs in the US in terms of level of development . Moreover, since the beginning of 2011 average 3M futures at the TTF varied only by 3,8% from the European average of Day-ahead prices and 3,6 % from the continental average. CEE region does not have its hub yet, although there has been a concept of creating one in Poland. Nevertheless, European hubs already play a vital role in CEE region. Such a regional hub could be a reference point for CEE region. However, due to almost perfect correlation between other EU hubs, for example the TTF may play such role for the region.

2) CEE region has no direct access to global LNG markets. It is highly dependent on the pipeline gas supply. Its infrastructural development and market developments are insufficient or non-existent. In the same time other EU regions have either access to the global LNG markets or/and are internally highly interconnected. They have also developed hub markets. These circumstances influence pricing mechanisms in LTCs in CEE regions. Lack of an alternative that the LNG market gives leads to dependence on external suppliers. The perspective development of LNG terminals in the region may change the situation.

3) The EU is home to 26% of the global storage volume. Out of that CEE makes 21%. CEE countries are not uniform when it comes to capacity of working storage facilities and gas storage to domestic gas consumption ratio. Poland has however one of the smallest storage capacities in CEE region, outpacing only Bulgaria and the Baltic states. Out of V4 countries Poland can store the smallest amount of gas. Taking into account how much of annual consumption can be secured by stored gas Poland is far behind the EU, CEE and V4 countries. It makes certain countries within the region vulnerable to exporters, market power.

4) There are no regional similarities between CEE countries with regard to physical possibilities and the regulatory approach. However, shale gas development in Poland may affect CEE region by providing an alternative source of gas to the market. Infrastructural integration of the region may make the common approach to regional security of supply feasible. An additional amount of spot gas on the market may lead to a more intense erosion of LTCs. It may also affect pricing mechanisms in LTCs. Increased unconventional gas exploration boosts the amount of gas on the market. Some potential producers are LNG exporters, which means that gas may reach global markets. It may improve their competitive and market power in regard to gas supply agreements, making LTCs more dependent on market conditions than on political issues.

Due to the above-mentioned regulatory and market constraints of CEE region, gas market rules within the EU should be applied uniformly, based on solidarity principles, under auspices of the European Commission and the ACER, and in close cooperation with National Regulatory Authorities. It will enhance the negotiating powers of CEE and benefit the EU internal gas market.

Introduction

There is no uniform pricing mechanism for natural gas on a global scale. One can distinguish three regional markets: the United States, Asia-Pacific and Europe. The European market is not a single market as specific historical and market conditions show that there is a significant discrepancy between Central and Eastern Europe (CEE) and the rest of the European Union. The local specificity of these markets is reflected in a variety of contractual terms in long-term gas supply contracts (LTCs) and hence in differences in determining pricing formulas in these contracts. In the long run, there is a chance that increasing trade in liquefied gas (LNG) and the development of unconventional gas will integrate regional markets towards a more unified global pricing mechanism.

In recent years, it has been noted that the model of the gas market in the European Union has changed considerably. The change results from the gas market model based on competition rules and liberalisation principles approved by the EU member states and gradually implemented. The change has also been caused by the development of gas infrastructure in the member states, including interconnectors, LNG terminals and storage facilities, which gives more flexibility to the supply chain.

The historical developments of the natural gas market in the European Union led to the creation of two models of natural gas supply, and thus, two models of natural gas pricing in LTCs. The first one – called the continental model - was based on LTCs with prices largely indexed to prices of crude oil and oil derivatives. It began to develop in the 1950s after the discovery of large natural gas deposits in the Netherlands. The other one - the British one – was formed in the mid-1990s and was based on medium-term supply contracts of natural gas at a price to be indexed to a great extent to gas-to-gas competition. After some CEE countries entered the European Union, their LTCs showed important differences in relation to price formation mechanisms. The rates to which they were indexed to prices of crude oil and oil derivatives were higher than average EU rates.

Poor infrastructural connections and a fairly stable supply and demand balance in each of the EU national markets resulted in the coexistence of these two models of natural gas pricing in LTCs. What has been noted since 2008, to a great extent due to the economic crisis, is emerging oversupply of gas to the EU market, progressive integration of national markets within the EU market, and a gradual evolution of the methods for determining gas prices in LTCs. The changes concern different elements of LTCs, aiming to give more contractual flexibility to gas suppliers. Particular emphasis is put on the change of the indexation method, as the existing one is perceived as rather incompatible with gas market developments. More gas-to-gas indexation is required. The pace of evolution varies on different regional markets within the EU, with CEE lagging behind.

This analysis is intended to show the direction of changes in natural gas pricing in LTCs in CEE, taking into account trends on the EU and global markets. It aims to show particularities of these markets and the extent to which they are affected by the EU and global conditions of geopolitical, economic, and legal nature.

The legal and factual circumstances as of 31st September 2012.

1. Global and regional gas price drivers in LTCs

The world energy consumption has been steadily increasing in recent years and forecasts show that the trend is not to change in the years to come. Natural gas, which is a fuel with a share of almost 25% of the world's energy supply[1], fits into this global energy trend. The natural gas industry has been evolving over the past years to become what it is now. This evolution is a result of technological progress, the macroeconomic situation as well as the scarcity of resource. All of these implications have a direct or indirect influence on arrangements in LTCs. This chapter will highlight the recent macroeconomic situation, supply and demand parties on the natural gas market, fuel structure and energy intensity of global markets.

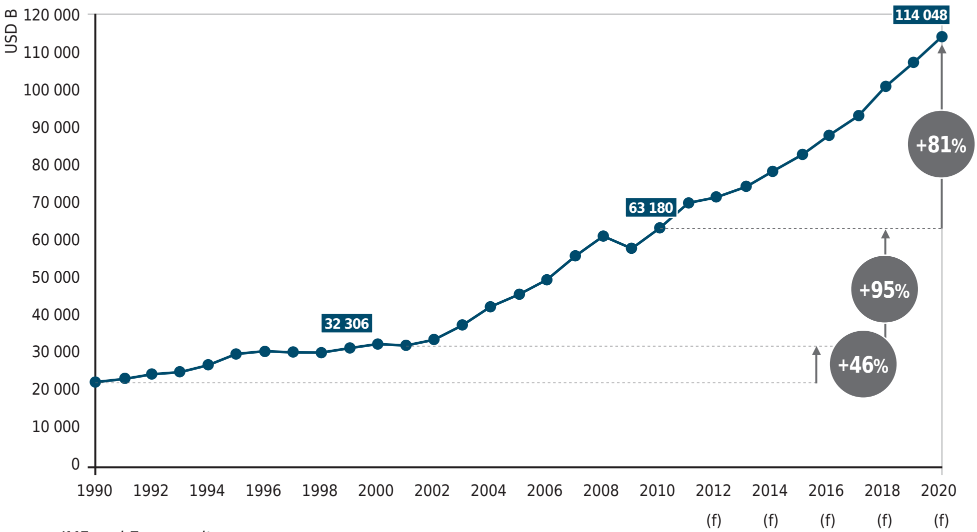
Macroeconomic highlights

In the last few years discussions regarding the economic situation have been dominated by the word "crisis". And indeed the world has experienced a downturn resulting in a GDP decrease reaching as much as 14-18% in the Baltic countries[2]. A vast number of economists say that the developed world will face another wave of downturn in the coming months. However, downturns are an inevitable element of a business cycle. They did occur in the past and will occur in future. This analysis will focus more on global long-term trends than on the post-Lehmann economic depression.

In the last twenty years the global GDP has maintained its growth, except for 2009 when the world economy declined by 0.6% in real terms[3]. It did not, however, prevent the economy from almost doubling in the first decade of the 21st century, whereas the 1990s brought roughly a 46% increase.

The pace of the current development shortens a business cycle, which translates into shorter periods of prosperity and shorter downturns, but the general trend is always upside. Apart from the archive data and current estimates, the curve below also presents the forecasts for the global GDP growth in the current decade. Analysts generally agree that it will be growing to almost double the status again from 2010.

GRAPH 1. **Global GDP in the period 1990-2020.**

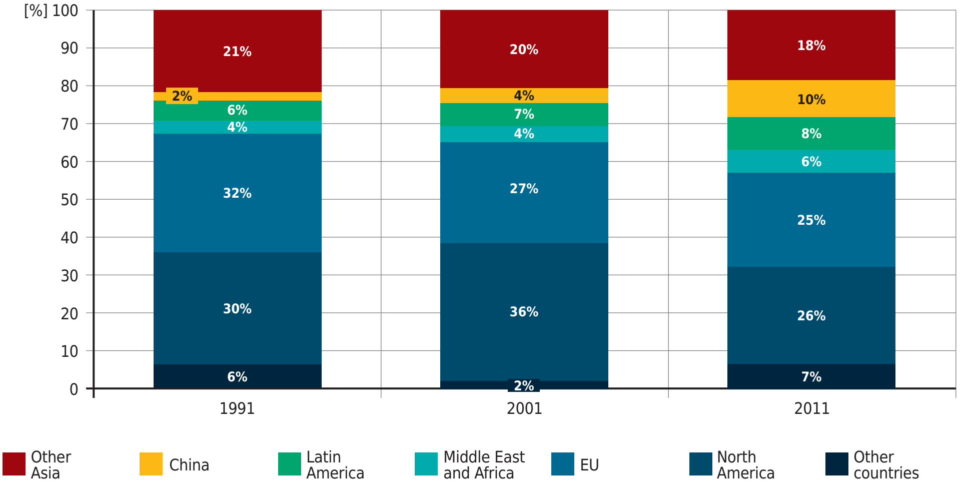


Source: IMF and Euromonitor.

What changed in the previous years though is the share in the global GDP of countries that are described as "developed". Remarkable is the fact that the EU[4] share in contribution to the global GDP has decreased by 7 % in the last 20 years. North American countries[5] contributed to a quarter of the global GDP in 2011, whereas 20 years before it was over 30%. 2001 was the year when the domination of North America amounting to 36%, which means that over 10 years the 3 NAFTA countries lost a share of 10%. The decreasing share of advanced economies makes room for new entrants. On the graph below China is presented separately from other Asian countries in order to highlight its rapidly growing significance in the world. 20 years ago the country contributed approx. 2% to the global GDP and doubled it to reach 4% in 2001. In 2011 the country generated 10% of the world's GDP.

The other challengers, although the pace is much slower, are Latin American countries. Each decade they increased their share by 1%. A modest increase can also be spotted for Middle East and African countries, which contributed 4% in 1991 and 2001 to increase their share to 6% in 2011.

GRAPH 2. **Contribution to the global economy by region.**

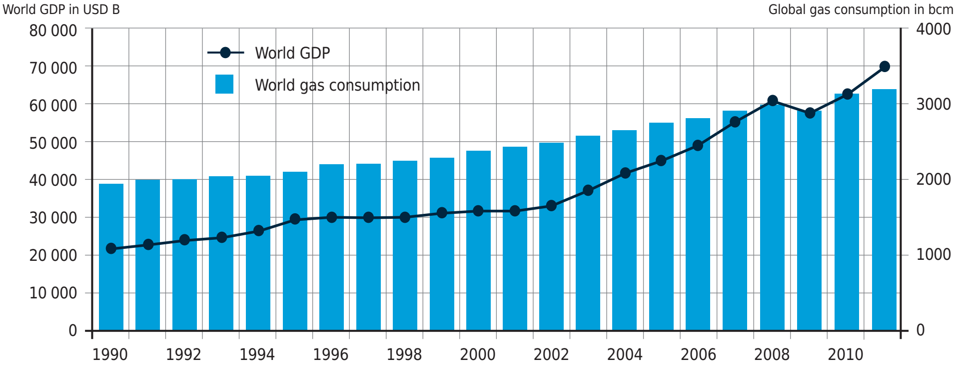


Due to rounding percentages may not total 100.
Source: *Euromonitor*

Changing share in the global GDP has a number of implications for the gas industry. The next picture reflects the link between changes in GDP and changes in gas consumption. The trend is most visible in the period of the last downturn when gas consumption decreased in a manner parallel to the GDP drop and recovered with the global GDP increase.

Another observation to be made is the fact that gas consumption has been growing much faster than GDP, which may be attributed to a higher substitution share of gas compared with other energy sources.

GRAPH 3. **Global gas consumption.**



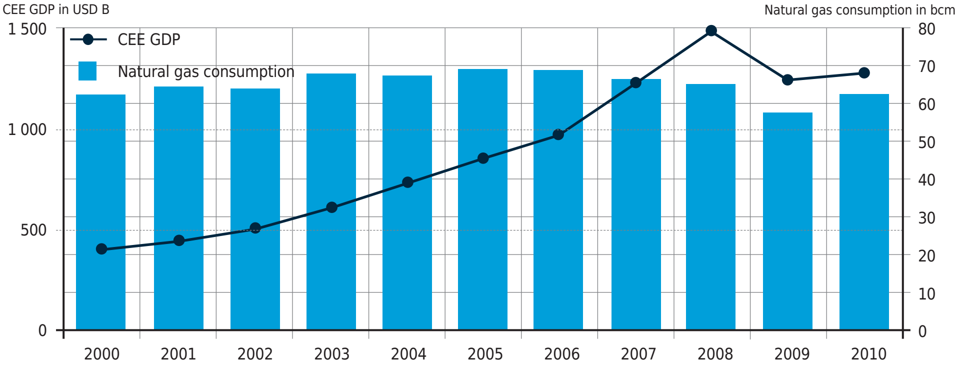
Source: *BP Statistical Review 2012, IMF.*

The trend is not that much visible in CEE countries that seem to have a relatively constant level of natural gas consumption. This might be a result of inflexible LTCs, with historically rooted gas supply only from Russia[6].

They freeze the supply/demand balance, not allowing natural gas to compete with other sources of energy at national level. On the other hand, more expensive natural gas does not dramatically lose its market share. Insufficient interconnections and depending on existing sources of supply maintain this status quo. CEE countries may not see incentives to boost gas-intensive undertakings under current conditions.

It does not mean that gas consumption is totally indifferent to market conditions. The 2009 downturn had a visible impact on volumes of consumed fuel. This situation causes resources not to be allocated in the most effective way.

GRAPH 4. **Correlation of the CEE GDP growth and natural gas consumption the period 2000-2010.**

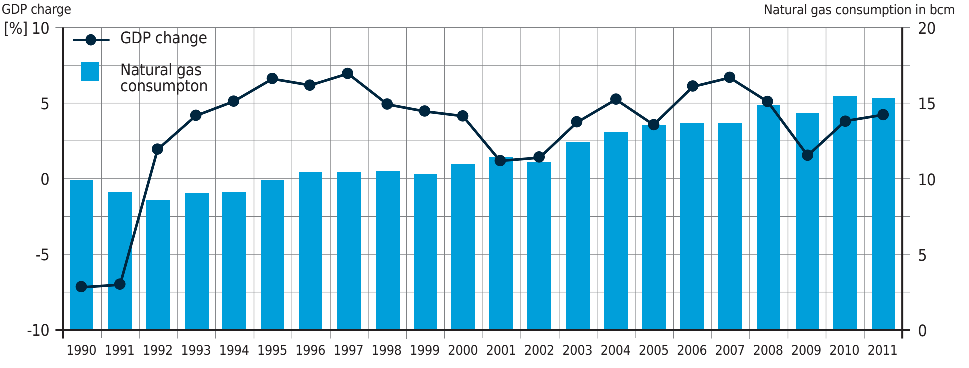


Source: *Author's calculation.*

Poland is a country that in recent years, unlike other EU countries, experienced a constant GDP growth with, as described above, comparable averages always above 4%. A detailed presentation of the Polish GDP annual changes is shown on the graph below. The short post-transformation GDP decline registered in 1990 and 1991 turned into growth years starting in 1992. The country experienced downturns in 2001 and 2008, but no recession was registered after 1991[7]. IMF forecasts modern growth rates in the years to come ranging from 2% in 2013 to 3.6% in 2017.

Domestic gas consumption was more volatile than the global one, but the upward trend is visible. In the first two years after the transition domestic consumption was shrinking. In 1995 it reached the level from 1990 and continued to grow.

GRAPH 5. **Correlation of natural gas consumption GDP growth in Poland in 1990-2011**



Source: *BP Statistical Review 2012, IMF.*

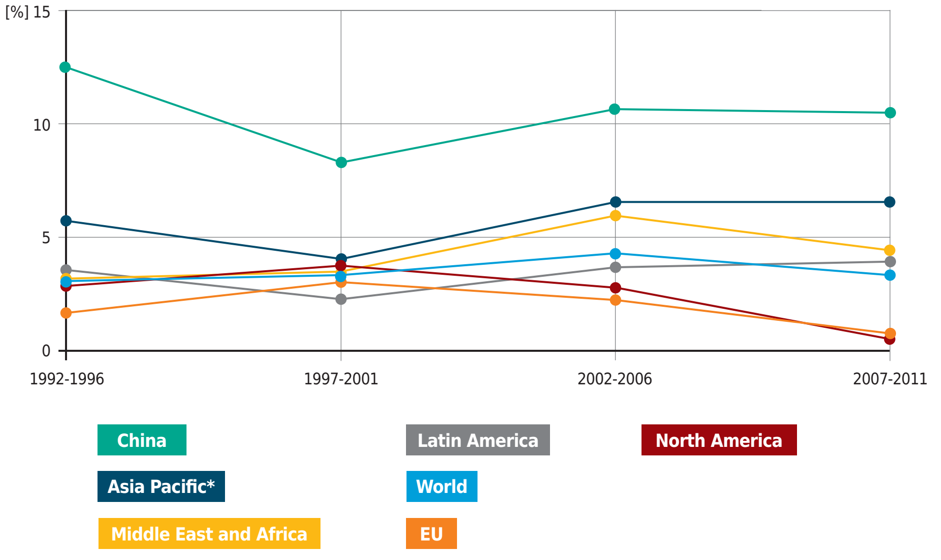
Changes of the players' share in the global economy results in the appearance of new significant consuming countries that were not present on the natural gas market 20 years ago.

A number of examples prove the correctness of this thesis. In 1990 China consumed 15.3 bcm of natural gas. In 2011 the consumption was 130.7 bcm, which constitutes a rise of 760%. Out of the countries with a higher share than 1% in the total world natural gas consumption, the ones whose consumption at least doubled in the last two decades are: Iran, China, Japan, Saudi Arabia, Mexico, the United Arabian Emirates, India, and Egypt. The share of economies that might be described as "emerging" is significant and highlights changing demand parties.

The pace of economic growth in the last 20 years reflects the trend in a growing contribution of emerging markets to the global GDP. The following curves present the average annual growth of GDP in five-year periods in the analysed world regions and China.

The European Union and North American countries registered the lowest GDP growth in the last five-year period and one of the lowest in the last 20 years.

GRAPH 6. **Average annual changes of GDP in five-years periods.**

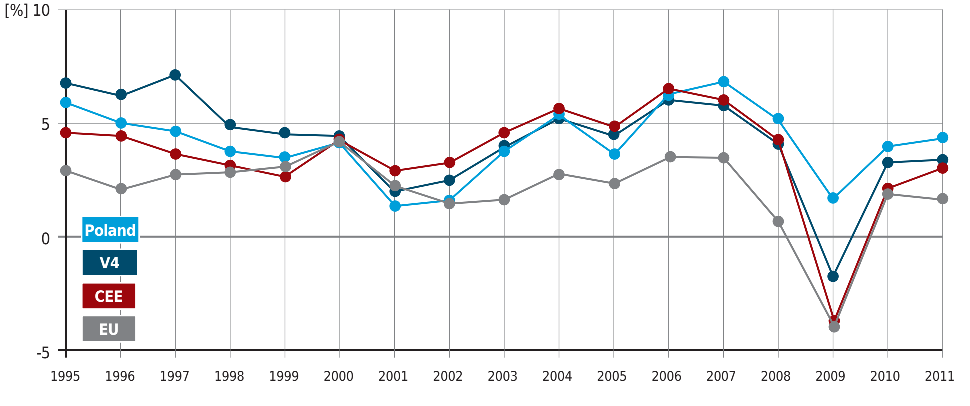


*Asia Pacific region incl. China

Source: *IMF.*

CEE stands out from the European Union and the GDP growth in the region has outpaced the Union's trend in the last 16 years. However, Central Eastern Europe has also experienced the downturn and the only exception was Poland. The growth of V4 countries in the last years is aligned with the trend in CEE apart from a milder downturn impact, which is mostly due to a constantly growing economy in Poland.

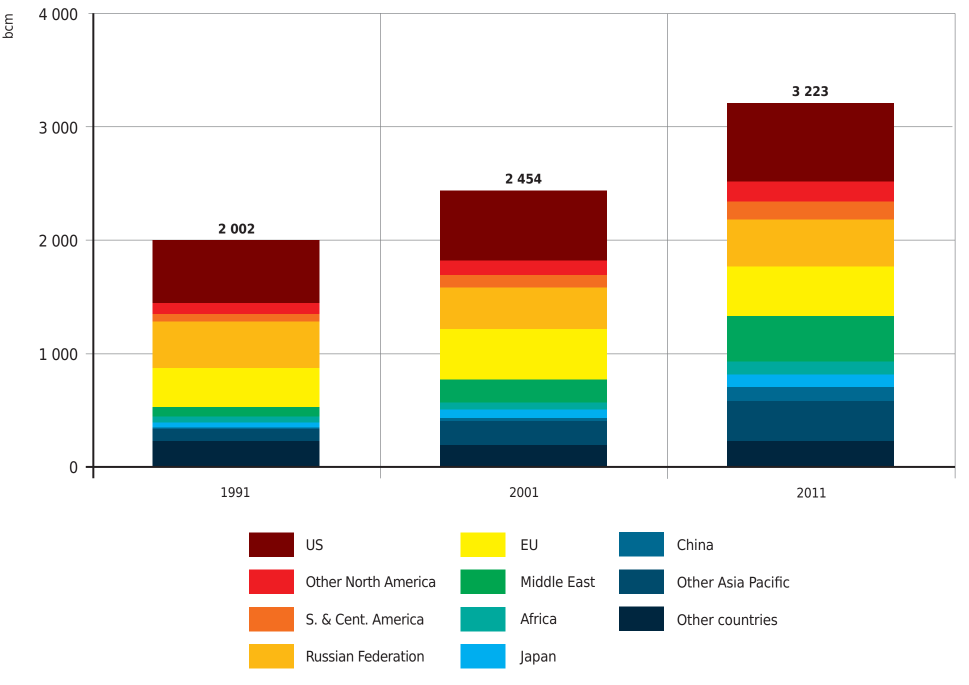
GRAPH 7. **GDP real changes in 1995-2011.**



Source: *Author's calculations based on the IMF data.*

The regional GDP trends described above are reflected in natural gas consumption. Although Asian regions base a considerable part of their energy production on coal, which will be analysed later in this chapter, their share in consumption of natural gas has been growing steadily. For the sake of the presentation of regional changes, four countries were "taken out" from their regions, not to spoil the results of the analysis. The United States is the biggest consumer of natural gas and its share has not changed much over the last years. The same applies to Russia and the EU. A significant increase can be noted in the case of Asian countries presented as shades of red. This can be attributed both to growing Chinese economy and to other markets' growth (e.g. India). Latin America and Africa still play a marginal role on the market.

GRAPH 8. **Global gas consumption by region.**



Source: *BP Statistical Review 2012, author's calculation.*

Demand and supply

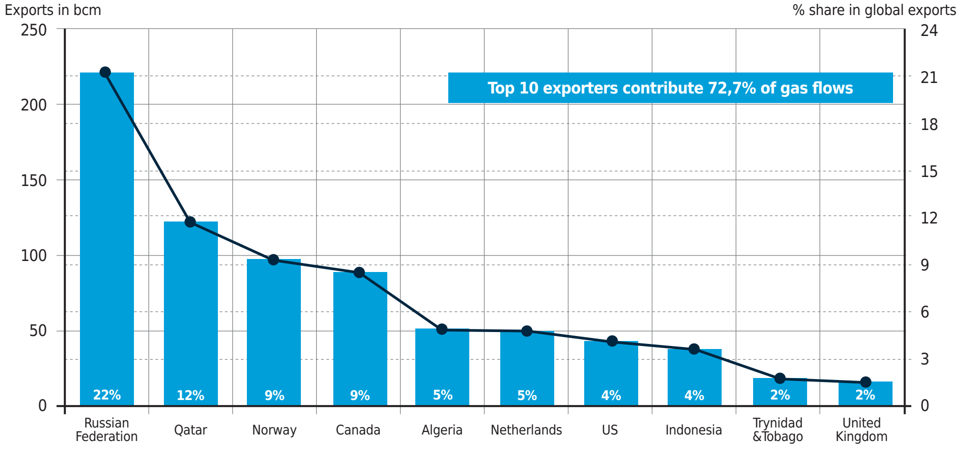
The world gas production stood at 3 276 bcm in 2011 and the world gas trade equalled 1 025 bcm, which means that one-third of total gas is subject to international trade. The major manufacturers of natural gas were the US and

Russia with production volumes reaching 651 bcm and 607 bcm respectively. There are significant differences between the two countries, which contribute 38% of the total natural gas production. Russia is the biggest exporter trading a one-third of its annual production. The US exports only 43 bcm, and in fact it is a net importer of 55 bcm.

The top 10 exporters of gas are responsible for over 70% of the commodity flow in the world. Last year Russia exported 221 bcm of natural gas, which accounted for some 20% of global exports. The second biggest exporter is Qatar with a share of over 12%. The development of LNG enabled multiple countries to enter the supply side of the gas industry and take part in the international exchange of this commodity. Other significant exporters are Norway and Canada, exporting 97 and 88 bcm respectively.

The right axis and the curve refer to the share of global exports, and the left axis refers to the volumes indicated by blue bars.

GRAPH 9. **Top 10 exporters of natural gas in 2011.**

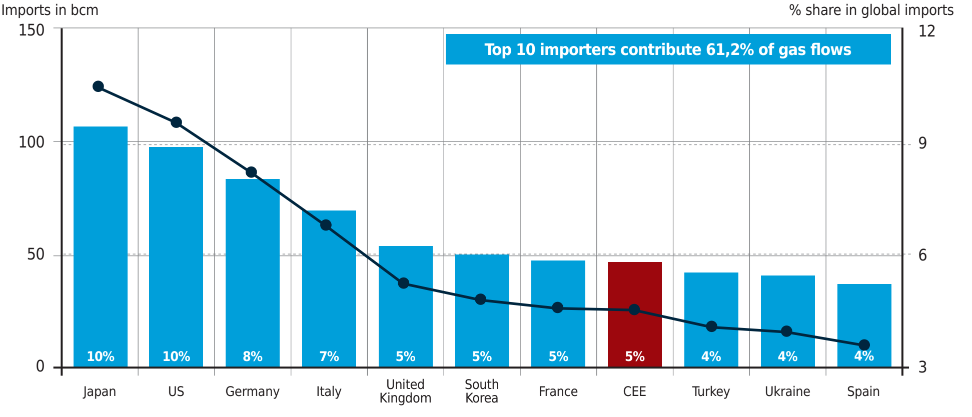


Source: BP Statistical Review 2012, author's calculation.

The biggest importer of gas is Japan, which does not have its own resource base and has to import 100% of consumed gas. The volume imported in 2011 equalled 107 bcm. There is no such disproportion between the biggest importing country and its followers. The US with an import volume of 98 bcm is the second biggest importer, being also the biggest natural gas manufacturer in the world. Apart from South Korea, the other countries on the top 10 list are from Europe. The amount of gas imported by them accounts for 73% of total imports.

The graph below presents the described volumes based on the above-mentioned methodology. It also positions CEE region among the top natural gas importers. None of CEE countries is positioned on the top 10 list, however, as a region Eastern Europe is a significant importer of natural gas.

GRAPH 10. **Top 10 importers of natural gas in 2011.**



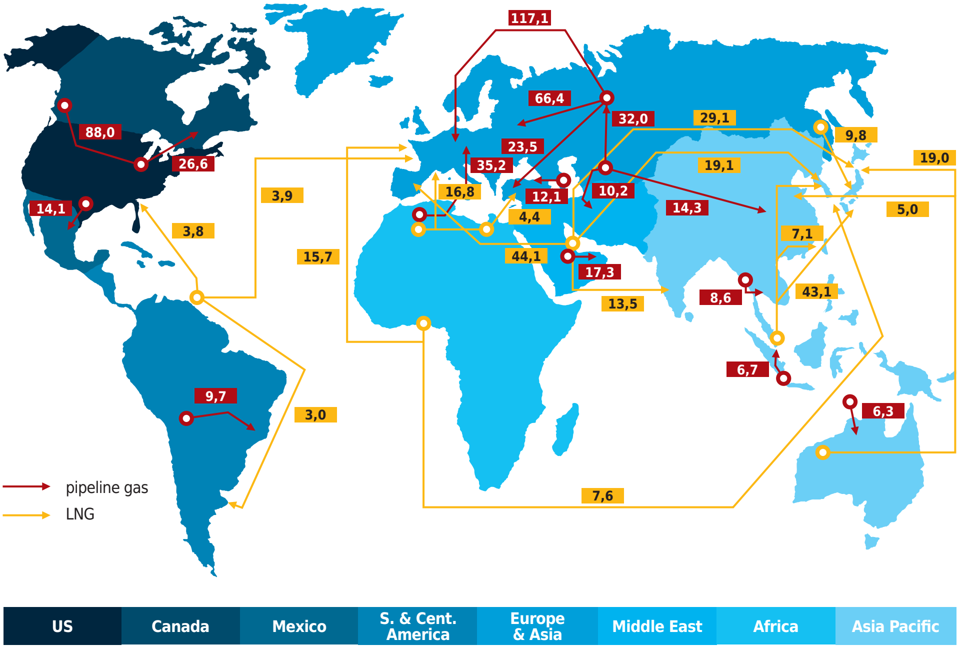
Source: BP Statistical Review 2012, author's calculation.

Due to the LNG technology, first used in the 1950s, international trade of gas became truly global. There are no obstacles, apart from economic profitability of the project, to ship natural gas on long-distance routes. In fact, LNG movements represent 32% of the global gas trade and the volume of traded gas within this channel amounted to over 330 bcm in 2011, over 10% higher than in the previous year.

The LNG market is analysed in chapter 7. The development of LNG transportation capabilities in the last decades has changed the industry dramatically. It includes the construction of multiple receiving terminals, new suppliers entering the market, and a possibility of receiving gas in the so-called "stranded areas". Potential gas consumers that cannot satisfy their needs for the resource from domestic production and that are not linked to an exporter by a pipeline system have been given a chance to introduce natural gas into the list of fuels.

The map below pictures the major gas movements in 2011. The vast majority of Europe is supplied by gas transported by pipeline, whereas Asia Pacific sources its gas from Middle East, Australia, and Africa, mainly in the form of LNG. The biggest importer of LNG in Europe is Spain.

GRAPH 11. **Major gas trade movements in 2011.**



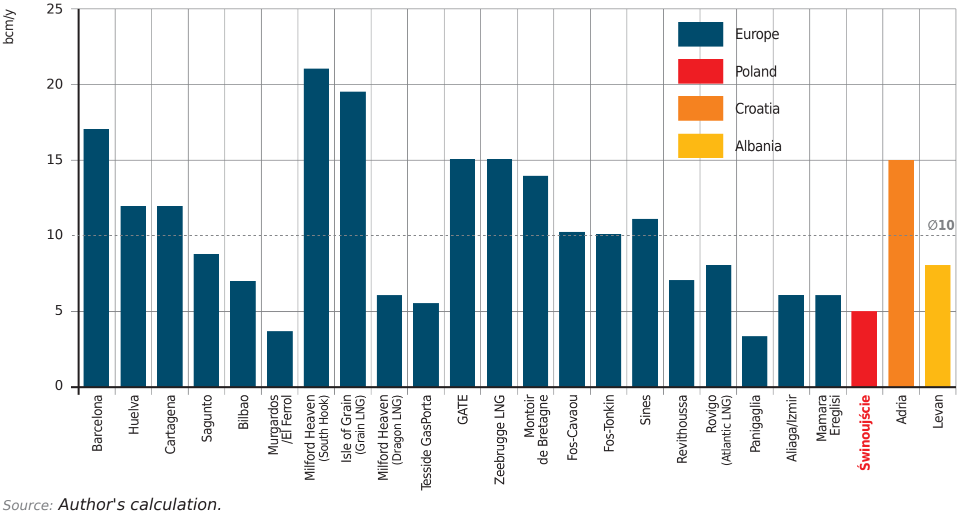
Source: *BP Statistical Review 2012.*

Gas for CEE is imported via pipeline connections with the Russian Federation. Poland is the first country that invested in diversifying import channels and is currently constructing an LNG terminal in Świnoujście with a capacity of 5 bcm/y. Croatia also plans to build a terminal, but the decision has been postponed to 2013. Its planned capacity is said to reach as much as 15 bcm/y[8].

Due to market proximity CEE might be also interested in an LNG project in Albania which is in its initial planning phase[9]. Once completed, the terminals will serve as an alternative to pipeline transportation.

The graph below presents the three mentioned terminals compared to their European counterparts. The Adria terminal in Croatia will be one of the biggest on the continent, and its capacity is 50% higher than the European average. Levan in Albania will be slightly beneath the average, whereas the terminal in Świnoujście is one of smallest installations in Europe. Regardless of their sizes, they aim at differentiating supply directions and as such will have an impact on regional gas markets as well as on arrangements in LTCs.

GRAPH 12. **Comparison of the CEE and Albanian LNG terminal projects with the existing European installations with regard to send-out capacity.**



Source: *Author's calculation.*

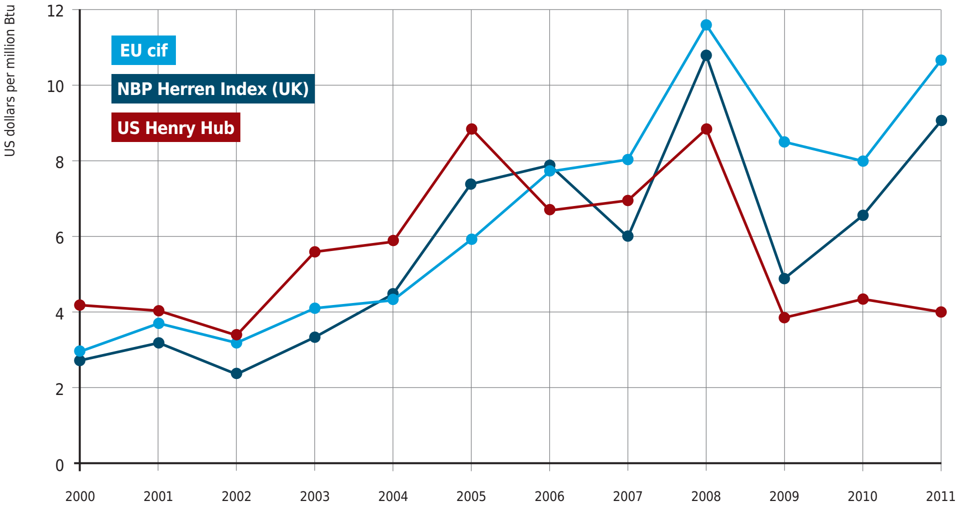
Other institutions, affecting the gas industry not only in terms of price setting but also in terms of availability of gas from other countries, are gas hubs. The most developed gas hubs are located in the United States and are in fact price indicators for all the gas sold on the US soil, both imported and produced domestically. Gas contracts in the US refer to gas pricing at the so-called Henry Hub in Louisiana, which is an indirect reference point for other US hubs. The reason for that is the linkage between the Henry Hub and the gas instruments traded on the NYMEX.

In Europe the most developed hub is the British National Balancing Point, which is somehow a price indicator for all European hubs. European hubs were developed about 10 years later than those in the US. Moreover, the European market is based mostly on gas imports and not on domestic production. On top of that the US gas supply infrastructure is a single-country undertaking, whereas creating a single gas market in the European Union requires multiple investments at national level as well as a stimulating regulatory framework. EU policy aims at creating a single market and the process is ongoing. All this results in underdevelopment of EU hubs as opposed to American ones, and their smaller influence on prices in LTCs.

Gas consumption of EU members comes mainly from imports. 15[10] out of 27 countries have to rely on imports in 90-100%, another two[11] in 80-90%[12]. Only Denmark and the Netherlands are net exporters of natural gas. This leads to a situation where gas exporters have a strong negotiating position, and where gas traded at hubs is dependent on prices in LTCs.

The graph below presents gas prices in the EU, the UK (separately) and the US. What can be noted is that in the last five years the gas prices traded on the markets where prices are set by market players were lower than prices vastly dependent on LTC linked to oil. Market prices, however, have a tendency to rise in times of prosperity, whereas it is not so quickly visible in oil-linked gas prices.

GRAPH 13. **Natural gas prices (2000-2011).**



Source: BP.

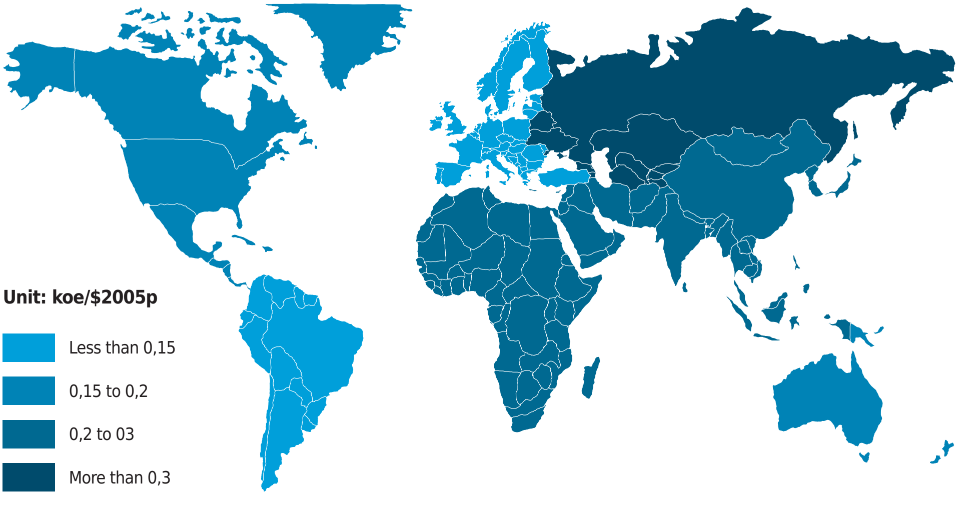
The next trend that might change the picture of the global gas industry on the supply side is the extraction of gas from unconventional sources. The topic will be analysed in detail in chapter 9. Today production of gas from this type of resources constitutes 14%[13] of the global gas pool and can be attributed to two countries: the US and Canada. The success of shale gas projects in the US has sparked international interest in unconventional sources[14], and that includes European countries and in particular Poland. Regardless of how much time the projects are to take, a number of countries decided to invest their resources in the exploration of that option. The International Energy Agency estimates that in 2035 in OECD European countries a quarter of produced gas might be extracted from unconventional sources. The same source claims that China will also shift to unconventional sources, and their domestic production from this source will be 2.5 times higher than the one from its conventional sources. Already in 2008 the unconventional gas production in the US was higher than the conventional one[15]. The characteristic feature of unconventional gas deposits is that they are distributed round the globe, and potentially all regions have a possibility of extracting gas from unconventional resources. The problem that needs to be faced is large investment outlays necessary both to start exploration for deposits and to extract gas. The use of multiple advanced technologies is needed to upstream fuels. In CEE unconventional gas extraction focuses on Poland. Romania, Lithuania, and Hungary are willing to extract shale gas, and exploration is carried out in other countries, but a large-scale extraction is planned solely in Poland. Nowadays, natural gas consumption in Poland is covered both from international supplies and from domestic production, of which the latter accounts for 30% of domestic usage[16]. This places Poland among the four[17] EU gas-importing countries with the lowest dependency ratio on imports[18]. A vast majority (86%) of imports were shipped from Russia, based on LTCs that expire in 2022, and the rest came from Germany and the Czech Republic. To diversify its supply base and secure gas deliveries, Poland has invested in an LNG terminal that will be the first regasification plant in CEE region. It is scheduled to be operational by June 2014[19], and it is to have a send-out capacity of 5 bcm/year in the first phase of construction with an option of expanding it to 7.5 bcm/year, if needed. Apart from the construction of the LNG terminal, Poland has also strongly pushed for exploration of shale gas, whose deposits in Poland are said to equal 1.5 tcm (trillion cubic meters), and according to the Polish Geological Institute the recoverable base ranges between 230 and 619 bcm[20]. Nevertheless, the Polish Ministry of Environment has issued 111 licences to explore and extract shale gas in Poland, and a number of international companies including Chevron, and ENI have shown interest in researching the potential[21]. There also exists a conception of establishing a gas hub in Poland that would serve the region. Poland could benefit from the concept because regional gas quotations would enable the decreasing of gas prices in contracts with Gazprom, but the Polish hub would also face competition from German and Austrian hubs[22].

Energy intensity

Energy intensity of an economy is usually measured as an amount of energy used in order to contribute a monetary unit of GDP. The values of this indicator show the level of a country's development. They may be influenced by a number of factors including: energy efficiency undertakings in the country (both at the level of the industrial and residential sector), structural changes of economies where more value added is generated in the services sector than in manufacturing, a shift of the industrial sector into the direction of higher performance in terms of the value added[23] (the higher a manufacturer is in the value chain, the higher the value added is). Additionally, there are welfare indicators that have an impact on energy intensity. A high standard of living generally increases energy usage, but it is linked with the level of development of a country and is usually balanced by the indicators which make countries more energy efficient, for instance, the use of vehicles with low fuel consumption, energy-efficiency of buildings, extensive networks of public transportation and other. Another factor that cannot be changed is climate – countries in a milder climate will tend to use less energy when compared to counterparts at the same level of development. Regardless of factors, there is a strict correlation between a country's level of development and energy intensity of its economy.

From the global perspective, European countries have one of the least energy-intensive economies along with countries in South America. North American countries[24] have more energy-intensive economies, with the US being close to the level of CEE countries, and Canada being close to the Asian average. Asia's low energy efficiency is mostly contributed by China, which needs over two times more energy to generate USD 1 of GDP than an average EU country. Most energy is used in CIS countries with the energy intensity three times higher than in the EU[25]. The international data provider uses the unit koe/$2005p[26] to compare countries.

GRAPH 14. **Energy intensity by region in 2010.**

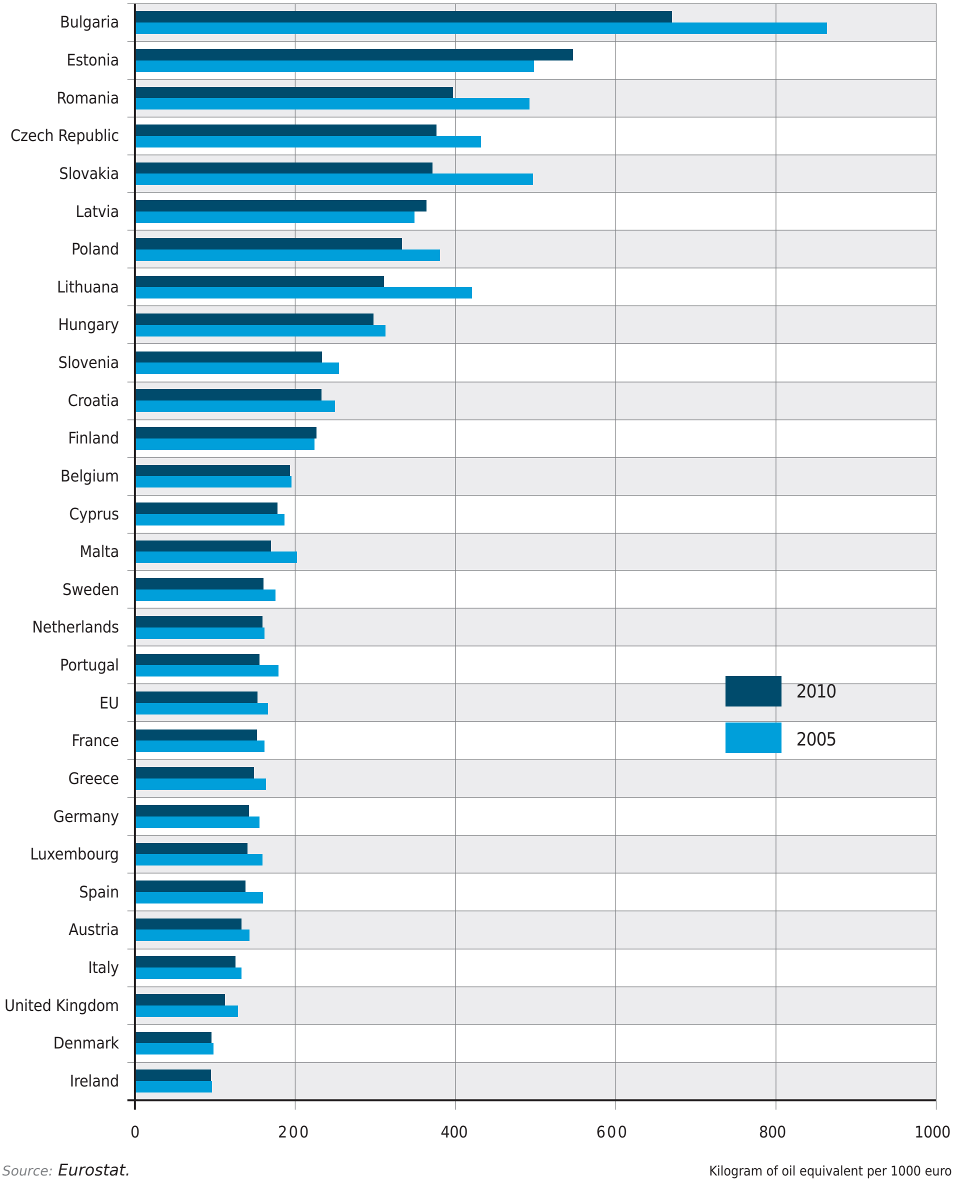


Source: *Enerdata.*

The European Union is the least energy-intensive region in the world, but its 27 members are not homogeneous in terms of energy needs for value creation. The graph below presents energy intensity in EU countries in kilograms of oil equivalent per 1000 euro of GDP.

Based on the correlation between a country's development and its energy intensity, the data for Europe fit global trends. The countries from CEE region are the most energy-intensive. Most energy per EUR 1 of GDP is used in Bulgaria, Estonia, and Romania. The next positions are taken by the Czech Republic, Slovakia, Latvia, and Poland, followed by Lithuania and Hungary. The ten most energy-intensive countries in the region are new members of the European Union. This proves that nowadays CEE region needs to use much more energy than its Western counterparts in order to generate EUR 1 of GDP, but this probably also means that to generate EUR 1 of GDP, CEE countries have to incur higher energy costs.

GRAPH 15. **Energy intensity in the EU and Croatia.**



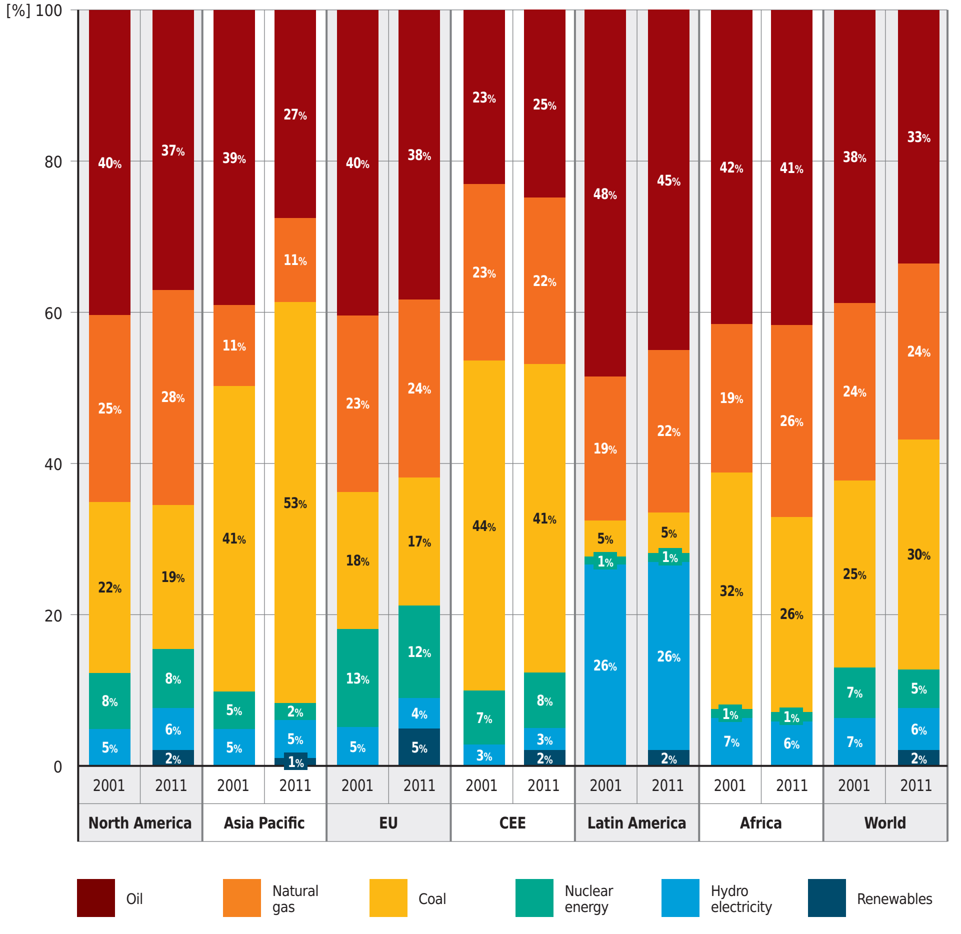
Source: *Eurostat.*

The trend that is visible on the graph above is rapidly decreasing energy intensity of CEE region with the exception of Estonia and Latvia. The scale of the decrease is much bigger than in Western Europe, which might indicate that more developed countries are close to very high energy-efficiency standards, and Eastern Europe is heading in this direction. This might also mean that CEE countries have moved up in the value chain, and that they have experienced the described economy transition that has implied a shift into more value added being generated in the services sector.

Energy mix

World energy production is basically based on six types of fuels: oil, natural gas, coal, nuclear energy, hydroelectricity and renewables[27]. The proportion of their share in energy generation varies by region and by country. The graph below presents a current share of fuels in energy consumption by region in 2001 and 2011. A relatively high share of oil fuels is characteristic for most regions in the world. Although it has decreased in the last decade by 5 p.p., from 38% to 33%, it is still close to or over 40% in North America, the EU, Latin America, and Africa. The highest decrease in share was spotted in Asia Pacific, where it used to be 39% in 2001 and is 27% now. The gap was filled in by a rapidly growing share of coal. Out of all the regions shown, CEE has the lowest share of oil in energy consumption[28]. It is relatively constant and accounts for 25% of energy consumption, which means a 2% increase compared with 2001. Along with Asia-Pacific, CEE countries consume large amounts of energy from coal. Although its share decreased by 3 p.p., it is still over 40%, whereas in the European Union it is only 17%. In other regions coal accounts for 26% (Africa), 19% (North America) and 5% (Latin America) of energy consumption. Globally, energy from coal constitutes almost one third of primary consumption[29]. In Asia Pacific the consumption of energy from coal represents 50% of the share in the basket. Natural gas accounts for 24% of the world's energy usage and most regions are aligned with the global average. In North America natural gas constitutes 28% of energy, in the EU 24%, in CEE 22%, in Latin America 22%, and in Africa 26%. It is quite low in Asia Pacific and equals as much as 11%, retaining its position from the beginning of the last decade. World nuclear energy is concentrated in North America and the EU. Its global contribution to consumed energy amounted to 5% in 2011, which was 2 p.p. lower than in 2001. In the EU nuclear energy makes up 12% of consumption, in the US and CEE 8% and in other regions it does not exceed 2%. Hydroelectricity globally represents 6% of primary energy consumption and is located basically only in Latin America, where it constitutes 26% of the energy mix basket. The share does not exceed 6% in other regions. Renewable resources[30] still have a marginal position, both globally and regionally. They amount to 5% of the EU energy consumption.

GRAPH 16. **Energy mix in world regions in 2001 and 2011.**



Source: *Author's calculation.*

CEE remains heavily dependent on coal, but the trend of a slowly decreasing share of coal is visible. Natural gas is relatively well-established, accounting for over 20% of the region's energy consumption. The high share of coal is linked with domestic extraction of this fuel and therefore lower purchasing costs for companies generating electricity.

Conclusions

The world economy has been steadily growing and despite the crisis that occurred in 2009 and downturns expected to come afterwards, the trend will not change in the long run. The economic growth is accompanied by the growth of fuels usage, in particular, the usage of natural gas. On the global market gas exporters will have to face competition from their counterparts from new gas sources. However, they will not be the only ones facing competition. As growing economy boosts investment in resources' extraction there will be more parties on the supply side. LNG development and shale gas potential already have and will have an impact on the amount of fuel on the market. Therefore, looking for demand, gas exporters will have to adjust their offer to market conditions and make it more attractive to potential consumers.

These macroeconomic changes also concern CEE countries. A fairly constant GDP growth in this region and close global correlation between this growth and gas consumption lead to further growth of gas demand. This growth pace is related to a number of factors, such as energy intensity, the structure of the energy mix, the netback value of gas compared to alternative fuels. It will also change gas supply routes to the region.

CEE position on the global gas market map has been disadvantageous compared to European counterparts in a number of ways: very high dependency on one gas supplier, limited pipeline connections, underdevelopment of infrastructure linking the country with Western Europe. The growing market, EU single gas market investments, new alternatives, and potential shale gas extraction are transforming the region into less of a price-taker than it used to be. Lower energy intensity of CEE countries, the sound position of gas in the energy mix and the economic growth outpacing Western Europe make the market more attractive to exporters. Along with the development of the single gas market in the EU there might be a chance of adjusting LTCs to market conditions.

1. *BP Statistical Review 2012.*
2. *Estonia, Latvia and Lithuania – data according to the Worldbank.*
3. *World Economic Outlook Database, IMF, October 2012.*
4. *The EU defined as 27 member states regardless of the period.*
5. *NAFTA: the US, Mexico and Canada.*
6. *Apart from Croatia.*
7. *World Economic Outlook, IMF, October 2012.*
8. *http://www.reuters.com/article/2012/07/03/croatia-lng-project-idUSL6E8I36O620120703.*
9. *http://www.energiafalcione.com/energia_falcione_home.html.*
10. *Finland, Sweden, Estonia, Lithuania, Bulgaria, Greece, Italy, France, Belgium, Luxembourg, Spain, Portugal, Ireland, Slovakia, Slovenia.*
11. *Germany and the Czech Republic.*
12. *EU Energy in Figures.*
13. *Golden Rules for a Golden Age of Gas, International Energy Agency, 2012.*

14. *World LNG Report 2010, International Gas Union.*
15. *Golden Rules for a Golden Age of Gas, The International Energy Agency, 2012*
16. *Charakterystyka rynku paliw gazowych w 2011 r., Urząd Regulacji Energetyki (The characteristics of the gas market in 2011, The Energy Regulatory Office), http://www.ure.gov.pl/portal/pl/459/4588/2011.html.*
17. *Disregarding net exporters.*
18. *EU Energy in Figures.*
19. *http://www.polskielng.pl/terminal-lng-w-polsce/inwestycja/.*
20. *http://gospodarka.dziennik.pl/news/artykuly/384117,mniejsze-zasoby-gazu-lupkowego-w-polsce-niz-sadzono.html.*
21. *http://gazlupkowy.pl/koncesje*
22. *http://www.forbes.pl/artykuly/sekcje/wydarzenia/polska-stworzy-regionalny-rynek-gazu,29829,1.*
23. *The European Environment Agency, EN17 Total Energy Intensity, http://www.eea.europa.eu/data-and-maps/indicators/en17-total-energy-intensity/en17-total-energy-intensity/at_download/file.*
24. *Canada and the US.*
25. *Enerdata.*
26. *A kilogram of oil equivalent (10-3 toe) / dollars at a constant exchange rate, price and purchasing power parities of the year 2005.*
27. *BP definition excludes hydro energy from renewable sources.*
28. *The CEE countries in the survey include: Bulgaria, the Czech Republic, Hungary, Lithuania, Poland, Romania, and Slovakia.*
29. *Primary energy comprises commercially traded fuels including modern renewables used to generate electricity.*
30. *No comparable data for 2001.*

2. Types of price formation mechanisms in LTCs

The way natural gas is priced can vary globally from region to region. Over time different formulas for determining prices in gas supply contracts, including long-term contracts (LTCs), have emerged, and the world has yet to converge in terms of the models utilised to set gas prices. Although there is some overlap as regards pricing mechanisms in the three main regional gas markets of North America, Europe, and Asia-Pacific, contrasting pricing mechanisms are becoming clear. These differences are due to regional characteristics such as existence or lack of a spot market, a degree of market opening, transparency, and regulation practices among others.[31]

The main identifiable mechanisms include the following: 1) gas-to-gas competition, 2) oil price escalation, 3) bilateral monopoly, 4) netback, and 5) regulation[32]. Other classifications of pricing mechanisms exist, but they generally combine some of the above-mentioned mechanisms.

Gas-to-Gas Competition

Gas-to-gas competition (also called hub pricing) is a dominant gas pricing mechanism in North America and the United Kingdom. It is also gaining importance in Europe. According to the International Gas Union (IGU), in 2009 33.4% of the world's gas consumption was made up of gas-to-gas competition[33]. Prices within gas-to-gas competition were set on the basis of market prices of natural gas, which were determined through the trading of futures contracts at physical hubs such as the Henry Hub (HH) in the United States or virtual hubs such as the National Balancing Point (NBP) in the United Kingdom. Operations at hubs send price signals about the market value of gas, thus allowing for supply and demand to play the leading roles in the determination of natural gas prices.

This mechanism was created in the US, following the deregulation of the natural gas industry, which resulted in the solidification of several factors required for the development of a natural gas market. The prerequisites to the formation of gas-to-gas competition pricing model include the construction of hubs, competitive environment, and transparent regulatory environment. Spot transactions and futures are essential to develop market-based pricing. The futures market, however, attracts a wider range of investors, including financial institutions than the spot one as it is less volatile. The prices there may follow seasonal gas market fluctuations. This feature, as well as sufficient depth of the market, makes it better than the spot one on account of a mechanism of price base formation and its indexation in long-term contracts. Additionally, this pricing model will not develop on its own but requires regulatory actions.

Generally, prices based on gas-to-gas competition have been associated with short-term or spot contracts while oil-indexed prices have been linked with long-term contracts. Long-term contracts used to be preferred in the gas sector as they secure gas supply at the same time ensuring investment security for the producer. Additional contract clauses divide risks between the producer and the supplier.

Oil price escalation was a preferred option in long-term contracts giving required investment security due to predictability of oil market prices. However, the combination of market-based pricing and long-term contracts may still be a relevant option. The use of long-term contracts wherein the price is linked to a gas market is perceived as an attractive option. It would allow for security of supply, while at the same time provide the buyer with a price that reflects the market value of the product.

The primary benefit of this type of a pricing system is that prices are competitive and reflect the market value of gas, not oil. In the past this resulted in a price differential of USD 1-2 per MMbtu between the areas that applied gas-to-gas competition rules compared with other methods, the former being cheaper. A disadvantage of gas-to-gas competition is short-term price volatility that accompanies swift changes in supply or demand. Price spikes and drops that can occur within this type of system can be painful for buyers and sellers in the short run, but there is little discussion regarding the transition to a more regulated pricing scheme. In general, gas-to-gas competition is viewed as the best option when compared with the alternatives. Gas price determination through multiple sellers competing for multiple buyers with minimal regulatory interference seems to be widely perceived as an end state without more efficient alternatives[34].

Also, by utilising forward pricing in contracts, the risk of price fluctuation can be managed by both the buyer and the seller.

Oil Price Escalation

Oil price escalation (also: gas-to-oil or oil-indexation) is a dominant pricing mechanism in Europe and Asia-Pacific. It links the gas base price in the contract and/or the escalation clause to the price of one or more competing fuels (HFO, LFO). According to the IGU's "Price Formation Mechanisms: 2009 Survey", in 2009 20.1% of the total world gas consumption was based on oil-indexed contracts.[35] Under oil indexation, prices are indexed to oil by the use of a specified formula within long-term contracts which vary in duration between 20 and 30 years. Thus, natural gas prices are not driven by the demand for or supply of natural gas, but rather by the rolling average prices of oil and oil derivatives.

This traditional form of pricing developed in the late 1970s and early 1980s when oil was a predominant source of energy. The logic behind oil indexation was that by the contractual linkage of prices of competing fuels in such a way, the end user was provided with a choice between consuming natural gas or oil. The belief was that with this price incentive, consumers would switch from burning oil to gas.[36]

The ways in which oil price escalation prices are determined vary according to a given region. While in Continental Europe prices are generally tied to a basket of heavy and light fuel oils, the indexation trend varies from source to source. For example, imports from Russia, Norway, and the Netherlands are pegged at over 80% to fuel oil while natural gas imported from Algeria is linked at only 70% to oil and oil derivatives. The region from which the purchaser originates also has an impact on the price. Fuel oil accounts for up to 30% of the price formation mechanism in the United Kingdom and around 95% in Eastern Europe[37]. The pricing formula used in Europe under the netback concept of long-term contracts is generally set up in the following manner:

Pm=Po + 0.60 x 0.80 x 0.0078 x (LFOm-LFOo)
+ 0.40 x 0.90 x 0.0076 x (HFOm-HFOo)

I. The gas price Pm:

Applicable during the month m is a function of:

- the starting gas price Po
- and the price development of competing fuels compared to the reference month, in this example: Light Fuel Oil (LFO) and Heavy Fuel Oil (HFO)

II. 0.60 and 0.40 are shares of gas market segments competing with respective fuels (no dimension):

- Light Fuel Oil/Heavy Fuel Oil
- These shares will be different from the shares of these fuels in total energy use; e.g., the share of heavy fuels used in most European markets is now rather small, however, it remains the best available alternative for most of the gas used for industrial purposes

III. 0.80 and 0.90: Pass through factors (no dimension):

- Sharing risk and reward of the price development between seller and buyer
- Most of the risk and reward for the seller (0.80/0.90)
- May be different for different fuels

IV. 0.0078 and 0.0076: Technical equivalence factors to convert the units of prices for fuel into units of gas price

In this example:
Gas in kWh (GCV), Fuel oil into t
Dimension: Euro cts/kWh/Euro/t

V. Competing fuels:

Quotations reflecting the market
With or without taxes on competing fuels
Time lag and Reference Period to be defined

LFO:	Price of Light Fuel Oil
LFOo:	Price of Light Fuel Oil for starting month o
LFOm:	Price of Light Fuel Oil resulting for month m (may refer to an average value of previous months depending on reference period and time lag agreed)

LFO is usually reflecting competition for medium and smaller customers whose alternative is using Light Fuel Oil (typically small industry, commercial, administration, households).

Source: *Energy Charter Secretariat, International Pricing Mechanisms for Oil and Gas, Brussels: Energy Charter Secretariat, 2007, p. 154.*

Oil price escalation is typically associated with long-term contracts. Traditional European long-term contracts included a “price review” clause to account for changes in market conditions throughout the specified term of the contract. This clause allowed for the indexation formula to be modified after an agreed-upon period of time, usually every three years. Prices within the contract are usually reset according to an average calculation of mostly oil prices in the previous 6-9 months, frequently with a lag of three months. Many contracts also have a special clause that allows both the buyer and the seller to request a re-examination of the price outside the contracted review time, either one time within each three-year slot, or one time during the full length of the agreement (a so-called “joker”). If this option is a viable though depends on whether or not both parties agree that the price must be reset due to a change in economic conditions that are not within the buyer or seller’s control.[38]

On the other hand, Asia-Pacific LTCs are most often connected to the price of oil imported into Japan, also known as the Japanese Crude Cocktail (JCC) with the exception of contracts in Indonesia, where the price index is a basket indexation of five types of oil imported into Indonesia[39]. The pricing formula in LTCs contains a base price and a variable part which is related in 80-90% to the JCC. The formula for Asian contracts typically looks as follows: P = a + bX, where "a" is a fixed base price established during negotiations, "X" is a variable component (the so-called "floating part") reflecting changes in oil prices, and "b" is a factor reducing exposure to oil prices.

In connection with the reduction in oil prices in 1986, countries exporting gas to the Asian region led to the renegotiation of supply contracts and the introduction of the so-called “S-curve mechanism" determining the expected volatility of oil prices for which the price formula was applicable in LTCs in its basic form. This modification was designed to protect importers in times of high oil prices and similarly to protect exporters in the periods in which oil was cheap. The continuation of these changes in the 1990s was a mechanism which introduced a new clause , the so-called “floor and capping” (also called “floor and ceilings”), to determine the maximum and minimum impact of the oil price on the price change of natural gas in long-term contracts. In the last three decades of the 20th century, long-term contract prices were adjusted to sudden changes in oil prices directly by changing base price “a” or/and factor "b" to maintain a balance between suppliers and consumers of natural gas. The introduction of the maximum price somehow puts an end to complete dependence of prices in LTCs on oil prices. Gas price indexation in long-term contracts in Asia is evolving due to the activity of new gas importers, India and China, which may further modify gas price formation mechanisms in long-term contracts.

Oil-indexed pricing means less price volatility and better long-term price predictability on account of oil market development. However, the main drawback of oil indexation is that it comprises all the market risks of the oil sector, not the gas sector. These risks may be different and have different influence on the price. It also affects security of gas supply.

Bilateral Monopoly

The above pricing model was the prevailing principle in interstate transactions within the former Soviet Union and Central and Eastern Europe. Here, gas prices were set for a specified amount of time (usually one year) based on bilateral government agreements. Payment often came in forms other than monetary exchange, such as participation in energy projects or transportation activities. This mechanism had little to no transparency, with politics playing a major role and economics lagging behind.

Although bilateral monopoly pricing schemes are rare, they can be found in a small number of countries with underdeveloped gas markets that encompass one primary supplier and a few dominant buyers. A 2009 survey administered by the International Gas Union (IGU) found that a mere 6.9% of natural gas was consumed under the prices established through bilateral monopoly, out of which 4.6% originated in the former Soviet Union[40].

Experts predict that terms of bilateral monopoly pricing could lose importance as Russia moves to negotiate prices based on other models. Oil indexation will probably substitute bilateral monopoly pricing.[41]

Netback

Netback from final product pricing refers to a system wherein the price is determined through a backward calculation of the gas price beginning with the consumer and going back to the producer. Essentially, the price is calculated by subtracting costs referring to operation, processing, and transportation from the final price of the finished product.[42]

The netback value approach was first established in the 1960s by the Dutch in an effort to raise the maximum amount of revenue for the state.[43] As the Netherlands exported gas to various countries, it was able to charge different prices for the product since the market value was different in each location.

It is unlikely that netback pricing will ever become a major price model such as gas-to-gas competition or oil price escalation. However, even though netback pricing makes up a small portion of the world's pricing mechanism mix (1%), it is expected to continue to be utilised by particular market players. From the vantage point of industrial consumers, it is a manner through which market risk can be shifted upstream, and for sellers it serves as an avenue to sustain industrial demand.

Regulation

Prices determined under the regulation model come in various types. These types can be categorised as regulation on a cost of service basis, regulation on a social and political basis, regulation below cost. They are united by the common theme of state-owned companies as dominant market players, at least in the beginning. Moreover, this method is most commonly used in countries that are able to produce gas domestically. This model of gas pricing plays an important part in valuation of globally consumed gas. According to the estimates, 38% of gas consumed globally is valued with one of these three methods, with regulation below cost playing the biggest part (26% in 2007)[44].

First, prices determined under cost of service regulation are approved by a regulatory authority and based on the cost of providing the product plus a reasonable rate of return. What is considered "a reasonable rate of return" remains at the discretion of the public authority. Although they are not determined by free market forces, these prices have the potential to be at least somewhat reflective of the cost of production and distribution.

Next, more often than on the basis of cost of service regulation, prices are set with respect to a political or social situation in order to appease the final buyer. Often, the regulatory authority can use this method to boost a targeted industry or to balance perceptions of social needs. Usually, particular industries and households are those that are catered to under this type of pricing.

Lastly, below cost regulation results in the end consumer paying a price that is actually lower than the cost of production and transportation. This works as a form of subsidy for the activity for which gas will be utilised.

The regulation of natural gas prices by a specified authority was practised extensively in countries with centrally planned economies. It is still prevalent in less economically developed countries that are home to large state-owned gas companies. The former Soviet Union, China, and India serve as examples of countries that either have relied or continue to rely heavily on this sort of system to set natural gas prices.

Conclusion

While different mechanisms have been able to coexist for many decades, it is unlikely that the situation will remain the same in future. Several countries that traditionally engaged in below cost pricing have moved to reform the regulatory environment and address the price distortions that these types of policies caused. Also, 2009 saw the opening of a huge gap between the prices set by oil indexation in Continental Europe on the one hand and the spot market prices in the United States and the United Kingdom on the other. More specifically, oil-linked prices were even twice higher than the spot price in 2009.[45] Competition from suppliers offering much lower prices forced some natural gas suppliers to renegotiate their contracts. Companies demanded that both their previously contracted volumes and prices be reduced. As a result, in 2010 the Russian giant Gazprom agreed to change some of their contracts under the provision that a 15% share of the price indexation would be based on hub pricing for a period of three years starting in October of 2009.[46]

Additionally, LNG development in recent years has provided greater availability of natural gas on the global market, frequently coming from previously inaccessible areas. This has significantly increased the availability of various new sources of gas on the global market. This potential is not yet fully exploited but its influence on the global gas market and gas pricing will increase.[47]

The problems of contrasting price models effectively initiated an important debate about which manner of pricing is the best, and whether or not the coexistence of varying methods that can lead to such huge differences in prices is even sustainable. Many argue that the logic behind oil indexation no longer applies to the current situation, making the transition to hub pricing throughout the world inevitable.[48] However, this prediction has yet to become reality.

While the US and the UK have fully liberalised and competitive market systems, Continental Europe, especially CEE countries and Asia remain a few steps behind. A market based on short-term spot prices has yet to emerge, and most countries still rely on oil-indexed long-term contracts in order to ensure supply. Although oil-indexed prices are less volatile than spot ones, on average they have been typically higher. Even so, some envision the continued prominence of oil-indexed pricing for natural gas in the foreseeable future on account of a number of issues. For instance, the creation of a spot market requires a competitive and diverse supply as well as open transmission systems.[49] This process is on-going in Northwest Europe and the UK, but CEE countries are still lagging behind. Asia, however, is characterised by little competition and a minimal number of gas hubs.[50] Also, many Asian countries are more interested in securing supply than in fighting for lower prices.

31. *R. Davoust, Gas Price Formation, Structure & Dynamics, 2008, p. 2.*
32. *The term "regulation" is often divided into subcategories of administratively regulated prices such as "regulation on a cost of service basis", regulation on a social and political basis", "regulation below cost". Due to negligible importance of these mechanisms for Europe we will not divide this term.*

33. *J. T. Jensen, Asian Natural Gas Markets, Supply Infrastructure and Pricing Issues, 2011, p. 12.*
34. *Wholesale Gas Price Formation – A global review of drivers and regional trends 2011,IGU, p. 5, 23, 43.*
35. *J. T. Jensen, Asian Natural Gas Markets, Supply Infrastructure, and Pricing Issues, 2011, p. 12.*
36. *M. Kanai, Decoupling the Oil and Gas Prices, 2011, p. 15.*
37. *R. Davoust, Gas Price Formation, Structure, & Dynamics, 2008, p. 13.*
38. *Stern, Rodgers, The Transition to Hub-Based Gas Pricing in Continental Europe, 2011, p. 5, 28, 29.*
39. *Wholesale Gas Price Formation, IGU, 2011, p. 20.*
40. *J. T. Jensen, Asian Natural Gas Markets, Supply Infrastructure and Pricing Issues, 2011, p. 12.*
41. *Wholesale Gas Price Formation, IGU, 2011, p. 6.*
42. *Mian, Comparison of methods used to calculate netback value, 2007.*
43. *A.J. Melling, Natural Gas Pricing and Its Future: Europe as the Battleground", Carnegie Endowment for InternationalPeace, Washington 2010, p. 16.*
44. *Wholesale Gas Price Formation – A global review of drivers and regional trends, IGU 2011, p. 4.*
45. *M. Kanai, Decoupling the Oil and Gas Prices, 2011, p. 2.*
46. *J. Stern, Rodgers, The Transition to Hub-Based Pricing in Continental Europe, 2011, p. 25.*
47. *R. Zajdler, Development prospects of price formulas in long-term contracts for natural gas supplies and their significance for the creation of a gas hub in Poland for the countries of Central East Europe, Warsaw 2012, p. 75.*
48. *Kanai, Decoupling the Oil and Gas Prices, 2011, p. 16.*
49. *J. T. Jensen, Asian Natural Gas Markets, Supply Infrastructure, and Pricing Issues, 2011, p. 30.*
50. *Wholesale Gas Price Formation, IGU, 2011, p. 5.*

3. Historical developments of gas markets

Recently the natural gas market of regional or very often local nature has been developing rapidly towards the global market. It particularly concerns gas trading, which owing to LNG flexibility takes advantage of new market possibilities. The discovery of large quantities of unconventional gas in recent years with its reduced technological costs and fairly easy access to the market has reshaped the contractual model of the natural gas market making it more sophisticated. These changes go hand in hand with regulatory changes on the national gas markets in the United States, the European Union and Asia-Pacific countries. Regulatory and policy environment of countries importing and exporting gas plays a key role in shaping future pricing mechanisms in gas contracts, in particular LTCs. The overview of regional trends will help to understand a future gas pricing model.

Historical developments of the US gas market

The historical trajectory of the US natural gas market began in 1821 when William Hart dug the first well with the primary purpose of extracting natural gas in Fredonia, New York. This is when the Fredonia Gas Light Company was established as the first natural gas company in America. At this time, pipelines were almost non-existent, which made transportation an almost impossible task.

The start of the 20th century saw the first investments in exploration and pipeline infrastructure. In the beginning, the natural gas industry operated locally since secure means of transportation and distribution were lacking. The development of the natural gas market was followed by regulatory activities which varied throughout that time[51].

Prior to the extensive deregulation that occurred in the mid-1980s, the industry's structure was vertically integrated. The price charged by the local distribution company included the cost of gas itself as well as all costs incurred from its transportation from the producer to the final consumer. End users had minimal choice to change their supplier of gas and provider of transportation services. It encouraged regulation at federal and state level and division of regulatory competencies. The federal government was responsible for regulating the prices that the producers charged a transportation company, as well as the prices that the transportation company charged local distribution companies. The US had the responsibility to oversee the rates at which local distribution companies charged their customers.

The development of transmission pipelines, which span across the US borders, created a need for additional regulation. There were no federal rules at that time. The need for them was noticed in the US Supreme Court ruling in 1924. In Missouri v. Kansas Natural Gas Co[52]., the US Supreme Court decided that production of natural gas in one state and its sale in another qualified as interstate commerce, and therefore outside single state regulation[53]. This prompted federal authorities to prepare first bills concerning the sector. Additionally, the absence of federal rules gave the industry considerable freedom to operate.

In the 1930s, the federal government began to get involved with regulation of the natural gas industry. At that time the gas sector had a monopolistic structure. To keep these companies from abusing their market powers and gain more regulatory control, the Public Utility Holding Company Act (1935) was passed. It unbundled gas distribution (transport service) from gas supply (carried out by local distribution companies) within vertically integrated companies.

In 1938 the Natural Gas Act was enacted. The act focused on interstate transportation by inter alia, setting transmission, licensing of new pipelines, competition aspects. It gave regulatory powers to the present Federal Energy Regulatory Commission (FERC), however, its jurisdiction was not comprehensive and was complemented by state commissions. The Natural Gas Act regulated the price formation mechanism for transportation services between the states. It was not clear which authority could control natural gas prices. In the court case, Phillips Petroleum Co. v. Wisconsin (1954), the US Supreme Court ruled that the price for production of natural gas was not covered by the Natural Gas Act. Because it concerned only the steps in between production and sale of natural gas covered by federal law. It exempted natural gas prices from the federal regulation because they referred to a particular state. The US Supreme Court decided that based on the Natural Gas Act the Federal Power Commission was competent to regulate prices of natural gas. It was a clear extension of the powers of federal authorities to regulate prices of natural gas but only at interstate level, leaving prices at intrastate level to state authorities.

This ruling brought the rates of natural gas sold by producers in the interstate market under federal regulation. The Federal Power Commission (present FERC) set natural gas rates in accordance with 'cost plus' rather than market value. Prices of natural gas were maintained at artificially low levels which created a huge demand for natural gas as it was cheaper than other sources of fuel. Producers had little incentive to invest in the exploration of new natural gas resources. They had incentives to only intrastate pipelines and sell natural gas at state level, which was outside the regulatory powers of the Federal Power Commission and therefore offered higher prices. Producers turned from interstate to intrastate markets, which benefited the states that produced natural gas. This resulted in extreme shortages of natural gas in the 1970s.

The gas shortages shed light on poor pricing policy. It served as a rationale for the Natural Gas Policy Act (NGPA) of 1978, which eliminated the dual market in natural gas and provided deregulation of gas prices. The NGPA worked to eliminate certain price caps, while putting into place varying wellhead price ceilings that were set to rise over time and eventually disappear altogether. Although it did allow for a rise in price in the interstate market, a subsequent unanticipated decline in demand coupled with higher prices led to oversupply, which fuelled other problems.

The consequence of the NGPA (1978) was the problem with take-or-pay contract clauses. It meant that transportation (pipeline) companies were still required to make payments for the product they no longer needed due to decline in demand for natural gas. This issue was addressed in the FERC's Order 380 (1984), which released local distribution companies (LDC) from long-term take-or-pay contracts, allowing them to buy gas in a developing spot market.

Thereupon, the FERC issued Order 436 of 1985, which introduced voluntary open access to interstate pipelines. Pipeline companies could choose whether to bundle transport and gas sale and remain regulated, or concentrate on transport services. It enabled local distribution companies to buy gas directly from producers.

Transmission companies were obliged to provide transmission services on the uniform basis without discrimination on the first-come-first-served basis. Even though this was a voluntary framework, it was widely accepted by transmission companies. In the short run, this meant lower spot market prices for customers, which created tension between pipeline companies and customers. The latter ones were still obliged to pay under previous take-and-pay contracts. In the long term, this order made the transport of natural gas the sole business activity of transmission companies. It led to diversification of transportation and purchasing options. It made the netback pricing a popular contractual clause.

The start of deregulation with the NGPA and subsequent actions culminated in the total deregulation of production prices in 1989. The Natural Gas Wellhead Decontrol Act of 1989 (NGWDA) repealed the regulation of production prices and amended the NGPA by allowing for a more timely removal of price controls. It stated that by January 1, 1993, price ceilings would be removed in the hope that production gas prices would be more in alignment with actual market prices. A primary objective of the NGWDA was to eliminate imbalances on the market which had arisen in the face of pricing regulation under the NGPA. Since prices were already safely below the price ceilings, the immediate effect of the Act was not significant. However, in the long run, the NGWDA expanded the spot market and services of pipeline companies.

After further deregulation under the NGWDA, the FERC's Order 436 was extended. In 1992 it issued Order 636. It was not voluntary, but it mandated transmission companies to unbundle their services. It was meant to allow customers to choose any provider for any part of the production, sale, and distribution process to best serve his or her needs. Bundled services in any form were no longer allowed, essentially eliminating unfair advantages that could have been taken by pipeline companies in the face of deregulation.

The requirements of 'capacity release' programs, 'no-notice' transportation and flexibility of delivery were also embedded in this Order. Capacity release referred to the reselling of all or a portion of unused capacity from one pipeline customer to another. In order to develop this process, it was required that pipeline companies set up electronic bulletin boards to provide their customers with accessible and current information regarding the available capacity on their pipelines. No-notice transportation on the other hand, refers to the allowance of local distribution companies to receive natural gas on demand so as to be able to provide customers with the product during peak times.

After the turbulent century of regulation and then deregulation, the structure of the natural gas industry has changed. Today, the system is much more flexible and open to preference. The producer can sell gas to final consumers, marketers, or local distribution companies. Instead of offering bundled services, the interstate pipeline serves solely as a transporter from the producer to the next party. The newly created role of the marketer serves many functions. A marketer can arrange the movement of gas from the producer to the end user by contracting storage or transmission, or can even own gas personally. He or she can offer individual or bundled services, and essentially their purpose is to facilitate the transaction by serving as a middle-man. Presently, the ownership of local distribution companies differs. They are mostly owned by entities independent from producers or transportation companies.

Today, interstate pipelines continue to be regulated by the FERC which grants pipeline companies the permission to set certain rates which the agency has concluded to be the cost of expenses plus a fair return. The oversight of LDC prices falls in the hands of individual states that use similar mechanisms to decide upon fair rates. The price of produced gas, however, is governed by competitive market forces as a result of the deregulation in the late 1980s. The historical experiences of the last century have revealed the consequences of over-regulation in certain areas, and have greatly impacted the regulatory environment of the natural gas industry as it exists today. Now, there is much more room for competition with on the market. The restructuring of the natural gas market has left many parts of the supply chain largely unregulated, but not all. Local distribution companies are overseen by state regulatory utility commissions that aim to ensure that their prices are fair. State commissions also oversee sitting, expansion, and construction of distribution systems. Transportation and distribution also continue to be overseen by the FERC.

Historical developments of the EU gas market

The influence of the gas market development on gas prices in the European Union's (EU) member states was different from that in the US. From the early beginning the gas market in the present EU was developed at national level. The market was highly integrated within the countries' borders and centrally co-ordinated by public entities. Gas companies enjoyed a certain level of market exclusivity in national markets being at the same time entrusted with various public service obligations. They were able to pass on costs of their activity directly to final consumers. Certain competition was existent in the upstream market where non-EU countries had to compete for supply contracts to EU countries. The competition in the downstream market was limited to the control whether the prices were acceptable for consumers and did not increase the risk of the fuel switch. Therefore, public control over gas companies was limited to ensuring acceptable levels of costs enclosed in bundled tariffs. Additionally, destination clauses in long-term supply contracts (LTCs) prevented from price arbitration between national markets within the EU.

Deregulation of national markets was also achieved through regulation at European level. During the late 1980s and early 1990s, the Commission began to challenge the existence of these monopolies and their exclusive rights on the grounds that they made the existence of a European market - an internal market – for these goods impossible.[54] The European Commission also examined the state of the internal gas market[55] concluding that:

"(…) the energy market is still comparatively partitioned in the Community and there are therefore many barriers to the free movement of energy products."

It indicated existing barriers to the creation of the internal gas market and ways of restructuring it. Further development of the European gas market was patronised by the EU legislative initiatives and regulatory changes giving additional competencies to EU institutions against the powers of the EU member states.

The first important regulations for the pricing of natural gas, concerning the improvement of transparency of gas and electricity prices charged to industrial end-users, were introduced by Directive 90/377/EEC[56]. Its aim was to achieve more price transparency, which was a condition for a competitive gas market. It was followed by the regulation of natural gas transit. Directive 91/296/EEC[57] required the member states to take the measures necessary to facilitate transit of natural gas between high-pressure transmission grids.

The framework regulation on a new gas market model was proposed by the European Commission in Directive 98/30/EC[58] concerning common rules for the internal market in natural gas which was part of the so-called the "First Energy Liberalisation Package". It was decided there to do as follows: (1) distinguish clearly between competitive parts of the market (e.g. supply to customers) and non-competitive parts (e.g. operation of networks), (2) oblige operators of the non-competitive parts of the market (e.g. the networks and other infrastructure) to allow third parties to have access to the infrastructure, (3) free up the supply side of the market (e.g. remove barriers preventing alternative suppliers from importing or producing energy), (4) remove gradually any restrictions on customers from changing their supplier.[59] Directive 98/30/EC related directly to the issue of LTCs. According to Article 25 of Directive 98/30/EC, if a natural gas undertaking encounters, or considers it would encounter, serious economic and financial difficulties because of its take-or-pay commitments accepted in one or more gas-purchase contracts, it may apply for temporary derogation from market rules on access to the system. LTCs were regarded as an important part of the supply chain, however, control over such contracts was perceived as important.

In the meantime the issue of security of EU energy supply came up on the political agenda. The European Commission presented its analysis – "Green Paper – Towards a European strategy for the security of energy supply". [60]According to it, EU external energy dependence was constantly increasing. The EU met 50% of its energy needs through imports. If no action was taken, it predicted that energy dependence would rise to 70% by 2020 or 2030. This external dependence involves risks for the EU. Energy imports account for 6% of the total imports to the EU, out of which 45% of oil imports come from the Middle East and 40% of natural gas imports come from Russia. As a remedy was recommended the creation of common rules on the security of energy supply aimed at reducing the risks linked to this external dependence. The security of supply aspect was particularly important for Central Eastern European countries which did not have diversified sources of gas supply.

The process of liberalisation of the internal gas market was enhanced by the adoption of the so-called "Second Energy Liberalization Package". The natural gas market was regulated by Directive 2003/55/EC[61] on the internal gas market and Regulation 1775/2005[62] on the cross-border gas trade. The new rules were more explicit and stringent in several aspects. The negotiated third party access (TPA) was abandoned leaving the regulated TPA as a mandatory mechanism, based on approved and published tariffs, applying to transmission, distribution and LNG operators. It required full market opening and a wider scope of unbundling, including legal and management unbundling. The Regulation provided supplementary rules aiming to ensure fair access to transmission networks. These binding rules were supplemented by non-binding instruments, such as guidelines and soft rules prepared in co-operation with gas sector entities. These rules primarily regulated competitive access to infrastructure leaving regulation of prices to either national authorities (final consumers' prices) or to bilateral contractual agreements between suppliers dominating national markets and producers. The so-called 'second tier suppliers' (the ones being active in the national market but not being the incumbent suppliers) although existed on national markets their role in price creation was not limited. Article 27 of Directive 2003/55/EC sustained the earlier regulation on temporary derogation from the TPA rules if a natural gas undertaking encounters, or considers it would encounter, serious economic and financial difficulties because of its take-or-pay commitments accepted in one or more gas-purchase contracts. Thus, the article indicated the importance of LTCs and a still existing division of the EU gas market in national gas markets.

Due to insufficient progress in creating a competitive internal gas market, the European Commission launched an energy sector inquiry in 2005[63], aiming to assess the wholesale gas and electricity markets and to identify issues hampering their development. The analysis emphasised, in particular, high level of concentration and insufficient liquidity of the wholesale gas market. Insufficient efficiency and transparency of pricing of natural gas, lack of reliable and timely information about the market and limited access to infrastructure (including cross-border interconnectors) were noted as drawbacks of market development. Wholesale gas trade was growing slowly and acting incumbents remained dominant in their markets. Pricing of gas in import contracts was noted as possibly having a negative effect on the market. The inquiry though concentrated on the competitive aspects of the wholesale market.

The inefficiencies of the integration of the internal gas market were widely discussed. It was concluded that natural gas imports were dominated by long-term contracts (LTCs), where in general pricing was coupled with the price of oil. Trade within Europe is dominated by over-the-counter (OTC) deals on physical and virtual hubs. Exchange trade is still marginal and very illiquid, except for the mature UK market. Considerable price differences exist between the member states, due to both differences in energy prices and taxes. Retail markets are still very concentrated. Competition is very limited in retail markets[64]. In order to change these drawbacks, new regulation was proposed by the European Commission ("Third Energy Liberalisation Package"). [65]

The general framework of the Package concerns the following: (1) high standard of public service obligations and customer protection, (2) structural separation between transmission activities and production/supply activities of vertically integrated companies, (3) stronger powers and independence of national energy regulators, (4) enhanced rules to harmonise market and network operation rules at pan-European level and (5) a new institutional framework: the ACER and the ENTSOG[66]. This legal initiative was followed by additional legal action on the gas release programme, aiming to overcome inadequate access to gas supplies or pipeline capacity[67]. There were also legal actions aiming to remove the destination clauses from LTCs.

The European model of creating a competitive gas market is based on more in-depth co-operation among the member states and gas market actors. The integration is supported by infrastructural development which helps to practically integrate national markets. Integration is based on earlier experiences supported by more pan-European actions. It can be also noted in relation to gas prices and regulation of LTCs. The EU gas market integrates national markets and gas hubs, trying to create a uniform but geographically dispersed gas trading platform. At the same time, the purpose of employing EU competition rules is to eliminate uncompetitive elements in LTCs such as destination clauses. At the same time the division of the internal gas market by different prices of gas proposed in LTCs may be eliminated by antitrust rules. Public action aiming to release additional volumes of gas available on hubs supports market development.

Historical developments of Asia-Pacific gas markets

The Asia-Pacific region is becoming an important producer and consumer of natural gas. It particularly concerns a small number of countries whose market and infrastructural development enables them to use natural gas commercially. Among the importing countries the biggest regional consumers are Japan, South Korea, Taiwan, China, and India. Among the producers are Indonesia, Malaysia, and Australia[68]. The region is, however, far from having a similar regulatory standard and level of market development. These differences and the present development of the global gas market influence the pricing model in LTCs.

Traditionally, natural gas markets in Asia-Pacific were either local – gas was used where it was produced - or based on bilateral agreements upon which gas production and consumption occurred at either end of a gas pipeline. This local nature of the gas market determined lack of a general regulatory framework. At the moment trading in natural gas takes place via sea transport. The use of large-scale gas liquefaction technologies and its developments is the result of limited possibilities for the construction of pipelines (of international reach) in Asia-Pacific. Investment in the gas sector, determined by the need to achieve the supply/demand balance and the need to secure gas supply for the economy, caused regulatory changes. LNG development additionally opened up and integrated previously stranded regions for the global trade.

Generally, gas market liberalisation in the EU or in the US sense has not proceeded to any significant extent among Asian countries. However, there is a distinction between importing and exporting countries. More extensive market reforms were observed in countries with indigenous gas reserve such as Australia.

The ones with little domestic production and no imports have not developed a regulatory gas market framework. Import-dependent countries such as South Korea and Taiwan have extended their sources of supply by building terminals to handle LNG, but so far their natural gas industries are still dominated by incumbents.

Japan, South Korea and Taiwan are dependent on LNG imports with long-term contracts (LTC) that are based on oil linkage. Until recently, Asian natural gas contracts often had a capping mechanism—usually S curves—to insulate them from high oil prices. During the tight sellers' market in Asia, suppliers were able to reopen many contracts to remove capping clauses. Most of these clauses are now gone. They have also imported LNG on short-term contracts, but aside from Australia, Asia has not moved very far along the path to liberalisation. Asian governments also subsidise gas consumption. Asian countries have competitive suppliers of domestic gas, either because they are essentially dependent on LNG, as in Japan, South Korea, or Taiwan or because they have a legacy of centrally planned economies, as in China.

A short presentation of the regulatory framework and market development of most important Asian gas importers and exporters shall indicate particularities of this region, which influence the pricing of gas in supply contracts.

Japan's regulatory framework of the gas industry is related to a specific character of this country. It is spread on islands, which discourages from the creation of an integrated pipeline system, and is heavily dependent on external gas supply. The gas industry is dominated by a small number of large companies holding geographical monopolies. Gas supply is restricted to areas linked to pipelines or LNG terminals. Japan does not have an integrated network of gas pipelines. Separate pipelines constitute a large proportion of the transportation system, regionally integrated with LNG terminals, storage facilities or own production. Although there are several types of gas companies, their services are generally bundled. Since privately owned gas companies own pipelines, access to the infrastructure is regulated on a contractual basis. However, certain rules on third party access to pipelines have been legally provided. Denial of access is under administrative supervision and on justifiable causes. Gas trade is based on bilateral contractual relations. There is no gas hub, therefore there is no spot, future or OTC pricing.

South Korea's gas industry is highly integrated. The economy depends on external sources of natural gas transported primarily by LNG terminals. This character of the country is translated into a regulatory framework. The gas industry is dominated by one main gas company dominating all gas activities (import, transmission, distribution, and supply). Gas supply is restricted to areas linked to pipelines or LNG terminals. South Korea does not have an integrated network of gas pipelines. Separate pipelines are integrated with LNG terminals and own production facilities. Transportation services (transmission and distribution) are bundled. There is no rule on third party access. Internal gas prices are administratively regulated. Gas trade is based on bilateral contractual relations. There is no gas hub, therefore there is no spot, future or OTC pricing.

Taiwan's gas industry is highly integrated. The economy depends on external sources of natural gas transported primarily by LNG terminals. This character of the country is translated into a regulatory framework. The gas industry is dominated by one main gas company dominating all gas activities (import, transmission, distribution, and supply). Gas supply is restricted to areas linked to pipelines or LNG terminals. Transportation services (transmission and distribution) are bundled. There is no rule on third party access. Internal gas prices are administratively regulated. Gas trade is based on bilateral contractual relations. There is no gas hub, therefore there is no spot, future or OTC pricing.

China's gas industry is integrated. The economy depends on external sources of natural gas transported by LNG terminals and also by pipelines. The gas industry is dominated by a small number of gas companies, in particular, at upstream and transmission level. Local distribution and supply, though bundled, is more open to competition. Major users are unable to buy directly from producers but have to buy from local distributors. China does not have an integrated network of gas pipelines. Separate pipelines are integrated with LNG terminals or production facilities. A remarkable development in China began with the reform of the system for pricing gas. Gas prices had been based on a cost-plus formula, but it was changed to the prices of other sources of energy. This started to solve the problem of pricing gas too low, which in 2009 led to gas shortages. Despite the significant progress, differences remain between average prices in China and world prices, between cities for the same types of users and between users in the same cities. The low gas price tends to bring about overuse and adds to the risk of gas shortages in China. Declining self-sufficiency and price gaps are likely to force further price changes. Aligning the now low domestic price with the higher international price would undoubtedly become the trend of the further gas reform, however, at present there is a great deal of argument about the reform policy. Among the options, the use of a weighted average of domestic and international prices seems to be more acceptable in the short term.[69]

India's natural gas market is characterised by a supply deficit, primarily due to the low availability of natural gas and inadequate transmission and distribution infrastructure. The LNG and domestic production increase minimize the deficit. India has both pipeline and LNG import options. The development of transmission and distribution infrastructure aims to secure supply.

Indonesia's regulatory framework of the gas industry is related to a specific character of this country. It is also an important regional gas exporter via pipelines and LNG terminals. Historically, the transmission and distribution of gas was dominated by a state-owned company. However, in 2001, it was opened to private parties. The gas contained within Indonesia's jurisdiction is controlled by the government (generally via a Production Sharing Contract ("PSC")) as the holder of the relevant concession. Law no 22/2001 dated 23 November 2001 differentiates between upstream business activities (exploration) and downstream business activities (processing, transportation, storage, and supply). It stipulates that upstream activities are controlled through "Joint Cooperation Contracts" (which are predominantly PSCs) between the business entity/permanent establishment and the executing agency (BP Migas). Downstream activities are organized by business licenses issued by the regulatory agency (BP Migas).[70] BP Migas serves as the upstream regulator.[71] The state-owned PT Pertamina, though still active in upstream exploration and production, no longer serves a regulatory role. Pertamina accounts for about 14 % of natural gas production. Companies such as Total E&P Indonesie (32%), ConocoPhillips (15%), BP Tangguh (13%), and ExxonMobil (8%) dominate the upstream gas sector.[72] Natural gas transmission and distribution activities are carried out by the state-owned utility Perusahaan Gas Negara (PGN).[73] In 2001 Indonesia began exporting natural gas via an undersea pipeline to Singapore. In 2003 the second pipeline connecting those two countries was completed. In 2002, however, Indonesia started to export gas to Malaysia.[74] Gas supply is opened to competition, though upstream entities are prohibited from downstream entities and vice versa (article 10 of Law 22/2001, exceptions in article 1).[75] Moreover, for upstream business activities a company needs to be a foreign incorporated enterprise with a permanent establishment (PE).[76] Indonesia wants to develop its domestic downstream gas market further for the benefit of the country's economic prosperity, but it is facing serious natural, institutional, and economic barriers. Indonesia does not have an integrated network of gas pipelines, however, the government intends to integrate the system. Lately LNG exports have been a politically charged topic in Indonesia, because of the perception that LNG exports remove much needed gas from the domestic market. Indonesia wanted to have a strong domestic market, instead of exporting a larger part of gas from Indonesia as LNG. [77] There is unbundling of transportation services based on tender processes and licences, however, it seems that unbundling in the European sense functions solely in relation to transmission pipelines. Access to this infrastructure is regulated on a contractual basis. However, certain rules on third party access to pipelines have been legally provided. Denial of access is under administrative supervision and on justifiable causes.

Malaysia's gas industry is highly integrated. It has vast natural gas resources and one of the most extensive natural gas pipeline networks in the Asia-Pacific region. The gas industry is dominated by an integrated company dominating all gas activities (export, transmission, distribution and supply). Petronas (Petroliam Nasional Berhad) is wholly owned by the Malaysian Government and is vested with entire ownership and control of gas resources in Malaysia.[78] It is involved in upstream and downstream activities and has emerged as a global player in offshore oil and gas export and production. Nevertheless, natural gas distribution is carried out not only by PETRONAS Gas Bhd but also by Gas Malaysia Sdn Bhd.

The Association of South East Asian Nations (ASEAN) is promoting the development of a trans-ASEAN gas pipeline system (TACP) aimed at linking ASEAN's major gas production and consumption centres by 2020. Because of Malaysia's extensive natural gas infrastructure and its location, the country is a natural candidate to serve as a hub in the ongoing TACP project. The first pipeline that connected Malaysia with Singapore was commissioned in 1991. This was followed by the gas pipeline links between West Natuna, Indonesia, and Duyong, brought into operation by Malaysia, in 2002, and the Trans-Thailand-Malaysia gas pipeline brought into operation in 2005 which allows Malaysia to transport natural gas from the Malaysia-Thailand JDA to its domestic pipeline system. Construction began on Petronas' Sabah Oil and Gas Terminal (SOGT) in Kimanis, Sabah in 2011 and is expected to be completed by the end of 2013. It will have a handling capacity of 13.3 bcm/y of natural gas per day.[79]

Companies with foreign capital eager to begin exploration for energy resources in Malaysia must conclude an agreement with the state called a PSA (Production Sharing Agreement). The Economic Planning Unit is a policy maker responsible for upstream[80], whilst the regulatory body for downstream distribution is the Energy Commission[81].

Internal gas prices are administratively regulated. The Gas Supply Act 1993 was enacted to safeguard the interests of consumers supplied with gas through pipelines and from storage tanks or cylinders specifically used for reticulation of gas. Gas was reticulated to commercial and industrial outlets as well as residential consumers. It came into effect simultaneously with the issuing of the Gas Supply Regulations 1997. The Regulations include procedures for the issuance of a license to supply installation of gas pipelines, inspection, tests and maintenance of gas installations as well as the certification and registration of competent persons to undertake relevant work in such a manner as to ensure public safety. Both the Act and its Regulations are enforced by the Director General of the Electricity and Gas Supply Department.[82] Before 1997 gas prices were based on oil price escalation for power, industrial needs and reticulation. After 1997 gas prices began to be subsidised, however by 2015 gas prices will be reflecting market value according to the National Energy Policy (2010).[83] According to that policy, the upstream gas sector will remain with PETRONAS, whilst the downstream gas sector (wholesale, transmission, distribution, retail) will be regulated by the Energy Commission. Third party gas suppliers are expected to enter the liberalised gas market.

Australia's regulatory framework of the gas industry is related to a specific character of this country. There is competition in each gas sector service (production, transmission, distribution, supply). Transportation services are bundled although pipeline-to-pipeline competition exists. Since privately owned gas companies own pipelines, access to the infrastructure is regulated on a contractual basis, but the grid code also regulates the access regime.

Conclusions

The US and the UK have fully liberalised their gas markets and introduced competitive market systems. Continental Europe, especially CEE countries remain a few steps behind. Asia-Pacific (apart from Australia) seems to be at the beginning of this process. This difference in gas market development among the regions requires more caution in comparing different elements of gas market functioning in these countries. Even the regulatory framework between the US and the EU which seems similar at the first sight, requires more in-depth analysis. There is also a risk that deregulation of gas markets in Asia-Pacific countries may create market disturbances similar to the ones noted in the US. It may temporally influence the global gas market.

51. *D. A. DeVane, Highlights of Legislative History of the federal Power Act of 1935 and the Natural Gas Act of 1938, George Washington Law Review. 14. (1945-1946): 30-41. Web. 22 May 2012. http://www.heinonline.org.libproxy.helsinki.fi/HOL/Page page=30&handle=hein.journals/gwlr14&collection=journals, p. 31-32.*
52. *Missouri v. Kansas Natural Gas Co., 265 U. S. 298, 44 Sup. Ct. 544, 68 L. ed. 1027 (1924).*

53. *D. A. DeVane, Highlights of Legislative History of the Federal Power Act of 1935 and the Natural Gas Act of 1938, George Washington Law Review. 14. (1945-1946): 30-41. Web. 22 May. 2012. http://www.heinonline.org.libproxy.helsinki.fi/HOL/Page?page=30&handle=hein.journals/gwlr14&collection=journals, p. 32.*
54. *C. W. Jones, EU Energy Law, Volume 1, The Internal Energy Market, 2006, p 1.*
55. *Commission of European Communities: The Internal Energy Market" COM(88)238 final of 2nd May 1988, par. 12.*
56. *Council Directive 90/377/EEC of 29 June 1990 concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users, (OJ L 185, 17.7.1990, p. 16–24).*
57. *Council Directive 91/296/EEC of 31 May 1991 on the transit of natural gas through grids, (OJ L 147, 12.6.1991, p. 37–40).*
58. *Directive 98/30/EC of the European Parliament and of the Council of 22 June 1998 concerning common rules for the internal market in natural gas (OJ L 204, 21.7.1998, p. 1-12).*
59. *http://ec.europa.eu/competition/sectors/energy/overview_en.html.*
60. *COM/2000/0769 final.*
61. *Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC (OJ L 176, 15.7.2003, p. 57–78).*
62. *Regulation (EC) No 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks (OJ L 289, 3.11.2005, p. 1–13).*
63. *Communication from the Commission Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report) {SEC(2006) 1724} (COM/2006/0851final).*
64. *EU Energy Markets in Gas and Electricity – State of Play of Implementation and Transposition, European Commission, Brussels 2010, p. 11.*
65. *The Third Energy Liberalisation Package consist of: Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC (OJ L221 of 14.08.2009, p. 55), Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC (OJ L221 of 14.08.2009, p. 94), Regulation (EC) No 714/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity and repealing Regulation (EC) No 1228/2003 (OJ L221 of 14.08.2009, p. 15), Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005 (Text with EEA relevance) (OJ L 211, 14.8.2009, p. 36–54), Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators (Text with EEA relevance) (OJ L 211, 14.8.2009, p. 1);*
66. *See also C. W. Jones (edit.), EU Energy Law, Volume 1, The internal energy market, The Third Liberalisation Package, 2010, p. 1.*
67. *H. V. Rodgers, LNG Trade-flows in the Atlantic Basin: Trends and Discontinuities, Oxford Institute for Energy Studies, March 2010, p. 20.*
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4. Regulatory determinants of gas pricing in LTCs in the EU

Legal development of the EU energy market plays a central role in determining changes in natural gas price formation mechanisms in LTCs. Based on the recent regulatory framework, the natural gas market model is changing from the one focused on co-operation among national gas markets towards the pan-European model. The target model is based on competition rules, which respond to challenges of security of supply and environmental protection. It is fostered by stronger administrative and regulatory control of EU-wide nature, with particular emphasis on close co-operation with the gas sector. The regulatory framework gives a picture of the future role of LTCs and necessary changes in gas price formation.

Towards the prospective gas market model

“Energy 2020”

The EU energy policy has evolved around such objectives as security of supply, competitiveness, and environmental sustainability. Its practical aim is to ensure the uninterrupted physical availability of gas and gas-related services on the market at acceptable prices while contributing to the EU's wider social and climate goals. The earlier regulatory frameworks did not give sufficient incentives to achieve these goals. The EU has managed to indicate the most important drawbacks of the existing regulatory framework.

In order to enhance necessary changes, the European Commission presented “Energy 2020” - a strategy for competitive, sustainable and secure energy”[84]. Its objective is to ensure that the EU energy market is based on the following priorities: (1) energy efficient Europe, (2) a pan-European integrated energy market, (3) strong consumers, (4) the highest level of safety and security, (5) Europe's leadership in energy technology and innovation, (6) a strengthened external dimension of the EU energy market.

Two aspects of this strategy are important for the prospective target gas market model and price formation mechanisms in LTCs. The first one is security of supply. It is achieved by diversified import by pipeline and LNG terminals, the development of energy infrastructure with third countries, enhanced bilateral and unilateral relations of the EU and its member states with third countries. The strategy emphasises the importance of the development of own fossil fuels resources, one of which is unconventional natural gas. The other aspect is the development of a competitive internal gas market. It is achieved by further consolidation of national gas markets, legal action against companies breaching the EU competition rules, and encouragement of co-operation with third countries on the rules applied to the EU market. LTCs may be an important feature of the EU gas markets, but their positive features may not be undermined by their uncompetitive features such as market partition, uncompetitive price formation mechanisms or too frozen volatility.

The Treaty of Lisbon clarified and strengthened the external dimension of the EU energy policy. This legal tool is used to ensure solidarity, responsibility, and transparency among the member states, reflecting the EU interest and ensuring the security of the EU's internal energy market. Strengthening the EU's role in the external policy may help to co-ordinate bilateral relations among the member states at EU level. Business relations with third countries should be based on agreements which are adapted to the internal market rules.

The aim of Energy 2020 is, therefore, to make changes to the way gas is produced and consumed while building on what has already been achieved in the area of energy policy. The strategy is to help to achieve 20% energy savings by 2020. With regard to price formation mechanisms in LTCs, it aims to better interconnect EU national markets with third countries, from where import comes. Special emphasis is put on infrastructural development which will help to create a unified method of gas pricing mechanisms based on the pan-European model. Indirectly it may help to create a better wholesale gas market.

"Energy Roadmap 2050"

The Strategy "Energy 2020" is further developed by the EU proposal "Energy Roadmap 2050"[85], where the EU committed itself to reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050 by joint efforts of all member states. The strategy requires transformation of the EU energy systems.

Irrespective of the model applied, gas will play a key role in this process. Its share in energy consumption of the EU will always range around 25% of its primary energy consumption in 2005. Its exact level of deployment depends, in particular, on the following: prospective security of gas supply, gas price level and stability of prices in comparison with alternative fuels, shale gas expansion, level of integration of renewable energy in the EU energy mix, and development of clean coal technologies. The above-mentioned factors influence future gas deployment and its prices.

Global gas markets are changing, notably due to the development of shale gas in North America. With LNG, markets have become increasingly global since transport has become more independent from pipelines. Shale gas and other unconventional gas sources have become potential and important new sources of supply in or around the EU. Together with internal market integration, these developments could relax concerns on gas import dependency. However, owing to the early stage of exploration it is unclear when unconventional resources might become significant. As conventional gas production declines, Europe will have to rely on significant gas imports in addition to domestic natural gas production and potential indigenous shale gas exploitation. These changes influence the future EU target gas market model and the role of LTCs. Larger volumes of gas from the EU internal sources, probably more dispersed than the existing ones, and flexible LNG deliveries influence the importance of LTCs and pricing mechanisms. Short and medium term contracts with prices correlated with hubs may play a considerable role.

Natural gas may play an important role in electricity production in the EU. The economic advantages of gas, e.i. generating a reasonable rate of return and lower investment risk, are incentives to invest in gas-fired power plants. Gas-fired power plants have lower upfront investment costs, are rather quickly built, and are relatively flexible in use. Moreover, investors can hedge against risks of price developments with gas-fired generation often setting the wholesale market price for electricity. Operational costs may be higher in future due to the climate policy but irrespective of that, it may play a vital role in future electricity market. The development of clean fossil fuels technologies may further enhance the use of gas in the electricity sector. Irrespective of that, the EU climate policy treats gas as a reference fuel while estimating emission rates of different generation technologies which give natural gas additional benefits compared with other fuels. It gives an important perspective for natural gas, requiring flexibility in its contracting.

The importance of natural gas in the EU's economy also depends on the development of a competitive integrated gas market. The recent development of this market is perceived as not sufficiently liquid and diversified. It depends as well on the gas infrastructure development. The importance of the development of the North-South corridor and interconnections with third countries was noted. These changes will help to develop a properly functioning wholesale gas market in the EU with flexible gas supply and competitive gas prices.

The Roadmap directly emphasises the role of LTCs in supply of natural gas. These agreements may be still needed in order to secure investment in infrastructure for the production and transmission of natural gas. However, it stresses that greater flexibility in price formulas, moving away from pure oil-indexation in the direction of market mechanisms, will be needed. The expected increase in the use of renewable sources of energy in the economy, including the transport sector, causes the role of oil as a determinant of gas prices to lose its rationale.

Legal developments in the internal gas market

Liberalisation of the EU energy market is still an unfinished and open process. Both the member states and the EU institutions (especially the European Commission) keep making efforts to ensure the creation of the Pan-European gas market and eliminate contractual and regulatory obstacles in this regard.

The objective of the EU energy policy was defined in Article 194(1) of the Treaty on the Functioning of the European Union. According to that article:

"In the context of the establishment and functioning of the internal market and with regard for the need to preserve and improve the environment, Union policy on energy shall aim, in a spirit of solidarity between Member States, to:

a. ensure the functioning of the energy market;
b. ensure security of energy supply in the Union;
c. promote energy efficiency and energy saving and the development of new and renewable forms of energy; and
d. promote the interconnection of energy networks."

These Treaty rules emphasise the role of the wholesale gas market and infrastructural interconnections within the EU and with third countries[86]. They play an important role in future contractual arrangements in an integrated EU gas market. However, more detailed rules are indicated in secondary EU legislation.

Energy liberalisation

A number of EU laws apply to the natural gas market. They regulate particularly the operation of infrastructure (networks, LNG terminals, generation and storage facilities), market mechanisms (access infrastructure, gas trading rules, a market structure and business operators), environmental protection (protection of the environment in an investment process, social participation, environmental costs of business operation) and security of supply (supply divergence, infrastructure development, SOS mechanisms). These regulations directly or indirectly govern pricing formulas in long-term gas supply contracts.

A number of EU regulatory acts such as the Third Energy Liberalisation Package4 (Directive 2009/735, Regulation 715/20096), Regulation 1227/20117, Regulation 994/2010, and Directive 2008/929 relate to the pricing formulas in LTCs.

The Gas Market Model

The process of creating a competitive pan-European gas market began slowly. It has accelerated in recent years, particularly, with the adoption of the Third Energy Liberalisation Package. The activities involved in this process are twofold. On the one hand, Article 4 of Directive 2009/73 requires abolition of exclusive rights for national incumbents through the provisions of market opening, third party access (TPA) and the obligation to establish non-discriminatory authorisation procedures for the construction of natural gas facilities. Their aim is to waive exclusivity favourable for national incumbents and establish European-wide transparent rules on business activity. On the other hand, Article 7 of Directive 2009/73 creates new rules on regional integration of EU national gas markets. They require the member states and their National Regulatory Authorities (NRA) to co-operate in order to integrate their national markets at one and more regional levels.

The forerunners of regional integration were the initiatives set up in the spring of 2006 by the ERGEG, at the request of the European Commission, as an interim step in moving from national electricity and gas markets to a single internal energy market. As a result, three gas regions were created, which constitute platforms for enhanced co-operation between the member states on security of supply, a common framework of infrastructural development (including interconnectors), interoperability and transparency of trading. Several countries participate in more than one region. There are also mechanisms of inter-regional co-operation. It is intended to provide further development of the market. Poland belongs to two gas regions: the central-east and BEMIP[88] regions (incl.: Denmark, Estonia, Finland, Germany, Lithuania, Latvia, Sweden and Poland). Another country that is located in the two gas regions apart from Poland is Germany. Such co-existence of the two countries in the two regions can be beneficial for building common market mechanisms.

Article 7 of Directive 2009/73 creates a new model of gas market integration of bipolar nature. The previously established top-down model of integration aiming to unilaterally integrate all the member states within uniform EU mechanisms has been supplemented with bottom-up regional integration aiming firstly to create common regional rules which will be further supplemented by the integration of regions with the aim of creating an internal EU gas market.

As was indicated in Para 57 of Directive 2009/73:
"The development of a true internal market in natural gas, through a network connected across the Community, should be one of the main goals of this Directive and regulatory issues on cross border interconnections and regional markets should, therefore, be one of the main tasks of the regulatory authorities."

Such regional co-operation of the member states and gas companies is expected to rely first and foremost on market-based mechanisms and should not impose a disproportionate burden on or discriminate against market participants (see Para. 55-56 of Directive 2009/73). The obligation imposed on the member states is to promote such co-operation (Article 12(3) of Regulation 715/2009). Co-operation is also required from national TSOs.

The new rules oblige the ENTSOG to present a Gas Target Model which is expected to guarantee as follows: (1) the efficient use of existing infrastructures, (2) well-functioning wholesale markets in all of Europe, (3) connected functioning wholesale markets in all of Europe, (4) secure supply patterns that ensure gas flowing to Europe, and to ensure (5) that economic investments take place. The cornerstones of this model are liberalisation of gas retailing and the development of an open gas transmission system allowing gas from the widest possible set of sources to be delivered anywhere within Europe. It requires better integration of LTCs with the gas market supply/demand balance.

Special emphasis has been put on well-functioning wholesale markets in all of Europe. Article 12(2) of Regulation 715/2009 obliges transmission system operators to promote further the development of energy exchanges as a mechanism for selling gas and setting prices. Regional co-operation and additional co-operation mechanisms integrate national markets within the EU gas market. Such integration is observed in CEE region. In Poland, due to the establishment of more efficient gas interconnectors with other EU countries, some gas supply contracts relate to the market prices at German hubs. Creating more regional Polish relations with the neighbours and commissioning the LNG terminal in the country can increase Poland's importance as a country that is actively building the regional natural gas market. It will also influence the prices in LTCs, exerting pressure to relate them to the hubs more effectively.

Transparency and integrity of the gas market

The recent development of the gas market lacks transparency and liquidity, which is directly expressed in Para 36 of Directive 2009/73 whereby:

"The internal market in natural gas suffers from a lack of liquidity and transparency hindering the efficient allocation of resources, risk hedging and new entry. Trust in the market, its liquidity and the number of market participants needs to increase (…)"

The establishment of the target gas market model improves these aspects, providing greater credibility of price formation mechanisms, which are a prerequisite of a competitive gas market. Transparency is required in every element of the gas supply chain.

Special emphasis is put on transparency in the wholesale gas market. Owing to the development of EU law national wholesale gas markets are increasingly integrated. Manipulation on one market affects the others in relation not only to wholesale gas prices but also to retail prices, consumers, and micro-enterprises. Manipulation also has a negative impact on the perception of the wholesale natural gas market as a reliable instrument for pricing gas. EU Regulation No 1227/2011 on wholesale energy market integrity and transparency[89] is designed to prevent: manipulation or its attempt (such as false or misleading transactions, price positioning, use of fictitious transactions mechanisms, dissemination of false or misleading information), use of insider information or improper disclosure and formulation of recommendations. Transparency ensures accountability of the market and influences the volume of trade and its increase. Its outcome would be that such a market as the wholesale gas market would price gas in LTCs in a transparent way and at the accepted level.

The importance of transparency in gas supply contracts was indicated in Para. 37 of Directive 2009/73:

"Natural gas is mainly, and increasingly, imported into the Community from third countries. Community law should take account of the characteristics of natural gas, such as certain structural rigidities arising from the concentration of suppliers, the long-term contracts or the lack of downstream liquidity. Therefore, more transparency is needed, including in regard to the formation of prices."

Concentration of suppliers, LTCs and lack of downstream liquidity are perceived as circumstances negatively affecting the competitive internal gas market. Transparency in gas price formation improves market mechanisms.

Transparency in gas price formation does not apply only to the relationship between a producer coming from a third country and an incumbent national supplier but also to retail prices, to consumers and micro-enterprises. Directive 2008/92[90] concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users introduces an obligation to provide public institutions with information about prices and price formation mechanisms with regard to industrial end-users. It is a mechanism for public control of price formation. Price transparency is intended to encourage competition in the natural gas market.

EU law focuses on gas market development based on competition mechanisms. It requires market actors, being public and private entities, to enhance co-operation aiming to establish such market rules. The pricing of gas should be also based on such mechanisms. Indexation of gas prices is not per se perceived as incompatible with the common market. Emphasis is put on its transparency, influence on security of supply, adequacy in giving the appropriate price of gas.

Infrastructural development

Investments in tgas infrastructure are regarded as a tool aiming to ensure the proper functioning of the internal market in natural gas. It is based on community-wide planning and administrative supervision.

Pursuant to Article 8 of Regulation 715/2009, the ENTSOG shall adopt and publish a Community-wide network development plan every two years. The Community-wide network development plan shall include the modelling of the integrated network, scenario development, a European supply adequacy outlook and an assessment of the resilience of the system. The Community-wide network development plan shall, in particular, build on national investment plans, taking into account the following: (a) regional investment plans and, if appropriate, Community aspects of network planning, including the guidelines for trans-European energy networks, (b) reasonable needs of network users and long-term commitments of investors regarding cross-border interconnections, and (c) investment gaps, notably with respect to cross-border capacities. Such a plan is based on national network development plans prepared in collaboration between companies and NRAs. The Community-wide network development plan is also reviewed by the ACER. Community-wide co-ordination of infrastructure development supports development of an integrated EU gas market which, although divided into national markets, owing to adequate infrastructure development and unified market rules may work as a unified platform that gives adequate price signals.

Additionally, EU law provides for temporary derogations from the internal gas market rules which aim to foster development of new gas infrastructure. As a rule, Article 32 of Directive 2009/73 requires the member states to ensure the implementation of a system of third party access (TPA) to the transmission and distribution system and LNG facilities based on published tariffs, applicable to all eligible customers, including supply undertakings. Such a system should be applied objectively and without discrimination between system users. The rate of return from the use of infrastructure is regulated by administratively approved tariffs. However, some new investments (cross-border gas pipelines, gas storage facilities, LNG terminals) may be temporarily derogated from these rules if investment risk is so high that derogation is necessary. Exemption – based on Article 36 of Directive 2009/73 – concerns in particular the access rules to infrastructure and gas price formation. That regulation may stimulate investment in cross-border pipelines and LNG terminals, whose development is important for a better integrated internal EU gas market.

The EU also supports the development of gas infrastructure within the trans-European energy networks policy, which includes projects important for the whole Community. These comprise interconnection (including with third countries), LNG terminals and storage facilities. It is clear that EU-wide integrated gas networks are vital for ensuring a competitive, well-functioning integrated gas market. From the perspective of Visegrád Group members: the North-South gas interconnections in Central Eastern and South Eastern Europe ("NSI East Gas"), the Southern Gas Corridor ("SGC") and the Baltic Energy Market Interconnection Plan in gas ("BEMIP Gas") are important[91]. They help to interconnect regional infrastructure more effectively, particularly, in the north-south direction. Better interconnections within the region will help to integrate national gas markets at regional level, leading to convergence of prices. It will foster the development of market based mechanisms for pricing gas in LTCs. There are also several infrastructural investments linking supply from sources outside the EU with the EU internal market. However, they may indirectly influence CEE countries because the target submarket for gas supply are western EU countries.

Long-term contracts

The specificity of the gas market makes it rational for parties to conclude long-term supply contracts. The EU law requires their compatibility with the competition policy and the internal market rules.

According to Para 42 of Directive 2009/72:

Long-term contracts will continue to be an important part of the gas supply of

Member States and should be maintained as an option for gas supply undertakings in so far as they do not undermine the objective of this Directive and are compatible with the Treaty, including the competition rules. It is therefore necessary to take into account long-term contracts in the planning of supply and transport capacity of natural gas undertakings.

However, LTCs may freeze volatility of a certain quantity of supply, reducing market flexibility. It may have negative consequences if gas in LTCs is priced based on mechanisms which do not reflect market changes. This provision in practice implies that the clauses contained in the LTC should "follow" market development.

Competition policy

Historically the gas sector was dominated by incumbent state-owned monopolists that performed public utility functions and were characterised by strong government presence for decades. Very little competition (if any) was possible in the sector. The activity of gas suppliers was limited to national borders. Cross-border co-operation between energy companies remained limited to security of supply issues (balancing electricity grids to prevent blackouts). Consequently, hardly any cross-border trade took place due to missing interconnectors, and there was hardly any cross-border competition at supply level, with a large disparity of price levels in the EU member states. Economies of scale in the sector remained limited to national markets, and there were inefficiencies and little innovation. This situation has been gradually changing owing to the single market legislation introduced in 1998, 2003, and 2009, and competition law enforcement[92].

Presently, the EU competition policy plays an increasingly important role in the development of gas prices in supply contracts. The European Commission's actions in the area of competition helped to identify deficiencies in the functioning of the gas market. In particular, with regard to concerns about the development of wholesale gas and electricity markets, problems with entry for new suppliers and a limited choice raised by consumers, the European Commission launched an energy sector inquiry in 2005[93]. Its aim was to assess the wholesale gas and electricity markets and to identify issues hampering their development. The inquiry was the basis for the future Third Energy Liberalisation Package.

The energy sector inquiry indicated, in particular, a high level of concentration and insufficient liquidity of the wholesale gas market, insufficient efficiency and transparency of natural gas pricing, lack of reliable and timely information about the market and limited access to infrastructure (including cross-border interconnectors). Based on the inquiry, the wholesale gas trading was growing slowly and acting incumbents remained dominant in their markets. Gas pricing in import contracts was an important aspect analysed by the Commission.

According to the Communication[94]:

Gas import contracts use price indices that are linked to oil derivatives (e.g. light fuel or heavy fuel) and prices have, therefore, closely followed developments in oil markets. This linkage results in wholesale prices that fail to react to changes in the supply and demand for gas, which is damaging to security of supply. No clear trend towards more market based pricing mechanisms can be observed in long-term import contracts. Ensuring liquidity is crucial to improving confidence in price formation on gas hubs, which will allow for a relaxation of the linkage to oil.

Oil indexation in LTCs was perceived as inadequate with the EU competitive gas market. It did not give the consumer sufficient confidence in market mechanisms and could influence security of supply. The European Commission noted the need for change. In particular, the energy sector inquiry indicated that the concentration of gas import contracts in the hands of a few incumbents was one of the main reasons why competition at the subsequent level of trade did not work effectively. It did not directly put in question the existing long-term contracts and price formation mechanisms enclosed therein but emphasised that the LTC "requires attention with respect to their effects for the downstream markets."[95] The law on rules of competition may be a tool for clarifying this issue.

Recently, taking into account price formation mechanisms, the EU internal gas market remains divided into three regional markets: Northwestern Europe, the United Kingdom and Central and Eastern European markets. They differ in the level of competition, the liberalisation process and the price models of natural gas supply in long-term contracts. Today LTCs in Central and Eastern Europe still insufficiently reflect changes on the market and geopolitical changes that have occurred, which are relevant to the price formulas in the LTC in Western Europe. Based on earlier positive experience with the enforcement of competition law in gas and electricity, price formation mechanisms in upstream and downstream gas supply contracts in Western Europe, the European Commission seems to move to Central-Eastern Europe, where competition problems seem to be the same as the ones already solved in Western Europe. It is mentioned in the Annual Progress Report on the Lisbon Strategy, where the European Commission pledges to "speak with one voice" in negotiations with the external energy suppliers[96]. It particularly concerns linkage of the gas price in import long-term supply contracts with oil and oil derivatives, which results in merging gas prices with risks of the oil market and influencing negatively market liquidity and confidence in price formation on gas hubs[97]. The outcome of the earlier Commission's investigations and decisions on gas pricing may give signs of possible changes in CEE.

One of the most important aspects of the EU competition policy is antitrust activity. It is performed on the basis of the Council Regulation[98]. The European Commission's decisions in antitrust cases may be grouped into three subsets[99]:

- those aimed at increasing liquidity of wholesale markets (concerning long-term contracts that result in the exclusion of competitors, i.e. the Distrigaz, EdF, Electrabel cases)

- those aimed at improving access to infrastructure, including transmission and distribution networks, gas pipelines and storage (E.ON, RWE)

- those aimed at increasing market integrity – by releasing the capacity of interconnectors or pipelines (ENI, SvK, GdF Suez, E.ON).

In the Belgian Distrigas case[100], the European Commission found that Distrigas, the largest gas supplier and importer in Belgium, prevented new suppliers from entering the Belgian gas market. Due to long-term contracts with many industrial consumers, a significant part of gas demand in the country was blocked from competition for a long time.

In the French electricity wholesale market case (EDF)[101], the European Commission concluded that EDF, which had a near-monopoly of the production, transmission, distribution, and supply of electricity in France in the pre-liberalisation period, continues to hold a dominant position on the market for the supply of electricity to large industrial customers in France. EDF abused its dominant position by concluding supply contracts which, by virtue of their scope (i.e. the total volume covered by all the contracts, their duration and their nature), significantly limited competition for the supply of electricity to large industrial customers in France. The Commission also took the view in its Statement of Objections that EDF imposed clauses in its supply contracts that restricted the resale of electricity by large industrial customers. The effect of such clauses may have been to prevent EDF customers from optimising their portfolio, either by themselves or with the support of specialised companies. Such restrictions have made it impossible for industrial firms to resell electricity (themselves or through an intermediary) when the contract price was below the market price.

In reply to the competition concerns identified by the Commission in the statement of objections as regards the LTC respectively, both companies Distrigas and EDF offered to reduce significantly the volume of gas/electricity that had already been contracted, and to change the contract terms (in particular to shorten their period) in the case of new contracts. Furthermore, EDF pledges that new contracts concluded with large industrial customers, and the general and specific conditions of sale, will not include any resale restrictions. EDF has also informed large industrial customers who have concluded a contract for the supply of electricity that any clause restricting resale will be deemed null and void, and that the provisions of their supply contract no longer restrict the resale of the electricity purchased under the contract. The Commission approved the proposed commitments in all these cases as they helped to improve the wholesale market liquidity and solve the identified competition concerns.

A number of cases concerning territorial restriction clauses (destination clauses) in gas upstream import contracts were analysed by the Commission. They undermine the creation of a common energy market by preventing the buyer from reselling gas outside a defined geographic area, normally an EU member state, impeding arbitrage between low price areas and high price areas. The Commission activity in this area resulted in the deletion of destination clauses from upstream gas supply contracts. Commitments were received from inter ailia[102]: Norwegian Statoil and Norsk Hydro[103], Nigerian NLNG[104], Italian ENI[105], Austrian OMV[106], and German E.ON Ruhrgas[107]. Although it does not seem that the outcome was total success, it initiated a process of change of uncompetitive clauses in up-stream supply contracts.

Recently, several disputes were initiated by gas suppliers against their upstream producers. Disputes against a company within the Gazprom group received big publicity. Statements of claims concerning gas prices were raised by E.ON (Germany), RWE (Germany), EDF (France), ENI (Italy), Lietuvos Dujos (Lithuania), Bulgarian Energy Holding (Bulgaria) and PGNiG (Poland). Gazprom's response seems to depend on the region of the EU where the counterparty acts. Gazprom revised prices with Wingas (Germany), GDF Suez SA (France), EconGas GmbH (Austria), SPP AS (Slovakia) and Sinergie Italiane Srl (Italy).

Based on concerns about anticompetitive behaviour of Gazprom in relation to Central and Eastern European suppliers, on 4th September 2012 the European Commission decided to open formal proceedings to investigate whether Gazprom might be hindering competition in Central and Eastern European gas markets, in breach of EU antitrust rules[108]. The Commission has concerns that Gazprom may be abusing its dominant market position in upstream gas supply markets in Central and Eastern European member states, in breach of Article 102 of the Treaty on the Functioning of the European Union. Earlier inspections carried out by EU inspectors at the premises of gas companies seemed to be in relation to this decision[109]. At the same time, the President of the Russian Federation signed a Decree "On measures to protect the interests of the Russian Federation during engagement by Russian legal entities in foreign business" which imposes an obligation on strategic companies (including Gazprom) to receive prior consent from a competent federal authority to several actions. They include amendments to agreements concluded with foreign partners and to other documents relating to their commercial (pricing) policy with foreign countries.

Initiation of the antitrust proceedings against Gazprom is a precedent in EU energy relations and in Russia. It confirms the EU's determination to implement EU law, including the rules of the Third Energy Liberalisation Package, which support more in-depth liberalisation of the gas market in the EU. The EU competition policy satisfies the European Commission's desire to play an increasingly important role in shaping energy policy within the European Union. This confirms the Commission's efforts to influence the negotiation of contracts for the supply of gas to the EU. Natural gas producers will have to adapt to a changing market where the importance of the EU policy increases or to accept a marked decrease in their own market position.

Security of supply

Natural gas is an essential component of the energy supply in the EU. Regulation 994/2010 and Regulation 715/2009 of Directive 2009/73 contain provisions with respect to security of supply. They introduce measures to be respected at national and EU level.

Article 5 of Directive 2009/73 requires the member states to monitor security of supply. Monitoring should cover the balance of supply and demand in the national market, the level of expected future demand and available supplies, envisaged additional capacity being planned or under construction, and the quality and level of maintenance of the networks as well as measures to cover peak demand and to deal with shortfalls of one or more suppliers. The level of supply flexibility from LTCs and the influence on the wholesale market is part of such monitoring.

Regulation 994/2010 establishes a common framework, where the security of supply is a shared responsibility of natural gas undertakings, the member states, and the EU. It provides a mechanism for a co-ordinated response to an emergency at national, regional and EU level.

As regards the compatibility of LTCs, two aspects of this regulation are important.

The first one requires preparation of the Preventive Action Plan and the Emergency Plan. The former contains measures needed to remove or mitigate the risks identified by national authorities in the national market assessment. The latter introduces measures to be taken to remove or mitigate the impact of gas supply disruption in emergency situations. While preparing these plans, the market-based security measures enlisted in Annex II of Regulation 994/2010 have to be taken into account. On the supply side they contain inter alia: increased import flexibility, diversification of gas supplies and gas routes or use of long-term contracts (LTCs). These measures, if adequately regulated, may enhance security of gas supply. However, it is emphasised that the conditions for the supply from third countries should not distort competition and should be in accordance with the internal market rules (Para 46 of Regulation 994/2010).

The other one establishes regional co-operation among the member states, which aims to commonly secure gas supply for members of each regional group. National markets of the member states, increasingly interconnected and interdependent by collective actions, can guarantee security of gas supply. The member states were divided into regional emergency groups. Poland stays within two groups, one with the Baltic States (Estonia, Latvia and Lithuania) and the other with Germany. Other Viseghrad Group countries are in other groups. The Czech Republic stays in one group with Germany and Slovakia. Hungary stays in a separate group with Slovenia, Italy, Austria, and Romania. Therefore, there are no common security objectives in Vishegrad Group countries. There are neither common security objectives of other CEE countries. However, Regulation 994/2010 enables extension of the above-mentioned groups if it enhances security.

The influence of the EU regulation concerning aspects related to security of supply in CEE countries is not uniform. On the one hand, based on the existing and planned regional market integration of infrastructure and possible interrelation of the wholesale markets, the security of supply monitoring provided by each Member State should take into account regional interrelations. It should also take into account availability of gas and contractual arrangements related to it. However, the regional division of countries with reference to SOS mechanisms does not create CEE regional mechanisms in the attempt to integrate particular CEE Member Countries with their Western European neighbours. It lessens SOS regional ties though by requiring stronger wholesale market relations with the countries being within the same SOS mechanism.

Summary of key findings

The entry into force of the Third Energy Liberalisation Package has changed the regulatory framework of the gas market. The European gas target model is still under discussion. Irrespective of its outcome, the role of LTCs will change based on EU regulatory changes. The existing and future LTCs must be in line with competition law requirements and must be in line with the rules integrating the EU internal gas market. The European Commission in cooperation with the ACER and NRA will force further market integration and application of EU competition rules also with regard to gas pricing mechanisms. All the contractual arrangements which fail to meet these objectives will no longer be acceptable. Gas hubs will play an important role in the new market model. Gas market liquidity and integration will increase, which will make hub prices more reflective of the EU demand/supply balance and less vulnerable to manipulations. The long term EU policy perspective will enhance the role of gas, which may create additional market liquidity forcing the parties to LTCs to make further amendments.

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86. *R. Zajdler, Legal Aspects of Electricity Gas Interconnections with Third Countries [in:] R. Zajdler, EU Energy Law: and Constraints with the Implementation of the Third Liberalisation Package, Cambridge Scholars Publishing 2012, p. 162.*
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88. *The Baltic Energy Market Interconnection Plan.*
89. *Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (OJ C 326 of 8.12.2011, p. 1).*
90. *Directive 2008/92/EC of the European Parliament and of the Council of 22 October 2008 concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users (OJ L 298, 7.11.2008, p. 9–19).*
91. *Proposal for a Regulation of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC (COM/2011/0658 final).*
92. *See: K. Kloc, D. Końska, Competition Law Mechanisms as additional tool of the Third Package Implementation [in:] R. Zajdler, EU Energy Law: Constraints with the Implementation of the Third Liberalisation Package, Cambridge Scholars Publishing 2012, p. 27.*
93. *Communication from the Commission Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report) {SEC(2006) 1724} (COM/2006/0851final).*

94. *Communication from the Commission Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report) {SEC(2006) 1724} (COM/2006/0851final), par. 28.*
95. *Communication from the Commission Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report) {SEC(2006) 1724} (COM/2006/0851final), par. 47.*
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101. *Commission Decision of 17 March 2010 relating to a proceeding under Article 102 of the Treaty on the Functioning of the European Union and Article 54 of the EEA Agreement (Case COMP/39.386 — Long Term Electricity Contracts France).*
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108. *Press release IP/12/937 of 4 September 2012, Antitrust: Commission opens proceedings against Gazprom.*
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5. Developments in gas price formation in LTCs in EU

For decades LTCs secured energy supplies, but recently the changing natural gas market has altered their role. Although still in existence and very important to some regions, such as the EU, LTCs have undergone changes in terms of contract length, volume flexibility, base price change flexibility or pricing indexation mechanisms. The changes differ depending on the region of the world. However, despite market economics, the historical development of the market and regulatory changes influences the present state of the gas pricing policies in each of these regions.

Global trends

When analyzing the development of pricing formulas in LTCs, the global gas market should be considered from a general perspective. In 2011 the total world gas consumption was 3223 bcm, out of which North America (incl. US, Canada and Mexico) consumed 27%, the former Soviet Union 19%, Europe 18% and Asia-Pacific (incl. China and India) 18%. In the same time, the total world gas production (2011) was 3276 bcm, out of which major gas producers were North America (26%), the former Soviet Union (23%), Asia-Pacific (incl. China and India) (15%) and Europe (8%)[110]. The EU is the region where a production/consumption ratio is the most negative, making the EU dependent on external supplies.

This ratio indirectly indicates the influence that each world region has on gas price formation. Therefore, the wholesale market is more seller-oriented or buyer- oriented, which affects prices. Globally, prices for gas delivered by suppliers to national markets do not necessarily follow a market price of gas, although the trend to make the gap narrower is noticeable. Price formation mechanisms depend also on gas supply corridors between and within regions. A growing number of gas-acquisition methods give better price arbitration possibilities.

Global gas is imported by use of pipelines and LNG terminals. Gas transport option influences price formation mechanisms. With respect to the world pipeline import, 694 bcm (2011) accounted for 22% of the global gas consumption, Europe accounted for 52.7%, followed by North America (18.4%) and the former Soviet Union (23%). The main price formation mechanism was oil price escalation (47%), followed by gas-to-gas competition (26%) and bilateral monopoly (27%). The global trend is to increase gas-to-gas competition and bilateral monopoly at the expense of oil price escalation, with consumption growing through pipeline transportation route (from 660 bcm in 2005 to 694 bcm in 2011). The change of more gas-to-gas competition concerns primarily Europe, as bilateral monopoly concerns the former Soviet Union and North America. North America pricing mechanism is based on hubs and do not influence oil price escalation.[111]

With respect to the world import of LNG, 330.8 bcm (2011) accounted for 10.3% of global gas consumption, Asia-Pacific (including China and India) accounted for 63%, followed by Europe (27%) and North America (5%[112]). The main price formation mechanism was oil price escalation (70%), followed by gas-to-gas competition (27%) and bilateral monopoly (3%). The global trend is to increase gas-to-gas competition at the expense of oil price escalation and bilateral monopoly, with consumption growing through LNG transportation route (from 190 bcm in 2005 to 330.8 bcm in 2011). The change may concern either Asia-Pacific or Europe as major LNG importers[113].

Globally, the share of oil price escalation lowered from 62% (2005) to 53% (2007) with an increasing share of gas-to-gas competition[114]. The North American market plays a pivotal role, however an increasing share of gas-to-gas competition is noted also in the EU. It particularly concerns EU regions with flexible LNG deliveries and the UK market. CEE region does not seem to benefit considerably from this trend.

Europe outlook

Europe is heavily dependent on natural gas both imported through pipeline and LNG. Sources of supply vary within Europe, dividing it into a region with more diversified sources such as Northwestern Europe and Southwestern Europe, and CEE which is more dependent on a single supplier. Dependence on limited number (or single) of external sources of supply in CEE and V4 countries is disadvantageous to them when it comes to their influencing a gas pricing formula in LTCs.

Other important aspect is share in total gas consumption, indicating how a particular regional market of the EU is important to importers. Out of a total world gas consumption of 3223 bcm, the European share was 471 bcm[115] (14.6%). This European share divides between the EU regions, out of which CEE share is 62.3 bcm (11.6% of the EU consumption) and the V4 countries (8.3% of the EU consumption)[116]. This share is relatively small comparing to, for example, the United Kingdom (17%), Germany (15.4%), France (8.6%), and the Netherlands (8.1% bcm).[117] Relatively small and scarcely intra-interconnected CEE markets may not be so important for external importers as the market in Northwestern Europe.

Additionally, Europe is a dual pricing region. For a total amount of gas consumed in Europe[118], oil price escalation was a dominant mechanism (72.2%), followed by gas-to-gas competition (22%). These shares differ depending on a source of gas. Gas from Europe domestic production (149.4 bcm) was valued by oil price escalation in 35.2% and by gas-to-gas competition in 45.2%. Price regulation (social/political factor) played an important role (13.6%). However, while taking imported gas into account, oil price escalation shared 82.4%, while gas-to-gas competition 15.5%. The share of gas-to-gas competition in European countries pricing mechanisms was higher in countries which had diversified sources of supply or produced it domestically. Diversification of supply enables to make price arbitrage or use domestic production to lower higher prices of imported gas.[119] As it was indicated in Chapter 10, CEE region does not have significant domestic gas production.

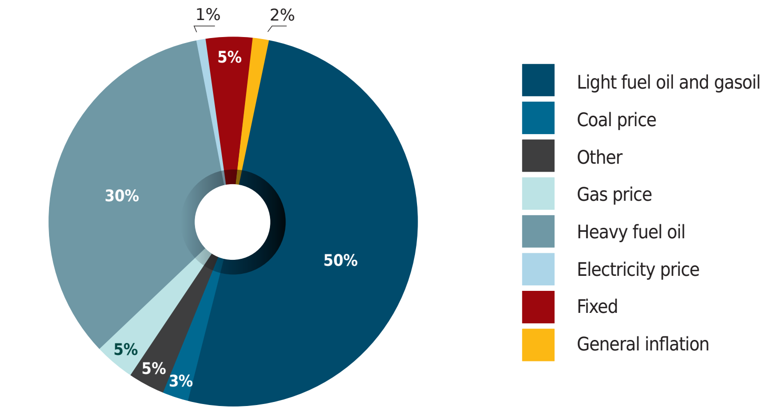
The level of diversification of external supply is also fairly low. It makes CEE countries vulnerable to the 'sellers' market, making the price arbitration difficult.

Historical outlook on gas price formation in EU

In the period 2005-2006 the European Commission launched an energy market sector inquiry which aimed to indicate a level of competition on the EU electricity and gas markets. It was to show inter alia barriers in the development of the EU internal gas market. Based on data collected, the report presented gas price indexation in LTCs patterns in different EU regions.[120]

At that time LTCs in Western Europe were in 50% indexed to light fuel oil and gasoil, in 30% to heavy fuel oil and in 5% to crude oil. Only 15% of indexation was to other index than oil and oil derivatives.

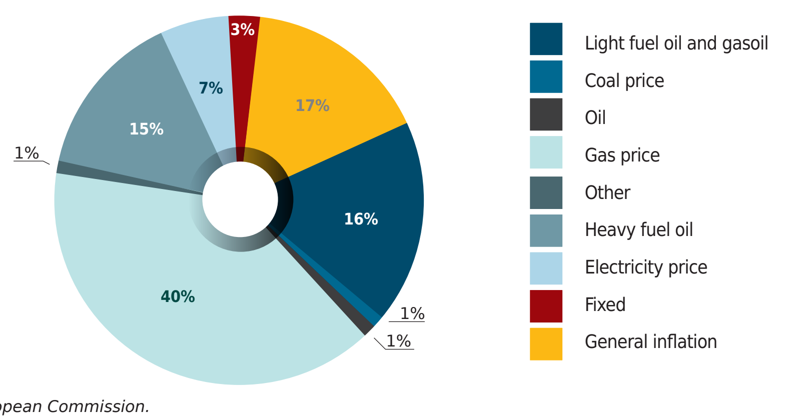
GRAPH 17. **Price indexation of LTCs in Western Europe.**



Source: *European Commission.*

The composition of indexation clauses was different in the LTCs concluded in the United Kingdom. The highest share is the gas price amounting to 40.1%. The combine share of oil derivatives was 31% and crude oil only 1%. There is a considerable share of general indexation (17%) and electricity price (7%).

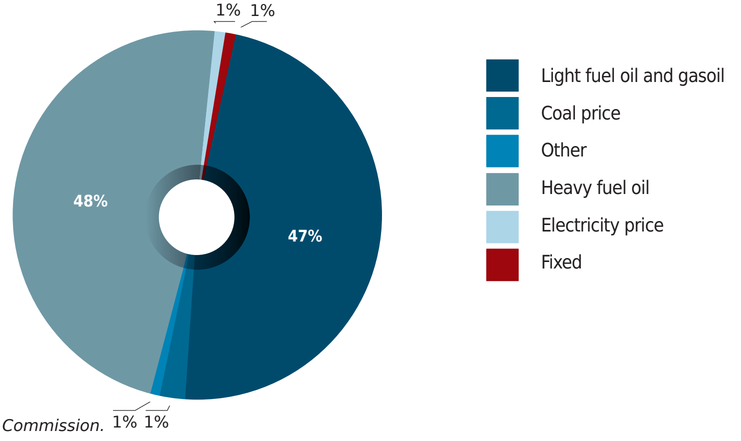
GRAPH 18. **Price indexation of LTCs in the United Kingdom.**



Source: *European Commission.*

In Eastern Europe LTCs a price indexation model is considerably different. Indexation is based on heavy fuel oil in 48%, light fuel oil and gasoil in 47% and 1% is crude oil. Other components form only 3% of a price indexation formula.

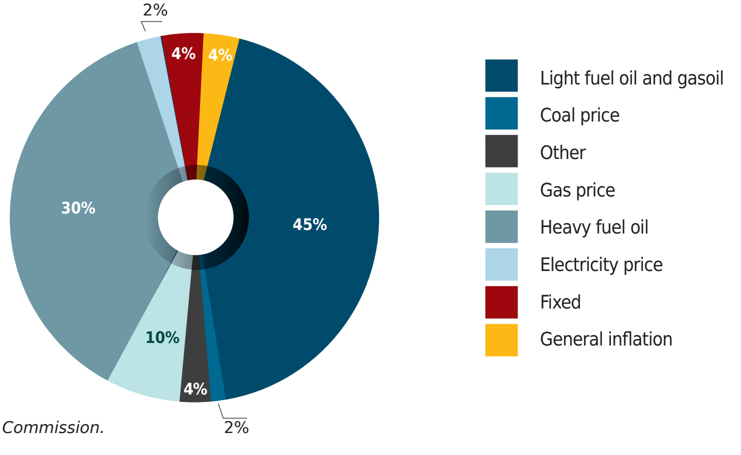
GRAPH 19. **Price indexation of LTCs in Eastern Europe.**



Source: *European Commission.*

Based on the European Commission energy sector inquiry, the EU consists of three regional gas markets in relation to LTC price indexation mechanisms. The graph below shows average weights of each of the component of an indexation formula in LTCs. Weights refer to gas volumes contracted. Despite differences between the three regional markets, indexation to oil derivatives is 75% of the price indexation formula, while crude oil plays another 4%. Components not related to oil and oil derivatives constitute 18% of the formula, with 10% related to gas price.

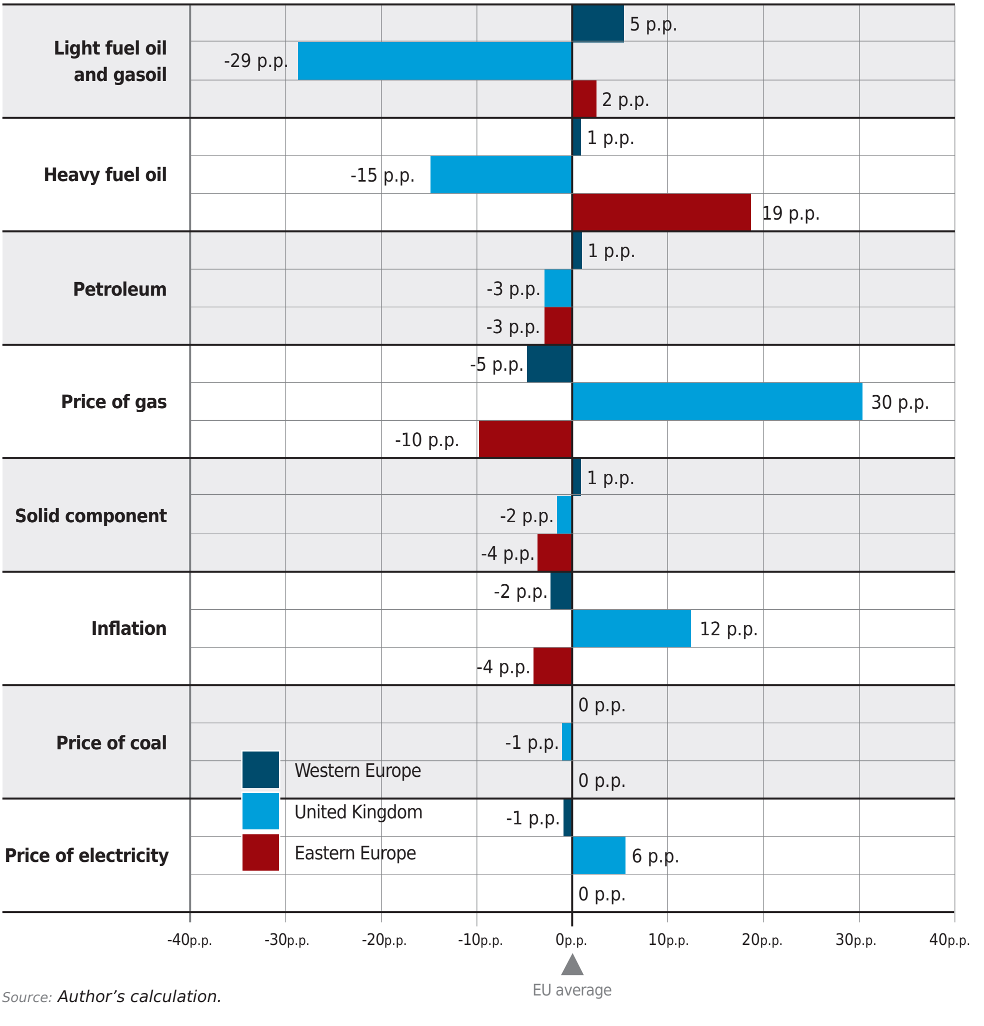
GRAPH 20. **Price indexation of LTCs in the EU.**



Source: *European Commission.*

The following graph shows the variation of individual elements in regional price indexation in LTCs to the EU average. The first three indicators are: light fuel oil and gasoil, heavy fuel oil and the crude oil. The UK market is characterized by a large deviation from an EU average reaching 29 percentage points for light fuel oil and gas oil. In case of heavy fuel oil the difference is 15 percentage points. Pricing formulas in LTCs in Western Europe based on light fuel oil and gasoil had a share of more than 5 percentage points and heavy fuel oil of 1 percentage points higher than the EU average. Eastern Europe share of light fuel oil and gas oil was close to the EU average, however the share of heavy fuel oil was higher of 19 percentage points than the EU average. It shows a need to adjust at least the share of heavy fuel oil in these countries to the EU average. In Eastern Europe and the UK there was also a considerable difference in relation to the gas price. Gas-to-gas indexation was 30 percentage points higher in the UK than the EU average. It was in the same time 10 percentage points lower in Eastern Europe than the EU average. This difference forms a huge gap and an important competition drawback when the regional markets start to integrate more closely.

GRAPH 21. **Deviation of the UE average**



Source: *Author's calculation.*

The UK model of price formation in LTCs with more gas-to-gas indexation could be a target model for a competitive and integrated EU gas market. It combines the EU particularities with global trends. Close correlation between the UK and Northwestern European hubs (in particular the TTF) makes this platform of price formation adequately structured on the EU market.

Eastern European member states differed significantly from the UK model and did not reflect the market trends. Also, oil and oil derivatives price indexation components in Eastern Europe were considerably lower than the EU average.

In order to create an integrated EU gas market, it is important to make a closer correlation within the EU in relation to the share of different price indexation components.

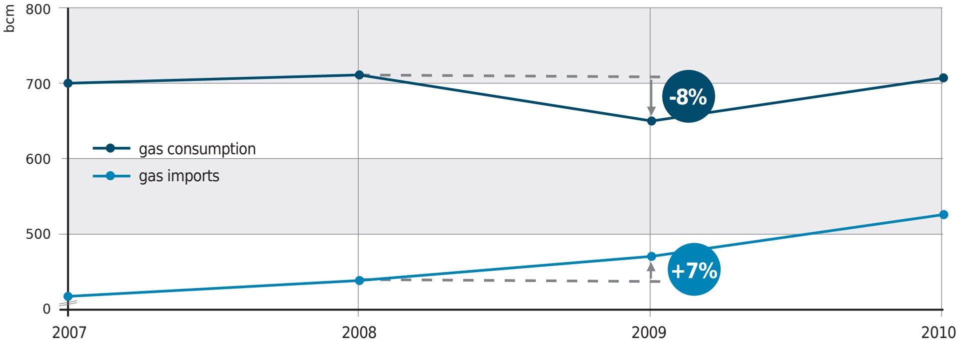
Recent developments in gas price formation in EU

The EU LTCs generally contain clauses that provide for periodic renegotiations of a base price, indexation terms and off-take arrangements. There are certain conditions that have to be fulfilled to make such a price review. A re-opener clause requires consent of parties to an agreement that conditions enabling renegotiations are fulfilled. In the event that the parties are unable to agree on renegotiations, a contract provides for a dispute resolution procedure, giving each party to the agreement a possibility of solving the dispute by arbitrator(s) or external experts (or by their panel).

Historically, contractual parties preferred to solve a dispute amicably but certain disputes were reported anyway[121]. Since 2009 many arbitration disputes have been reported. Information on disputes revealed to the public does not give any ground for in-depth analysis of trends in this respect; it shows, however, a certain level of correlation which concerns the position of importers, the position of EU suppliers, and preferred clauses of LTCs to be amended.

The end of 2009 and the beginning of 2010 was a period of intensive renegotiations. Gas producers were under pressure from EU gas suppliers to agree on discounts prices in LTCs. It was basically related to a change of gas consumption vs. gas import ratio inconvenient for the supplier. Gas consumption lowered by 8% and in the same time gas import increased by 7%.

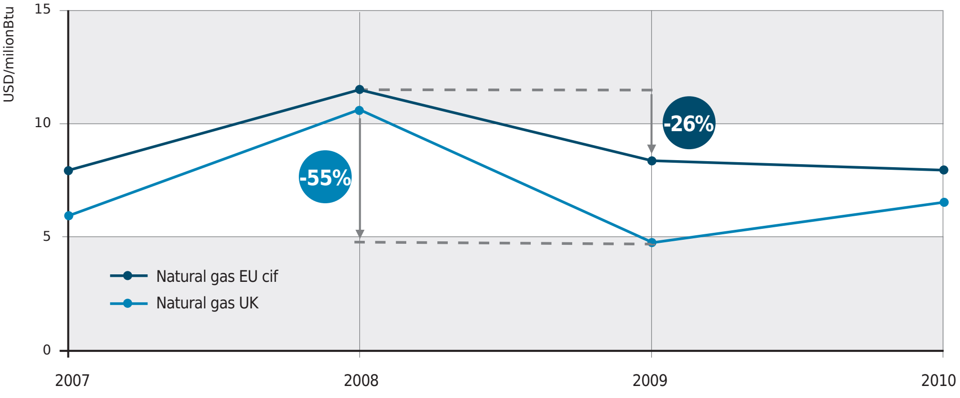
GRAPH 22. **Impact of the 2008 crisis on gas consumption and import in Europe and Eurasia (excl. Russia).**



Source: R. Zajdler, Development prospects of price formulas in long-term contracts for natural gas supplies and their significance for the creation of a gas hub in Poland for the countries of Central East Europe, Warsaw 2012.

The economic crisis was reflected in the prices of natural gas on the continent and in the UK. The liquid gas market forced the UK suppliers to lower prices significantly. The price gap between the UK and the gas market in Continental Europe widened. Gas prices on the borders of the European Union dropped by 26%, whereas prices for the NBP hub by more than half. Presently, the difference in spot and oil-index gas prices is assessed at 5 USD/MMBtu.[122]

GRAPH 23. **2008 economic crisis and gas prices in Europe.**



Source: Author's calculations.

Price negotiations

Several EU LTCs gas suppliers and producers, mostly from Germany, France, Italy, Spain, Austria, and Denmark came to agreement on contract revision.[123] In several cases lack of amicable settlement was noted[124]. We may now observe more activity from some CEE countries as Slovakian and Bulgarian suppliers came to agreement with producers.[125] However, lack of consent with producers has led suppliers from the Czech Republic, Poland and Lithuania to bring their cases to arbitration[126]. In the Czech Republic one of them has won a case on liabilities from the take-or-pay clause[127].

Based on this information a certain evolution may be observed. Earlier settlements between producers and EU suppliers gave temporal release to suppliers. Producers gave them three-year concessions which included more spot price indexation to contractual volume. It enabled EU suppliers to catch up with market trends and to reduce the price gap between LTC price and spot price. This move did not change the general structure of gas pricing. Further market development requires more structural changes which producers are not so eager to satisfy.

The way price is established in LTCs gives a wider scope of possibilities to balance the situation of the parties in the short run rather than to only increase spot indexation. It was used by producers to discourage suppliers from bigger spot indexation. Several concessions on: base price change, volume reduction, destination clause flexibility, re-opener clause flexibility were noted. Some suppliers agreed with such contractual balance, however there are others requiring a significant move toward greater spot price indexation. In seems that gas producers are still more eager to accept concessions on contractual flexibility related to volumes, a take-or-pay clause or revision of a base price than to change permanently an indexation formula allowing for higher spot price indexation. It aggravates the situation of CEE suppliers. Infrastructural circumstances and gas supply dependence on limited sources makes price negotiations difficult. Lack of uniform position of major EU suppliers makes this situation even more difficult. An antitrust procedure opened recently by the European Commission against Gazprom and arbitration award in case RWE Transgas vs. OAO Gazprom may give additional arguments to amendments in price formation mechanisms in CEE LTCs aimed at adopting a pricing model more in line with the EU average.

Length of Contracts

Traditionally, LTCs, which supplied natural gas to Europe, were concluded for a period of 15-30 years.[128] The length of contracts has decreased in the last several years. More precisely, from the end of 2001 to 2004, no LTCs for over 20 years were signed, 10-15 year contracts made up 50% of all deals, 20-year contracts made up 45%, and contracts for 1-5 years 5%[129]. Now suppliers either want to cut down on duration of existing contracts or do not plan to sign any new ones[130]. Some countries in CEE region start to renegotiate duration of contracts. They seem to stay a step behind their EU counterparts because results of their renegotiations of LTCs are noted several years later.

Spot indexation

During the revision in 2009-2010 several producers agreed to some concessions in on higher share of gas-to-gas indexation towards their EU counterparts. Gazprom agreed to temporarily (for a 3-year period) increase the level of spot indexation to 15% of a certain volume of gas delivered based on LTCs.[131] Such concessions seemed to be a temporal solution for EU suppliers. Some of them requested even 100% spot indexation[132].

It seems however, that EU suppliers treated such a big concession to spot indexation as a negotiation position rather than a real option. They prefer either lowering the base price in the LTC or some other contract flexibility which would reduce their contractual risk.[133] It may be related to the fact, that they have already achieved concessions to higher gas-to-gas indexation which CEE suppliers have not so far achieved and instead of 'fighting' for higher gas-to-gas indexation with very reluctant producers it is more beneficial to receive other concessions.

According to some market estimates, major EU gas suppliers may have spot indexation with its LTCs up to 15%.[134] In the long run, they will renegotiate gas supply contracts in order to include a step-by-step readjustment of pricing. RWE boasted that its total portfolio of gas supply contract is more than 50% of gas-to-gas indexation[135]. It may give a vision of a possible future level of gas-to-gas indexation in contracts.

The case of CEE suppliers may be different. They may have considerably higher number of LTCs with oil indexation, which makes them more open to market risks. Additionally, their pricing formula does not reflect the netback value, as for example HFO is less important in CEE economics than coal. The importance of coal is undermined, which makes the pricing formula even less related to market conditions.

Maximum Annual Quantity

There are two general volume-oriented boundaries in LTCs: a take-or-pay clause (a minimum bill) and a maximum annual quantity clause (MAQ). The MAQ clause covers deliveries above an obligatory take-or-pay level in LTCs. Their level in European LTCs is estimated at 110-115% of an annual contract quantity (ACQ). This quantity may be purchased by a supplier for a price indicated in an LTC. The flexibility clause was also a method of committing producers to sell output above the LTC at a predominantly agreed price.

Recent changes on the EU gas market development enabling for relatively easy purchase of gas on market conditions with an existing oversupply on the EU market weakened the earlier role of the MAQ in LTCs. This clause is being substituted by spot market purchases. It may further diminish the role of the MAQ clause.

The suppliers from CEE countries also use this market opportunity; however insufficient infrastructural interconnections – small interconnection capacity on the EU borders and lack of a LNG terminal – diminish the importance of this option.

Take or pay (minimum bill)

A take-or-pay clause is related to a quantity of natural gas for which a supplier is obliged to pay within the duration of contract irrespective of whether he will physically take it from a producer. Historically, a minimum bill level was around – 85-90% of an annual contract quantity (ACQ). Certain flexibility has been observed.

Due to a recent decision in the case of RWE Transgas (Czech Republic) vs. OAO Gazprom, a court of arbitration decided that RWE Transgas did not have to pay fines under a take-or-pay clause. This ruling may encourage other EU suppliers to claim the same concessions from their producers. It is particularly important for CEE countries, such as Bulgaria, Hungary, Poland and the Czech Republic for which Gazprom is the main or the sole supplier and where prices of gas under LTCs are considerably over a market price. This ruling gives additional volumes of gas available on the market conditions, which may further cut LTC prices. It is particularly important for CEE region, which covers considerable amounts of gas need via LTCs.

Base price negotiations

Recently observed negotiations of LTCs concern also a base price of gas. Producers have agreed to adjust a base price to a market price. Such an adjustment may lower a contract price near a level of spot price restoring competitiveness of gas in a LTC. It is treated as another option instead of a more permanent change in price indexation to higher share of gas-to-gas indexation.[136] This trend may also be a part of negotiations run by CEE gas suppliers.

Destination clause

The destination clause forbids a supplier to resell gas outside a country of its business activity related to a contract. It helps a producer to maintain price differentials between national or regional markets. The EU regarded such clauses as incompatible with the EU internal gas market, as they restrict competition and create restrictions to the free movement of goods. Although regarded as incompatible with the EU internal gas market, such clauses were not completely eliminated from EU LTCs. During renegotiations of some LTCs the scope of this close was eliminated or limited, for example with respect to a right to divert LNG to other destination.

Summary

Until the economic crisis, there was little discussion about renegotiation of price arrangements in LTCs. Regular negotiations re-opening in LTCs was a mechanism aimed to achieve a contractual balance. There were, however, important differences in gas indexation clauses in LTCs, depending on the EU region. More developed gas markets in Northwestern Europe enabled their suppliers to conclude LTCs with producers on more market-oriented conditions. CEE countries lagged behind.

Recently, the trend to make LTCs more flexible is observed throughout the EU. Due to stronger negotiating powers the northwestern EU countries have received concessions from producers, while CEE region still tries to follow the market. Spot price indexation higher than 15% is one of the elements negotiated as an element making LTCs more flexible and in line with market trends. Other concerns such as base price change, volume reduction, destination clause flexibility, minimum bill change or re-opener clause flexibility reduce contractual risks of EU suppliers. CEE suppliers seem to follow this trend but reaching an agreement with producers seems to be far more difficult than for suppliers in Northwestern Europe. However, changes on the gas market make the changes in CEE region inevitable. The antitrust procedure initiated by the European Commission against Gazprom and a case recently won in arbitration by the Czech supplier proof the need for change in this part of EU as well.

Among countries that have chosen gas-to-gas competition as their pricing mechanism there are virtually no calls for shifts to other mechanisms. There is a concern about a level of price volatility, and a debate involving market actors, regulators, politicians and observers on how to deal with harmful effects of price spikes and troughs. But there is little talk about returning to more regulation or for a shift to some variation on the market value pricing theme. As such, gas price determination through multiple sellers competing for multiple buyers with minimal regulatory interference (apart from tariff control of the natural monopoly elements in the supply chain, aka the transmission link) seems to be widely perceived as an end state without more efficient alternatives.

110. *BP Statistical Review 2012 edition, p. 22-23.*
111. *Wholesale Gas Price Formation – A global review of drivers and regional trends, IGU, 2011, Chapter 7.*
112. *BP Statistical Review 2012 edition.*
113. *Wholesale Gas Price Formation – A global review of drivers and regional trends, IGU, 2011, Chapter 7.*
114. *Ibid. – relates to the survey was carried in 2007.*
115. *The European Union of the Natural Gas Industry, More consumers, consuming less gas, in 2011, Press release, Brussels 2012.*
116. *Ibid.*
117. *Wholesale Gas Price Formation – A global review of drivers and regional trends, IGU, 2011, p. 35.*
118. *Ibid. – relates to the survey was carried in 2007.*
119. *Ibid, p. 35.*
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134. *Gazprom beats E.ON on indexation, 16 July 2012, International Gas Report.*
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6. Gas hubs

Hubs play a significant role in the natural gas industry because on the wholesale gas market they form a platform for gas trade and provision of trade-related services. In developed gas markets they create transparent mechanisms for gas pricing. Recently, much emphasis has been put on hubs as mechanisms for verification of pricing formulas in LTCs. A price verification mechanism based on hub (so-called "spot indexation") contrasts with oil-indexation which so far has been the prevailing price verification mechanism. Irrespective of the final outcome of this discussion, it is important to understand the role of a hub in the gas market in future, as the selection of an adequate indexation mechanism (spot vs. oil indexation) is related to a target gas market model.

Due to the specific character of CEE countries, special emphasis is put on importance of hubs for pricing mechanisms in LTCs concluded by those counties.

Hubs at glance

Hubs are a major component in the transmission and distribution of natural gas in the US. They are physical locations marked by an intersection of pipelines where services such as transportation of gas between pipelines, longer-and short-term storage facilities, and coverage of short-term delivery needs are provided[137]. Hubs also provide a physical location for gas trading and spot market transactions.[138] The Henry Hub (HH) serves as the most significant hub in the United States. It is the reference point for natural gas prices in the US. Pricing arrangement in delivery contracts concluded on other markets also refer to the HH prices.

Europe is home to both virtual and physical hubs. The only three physical European trading hubs are the Zeebrugge hub (ZEE) in Belgium and the CEGH (Central European Gas Hub) in Austria. Along with Gaspool (Germany) they serve as transit points for the onward transportation of natural gas. Due to their physical characteristics they also serve as storage facilities for natural gas. Virtual European hubs—namely the NBP in the UK, the TTF in the Netherlands, the PEG in France, the PSV in Italy, and the NCG in Germany—serve as balancing or trading points where shippers trade gas. The European gas market is not even nearly as developed as the US market and thus it does not offer the same variety of services. More specifically, some of services offered at European hubs include onward transportation of gas, balancing, portfolio management, as well as trade on the Day-ahead, futures, and the OTC market.[139]Hubs in the United States, on the other hand, offer services such as parking, loaning, and wheeling. These services are not offered at European hubs as of yet. In general, each European hub differs in terms of provided contracts and services. However, a certain correlation among them may be observed, in particular when it comes to natural gas pricing. CEE countries do not have their own regional hub. In some supply contracts in CEE countries natural gas price formation mechanisms relate to the closest hub in other EU Member State that is most pipeline-interconnected. It is a reference point for prices and very often serves as a source of physical gas supply.

In Asia, natural gas hubs do not exist. Due to the lack of infrastructure, competition, and pricing transparency, they have yet to be developed in the region. However, an LNG terminal is under construction in Singapore which, as some believe, has the potential to become Asia's first hub. Therefore, apart from a more in-depth discussion in the following subchapters, Asia will be omitted in this chapter. The lack of regional gas hub influences specific contractual relations in gas supply contracts, also those related to methods of natural gas pricing.

These differences influence the way prices are determined in LTCs. Regional specificity influences natural gas pricing mechanisms. Experiences derived from other regional markets may only serve as a reference point.

Hub service offerings

Globally, there is no single model of services offered by a hub. Services provided differ depending on a region and local circumstances. A range of services offered by hubs indirectly influences the natural gas market as hubs satisfy the needs. They influence the depth of the market giving additional credibility to gas pricing. These aspects need to be addressed taking into account regional circumstances.

US

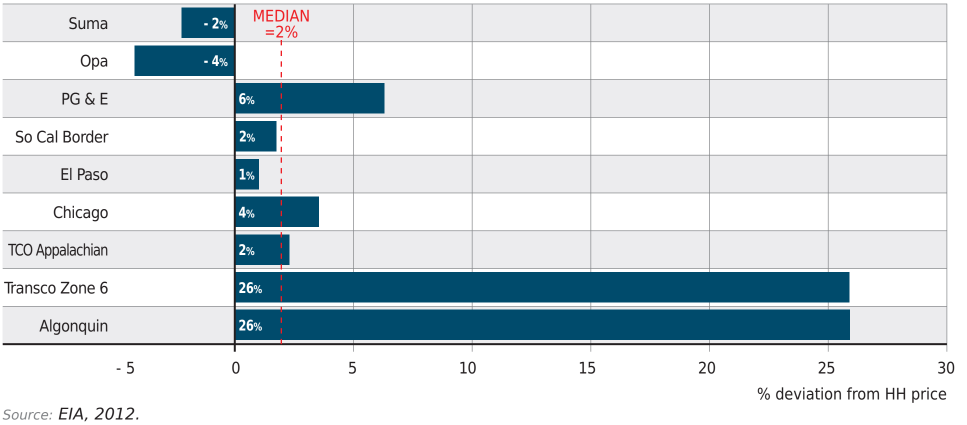
Services offered by hubs in the US vary from location to location. The EIA provides a broad description of general services provided. One of the most common is transportation/wheeling, which involves the transfer of gas from one pipeline to another. Parking is the service of storing gas for delivery intended in a near future. Loaning means completing a short-term advance of gas that is paid by a shipper soon after. A storage service allows for storing gas for a longer period of time. Peaking is a very short-term sale of natural gas to meet the needs of the buyer. Balancing refers to a temporary interruptible arrangement to address a short-term imbalance. Through pooling customers can combine natural gas from several sources and have it delivered to designated pooling stations. Market centres also often offer title transfer services by which ownership exchanges are tracked by a hub. Electronic nomination enables customers to submit electronically transport nominations, view bulletin boards, and view their own accounts. Administratively, market centres help shippers with natural gas transfers. Some gas compression services are also offered in order to increase pressure necessary to transfer gas from a lower pressure to a higher pressure pipeline. Another service is a hub-to hub transfer which means arrangement of simultaneous receipt at one centre and delivery at another[140].

For the financial aspect of the market, hubs are an indispensible part of the natural gas industry and nearly all are home to spot markets which send price signals about a market value of natural gas. In result of deregulation, the natural gas market is highly price transparent and competitive. Some would even argue that it is one of the most transparent commodity markets in the world[141]. The US market proves to be a pool of extensive data that provides price transparency at different market centres all over the country. Transparency, to a great extent, enables interested parties to participate in transactions of swaps, futures, options and other financial instruments that are connected to natural gas pricing[142].

The key role of the 'Henry Hub' is not only related to its size but also to the fact that it is important for the financial aspect of the market, because it serves as a delivery point for pricing natural gas futures contracts which are traded on the New York Mercantile Exchange (NYMEX). NYMEX has even adopted the name of 'Henry Hub' to refer to the price of these contracts. Natural gas marketers often use the Henry Hub as their physical delivery point and NYMEX as cash-market transaction platform.[143]

The prices which are set at the Henry Hub essentially dictate the price of natural gas on the North American natural gas market. Nonetheless, it is important to note that prices at different hubs across the country may not necessarily coincide with a price at the Henry Hub, which is indicated in the graph below. This is due to regional differences in, for example, transportation capacity and demand in relation to weather[144]. Even though price disparities may exist, the price at the Henry Hub remains the benchmark for the region. Also, the Henry Hub is not only important for the pricing of natural gas on the US market, but as some have even argued, it has the potential to become an international price reference for the gas trade[145]. Such price deviation between hubs on one market does not underestimate the credibility of the HH as an indication point.

GRAPH 24. **Price deviation from Henry Hub in 2011 at Major Trading Locations.**



Source: *EIA, 2012.*

EUROPE

European hubs are locations where traders may buy or sell natural gas based on services and contracts offered at a particular hub. Other than the NBP (National Balancing Point) in the UK, European (Continental) gas hubs are both relatively young in comparison to gas hubs located in the United States and they undergo constant transformation due to liberalization policies being put into effect by the EU as well as due to mergers between different gas hubs within countries (as is the case of Germany and France, for example).

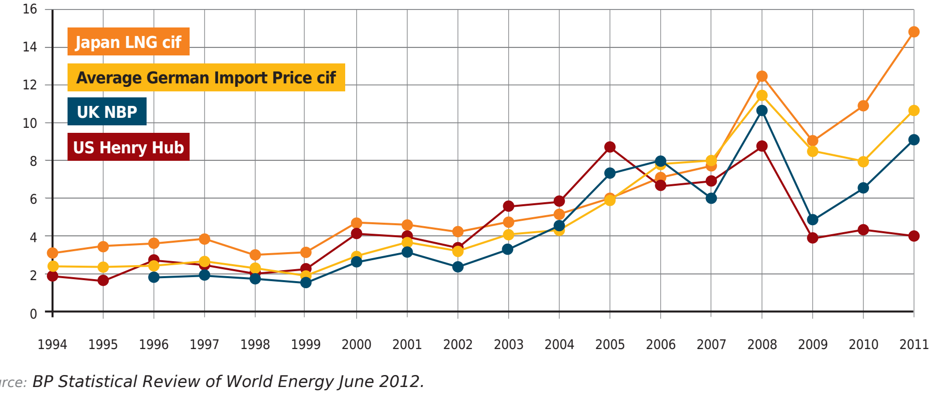
The variety of products and services offered by European hubs is not as wide as in the States, though a physical hubs range of services is getting close to overseas peers. For instance in the CEGH, the most developed terminal in terms of provided services, customers can take advantage of title transfer services, wheeling, no-notice storage nomination service (management of differences between predictable gas flows and nominated and already confirmed gas flows), online gas auctions, round-the-clock dispatching service, allocation reporting, online bulletin boards enabling advertising gas quantities for sale and for purchase as well as physical balancing service. The main offer at the Zeebrugge is limited to title tracking and back-up services enabling firm delivery in case of operational issues. Virtual hubs serve as trading points and do not themselves have any gas-related offerings other than trading.

As for the financial aspect of the market, hubs are still not indispensable part of the natural gas industry in the EU. They are correlated with spot markets which send price signals about a market value of natural gas, but a correlation mechanism on a case-by-case basis is still under development. In result of liberalisation of the EU internal gas market, the natural gas market is in the process of adopting a level price transparency required in developed markets. Market activity tends to be limited to different types of transactions (spot, futures). Irrespective of that, a simple comparison between the EU and the US hubs is not adequate. Due to legal differences between the gas markets in the US and the EU as well as the undergoing implementation of uniform legislative framework in Europe, hubs in the EU should be treated as one uniform market platform with more than one location.

Based on their market development, hubs in the EU are classified as: trading, transit, and transition hubs. Trading hubs are mature hubs which give traders the ability to manage their gas portfolios; transit hubs are physical transit locations where participants may trade gas, but they are most often used as an actual location that facilitates onward transportation of gas; and transition hubs are relatively underdeveloped but may transform into virtual hubs. However, they all have already set benchmark prices for gas in their respective regions.[146]

Most trade at European hubs is done under long-term contracts (LTCs) lasting between 25 to 30 years, with prices based on German border prices (GBP) for natural gas.[147] The historical role of LTCs in hub price formation has been changing constantly. Due to the development of spot and future markets and national programs of gas release, more natural gas is traded irrespective of LTCs based on GBP. More volumes of gas on hubs have been bought on spot price rather than on that related to LTCs.[148] This can be partially attributed to an increase in the trade in LNG, which has been influencing price formulas on the natural gas market in Continental Europe.

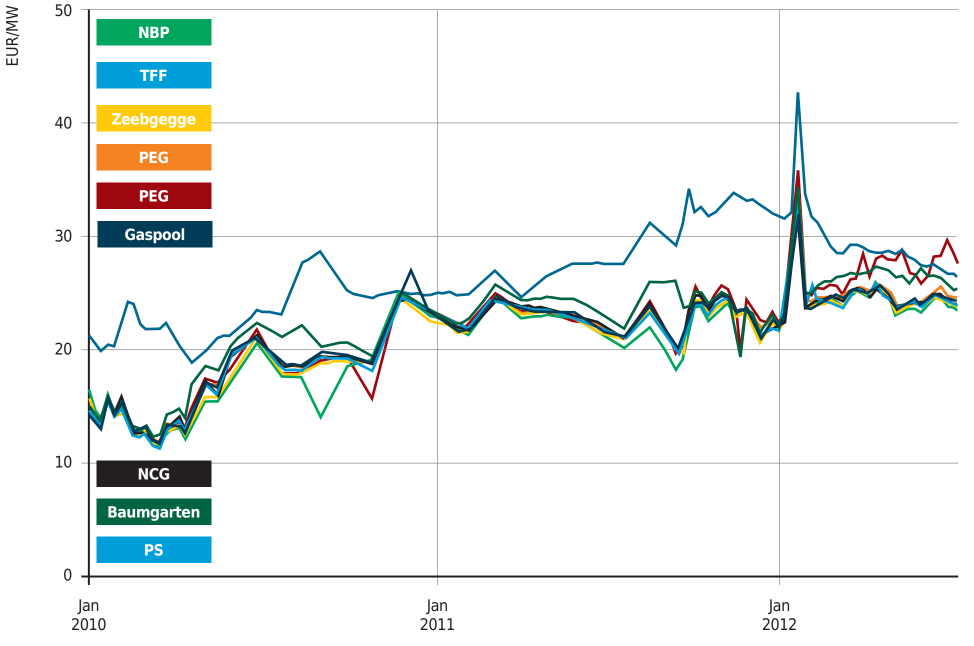
GRAPH 25. **Natural Gas Prices 1994-2011.**



Source: *BP Statistical Review of World Energy June 2012.*

Prices on European hubs, as it is the case in the US, are aligned with one another, even though there is no single reference point such as the Henry Hub. Although some of them stand out (particularly the Italian PSV), the trend is visible. The curves below represent Day-ahead pricing on 9 European hubs in the period from January 2010 to July 2012.

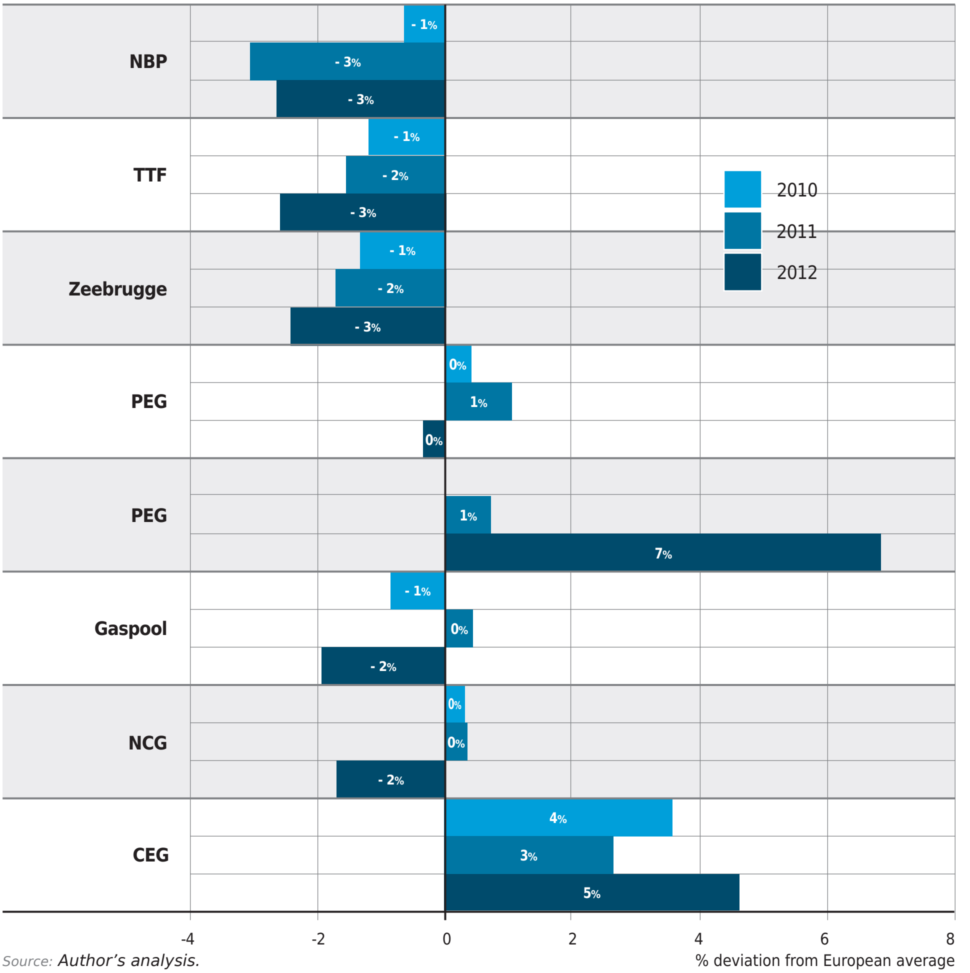
GRAPH 26. **Gas hub weekly day-ahead prices on European hubs.**



Source: *Platts.*

The price correlation is much more visible if the analysis focuses on price deviations in selected periods. Except for two hubs, most of them are almost fully correlated with an average European price with correlation levels of 99% for TTF, NBP, Zeebrugge, PEG Nord, Gaspool, NCG and 98% for CEGH. The correlation for the PEG Sudis weaker (88%) and for the PSV is the weakest (77%)[149]. This trend proves that in fact European gas prices are very much dependent on each other. The graph below presents a price deviation on European hubs in relation to an average price in Europe[150]. In fact, there is hardly any difference in comparison to the US market. Although Europe does not have a clear reference point such as the Henry Hub in the US most hub transactions reflect European price trends. Differences vary between 1-4% with extremes reaching only 7%. Another point that needs to be made is the fact that the most developed virtual hub in Continental Europe, the Dutch TTF, is not different in terms of prices than the NBP which is considered to be the only hub close to the US level of development. Moreover, average 3M futures at the TTF since the beginning 2011 varied only by 3.8% from the European average of Day-ahead prices and 3.6%[151] from the Continental average.

GRAPH 27. **Deviation of average annual prices in European hubs in relation to an average price for the hubs.**



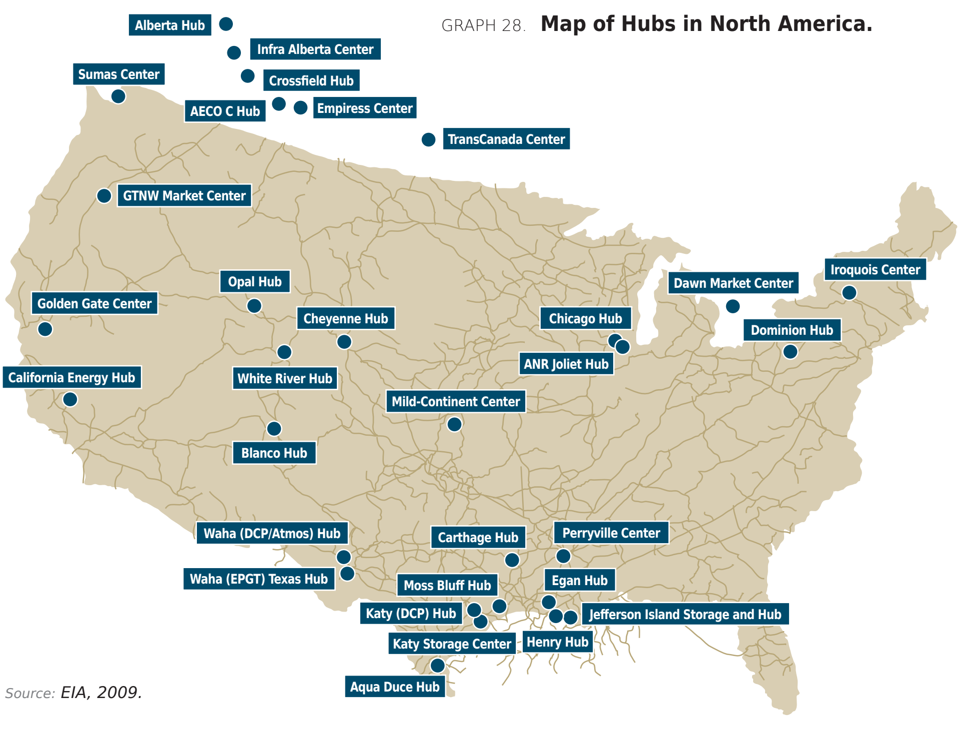
Source: *Author's analysis.*

There is no single hub which dictates gas prices in a way similar to the HH. A range of services offered by hubs in the EU differs from that in the US but is more uniform within the whole EU. The prices set at by hubs in the EU still do not dictate the price of natural gas on the EU natural gas market. This is due to the importance of LTC in Continental Europe. Nonetheless, it is important to note that prices at different hubs around the EU coincide due to the process of unifying regulatory framework. Therefore, hubs in the EU may be regarded as the benchmark for the region. Price deviation between hubs on a national market does not underestimate the credibility of the whole mechanism.

Hubs locations
US

Order 636 by which the Federal Energy Regulatory Commission (FERC) required gas pipelines companies to transform themselves from buyers and sellers to solely transportation services firms triggered the development of gas hubs in the US. Therefore, hubs arose in order to provide services that were previously included in the pipeline industry's bundling of services[152]. As of 2008, there were 24 hubs in the United States[153]. Although spread across the country, they are concentrated mostly in the South, in the states of Texas and Louisiana[154]. This concentration in the South is related to a huge increase in natural gas production that has occurred there since the early 2000s. While there has not been a huge jump in the number of hubs, in the last decade they have been a part of significant expansion projects which have greatly increased their operational capacities. Most of the growth has been in areas that have been expanding their natural gas production capacities or that are conveniently located along important transportation routes.

GRAPH 28. **Map of Hubs in North America.**



Source: EIA, 2009.

The most significant hub in the United States is the Henry Hub which is a large central distribution hub along the American pipeline system where 16 different pipelines intersect[155]. This physical intersection occurs in Louisiana and involves both interstate and intrastate pipelines. The Henry Hub is a full service centre that offers not only transportation services, but also balancing, parking and loaning, as well as intra-hub transfers[156]. Intra-hub transfers offered at the Henry Hub are used to track multiple title transfers of natural gas[157]. It provides connections to the Gulf Coast, East Coast, Midwest, and the Canadian Border[158]. The Henry Hub boasts a throughput capacity of 1800 MMcf per day, which is not the highest in the US but sufficient enough to serve as a main reference point for the country.[159]

Apart from the Henry Hub the other 23 hubs located in the United States contribute to the structure of the natural gas market as well. In their most general form hubs are physical locations where intersecting pipelines are linked to a facility whose purpose is to facilitate the transfer of gas from one pipeline to another. Each hub is unique in terms of its operation and services offered. In order to clarify differences between them, hubs are categorized according to their type of operation. The categorization includes the following: market hub, production hub, market centre, and storage hub[160].

Market hubs are distinguished by offerings of expanded services that serve to facilitate the process of purchasing, selling, and transporting gas. Such activities include storage and processing, trading, peaking, and transfer of ownership titles. Also, some market hubs provide the opportunity to seek information and engage in electronic trading[161].

Production hubs focus on providing transportation services to producers of natural gas.

Market centres often use pipelines and physical infrastructure to perform their services but they can be distinguished from other types of hubs because they do not necessarily depend on physical locations to carry out their operations. Also market centres sometimes offer extra services such as parking and loaning, as well as providing a place where natural gas, transportation, and pipeline capacity can be bought and sold. The Henry Hub is an important example of a market centre.

Storage hubs serve the purpose of providing a place for customers to store their natural gas until it is needed. This is done so that demand can be met at seasonal and peak times of the year.

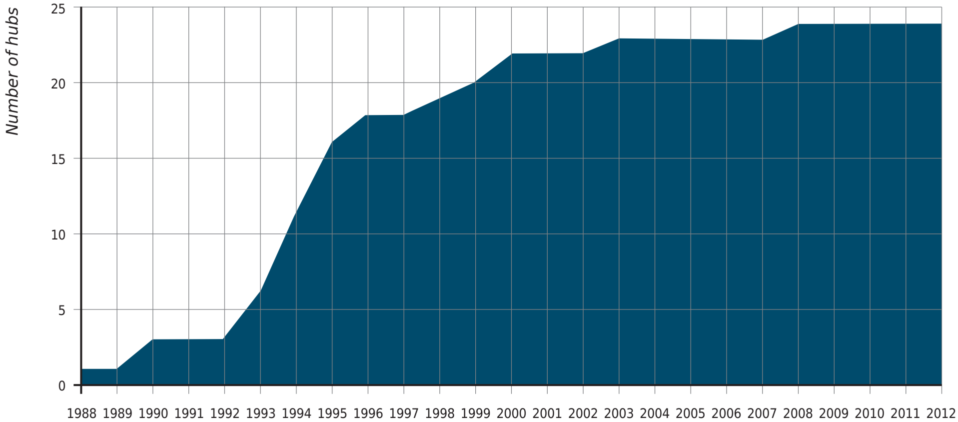
GRAPH 29. **Profile of Operational Natural Gas Hubs in the US (2008).**

CENTRAL REGION					
Location	**Hub**	**Infrastructure**	**Type of Operation**	**Started**	**Administrator**
Colorado	**Cheyenne Hub**	Header	Market Hub	2000	Colorado Interstate Gas Co.
Colorado	**White River Hub**	Header	Production Hub	2008	White River Hub LLC
Kansas	**Mid-Continent Hub**	Partial Pipeline	Market Hub	1995	Oneok Gas Transportation LLC
Wyoming	**Opal Hub**	Header	Production Hub	1999	Williams Field Services Co.
MIDWEST					
Location	**Hub**	**Infrastructure**	**Type of Operation**	**Started**	**Administrator**
Illinois	**ANR Joliet Hub**	Partial Pipeline	Market Centre	2003	ANR Pipeline Co.
Illinois	**Chicago Hub**	Partial Pipeline	Market Centre	1993	Enerchange Inc
NORTHEAST					
Location	**Hub**	**Infrastructure**	**Type of Operation**	**Started**	**Administrator**
New York	**Iroquios Centre**	Entire Pipeline	Market Centre	1996	Iroquoise Gas Trans Co.
Pennsylvania	**Dominion Hub**	Entire Pipeline	Market Centre	1994	Dominion Transmission Inc
SOUTHWEST					
Location	**Hub**	**Infrastructure**	**Type of Operation**	**Started**	**Administrator**
Louisiana	**Egan Hub**	Header	Storage Hub	1995	Egan Hub Partners LP
Louisiana	**Henry Hub**	Header	Market Centre	1988	Henry Hub Services Inc
Louisiana	**Jefferson Island**	Header	Storage Hub	1998	Jefferson Island Storage & Hub LLC
Louisiana	**Nautilus Hub**	Header	Production Hub	2000	Embridge Offshore Pipelines
Louisiana	**Perryville Centre**	Partial Pipeline	Market Centre	1994	Centerpoint Energy Gas Trans
New Mexico	**Blanco Hub**	Header	Production Hub	1993	TranswesternGas Pipeline Co
East Texas	**Aqua Dulce Hub**	Header	Production Hub	1990	ConocoPhilips Inc
East Texas	**Carthage Hub**	Header	Production Hub	1990	DCP Midstream Partners LP
East Texas	**Katy (DCP) Hub**	Header	Production Hub	1995	DCP Midstream LP
East Texas	**Katy Storage Centre**	Header	Storage Hub	1993	ENSTOR Energy Inc
East Texas	**Moss Bluff Hub**	Header	Storage Hub	1994	Moss Bluff Hub Partners LP
West Texas	**Waha (EPGT) Texas Hub**	Partial Pipeline	Production Hub	1995	Enterprise Productions Pipeline LP
West Texas	**Waha (DCP/Atmos) Hub**	Header	Production Hub	1995	DCP Midstream LP
WESTERN					
Location	**Hub**	**Infrastructure**	**Type of Operation**	**Started**	**Administrator**
California	**California Energy Hub**	Market Centre	Entire Pipeline	1994	Southern California Gas Co.
California	**Golden Gate Centre**	Market Centre	Entire Pipeline	1996	California Gas Transmision Co.
Oregon	**GTNW Market Centre**	Market Centre	Entire Pipeline	1994	Gas Transmision - NW

Source: *Energy Information Administration, Office of Oil and Gas – April 2009.*

In the graph above, the liberalized organization of the natural gas industry in relation to hubs is clear. There is a large number of companies who serve as administrators of hubs. The companies are not state-run, and many engage in operations not only at their associated hub, but across the US.

GRAPH 30. **Number of hubs in the period from 1988 to 2012.**



Source: *EIA.*

The diagram above pictures the development process of the US hubs. The first one was opened in 1988 and there were only 3 hubs by the end of the 1990's. The next decade was a period of rapid growth in the number of hubs. At the end of the 20th century there were 22 operational hubs in the US and afterwards the number has not grown. At the moment there are 24 hubs in the US.

As previously mentioned, the southwest part of the US, Texas and Louisiana in particular, is the most significant as the region has seen a considerable increase in the production of natural gas. The Henry Hub, the most recognized market centre is located there, but it is not the only hub of great importance. Extensive pipeline connections which can be accessed through the Perryville Hub in Louisiana have made it the second most significant market centre in the country according to information gathered in 2007-2008[162].

The Perryville Hub connects 15 interstate and 2 intrastate pipelines and its pipeline interconnect capacity increased by 402% from 2003 to 2008[163]. In the same period of time, the hub also experienced a rise in an average daily throughput capacity of 200%[164]. Therefore, in 2008, the EIA reported that the Perryville Hub average daily throughput was 1800 (MMcf/d) and its pipeline interconnect capacity was 11800 (MMcf/d)[165]. Apart from typical transportation provisions the hub offers other services such as wheeling[166], parking and loaning[167].

The Perryville Hub Trading Point (PTP) was created by CenterPoint Energy. Shippers are able to name the PTP as delivery or receipt location in their transportation contracts. The PTP is also a location for trading or exchanging gas ownership titles between customers, and it also provides Title Tracking Services[168].

Apart from the Henry Hub and the Perryville Center, there are many other hubs in the Southwest. The Egan Hub, for example, is a salt cavern storage hub that maintains interconnections with 8 major pipelines and claims around 800 million cubic meters of storage capacity[169]. It also offers a twelve-turn service, balancing, park and loan, peaking, wheeling, and market determination for pipeline interconnects[170]. A twelve-turn service refers to a service that allows a customer to secure an agreement for the injection and withdrawal rights to turn over their inventory twelve times in one year. The hub increased its average daily throughput by 100% and its interconnect capacity by 175% from 2003-2008[171]. Jefferson Island is also a storage hub with two salt caverns totalling 210 thcm of storage capacity.

Outside the Southwest, other regions have hubs which are especially important for the supply of natural gas in their general locations. In the Northeast, the Dominion Hub market centre holds plays the most important role. As of 2008, it connects 17 pipelines, has an estimated 2500 (MMcf/d) of daily throughput, and has a total of 8348 (MMcf/d) of pipeline interconnect capacity[172].

Serving as the dominating hub in the Central region in 2008, the Opal Hub in Wyoming boasts an average daily throughput of 1,450 (MMcf/d) and 6,038 (MMcf/d) in pipeline interconnect capacity and serves as a good example of a production hub[173].

In the West, the Californian market centres Golden Gate Center and California Energy Hub both have over 6000 (MMcf/d) in total pipeline interconnect capacity, and the former supports an estimated 2000 (MMcf/d) of average daily throughput in 2008[174].

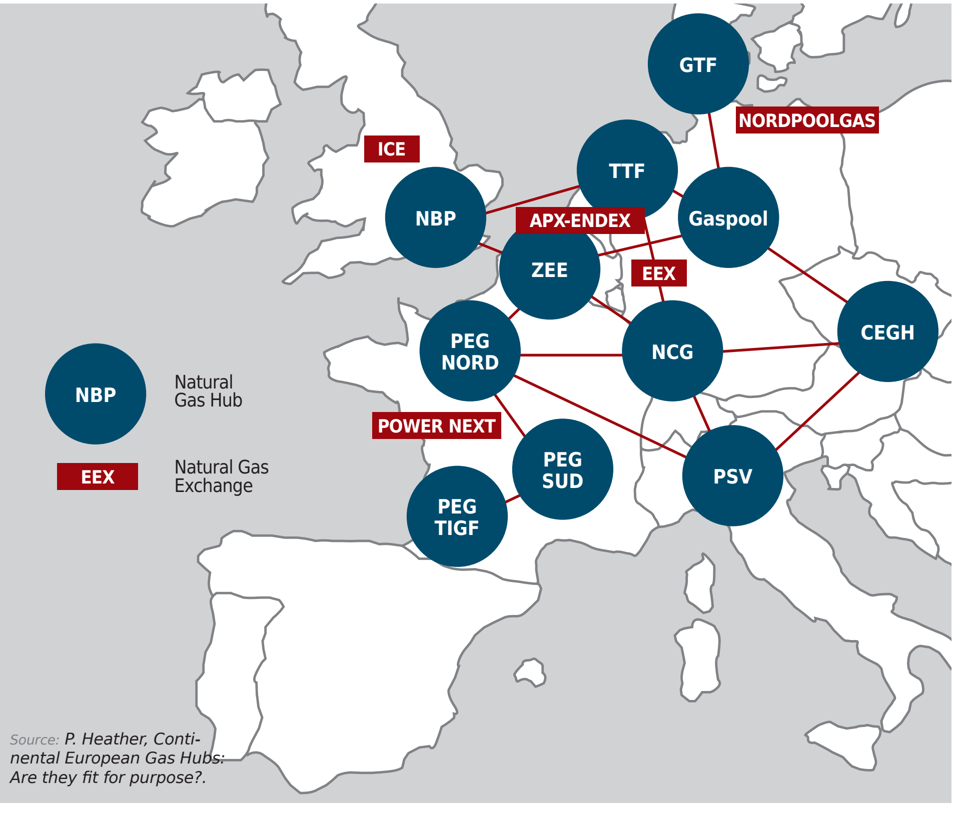
Finally, based on data from 2007-2008, the Midwest region is home to the third largest hub in North America, the Chicago Hub[175]. This hub has connection access to 8 different interstate pipelines[176].

EUROPE

As previously stated, each European gas hub differs in terms of provided contracts and services. In order to understand the natural gas market in Europe well, it is necessary to analyse each hub individually.

The diagram below shows locations of European gas hubs along with their respective gas exchanges. The four exchanges in play in Europe include the ICE, Endex, the EEX and Powernext, which create trading platforms for the NBP, the TTF, Germany-'s NCG and GPL, and for the PEG Nord, respectively.[177] Future contracts are available for traders at European hubs under these exchanges, but each exchange offers a variety of alternative products in addition to futures. For example, the EEX (European Energy Exchange, Germany) and Powernext offer deals on the spot market and on power derivatives.[178] Additionally, these exchanges are not limited to the natural gas market; they also, for example, deal with trade in electric energy and coal. Nor are these exchanges limited to the countries in which they are located but exchanges may also operate short-term trading platforms in other European countries due to exchanges' sharing of the EPEX Spot subsidiary.[179] Apx-Endex, for example, offers spot market platforms as well as future markets in the Netherlands, Belgium, and the UK.[180] Thus, exchanges are not limited to a single hub or country, and thus they facilitate trade on the European gas market.

GRAPH 31. **Map of European Gas Hubs and Gas Exchanges.**



Source: *P. Heather, Continental European Gas Hubs: Are they fit for purpose?.*

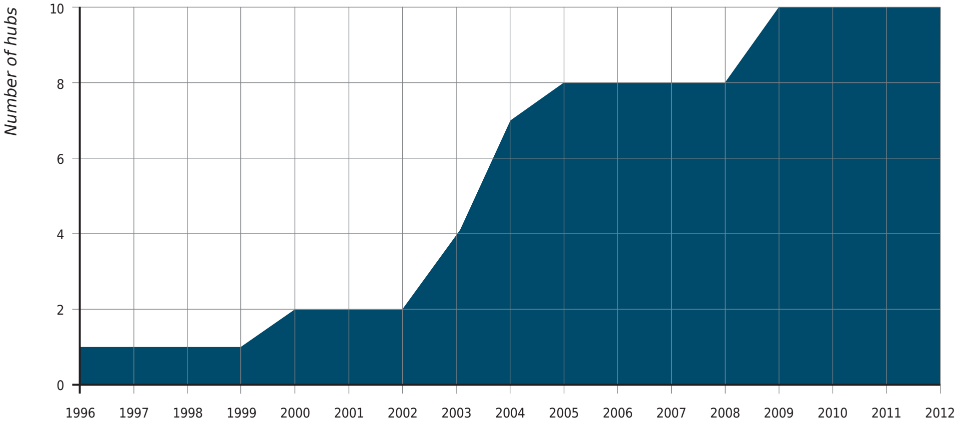
GRAPH 32. **Natural gas hubs in Europe.**

Physical Hubs	Operated from	Country	Hub Type
Central European Gas Hub (CEGH)	2005	Austria	Transit Hub
Zeebrugge	2000	Belgium	Transit Hub
Virtual Hubs	**Operated from**	**Country**	**Hub Type**
Gaspool (GPL)	2009	Germany	Trading Hub
National Balancing Point (NBP)	1996	United Kingdom	Trading Hub
NetConnect (NCG)	2009	Germany	Transition Hub
Points d'Echange de Gaz Nord (PEG)	2004	France	Transition Hub
Points d'Echange de Gaz Sud (PEG)	2004	France	Transition Hub
Points d'Echange de Gaz TIGRF (PEG)	2004	France	Transition Hub
Punto Di Scambio Virtuale	2003	Italy	Transition Hub
Tile Transfer Facility (TTF)	2003	The Netherlands	Trading Hub

Source: *Author's calculation.*

Comparing to the US Europe needed ten more years to start its gas hub development period. The first hub became operational in 1996 in the UK but the highest growth began in 2003. Due to less developed competition the whole EU market has only 10 hubs whereas in the US there are over 20 of them.

GRAPH 33. **European gas hubs development.**



Source: *Author's calculation.*

At the moment there is no hub in CEE, although there is one trading point, namely the CEGH in Hungary. There are also speculations and papers analysing the significance of a theoretical hub location in Poland[181]. The latter, however, would have to face strong competition from more experienced hubs in Germany and Austria, but on the other hand would the chance to profit from the location and serve as a gas trading centre for CEE.

National Balancing Point (NBP), United Kingdom

Established in 1996, the NBP is the most liquid traded hub in Europe, with a strong demand for UK gas through the Interconnector — connecting the Bacton Terminal with the Zeebrugge Terminal in Belgium — from Continental Europe. It is also unique in that it is the only liberalized gas industry in Europe. The NBP is characterized as the most effective virtual trading hub in Europe and "is rarely prone to entry/exit point congestion as is the case elsewhere in Europe."[182] Many traders also prefer the NBP because it is a vertically integrated market. Over the past two years, there has been an increase in the number of new traders (who are non-shippers) trading in ICE futures, a characteristic that makes the NBP a popular trading spot.

The increase in the number of traders dealing in ICE futures has led to a wider use of the ICE as a trading platform on the natural gas market, ultimately leading to the ICE's 20-25% share of the NBP market.[184]

Future trades make the NBP more liquid than other European hubs, and make it comparable to the Henry Hub in the United States. The NBP's churn ratio — or liquidity and depth indicator, as expressed by a total traded volume divided by a net traded/delivered volume over a specific time period[185] — is normally in the high teens or in the low twenties, hitting a churn ratio of 21 in the first quarter of 2012.[186]

The most vital players on the UK gas market come in three categories—key producers, utilities and banks. A larger number of players are key producers—including BP, ExxonMobil, Total, Shell, and ConocoPhillips—who are involved in the spot market, especially those who sell gas from the North Sea (which accounts for around 50% of the UK's gas supply[187]). The biggest player is Norway's Statoil, which uses the NBP to sell spot volume, whereas it sells LTCs to Continental Europe. Contracts with Statoil deliver 5 bcm/year through the Vesterled pipeline.[188] Pipe imports from Norway (the Snohvit LNG production plant has a capacity of 5.8 bcm/y [189]) also flow through the Langeled pipeline (which provides gas from the Ormen Lange field) and accounts for between one-quarter and one-third of the UK supply.[190] Utilities, including Centrica, E.ON, EDF, npower, Scottish Power and Scottish and Southern Energy, are the main buyers of further forwards. Financial institutions such as Goldman Sachs, Barclays Capital, Credit Suisse, JP Morgan and others are often sellers on the far curve. These key players mostly trade on Day-aheadDay-ahead products, with a significant number of spot products also traded in Within-day, Weekend, and WDNW contracts. The unpredictability of weather in the UK triggers fears of a rise or fall in a local distribution zone (LDZ) consumption.[191]

Players influence price direction by pipe connection, storage, LNG or Interconnector capacity, and other physical assets.[192] The demand from residential/commercial and power generation segments represents 43% and 36% of demand, respectively.

More trade is done on the near curve than on the far curve due to the predominance of buyers over sellers in the latter. Significant volumes of LNG are sold on a front-month index which dominates curve trading and influences the rest of the curve in the contract. If, for example, the front month is trading less than the spot market, then storage players withdraw gas rather than inject it.[193] Monthly contracts are most liquid during the winter months, during which trade may take place on a daily basis. On the other hand, there is a lack of commitment to volumes on seasonal contracts.[194]

Production prices are normally indexed 9% to electricity price, 37% to gas price, 1% to crude oil, 1% to coal price, 28% to general inflation, 9% to HFO, and 11% to LFO and gas oil.[195] Consumption prices, on the other hand, are indexed 7% to electricity price, 40% to gas price, 1% to crude oil, 1% to coal price, 16% to general inflation, 15% to HFO, and 16% to LFO and gas oil.[196]

The UK opted for LNG as it was predicted that there would be a shortage in gas production. This prediction was made based on data from the period from 2000 to 2009, during which gas production reduced from 115 bcm to 62 bcm.[197] Data shows that in 2010 the UK imported 6% (19.6 bcm) of the world's gas.[198] Other natural gas suppliers include Australia, the Netherlands, Norway, the United States, Algeria, Egypt, Nigeria, Qatar, Trinidad and Tobago, all to different extents.

LNG importers, such as the UK, approve of destination flexibility clauses (as opposed to "destination clauses") associated with these types of imports because they facilitate development of more liquid markets. Exporting countries, on the other hand, would prefer to establish a rent-sharing mechanism with marketing companies, an agreement that would allow governments to participate in the benefits of such trade which otherwise would end up in the hands of the marketing companies involved.[199]

Demand in the NBP may be affected for a number of reasons. First, the growing number of interconnections with Europe affects trade at the NBP on two grounds. Price differentials with the Zeebrugge, the TTF and German hubs dictate flows through the Interconnector.

Additionally, the use of other pipelines within Europe may change the demand for the UK gas depending on whether there are surpluses in continental hubs. Demand may also be affected by growing medium-range storage capacity which can both inject and withdraw gas within the same session. This "swing" affects intra-day movers of demand and spot pricing. Lastly, power plant generators base their price around the coal switch level (the "price below which power generators will switch to using gas rather than coal as baseload generation")[200], with each plant requiring different volumes of gas based on their levels of efficiency. Prices normally match spot and front-month NBP moves around switching prices.

GRAPH 34. **Factors effecting demand at the NBP.**

FACTORS EFFECTING DEMAND AT THE NBP		
Factor	**Reason**	**Explanation**
1. Growing number of Interconnectors with Europe.	Effects trade at the NBP.	I. Price differential with ZEE, TTF, and German hubs will be effected. II. Use of other pipelines may change demand for UK gas (ie; as caused by surpluses at continental hubs).
2. Growth of medium-range storage capacity.	Can inject and withdraw gas in the same session.	Can affect intra-day movers of demand and spot pricing.
3. Power plant generators base their prices around the coal switch level.	Each plant requires different volumes of gas based on levels of efficiency.	Prices normally match spot and front-month NBP moves around switching prices.

Source: *Author's calculation.*

Tile Transfer Facility (TTF), Netherlands

The TTF was established in 2003 and effectively takes up the entire Dutch gas grid.[201] It is similar to the NBP in that a large portion of trade is done on the forward curve up to three-years out, making it a market that could be used for both hedging and balancing purposes (called "Market Based Balancing").[202] The increase in volumes (due to an increase in trade on the forward curve) may be attributed to the trading of either high calorific or low calorific gas, as permitted by the TSO (Gas Transport Services) in July of 2009. Another reason for the latest increase in traded volumes at the TTF is the formation of contracts that deliver and price flat gas at the hub rather than based on LTCs.[203] This can be attributed to GasTerra (owned by the Dutch government, Exxon, and Shell) monetizing its assets and selling large quantities of gas on the TTF market, serving as an alternative option to physical deals at border points or factory gates. Some services offered at this hub include storage, gas transportation through the TTF's network, importation of LNG, and balancing of trades.[204]

GRAPH 35. **Major companies involved in the Dutch natural gas industry.**

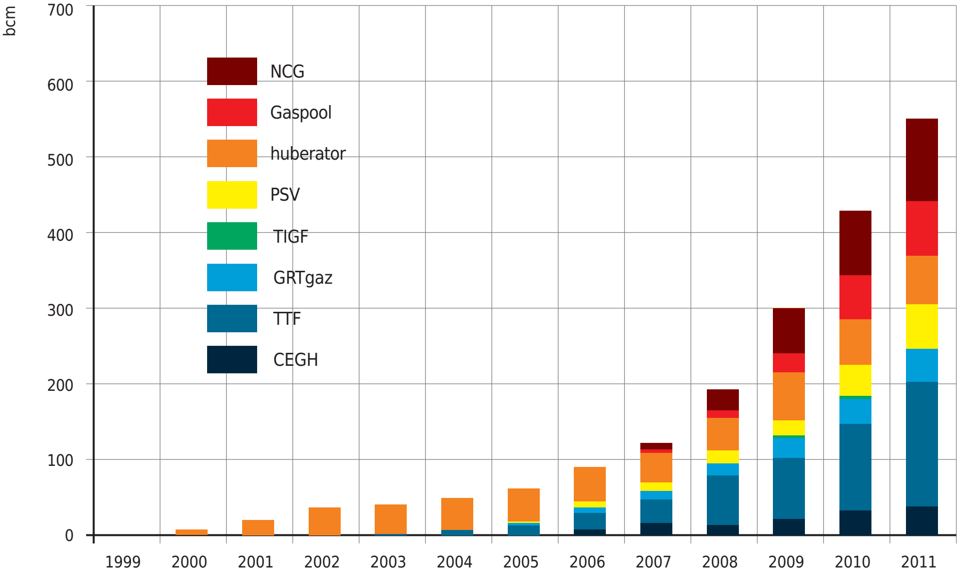
Company	Purpose	Owner(s) and Operator(s)
Dutch storage sites (Grijpskerk, Norg, Maasvlakte, Alkmaar, Bergermeer, Zuidwendig I and II)	Gas storage	Operators: NAM, Gasunie, TAQA Energy BV, Zuidwendig aardgasbuffer
Essent, Eneco, Nuon, Delta	Distribution and supply companies	Owners: Dutch provinces and municipal government
GasTerrra	Trading and supply	Owners: 50% state (10% directly and 40% through EBN, a state-owned company); 25% Shell; 25% Exxon
NAM	Largest gas producer in Groningen	Owners: 50% Shell; 50% Exxon
Gas Transport Services B.V. (GTS)	An affiliate through which Gasunie may own and operate the gas transportation network	Owner and operator: Gasunie
Gasunie	Infrastructure company	Owner: Dutch government

Source: *The Netherlands 2008 Review, www.iea.org, pp. 63, 69.*

Although trade at the TTF has been increasing significantly over the past few years, traded volumes are still far behind those at the NBP. More specifically, gas traded at the TTF was 696 TWh in January 2012, while it reached levels of 1.479 TWh during the same time period at NBP.[205] Out of this total, 320 TWh were OTC trades. Despite being behind the NBP, the rise in traded gas at the TTF attests to its significant growth; by 50 bcm/mth of gas was traded by the end of 2011, and there has been a 62% year-to-year increase in traded volumes at the hub.[206]

In Continental Europe the TTF is the biggest hub in terms of traded volume. Its share and rapid development is pictured on the graph below.

GRAPH 36. **OTC trade at continental hubs in Europe.**



Source: *CEGH.*

The TTF is a hub with easy access to the traded market, strong infrastructure, good access to storage, readily available financial risk management, and a reliable balancing point.

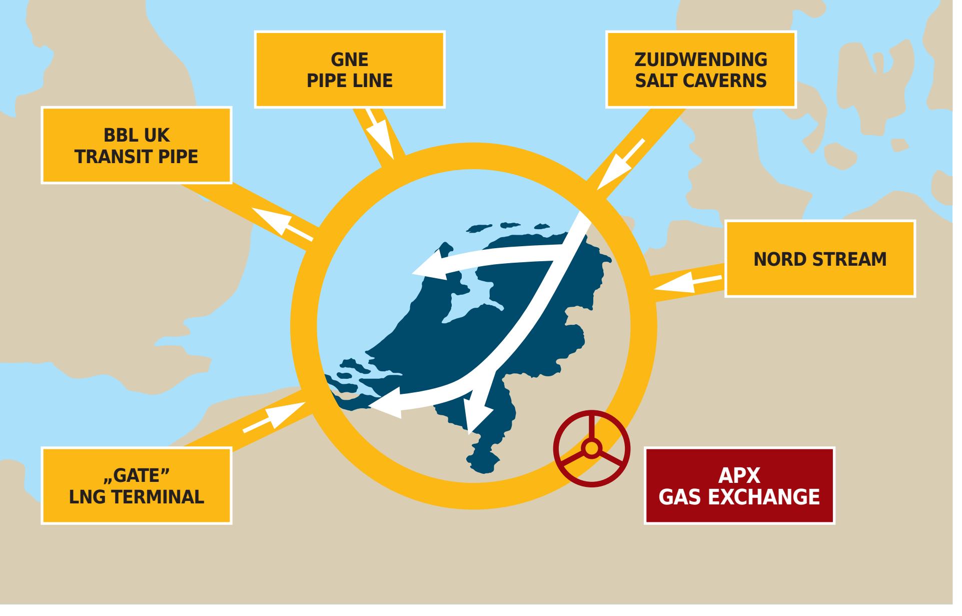
There are a number of improvements that the Dutch government would like to implement to the TTF. First, there is one entry and one exit point, which allows shippers to transport gas without having to pay a fee by avoiding the use of the Dutch system. The government would like to create one entry/exit point to increase activity at the TTF. The other and more important improvement would be to make the TTF a "Gas Roundabout" of Europe[207], since the geographic location of the Netherlands predestines the country to become a strategic market in Continental Europe. By becoming the gas "roundabout" of Europe, the Netherlands would "serve as a gas junction in the international transport of gas and as a gas distribution centre for Northwestern Europe."[208]

Apx-Endex reports that this development in the Dutch natural gas market would be very beneficial because it would increase hub liquidity, the number of market players, and transparency at both the TTF and other European hubs. Additional benefits include extra hub flexibility, an increase in investment in hub infrastructure (including foreign investment), as well as increased communication and collaboration between governments of the EU member states due to an increased integration of the gas market.

The Netherlands is the ideal country for such a roundabout since it already has a large number of players in its gas sector, which sets a solid foundation for such development.

The Dutch government is encouraging quick development of this gas roundabout given the numerous benefits it would provide to the Netherlands. It is predicted that the Netherlands will become a net importer of gas by 2025[209].

GRAPH 37. **The Netherlands as "Gas Roundabout" for Europe.**



Source: *E. Dam,"The Natural Gas Roundabout for Northwest Europe: 'Made in Holland', 2007.*

Zeebrugge, Belgium

The Zeebrugge hub in Belgium remains one of the most important gas hubs in the European Union. The Zeebrugge is a physical transit hub and trades volumes at prices that are closely linked to those available at the NBP and the TTF. It has an overall throughput capacity of 48 bcm/year[210] which includes both pipeline gas and LNG. Importing countries include Norway (via the

Zeepipe), the UK (via the Interconnector), Germany, and Russia. Huberator—a liability company that is a subsidiary of Fluxys—operates the Zeebrugge hub and ensures that volumes bought or sold at the hub by its 80 customers can be re-traded or re-delivered to alternate locations.[211] According to Fluxys, a total net volume traded at the Zeebrugge in 2011 was 769 TWh—more than 3.8 times the annual consumption rate of the Belgium market—and the churn factor rose to 3.9 from 3.3 in 2010.[212] Despite being one of the most important hubs in Continental Europe, the Zeebrugge is still considered insufficiently liquid (as compared to the NBP in the UK or the Henry Hub in the United States).

There are two forms of trading that are available at the ZEE: OTC, as facilitated by Huberator SA, and exchange-based, as facilitated by APX and Zeebrugge BV.[213] Traders using APX facilities may trade either on the within-day (relating to one hour's worth of gas) or Day-ahead (traded as individual days, weekend strips, balance of week, or working days next week).[214]

GRAPH 38. **The ownership and operation of the Zeebrugge hub[215].**

Part of ZEE	Operator	Owner(s)	Ownership (%)
Terminal	Fluxys LNG	Fluxys Tractebel	93 7
Hub services	Huberator SA	Fluxys	90
Spot market	APX Gas Zeebrugge BV	Huberator SA	42

Source: *Author's calculation.*

There are three terminals in Belgium's gas grid, out of which two supply pipeline natural gas flows to Belgium. These two locations to which pipeline natural gas arrives allow the Zeebrugge to serve "as a crossroads of two major axes in European natural gas flows."[216] The first is the Interconnector IZT Terminal operated by Fluxys, the Belgian gas transmission system operator. This terminal links Belgium with the UK via the Bacton terminal.

The second terminal is the Zeepipe terminal, which allows for pipeline imports from Norway. Together with the LNG terminal, the three terminals at the Zeebrugge hub have a throughput capacity of 40 bcm, or about 7% of gas consumption in OECD Europe.[217]

There are no direct barriers to trading at the Zeebrugge, there are two indirect barriers that effect secondary trading markets. The first is that there is a need for prior pipeline access for gas deliveries, yet this information is either not available or is unpredictable. The other barrier is the difference in gas quality specifications between the UK and Continental Europe, leading to lower trade volumes being traded at the Zeebrugge.[218] There are plans for improving Belgium's gas market, one of which is the creation of a virtual trading point that would be called the Zeebrugge Trading Point (ZTP). The ZTP would offer title trading and would function on the entry/exit model. Services at this virtual hub would be provided by APX-ENDEX.[219]

Central European Gas Hub (CEGH), Austria

The Central European Gas Hub (CEGH) of Austria is a physical hub established in 2002 by OMV Gas International GmbH. Its first activity was a gas action of the EconGas Gas Release Program in July 2003.[220] Like the Zeebrugge hub, it is characterized as a "transit hub," or a hub that primarily facilitates the transfer of large volumes of gas to other countries within Continental Europe. CEGH's location in Vienna allows it to serve as one of the major hubs within Continental Europe as evidenced by 40 bcm of natural gas traded in 2011.[221] The hub has three networks known as Control Areas; the eastern transit pipelines, a high-pressure transmission grid, and a high- and low-pressure distribution grid.[222] The hub is dependent on Russian gas and thus has low traded volumes from other suppliers. More specifically, Austria imports a total of 9.6 bcm of natural gas, out of which 51% (4.91 bcm) comes from Russia, 26% (2.54 bcm) from Norway, and the rest from other European countries.[223]

The CEGH is considered transparent, as it has 38 registered members and 32 active members. Some of the services offered by the CEGH include the Tile Transfer, or transfer of ownership of gas at specific trading points; wheeling; no notice storage nomination; online gas actions services; as well as the provision of an online electronic bulletin board.[224] The electronic trading platform is linked to Trayport, and allows for sale of additional volumes. Trading markets available at the CEGH are the OTC, spot exchange, and future exchange. The hub also services importers, traders, and shippers of gas via anonymous exchange trading, OTC trading for shippers and traders to transact, as well as Tile Transfer from shipper to shipper.[225] The Austrian market is not able to handle LNG imports because of its geographic location.

GRAPH 39. **Major companies involved in the Austrian natural gas industry.**

Company	Purpose	Owner(s) and Operator(s)
OMV AG	Exploration and production of natural gas	Owners: 31% state-owned Österreichische Industrieholding AG; 17.6% International Petroleum Investment Company, Abu Dhabi; 50.9% smaller national investors
Rohöl-Aufsuchungs AG (RAG)	Exploration and production of natural gas	Owners: 25% Shell Austria AG; 75% RAG Beteiligungs AG
Wienenergie, EVN, Erdgas Oberösterreich (OÖFG), Steirische Gas Wärme, Begas	Natural gas distribution companies	Owners: distribution companies that own the distribution network of the region Operator for Steirische Gas Wärme: Gasnetz Steiermark
---	Transmission system operators of the Austrian gas grid	Operators: 3 Transit TSOs (OMV Gas, BOG GmbH, TAG GmbH), 5 domestic TSOs (OÖFG, EVN, Gasnetz Steiermark, Begas, OMV Gas)
---	Transit pipeline operators (pipelines which connect the Austrian grid to the European grid)	Operators: TAG GmbH, BOG GmbH (WAG)
Central European Gas Hub Baumgarten (CEGH)	Hub operator	Owner: OMV AG (Gazprom to acquire shares in the future)
---	Natural gas storage	Owners: 75% OMV; 25% RAG

Source: *AUSTRIA 2007 Review, www.iea.org, pp. 65, 75, 77.*

There are six tradable locations associated with the CEGH: Oberkappel (Austria), Ueberackern (Austria), Weitendorf (Germany), Murfeld (Austria), and Mosonmagyaróvór (Hungary), with the most important being Baumgarten (Austria). The Baumgarten is owned and operated by Gas Connect Austria. It has an annual capacity of 89 bcm, and transports one-third of Russian gas destined for Germany, Italy, Slovenia and Hungary.[226] There are thirteen different locations within Baumgarten at which gas may be traded and which are connected by Wheeling Services, all of which ultimately lead to the Tile Transfer Service.

Gaspool and NetConnect, Germany

Germany's Gaspool (GPL) and the NCG (NetConnect) were both established in 2009 and are expanding fairly quickly. They are the result of multiple mergers of a number of zones into a two Market Area system.[227] Each hub is run by six TSOs, so a future merger between GPL and GNC would require a unanimous decision between the twelve TSOs. This possible merger into a unified German Market Area would allow the future German hub to set benchmark prices for gas in Continental Europe.

These two hubs differ from the UK's NBP in a way that prices are established based on the German Border Price (GBP) rather than on the spot market. The German Border Price comes in the form of LTCs with Gazprom that have been negotiated to be linked in 15% to spot indexation prices. The GBP is published by the BAFA (Bundesamt für Wirtschaft und Ausfuhrkontrolle) each month, and is calculated by dividing a total value of gas imports by a total quantity of energy units.

This price represents "an average of the oil-indexed contracts that comprised around 90 percent of German gas supplies (2008) and spot supplies that are increasingly available at the Dutch-German border and Norwegian pipeline terminals."[228]

Both the Germans and the Dutch use a netback value to calculate natural gas delivered at the border allowing for the displacement of competing fuels, a principle called Anlegbarkeit.[229] Both German hubs purchase more often than sell gas on the European Energy Exchange (EEX) or on their own energy platforms. Both had a combined trading of 82 bcm in 2009 and are operated by the same pipeline/service companies.[230] The two major German pipelines are owned by Ruhrgas and Wingas, both of which import gas and transport it domestically.[231]

The NCG is the leading German gas hub and includes the old E.ON Gastransport area. 25% increase in spot trade between October 2009 and September 2010 (from 38.9 TWh to 45.3 TWh)[232] has brought German utilities, European energy companies, and financial institutions to trade at the NCG. Although most contracts are oil-indexed contracts, their duration has been getting shorter with a maximum of about two years. Although most contracts are made on the Day-ahead curve, there is an increasing activity on future curve trading due to a predicted decrease in the number of oil-indexed contracts to be made after the current ones expire. Day-ahead and Within-day products are balanced using the European Energy Exchange (EEX) in the effort of increasing liquidity. The TTF is the main price driver for the NCG, with some room for other factors such as developments in German power, changes in oil prices (which effect the TTF), and supply dynamics. Storage is based on a "first come, first serve" basis, with a total German storage capacity of about 20 bcm in 49 operational storage facilities, the largest of which is E.ON Gas Storage (EGS).[233] There are four transmission systems operating for the NCG—Open Grid Europe (formerly E.ON Gastransport), GRTgaz Deutschland, GVS Netz, and Eni Gas Transport Deutschland—all of which follow the unbundling regulations established under the third energy package.

Gaspool Germany is not as popular as the NCG, although it is operated as a physical rather than a virtual hub. It is mostly used as a storage area, which the ICIS Heren suggests will boost volumes and liquidity at the expense of that of the NCG and the TTF. 21% of total Gaspool trades are Day-ahead trades, and the TTF is the main price driver. Gaspool and the NCG spot contracts are normally at parity, with only a €0.01/MWh discount.[234]

There is a variety of storage products available at Gaspool, and traders can easily cycle or withdraw gas as well. Nevertheless, there is some inefficiency within the storage system since many customers overbook due to much more expensive Day-ahead than annual capacity, leaving the grid "contractually congested and inefficiently used."[235] The Bundesnetzagentur (BNetzA) regulator is trying to find ways to counter this problem.

GRAPH 40. **Major companies involved in German natural gas industry.**

Company	Purpose	Owner(s) and Operator(s)
Ruhrgas, RWE-DEA, Gaz de France, Wintershall	Natural gas producers	Owners: Exxon, Shell
Small/municipal Stadtwerke companies	Gas marketing	Owners: local German governments
Regional Stadtwerke companies (Gas Union, Bayerngas GmbH, Saar Ferngas AG)	Regional gas utilities	Owners: regional governments
Large Stadtwerke companies (E.ON Ruhrgas AG, Verbundnetz Gas AG, Wingas GmbH)	Supra-regional gas utilities	Owners: ExxonMobil, Shell
RWE	Owner of VEW and Thyssengas (importers); Ruhrgas's largest distributor	---
Gaz de France (GDF), Danish DONG, Dutch Essent, BP, Italian ENI	Foreign players in German natural gas market	---
---	Storage facilities	Operators: E.ON Ruhrgas, Wingas, VNG, RWE, independent facility operators

Source: *GERMANY 2007 Review, www.iea.org, pp. 98, 100, 109.*

Punto di Scambio Virtuale, Italy

The Punto di Scambio Virtuale hub in Italy is a virtual hub operated by Snam Rete Gas. The PSV is considered a "transition hub," or a hub that is only starting to liberalise and to offer trading products.[236] The PSV deals not just with imports of LNG but also with imports of natural gas from Russia, Northern Europe, and Northern Africa (Algeria and Libya). The Italian PSV hub does not thrive as the German and the UK hubs do due to low availability of spot gas. The price benchmark for gas on the Italian market is based on the TTF index plus costs of transportation of gas to Italy, with the rest of the pricing depending on a company making the deal. LNG contracts with Algeria are in the form of long-term take-or-pay contracts with prices indexed to that of Brent crude. The low availability of spot gas may be attributed to "transfer of ownership" points for imported gas and to ENI's monopoly of indigenous gas supplies.[237] This leaves less room for competition, and thus limits gas-to-gas pricing mechanisms. This problem was noted by ICIS Heren in its analysis of the PSV where it was stated that the Italian hub just facilitates bilateral, private deals rather than makes prices transparent for all Italian gas companies.[238]

The use of LTCs also makes the hub inaccessible to those who wish to access the TAG and Transitgas pipelines on a short-term basis.[239] To make the PSV more efficient, the TAG pipeline was established to bring imports from wholesalers such as E.ON, GdF, RWE, and others who buy Russian volumes (which can only be bought on LTCs under ToP clauses) and sell to hubs.[240] Otherwise, bid and offer spreads are wide because the number of participants willing to transact at the PSV is limited.

GRAPH 41. **Major companies involved in the Italian natural gas industry.**

Company	Purpose	Owner(s) and Operator(s)
Snam Rete Gas (separated into two, belonging to National Gas Pipeline Network and Regional Gas Pipeline Network)	Main transmission operator, owner of Italian gas transmission system	Owner: ENI
Società Gasdotti	Transmission operator	---
Stoccaggi Gas Italia (Stogit)	Owner and operator of 8 out of 10 Italian storage facilities	Owner: Snam Rete Gas (part of ENI group)
PSV	Italian gas hub	Mostly operated by ENII
---	Retail sellers of natural gas	Market shares: 43.9% ENI, 16.4% Enel, 14.4% Romagna, 10.8% Piedmont, 8.1% Lazio, 7.2% Veneto, 7% Tuscany

Source: *ITALY 2009 Review, www.iea.org, pp. 104, 106, 108, 110.*

Points d'Echange de Gaz, France

There are three virtual hubs in France established in 2004, all owned by Gaz de France: the PEG (Points d'Echange de Gaz) Nord, the PEG Sud, and the PEG TIGRF. The first hub covers the high calorific entry/exit north market zone and is operated by GRTgaz, the second covers the southern market zone and is also operated by GRTgaz, and the third hub - the TIGF covers the southwest market zone and is operated by Total (TSO).

The PEG Nord consolidates into one hub the zones in the west, north, and east. These hubs are characterized as transition hubs that are only beginning to liberalise and serve mainly as a balancing tool. Powernext, a French trading exchange company, works alongside GRTgaz and TSO to balance the zones and to minimize price differentials between the three regions.

Since July 2011, for example, the price differential between regions has decreased from €1/MWh to zero.[241] The coupling of prices on the PEG Nord/Sud spread enables trade and thus allows for more participants to enter the French market.

GRAPH 42. **Major companies involved in the French natural gas industry.**

Company	Purpose	Owner(s) and Operator(s)
EDF	Grid operator	Owner: 84.4% state
GDF Suez	Grid operator	Owner: 35.7% state
GRTgaz	Manager of gas transmission system	100% Subsidiary of GDF Suez
TIGF (Total Infrastructures Gaz France)	Manager of gas transport network in southwest France	100% Subsidiary of Total
GrDF	Manager of gas distribution system	Subsidiary of GDF
Storengy	Storage	Subsidiary of GDF Suez
Elengy	Operator of LNG terminals	Subsidiary of GDF Suez (with some work by Shell and Vopack)

Source: *FRANCE 2009 Review, www.iea.org, pp. 22, 23, 57, 64.*

Services offered at these French hubs are varied. The PEG Nord offers contracts made on Day-ahead, Weekend, one month ahead, one quarter ahead, and one season ahead. Both the PEG TIGF and the PEG Sud offer contracts made on the Day-ahead and Weekend. The French investment firm Powernext offers spot contracts for all three hubs, as well as future contracts for the PEG Nord. Nevertheless, the PEGs have only been used as balancing points rather than areas of trade due to low levels of liquidity.[242]

Despite a 57% increase in spot trading, there has been a decrease in the exchange of futures as well as a one-third drop in OTC trades, for a combined 36% drop in gas trades from Q1 2011 to Q1 2012.[243] The most liquid of the three hubs is the PEG Nord.

Spain

There are no gas hubs in Spain, although the first hub is planned for construction in the near future. Thus current trade is done on a platform developed by Enagás called MS-ATR (Mercado Secundario de Acceso de Terceros a la Red). The MS -ATR was implemented in 2005 and was developed on a web system basis as part of the TPA IT System (SL-ATR: Sistema Logístico de Acceso de Terceros a la Red).[244]The MS-ATR oversees that gas transport services to receive offers to manage imbalances and allows negotiation of gas prices to be anonymous. Unlike the UK, there is no spot market for gas and thus both underground storage and OTC trade are important in order to allow new entrants into the market access to gas supplies and an ability to grow their market shares.[245] OTC is especially important for smaller gas traders, although there is no transparency for OTC prices on the market since they are not public. Most large LNG companies receive LNG tanks frequently and therefore rely less on OTC swaps. These larger companies make up a large portion of each regas terminal, making these "sub-markets" less liquid and harder for smaller traders to enter.[246] The CNE has, consequently, developed a price index for natural gas border prices that serves as a price reference for gas in Spain. Otherwise, LNG (as well as pipeline gas) is mostly purchased on long-term contracts based on oil-indexed prices such as Brent crude oil.[247] Buyers in the power sector sometimes base gas prices on wholesale electricity market prices and coal prices, although this pricing mechanism is in decline because electricity prices are volatile.

Asia

As previously discussed, while the natural gas hubs (the location where spot market prices are determined and oil shares traded) are important for both the US and Europe, they are nearly non-existent in Asia. The area lacks any sort of hubs that is relevant to the region from which prices can be linked to. The countries within the area lack pipeline connections between them, and their individual markets are dominated by one or two major actors. Also, invasive government regulation has led to a lack of transparency and competitiveness in regards to pricing mechanisms. Because of these factors no natural gas hubs have been created up to this point.

However, due to surging demand of natural gas, many believe that the construction of an Asian LNG trading hub is essential. Some even argue that a significant hub is in the works. Singapore's state-run LNG Corporation is currently constructing an LNG terminal with an initial operational capacity of 4.8 bcm/y that is due to open in 2013. By the end of 2013 the terminal will have a throughput capacity of 8.3 bcm/y[248]. Storage capacity will amount to 540 thcm once all three tanks are completed[249]

It is designed to be the first open-access terminal in Asia, meaning that it will allow for a variation of user and shipping types, and enable import and re-export of LNG. The terminal will lead to a diversification of LNG sources, which will help to alleviate risks associated with both price and supply[250]. Through storage of fuel from various suppliers for distribution to different areas, a benchmark price for natural gas could be created. This in turn could serve to allow for the trading of contracts with the Singapore terminal as a delivery location[251].

Hubs operators are anxious to offer services to accommodate the quickly growing LNG market in Asia and create a spot trading market. Experts involved in the project believe that Singapore is poised to become an LNG hub in the next five years.

Types of contracts

US

The NYMEX is where most of these financial natural gas transactions occur in the form of natural gas futures contracts. These contracts give the opportunity to buy or sell a contractual right which enables to buy or sell a specified amount of natural gas at a specific location at a specific time in future[252].

A typical contract is for 10000 MMBtu delivered to the Henry Hub (HH) in a following month or any other time within the next ten years or more[253]. Normally, these financial transactions do not actually end up in a physical transaction. In fact, the churn rate in the United States is 100, meaning that a contract is traded 100 times before reaching the consumer who will physically receive the gas. Most of trading on the NYMEX occurs in what is known as a 'bid week', which falls on the last week of each month. At this time, producers aim to sell most of their natural gas, and buyers seek to secure contracts which will meet their natural gas needs for a month.

Apart from natural gas futures contracts, there are various other instruments used in the NYMEX to hedge risk. They include over-the-counter instruments such as basic swaps, index swap futures, and swing swap futures[254]. Within basic swaps, parties hedge a price difference between the Henry Hub and a different location. Index swap futures are defined by management of the differential between the monthly and daily index at a specific location. The swing swap is the switching of a fixed price for a published daily price index such as the Gas Daily.

EUROPE

As previously stated, types of contracts available on the European gas market depend on a hub at which gas is traded. In general, gas is traded on long-term contracts with some adjustment to spot-market pricing. OTCs are gaining popularity at European gas hubs, but so far, future trades are low as compared to those in the United States.

GRAPH 43. **Types of contracts available at European gas hubs.**

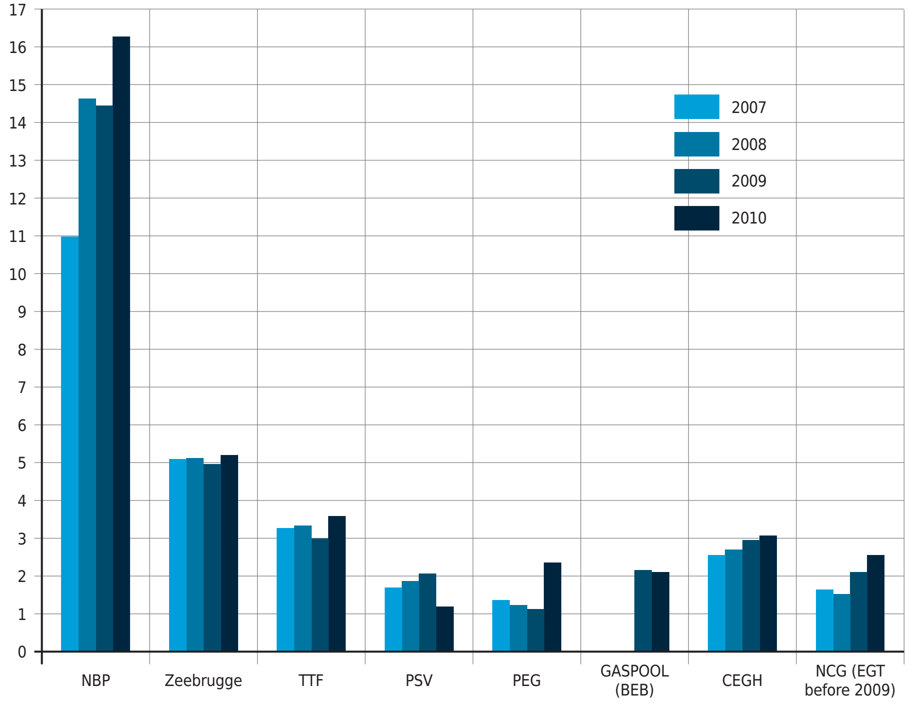
Hub Name		Type of contracts available
1	Central European Gas Hubs (CEGH), Austria	Day-ahead, weekend, one-month ahead
2	Gaspool (GPL), Germany	Day-ahead, weekend, three months ahead, four quarters ahead, four seasons ahead
3	National Balancing Point (NBP), UK	Day-ahead, weekend, WDNW, BOM, six months ahead, eleven quarters ahead, ten seasons ahead, two gas years ahead, two calendar years ahead
4	NetConnect (NCG), Germany	Day-ahead, weekend, WDNW, BOM, three months ahead, four quarters ahead, five seasons ahead, two calendar years ahead
5	Points d'Echange de Gaz Nord (PEG), France	Day-ahead, weekend, one month ahead, one quarter ahead, one-season ahead, OTC
6	Points d'Echange de Gaz Sud (PEG), France	Day-ahead, weekend
7	Points d'Echange de Gaz TIGRF (PEG), France	Day-ahead, weekend
8	Punto di Scambio Virtuale, Italy	Day-ahead, weekend, two months ahead, one season ahead, one gas year ahead
9	Tile Transfer Facility, Netherlands	Day-ahead, weekend, WDNW, BOM, three months ahead, six quarters ahead, six seasons ahead, one gas year ahead, four calendar years ahead
10	Zeebrugge, Belgium	Day-ahead, weekend, WDNW, BOM, three months ahead, six quarters ahead, three seasons ahead, one gas year ahead, one calendar year ahead

Source: *European Spot Gas Market Methodology, www.icis.com.*

Liquidity

A high level of liquidity is needed for a natural gas hub to be able to operate successfully. The facility must be able to maintain the trading interest of natural gas customers in order to make money.[255]

GRAPH 44. **Churn Ratio at European Hubs.**



Source: *A Choice to be Made; A View from Gazprom Export, Komlev, p. 7.*

Although liquidity - which is measured by a hub's churn rate, or a ratio between a total volume of trades and a physical volume of gas consumed[256] - on the gas market has increased due to price convergence between spot gas and LTCs, there is no consistency in liquidity between major European hubs. More specifically, the NBP has a depth of up to two years, while the TTF has a low level of hedging.[257] Thus, the NBP tends to be a price driver for all other markets. The NBP has a rate of 10 to 15, while Continental Europe has a churn rate of less than 10.[258] The increase in spot trading has increased transparency on pricing in the gas market, but major hubs such as the NBP still have access to information not available to a buyer. Additionally, there is a weak price-elasticity of demand in Europe for two reasons: gas imports often involve national companies—or whole buyers—on both sides of the exchange, and gas is not used so much in power plants.[259]

GRAPH 45. **Churn Ratios for European gas hubs[260].**

Hub Name	Churn Ratio
CEGH	3
GPL	2 - 2,5
NBP	15
NCG	2
PEG Nord	1,5
PSV	2
TTF	5
ZEE	5

Source: *http://www.oil-gas-energy-conferences.com/gas/html/speakers2010/Stream_LNG&Gas-Hubs_101004.pdf.*

Conclusions

Nowadays hubs are located in two regions: North America and Europe. In the US the rapid development of the hub concept started ten years earlier than in Europe. At the moment there are 10 hubs in Europe, 24 in the US and one is considered to be launched in Asia-Pacific.

Prices in hubs, both in Europe and in the States, are strongly correlated with each other. The reason for that is the fact that the US as a country and the EU as a Union with multiple single-market regulations are local markets where supply and demand play takes place on a regional and not a local level. It is particularly visible in Europe where hub-developed gas prices in a number of countries are in fact very close to the European average which allows for drawing a conclusion that the European hub gas market is close to a single gas market.

Europe does not have a single reference point such as the Henry Hub in the US, but there is a number of hubs which are more developed than others and might serve as a reference. The first one is the NBP, for the UK market stands out from the EU in terms of the progress of market development when compared to the US. The NBP is the most liquid and most transparent hub as well as the one in which the largest volumes in Europe are traded. The next in line are the Zeebrugge and the TTF. The Dutch government plans to implement a number of actions to make the country a "gas roundabout" of Europe. The TTF is already the biggest continental hub in terms of volume. It is also one of the most liquid hubs competing against the Zeebrugge. The geographical location of the Netherlands enables the country to merge multiple factors important for a gas market: pipelines, extraction, LNG terminals.

CEE region does not have its hub yet, although there has been a concept of creating one in Poland. Nevertheless, European hubs already play a vital role in the region. The European Union has been investing in the creation of a single gas market and plans to continue this trend. To some extent the countries of the region already have the opportunity to buy gas at hubs and this will be changing in the years to come. Rapid development in hubs is a result of market ambition for gas to be priced according to market rules[261]. This is facilitated by a number of factors described in this report such as LNG development, creation of a single market, potential unconventional gas production. Hubs are the "tool" enabling the supply and demand side to meet in market environment. Hubs have created an alternative that had not existed before and suppliers have to take it into account. There have already been a number of cases where Russian Gazprom agreed for concessions in LTCs which added a market factor in the form of indexation to hubs to a price calculation mechanism.

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7. Global developments of LNG

In the recent decades an important development has changed the sector of natural gas transportation. The process of liquefaction and regasification of natural gas has allowed for the development of the worldwide natural gas trade that before was possible only through the construction of international pipelines. By the end of 2011, there were 89 regasification facilities in the world compared to only 40 that existed in 2001, which shows the dynamics of this market[262].

The development of LNG technologies allowed for integration of what is known as "stranded areas", i.e. areas of production or consumption of natural gas which lack pipelines to transport gas – to the global market.

As for now Central and Eastern European countries have no direct connection with the global LNG market. Certain investments are, however, under construction, in particular an LNG terminal in Świnoujście (Poland), and some are about to be started, for instance an LNG terminal in Croatia[263]. Once those investments are completed, they will give CEE countries a direct access to global LNG markets. However, to some extent CEE countries may already benefit from the development of LNG in the EU. It is important to know to what extent developments on the global LNG market influence now and may possibly influence price formation mechanisms in CEE and in particular in the Visegrad Group countries.

LNG at glance

Liquefaction is a process in which natural gas is cooled until it condenses and transforms into a liquid form. The advantage of liquefied natural gas is that it takes up only one six-hundredth of its gaseous volume, which greatly facilitates transport. Liquid gas is loaded onto tankers and shipped to other destinations. After being unloaded from tankers at an importing destination, LNG is then regasified and then transported in its gaseous state via physical pipelines.

Liquefaction makes it feasible to transport natural gas efficiently by means other than pipelines and opens up a possibility of exporting it to many locations worldwide[264]. The development of LNG capabilities has stimulated investment in infrastructure for both the import and export of LNG. Since the second half of the 21st century many facilities have been constructed throughout the world to send or receive imports of liquefied natural gas LNG from abroad. Commercial LNG shipping was initiated when Europe's first import was delivered to Canvey Island in the UK from Lake Charles in the US in 1958. The first commercial projects began in 1964 when Algeria began delivering supplies to France and the UK, and Libya to Italy and Spain[265]. In Asia, the very first LNG import received in Japan in 1969 came from the Kenai LNG terminal in Alaska in the US. Two years later the US opened its first LNG receiving terminal in Everett, Massachusetts. Since the 1960s the interest in LNG has been on the rise and is forecast to continue at a steady rate. Since the very first shipments LNG trade has developed. In 2011 LNG made up 32% of the global gas trade, which constituted a 2% increase in comparison to the previous year[266]. Through the decades trade volumes had grown steadily and 2011 saw a record high imported quantity of 330.8 bcm, that is a 10% increase compared to the previous year[267]. In the period from 2005 to2009 LNG trade grew by an average of 7% yearly before making a huge jump of 22% in 2010[268]. During the period of economic recession (2008-2009), the worldwide demand for gas decreased significantly. It was related to the economic slow-down and high cost of oil-indexed natural gas. Yet, unlike natural gas, LNG pricing took into account market prices which were significantly lower than prices set in LTCs.[269] This is how Europe's increased consumption of LNG over natural gas began. The 22% jump in 2010 can be attributed to the end of the economic downturn as well as to an unusually cold winter, which led to an even more significant increase in LNG demand.[270] Experts predict that LNG trade will only continue to grow. LNG demand is expected to increase to over 880 bcm/y by 2030 from current 330 bcm/y[271]. A great number of LNG terminals under construction, approved, and planned globally proves the importance of this source of natural gas.

LNG by Region

In order to gain a more comprehensive understanding of the global LNG trade it is necessary to note significant differences that exist between various regions.

US

The United States (US) is the biggest player on the LNG market in North America. The US became involved with LNG in the 1960s when it began exporting it to Japan. Past estimates of natural gas reserves and extraction possibilities in the US were less than optimistic. Although it was expected that the domestic supply would run out within the next couple of decades, the relatively low demand for natural gas as a fuel source kept the situation under control. However, in the 1970s the demand surged, and the need to explore other means of acquiring natural gas became apparent. LNG was a solution to the problem of undersupply. Therefore, from 1971 to 1980 LNG import terminals in Louisiana, Massachusetts, Maryland, and Georgia were constructed[272].

Through the next several decades the construction of infrastructure related to LNG continued at a rapid pace. Advances in domestic gas production that culminated in the shale gas revolution in 2008 have completely changed the demand environment for LNG. Presently, the US is perceived as the world's largest producer of natural gas and the its natural gas production increased by 7.7% in 2011 compared with the previous year[273] outpacing the world's production 2.5 times. With the rise in production and estimates of reserves of shale gas that continue to be revised upward, the building of LNG import terminals has stalled. With regard to LNG, 2011 saw a drastic 25.1% drop in imports (net of re-exports) due to consistently high levels of production of unconventional natural gas. In fact, with the improved ability to produce natural gas the US is now on its way toward becoming an LNG exporter.

EUROPE

Despite relative improvements within the gas market in Europe, the International Gas Union predicts that gas production in Europe will decrease until 2030. This prediction is based on the assumption that European nations will not be able to take advantage of the following: increasing prospects for new gas discoveries; efficient reserve locations relative to main markets; high export opportunities arising from domestic and regional market development; stable political and legal framework with predictable policies; high availability of capital.[274] It is estimated that imports will represent over 80% of European gas supply with 38% representing LNG volumes by 2030.[275] This will, in turn, lead to an increased need for storage since pipelines gas deliveries have smaller volume flexibility than local production.[276]

A recent growth in LNG demand can thus be attributed to a growing demand for imported gas by the power sector while at the same time the domestic gas production in Europe declines. Major importing European countries include France, Spain, Italy, Belgium, Greece, Portugal, and Turkey. Germany is set to become a noteworthy importer of LNG especially because of its non-nuclear policy. This policy—which went into effect in 2011 after the Fukushima disaster in Japan—temporarily terminated activity in seven nuclear reactors in March of 2011, with another six to be closed down by 2021. The three remaining nuclear reactors will operate until 2022 to ensure power supply.[277] This new policy, in addition to a decrease in the amount of coal used for energy supply, will lead to an increase in LNG imports to Germany. Spain is currently the largest LNG importer in Europe, with volumes that reach almost 25 bcm/y[278]. Although spot and short-term LNG imports in Europe decreased by 7.8% in 2010, which resulted in a 2.6% loss in market shares,[279] the need for energy has stimulated LNG trade, and the market for that source of energy is steadily growing on the continent.

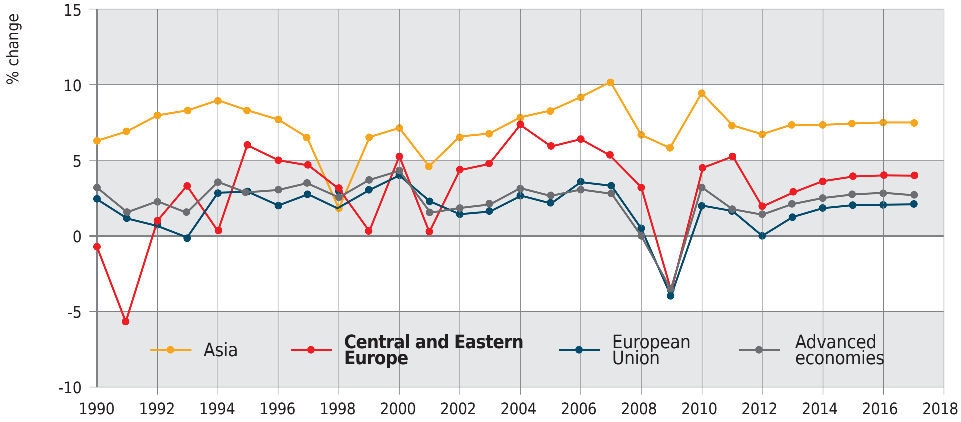
The current LNG development in CEE region includes the LNG terminal in Świnoujście in Poland which is scheduled for completion in June 2014 as well as terminals planned to be constructed in Croatia. Due to market proximity it is also worth to mention LNG plans in Albania. The initial capacity of Świnoujście terminal is set at 5 bcm/y and at the moment it is the only LNG terminal in the region under construction. The Croatian Adria LNG terminal has been discussed for last years and it seems the country is still interested in developing the investment, particularly given a possible EU investment participation. However, there are some factors slowing down the decision process such as slow decision-making procedures and expected oversupply of the commodity. Croatia's terminal is planned to operate at 15 bcm/y capacity whereas the country's domestic consumption stands at 3 bcm/y only. The disproportion aims at enabling Croatia to become a key transit country for gas transportation. It is planned that the final decision regarding the investment will be taken in 2013[280]. Due to market proximity Albania's LNG plans can also have influence on CEE market. The Levan terminal project was initiated in 2008 and it is still in a planning phase. The projected capacity stands at 8 bcm/y with the option to expand it to 12 bcm/y[281].

Investments in Poland, Croatia and Albania will open CEE market to a new supply channel of natural gas which will set an alternative to Gazprom commodity. Croatia's membership in the European Union as of July 2013 will result in the country's prospect plugging into the EU gas system and as such will ensure additional gas supply once the terminal is completed. CEE region will benefit from an increased amount of resources, which will have impact on regional LTC.

Asia

Economic growth and population increase are the most significant stimulators of growing energy demand[282]. Asia boasts the highest GDP growth from 1990 to 2011 with an average 7.2% annually[283].

GRAPH 46. **Gross Domestic Product Annual Changes in World's regions.**



Source: IMF.

It is also home to the highest proportion of the world's population when compared with other regions. Thus, with growing economies and populations, the region is anxious to utilise new, less traditional sources of energy in order to meet its demands. For example, in the two populous countries of India and China, coal has traditionally made up a huge portion of energy used. It was plentiful and its extraction was relatively simple. Now, alternatives to coal such as natural gas in the form of LNG have gained prominence. Since the 1960s, when Asia received its first shipment of LNG, consumption has increased dramatically. LNG has been and will be of great importance to the Asian region.

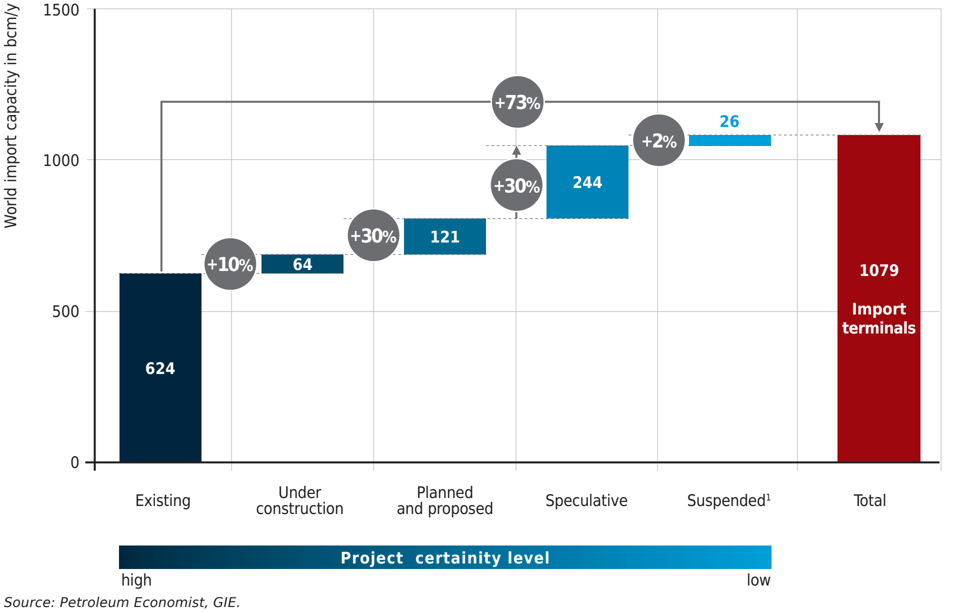
When discussing the major players involved in the LNG market within that area, the Asian Pacific countries should also be included. Expanding the Asian region (Japan, South Korea, Taiwan, China, and India), to the Pacific region (Australia, Malaysia, and Indonesia) makes it easier to understand the dynamics of the LNG trade. For instance, within the Asia Pacific territory there are stark differences in domestic supply of natural gas. Japan and South Korea, for example, are not endowed with large reserves of natural resources making them major importers of LNG. In contrast, Malaysia, Indonesia, and Australia have significant domestic supplies, which makes them major exporters of LNG. This results in large volumes of LNG being exchanged within the region itself. Apart from the lack of domestic supplies of natural gas in some countries, the geographical terrain has made the laying of physical pipelines challenging. Therefore, the Asian countries (Japan and South Korea especially) rely almost exclusively on LNG imports to meet natural gas demand. In fact, in 2011 LNG consumption in Asia accounted for 63.6% of the total global LNG trade[284].

While the LNG trade is relatively new in countries such as China and India, Japan and South Korea have a more developed and extensive experience with LNG. For decades Japan has claimed the position of a top importer of LNG in the world. By the end of 2011 the LNG consumption in Japan reached 32.8% of the global imports. South Korea came in second claiming 14.8% of the imports worldwide. With a continued population and economic growth, in China and India particularly, the role of LNG in the Asian region has become even more significant. Last year, the demand for LNG in India grew by 37.4% and in China by 36.1%[285]. Japan is another country whose demand is likely to increase in future. After the earthquake and subsequent tsunami which led to the Fukushima nuclear disaster in March 2011, the energy outlook for Japan has shifted. The government is now shying away from nuclear power and looking to other fuel sources to fill the gap. Natural gas in the form of LNG is one of the fuels that has been utilised to make up for the loss of nuclear capacity[286]. These huge jumps in demand originating from China and India combined with the sustained demand from Japan and South Korea will maintain Asia's position as a top importer of LNG.

LNG terminals development

There is a number of importing or exporting LNG terminals located worldwide. Currently, there are 11 terminals in the United States, 20 in Europe, and 44 in Asia. The other are located in countries where LNG imports are not that significant.

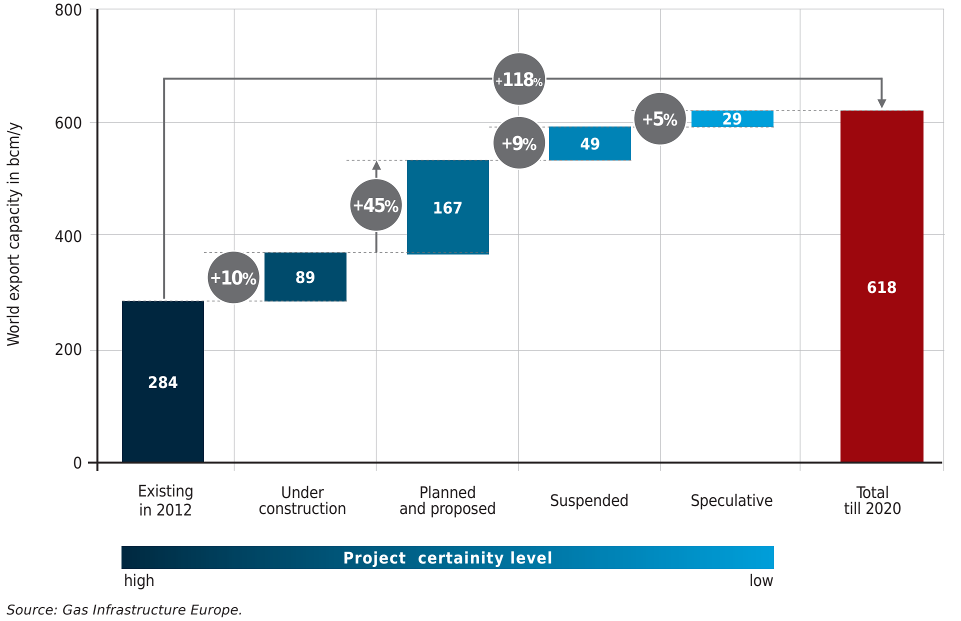
GRAPH 47. **World LNG import capacity forecasts till 2020.**



Source: Petroleum Economist, GIE.

Currently, the world's total import capacity is 624 bcm/y but it is to increase by 73% to 1079 bcm/y by 2020. LNG receiving terminals currently under construction will add an import capacity of 64 bcm/y (10% increase), planned and proposed terminals 121 bcm/y (30% increase), speculative terminals 244 bcm/y (30% increase), and suspended terminal projects 26 bcm/y (2% increase).[287] Blue colour shade indicates project certainty where darker blue means development the completion of which is most probable.

GRAPH 48. **World LNG export capacity forecasts till 2020.**



Source: Gas Infrastructure Europe.

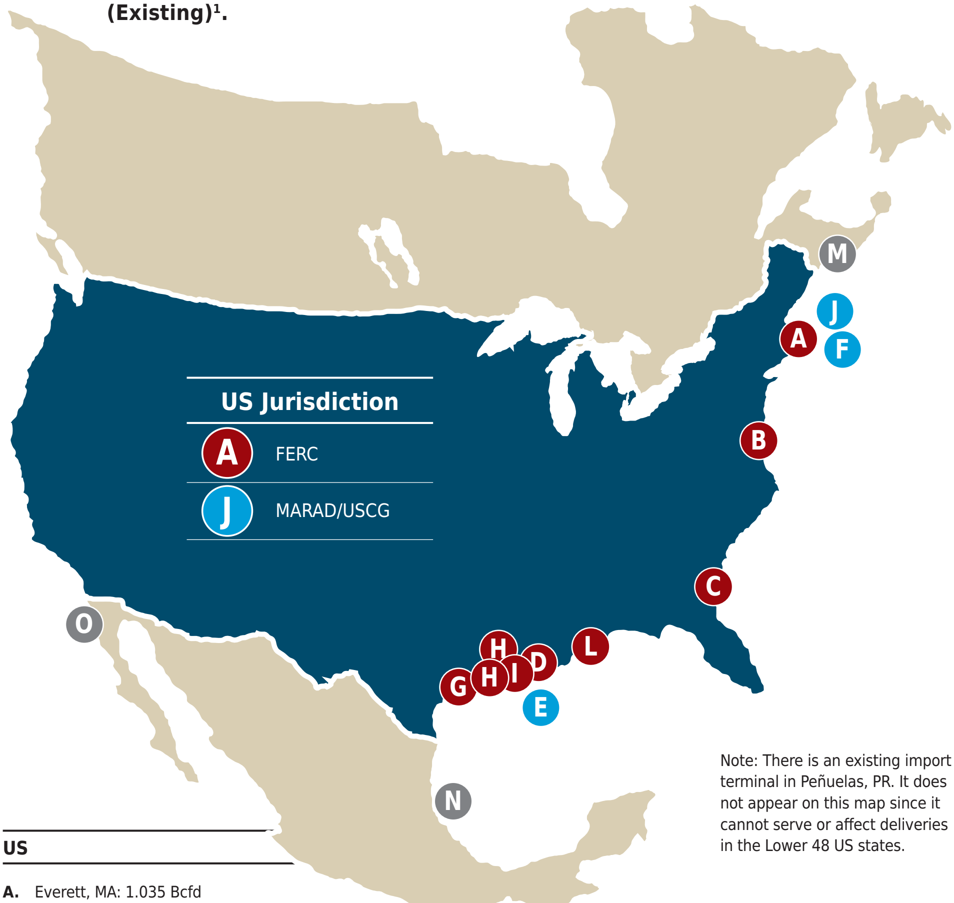
The operating world export terminals have a total export capacity of min 330 bcm/y[288]. However, in order to satisfy growing demand for LNG—especially in Europe and Asia—a number of new terminals will be opened. The terminals under construction will add an export capacity of 89 bcm/y (27% increase), those planned and proposed another 167 bcm/y, those suspended 49 bcm/y, and those speculative 29 bcm/y, for a total increase of 101%. Thus, a projected total export capacity in 2020 will amount to 665 bcm/y[289]. It is worth noticing that the attractiveness of LNG gas results in a much higher forecast import than export capacity, which puts an exporter in a better negotiation position.

The following subchapters will detail export/import terminals by region: the US, Asia-Pacific, and Europe. The sections on Asia and Europe will be divided by country to get a more accurate glimpse of the LNG terminals in those areas.

US

As of April 26, 2012, there are 11 LNG terminals in the United States under the Commission's jurisdiction[290]. Seven are situated in the Gulf Coast area, three along the Atlantic Coast, and one off the shores of Alaska.

GRAPH 49. **North American LNG Import/Export Terminals (Existing)[1].**



Note: There is an existing import terminal in Peñuelas, PR. It does not appear on this map since it cannot serve or affect deliveries in the Lower 48 US states.

US

- **A.** Everett, MA: 1.035 Bcfd (GDF SUEZ – DOMAC)
- **B.** Cove Point, MD: 1.8 Bcfd (Dominion – Cove Point LNG)
- **C.** Elba Island, GA: 1,6 Bcfd (El Paso – Southern LNG)
- **D.** Lake Charles, LA: 2.1 Bcfd (Southern Union – Trunkline LNG)
- **E.** Gulf of Mexico: 0,5 Bcfd (Excelerate Energy – Gulf Gateway Energy Bridge)
- **F.** Offshore Boston: 0.8 Bcfd (Excelerate Energy- Northeast Gateway)
- **G.** Freeport, TX: 1,5 Bcfd (Cheniere/Freeport LNG Dev.)*
- **H.** Sabine, LA: 4,0 Bcfd (Cheniere/Sabine Pass LNG)*
- **I.** Hackberry, LA: 1,8 Bcfd (Sempra – Cameron LNG)*
- **J.** Offshore Boston, MA: 0,4 Bcfd (GDF SUEZ – Neptune LNG)
- **K.** Sabine Pass, TX: 2,0 Bcfd (ExxonMobil – Golden Pass) (Phase I & II) * *
- **L.** Pascagoula, MS: 1,5 Bcfd (El Paso/Cres/Sonangol – Gulf LNG Energy LLC)

Canada

- **M.** Saint John, NB: 1,0 Bcfd (Respol/Ford Rellance – Canaport LNG)

Mexico

- **N.** Altamira, Tamulipas: 0,7 Bcfd (Shell/Total/Mitsui – Altamira LNG)
- **O.** Baja California, MX:1,0 Bcfd (Sempra – Energia Costa Azul)

* *Authorized to re-export deliveres LNG*
* * *Pending/Potential to re-export delivered LNG*
1. *The Kenai Alaska LNG terminal is not included on the map due to inactivity as of 2011.*
Source: US Department of Energy

In 2010 the existing LNG import terminals in the United States were responsible for the importation of 12.1 bcm of LNG[291].

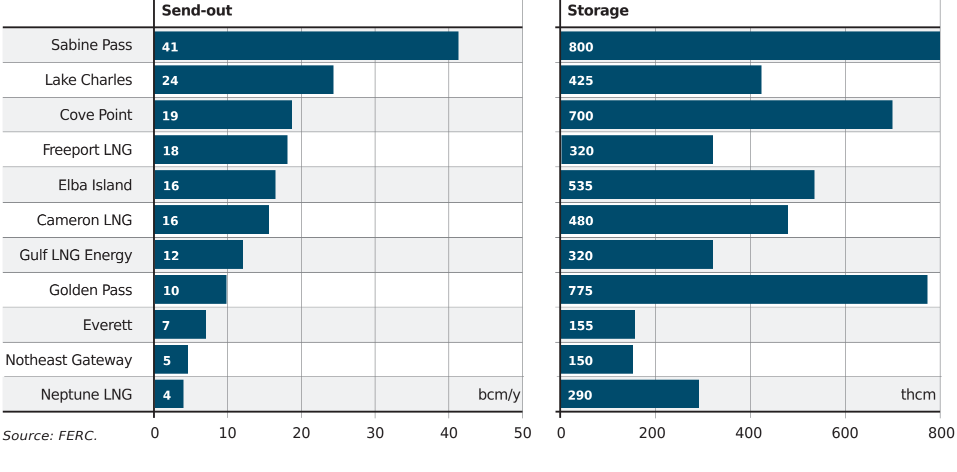
GRAPH 50. **Name and location of existing LNG terminals.**

Lp.	Name and location of LNG terminal	Operated from	Send-out capacity bcm/y	Storage capacity thcm
1.	Sabine Pass LNG in Cameron Parish, Louisiana	2008	41.35	800
2.	Lake Charles in Lake Charles, Louisiana	1982	24.30	425
3.	Freeport LNG in Freeport, Texas	2008	18.00	320
4.	Elba Island LNG in Elba Island, Georgia	1978	16.30	535
5.	Cameron LNG in Cameron, Louisiana	2009	15.50	485
6.	Gulf LNG in Pascagoula, Mississippi	2011	12.00	320
7.	Cove Point LNG in Cove Point, Maryland	1978	10.74	380
8.	Golden Pass LNG near Sabine Pass, Texas	2010	9.80	775
9.	Everett LNG located in Everett, Massachusetts	1971	6.9	155
10.	Guayanilla Bay LNG in Guayanilla Bay, Peñuelas, Puerto Rico	2000	3.75	160
11.	Kenai, Alaska	1969	0.22	108

Source: Existing FERC Jurisdictional LNG Import/Export Terminals, Federal Energy Regulatory Commission, The LNG Industry, GIIGNL, 2011.

The graph enables to compare American terminals by picturing their positions both in terms of send-out and storage capacities. Sabine Pass LNG terminal is the biggest terminal in the Americas and the fourth biggest in the world, preceded only by one Japanese and two Korean terminals. Its send-out capacities reach 41 bcm/y, which in fact is over 3,5 times higher than total US LNG imports in 2011. Storage capacities of US terminals vary from 150 thcm to 800 thcm. Due to the strategic significance of southern states on the gas market most terminals are located at the Gulf of Mexico in Louisiana and Texas. Pipelines connections allow natural gas transfer to almost any location within the country.

GRAPH 51. **US LNG terminals by storage and send-out capabilities.**

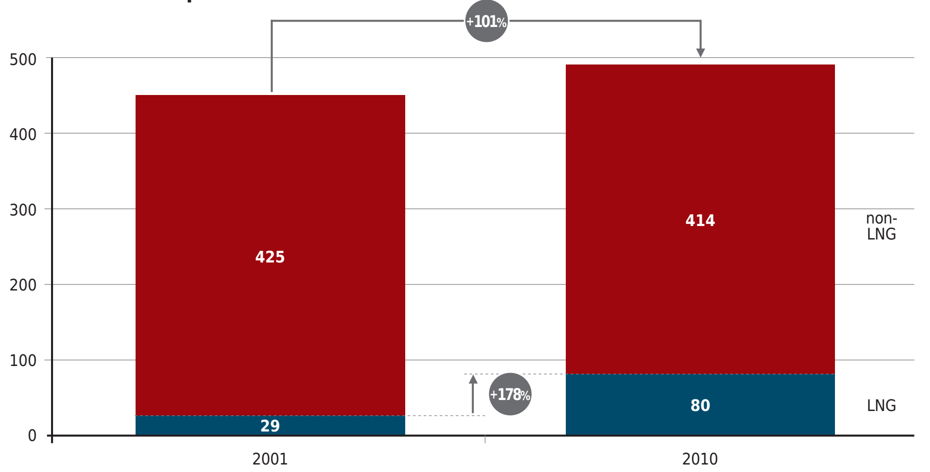


Source: FERC.

Europe

The LNG market is gaining increasing importance in Europe. The EU member states are particularly interested in increasing imports of LNG, which would decrease European dependence on natural gas coming mainly from Norway and Russia as LTC. In fact, the growth in LNG consumption is twenty times higher than the growth in natural gas consumption; there has been a 178% increase in LNG consumption between 2001 and 2010, from 29 to 80 bcm/y. Respective gas consumption fell from 425 to 414 bcm/y while LNG consumption increased significantly.[292] During that same time period, LNG imports grew an average of 12% annually as compared to an annual 1% increase in natural gas consumption, which shows the expanding dominance of LNG in Europe.

GRAPH 52. **Gas consumption in EU in bcm¹.**



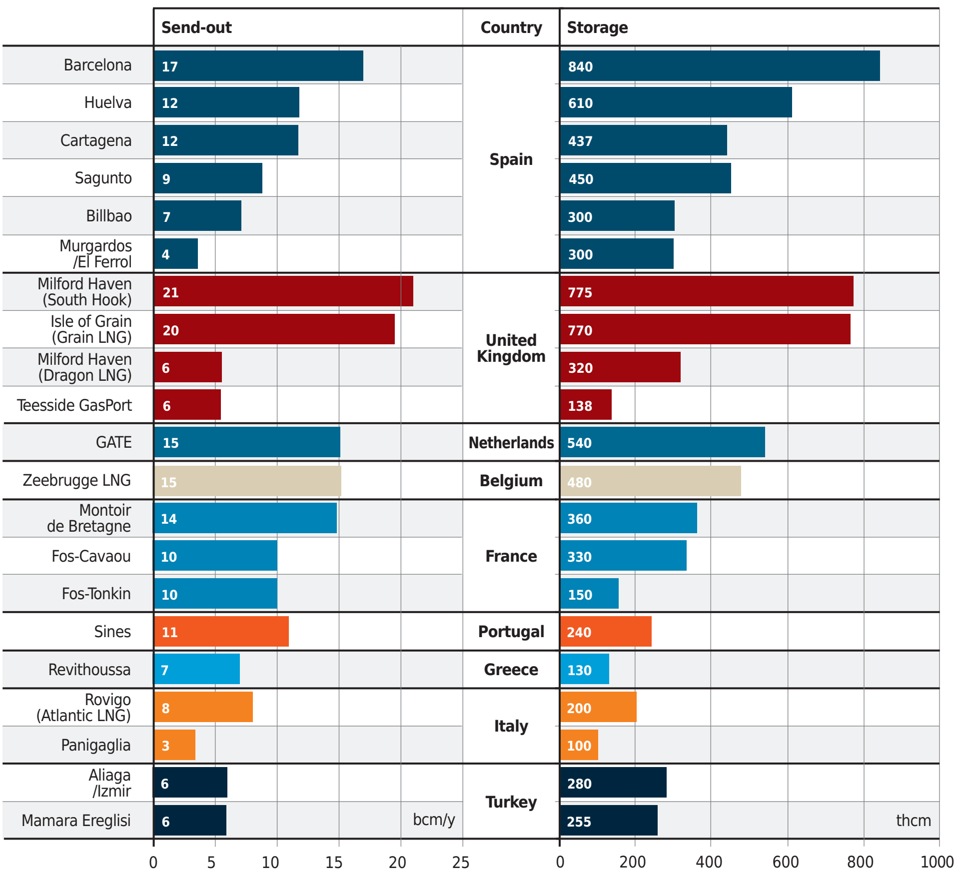
¹· EU countries based on BP Statistical Review, no data for Latvia, Estonia, Malta, Slovenia, Cyprus. 2001 EU data include 2004 and 2007 accessions for consistency.
Source: BP Statistical Review, author's analysis.

Thus, recent developments are aimed at expanding LNG infrastructure across Northwestern Europe, as new constructions are planned and proposed in the region and in Eastern Europe. In Northwestern Europe an increasing number of import facilities with regasification capacities is under construction. More specifically, currently in Europe there are over twenty working LNG terminals located in Belgium, France, Greece, Italy, Portugal, Spain, Sweden, the Netherlands, Turkey and the United Kingdom. There are also six terminals currently under construction in the European Union, namely in France, Italy, Poland, and Spain. In the long-term perspective there are plans to construct another thirty-six LNG terminals across the continent. The construction of an export terminal has also been proposed in Vassilikos, Cyprus. The terminal would be the only export terminal within the European Union. According to the International Group of Liquefied Natural Gas Importers, a total LNG imports to Europe represented 29.52% of the world LNG imports in 2010.

The graph below presents send-out and storage capacities of European terminals. The biggest player on the market is Spain with 6 terminals, followed by the UK and France.

Specific circumstances of the Spanish market enabled the development of LNG import infrastructure[293]. Comparing to Asian countries in Europe storage capacities are much smaller.

GRAPH 53. **European LNG terminals by storage and send-out capabilities.**

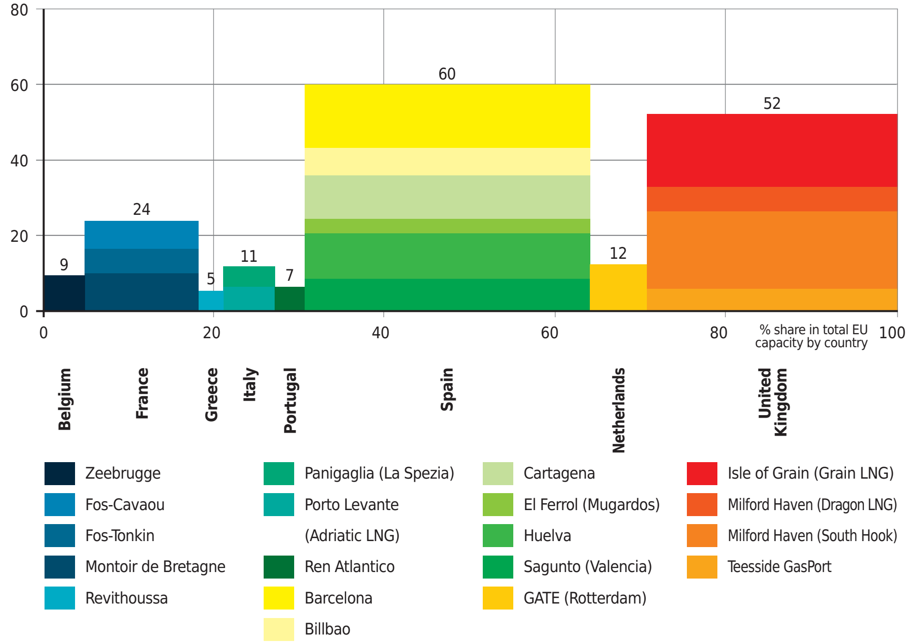


Source: Gas Infrastructure Europe.

The graph below shows the key players on the European LNG market. The x-axis represents the import capacity of each country in bcm/y (with horizontal bars within each vertical bar representing the capacity of individual terminals in each country), and the y-axis represents the per cent share each country has in Europe's total import capacity. From this representation, it is clear that Spain and the UK dominate the European market with over 50% of market shares altogether, and each also has a significantly larger import capacity than any other Member State with LNG terminals.

France has the next largest share on the market and import capacity in Europe, followed by the Netherlands, Italy, and Belgium. Greece and Portugal are the smallest LNG terminals with the lowest import capacities and percent shares in European market.

GRAPH 54. **EU[1] LNG terminal import capacities by country bcm/y.**

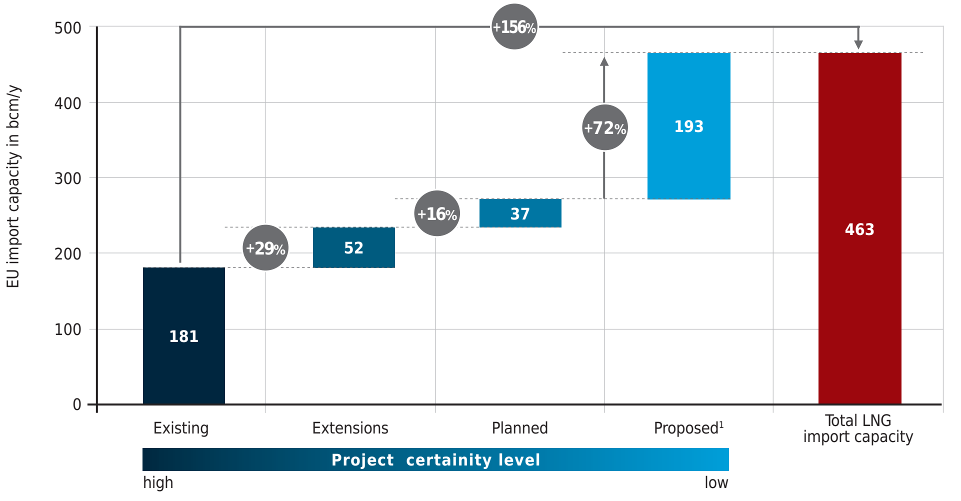


[1] Sweden with 0.5 bcm/y ommited
Source: Gas Infrastructure Europe.

In general, the import capacity in Europe is 181 bcm/y but it is expected to increase by 156% to 463 bcm/y, in the next few years. Extensions of the current facilities will add 52 bcm/y to a total import capacity (29% increase), planned facilities will add 37 bcm/y (16% increase), and proposed facilities will add 193 bcm/y (72% increase).[294]

The overall send-out capacity of the EU terminals is 215 bcm/y, but extensions to the current terminals and the construction of new ones will add approximately 35 bcm/y each, which amounts to a 16% and 14% increase respectively.

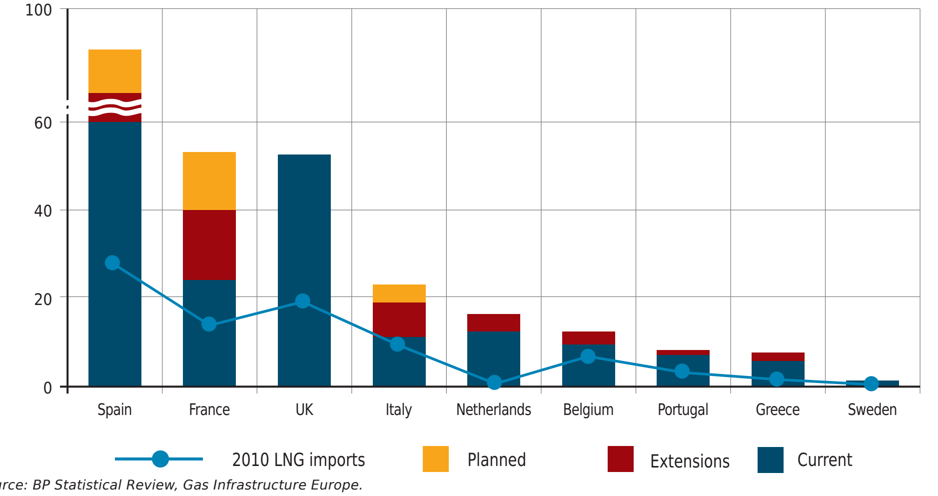
GRAPH 55. **EU import capacity forecast till 2020.**



[1.] Proposed terminals include 2 Croatian projects with capacity of 121 bcm/y
Source: Gas Infrastructure Europe.

The importance of LNG is clear when one looks at how dramatically the European market is to evolve in the coming years. The improvements planned only in the countries that already have LNG terminals will significantly increase the import capacity to the EU market. The following diagram gives a graphical representation of the extensions under way in Northwestern Europe. The purple shade represents the extensions that are under way in the existing LNG terminals of the region, and the orange represents the size of import capacity that new terminals would add to each country. With these improvements, the quantity of LNG imports will increase significantly in the upcoming future.

GRAPH 56. **Import capacity development of existing EU LNG terminals bcm/y.**



Source: BP Statistical Review, Gas Infrastructure Europe.

The following is a more detailed description of the most important LNG terminals in Northwestern Europe. These terminals include: the South Hook and Dragon terminals of Milford Haven, Isle of Grain, and Teesside in the UK; Barcelona, Cartagena, Huelva, Sagunto (Valencia), Bilbao, and El Ferrol (Murgados) in Spain; the GATE (Rotterdam) terminal in the Netherlands; Montoir de Bretagne, Fos-Cavaous, and Fos-Tonkin in France; Zeebrugge in Belgium; and Porto Levante (Adriatic LNG) and Panigaglia (La Spezia) in Italy.

The United Kingdom

The UK has a total regasification capacity of 5.8% of the world's gas capacity.[295] The National Balancing Point (NBP) hub in the UK is fairly new; it was established in 1996 with the opening of the South Hook LNG terminal at Milford Haven in Wales.[296] The flows within the South Hook, Grain, and Dragon terminals can reach 21.9 bcm/y, 11 bcm/y, and 6.2 bcm/y, respectively.[297] Qatar Petroleum and ExxonMobil control the South Hook terminal, while BG, Petronas and Petroplus control the Dragon terminal.[298] Excelerate Energy's Teesside GasPort is considered a "floating receiving terminal" which can send out 1-5 bcm/y of gas.[299] The Teesside GasPort, Grain LNG (Phase 2), Dragon LNG, South Hook (Phase 1), Gran LNG (Phase 3), South Hook (Phase 2) receiving terminals have a nameplate capacity of 4.14 bcm/y, 9 bcm/y, 6 bcm/y, 10,8 bcm/y, 7.2 bcm/y, and 10.8 bcm/y respectively.[300] All four terminals are located on shore.

The following graph summarises the import, send-out, and storage capacities of the four LNG terminals in the UK.

GRAPH 57. **Import, send-out and storage capacities for UK LNG terminals.**

Existing terminals	Operated From	Import Capacity (bcm/y)	Send-out Capacity (bcm/y)	Storage Capacity (thcm)
Milford Haven (South Hook)	2010	21	21.4	775
Isle of Grain (Grain LNG)	2011	19.5	23.2	770
Milford Haven (Dragon LNG)	2009	6	10.0	320
Teesside GasPort	2007	5.5	4.6	183
TOTAL	**-**	**52**	**59.2**	**2 003**

Source: Author's calculation.

In addition to those four terminals operating in the UK, three another LNG terminals are proposed, namely: Anglesey (Almwich Offshore), Canvey Island, and Post-Meridiam, out of which only Canvey Island would be an on-shore facility. The planned terminals have a projected import capacity of 13 bcm/y, 5.4 bcm/y, and 8 bcm/y respectively.

New LNG import terminals are constructed under self-contracting regimes of major oil companies. Those import terminals also deliver oil from the Vesterled and Balgzand-Bacton Line (BBL) pipelines, whose prices for LTC are linked to the International Petroleum Exchange (IPE) spot trade quotations on the NBP.[301] The Vesterled line has also been used to add import capacity from Norway into the UK.[302]

Belgium

There are three terminals in the Zeebrugge hub, one of which is an LNG terminal. The Zeebrugge LNG terminal has a storage facility and a regasification capacity of 9 bcm/y. The Zeebrugge LNG terminal, in particular, was completed in 1987 and is located on a 30-hectarsite in the outer port of Zeebrugge.

It has an unloading capacity of 12 thcm LNG per hour and can unload 110 LNG cargoes per year.[303] There are four storage tanks at that facility, with the first three having a capacity of 80 thcm of LNG and the fourth having a capacity of 140 thcm of LNG.[304]

The Netherlands

The GATE terminal in the Netherlands is a new European LNG terminal opened on 23 September 2011 on the Maasvlakte, Rotterdam.[305] It has a throughput capacity of 12 bcm/y (with a future import capacity of 16 bcm/y) and three storage tanks, two jetty's, and a process area that is used to regasify LNG.

A net capacity of each tank in the terminal amounts to 180 thcm (a total capacity of 540 thcm), and a gross capacity is 200 thcm per tank.[306] N.V. Nederlandse Gasunie (Gasunie) and Koninklijke Vopak N.V. (Vopak) are involved in the project. The GATE terminal is an on-shore facility with a 15 bcm/y maximum send-out capacity (with an expected future capacity of 20 bcm/y), and a storage capacity of 540 thcm (and a future capacity of 720 thcm).

Spain

Spain is one of the largest European importers of LNG. It has six LNG terminals within the country in Barcelona, Huelva, Cartagena, Bilbao, Sagunto, and Mugardos, all of which are located on shore. All the six terminals are regasification terminals. They receive most of its imports from Nigeria, the Persian Gulf, Algeria, Trinidad and Tobago, Egypt, Norway, Italy, Peru, Libya, and

Yemen. Between 1996 and 2010 the LNG market in Spain rose to 76% of a total Spanish gas market thanks to the use of the GME (Maghred-Europe) pipeline since 1996, another 24% was imported from Algeria through the same GME pipeline.[307] Most exports of LNG go to Portugal or to autonomous regions. Internally, it is used in a considerable amount in the electricity sector.[308] The autonomous regions include: the Balearic Islands, The Valencian Community, the Basque Country, Navarre, the Region of Murcia, the Community of Madrid, La Rioja, Galicia, Extremadura, Catalonia, Castile and Leon, Castile-La Mancha, Cantabria, Asturias, Aragon, and Andalusia.

The following graph outlines some basic information regarding the six LNG regasification terminals in Spain:[309]

GRAPH 58. **Import, send-out and storage capacities for Spanish LNG terminals.**

Existing terminals	Start-up date	Import Capacity (bcm/y)	Send-out Capacity (bcm/y)	Storage Capacity thcm
Barcelona	1969	17.08	17.10	840
Huelva	1988	11.83	11.80	610
Cartagena	1989	11.83	11.80	437
Sagunto	2006	8.76	8.80	450
Bilbao	2003	7.01	7.00	300
Murgardos/El Ferrol	2007	3.61	3.60	300
TOTAL	**-**	**60.12**	**60.10**	**2 937**

Source: Author's calculation.

The six regasification terminals have a total import capacity of 60 bcm/y.[310] The LNG terminals are not used to full extent because only a quarter of regasification capacity and capacity in storage, transportation and distribution system is reserved for short-term contracts.[311] By June 2011, there was 86 bcm/y of import capacity, which represented 2.4 times the level of demand in 2010 (36 bcm/y).[312] This is putting an increasing strain on the cost of infrastructure.

In addition to the six terminals, currently there are three planned LNG terminals in Spain, that is El Musel (Gijon), Gran Canaria (Arinaga), and Tenerife (Arico-Granadilla, Canary Islands), which would have import capacities of 7.01 bcm/y, 1.31 bcm/y, and 1.31 bcm/y, send-out capacities of 7 bcm/y, 1.3 bcm/y, and 1.3 bcm/y, and storage capacities of 300 thcm, 150 thcm, and 150 thcm, respectively. All three facilities will be located on-shore.

Italy

On the Italian gas market benefits from two LNG terminals with regasification capacity: Panigaglia in Liguria and the North Adriatic Sea offshore terminal near Rovigo. The Panigaglia terminal started to operate in 1969, is owned by GNL Italia, and has a capacity of 3.5 bcm/y. Porto Levante is a new LNG terminal opened in 2009 that is owned by Adriatic LNG, and has a capacity of approximately 8.0 bcm/y.[313] Italy's total import capacity is thus approximately 11 bcm/y. The two terminals also have send-out capacities of 3.3 bcm/y and 8 bcm/y, as well as storage capacities of 100 thcm and 250 thcm, respectively.

There is one terminal under construction—Tuscany (Toscana) offshore. This will be an off-shore terminal with an import capacity of 3.75 bcm/y and a storage capacity of 137 thcm of LNG. Another 11 terminals have been proposed to be constructed in Italy. The Alpi Adriatico, Falconara Marittima, Porto Recanati/Ancona, and Rosignano terminals would be located off shore, whereas the other —Brindisi, Gioia Tauro, Porto Empedocie, Rada di Augusta-Priolo, Taranto, Trinitapoli, and Zaule (Trieste)—would be located on-shore. The new terminals would increase Italy's import capacity by 85 to 89 bcm/y.

France

France was the second largest EU importer of LNG in 2009—importing 13 bcm/y or 20% of LNG coming into Europe[314]—and has three operating LNG terminals. They are: the Montoir-de-Bretagne terminal and the Fos Tonkin terminal, both owned by Gaz de France and managed by Direction des Grandes Infrastructures (DGI), and Société du Terminal Méthanier de Fos Cavaou (STMFC) at Fos Cavaou. France's LNG terminals have an overall import capacity of 24 bcm/y. The Fos Tonkin terminal was opened in 1972 and has a regasification capacity of 7.0 bcm/y[315], the Montoir-de-Bretagne terminal was opened in 1980 and has a regasification capacity of 10 bcm/y,[316] and the Fos-Cavaous terminal was built in 2010 and has a regasification capacity of 8.25 bcm/y.[317]

Another four LNG terminals are under construction: Dunkerque, located in the north with a projected capacity of 6-12 bcm/y; Antifer, located in the north with a capacity of 9 bcm/y; Le Vedon, located in the west with a capacity of 6-9 bcm/y; and Fos, located in the south with an 8 bcm/y capacity.[318] The Dunkerque facility is an on-shore facility planned for 2014.

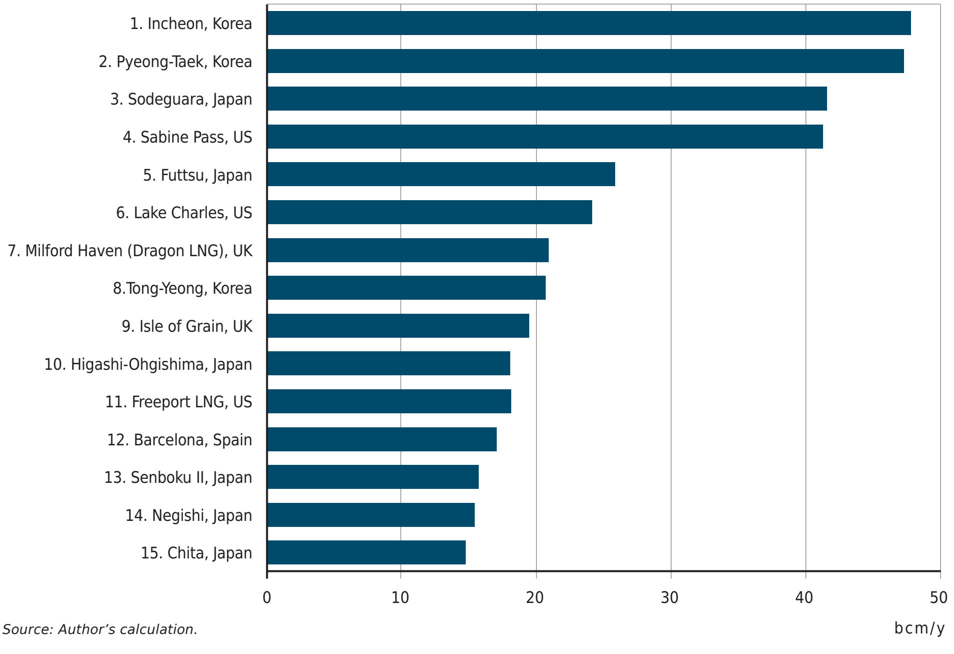
Other

In addition to the main European LNG terminals described-above, there are three smaller and more recent ones located on shore: Revithoussa in Greece, Sines in Portugal, and Brunnsviksholmen (Nyäshamn) in Sweden. These three terminals have import capacities of 5.3 bcm/y, 6.5 bcm/y, and 0.5 bcm/y, respectively. Revithoussa and Sines have send-out capacities of 7 bcm/y and 11 bcm/y, as well as storage capacities of 130 thcm and 240 thcm, respectively. The LNG terminal in Sweden has a storage capacity of 30 thcm.

Moreover, in Poland there is one additional planned LNG terminal called Świnoujście. This on-shore facility will have a bunker facility, an import capacity of 5 bcm/y (set to increase to 7.5 bcm/yr) and a storage capacity of 320 thcm (set to increase to 480 thcm).

Other LNG terminals will be constructed in numerous European countries, both in Northwestern Europe and elsewhere. The countries where new terminals will be built include: Albania, Croatia, Estonia, Finland, Germany, Greece, Ireland, Latvia, Lithuania, Romania, and Ukraine. Some of the new terminals will be located off-shore.

GRAPH 59. **World's largest terminals by send-out capacity.**



Source: Author's calculation.

Top 15 world LNG terminals have the send-out capacity enabling to handle all the imported LNG in the world. It amounted to 389 bcm/y in total. The above graph shows the domination of Asia in terms of LNG terminal capacity.

The Asian's region ability to receive and process LNG significantly overpowers both the US and Europe. But not only does it have the capability to receive LNG, it is also willing to pay significantly higher prices for the product. LNG exporters are drawn to the Asian region because of what is known as the "Asian premium" or the comparatively higher price levels for natural gas. In fact, according to a report from the beginning of 2012, spot LNG prices in Asia hovered around $15-$16 per MMbtu[319]. At the NBP they were below $10, and at Henry Hub they ranged from $2-$3[320]. Although the costs of shipping LNG to Asia are also high, the prices offered still create incentives to focus on the region.

This could be threatening to Europe where price levels and terminal capacities are significantly lower.

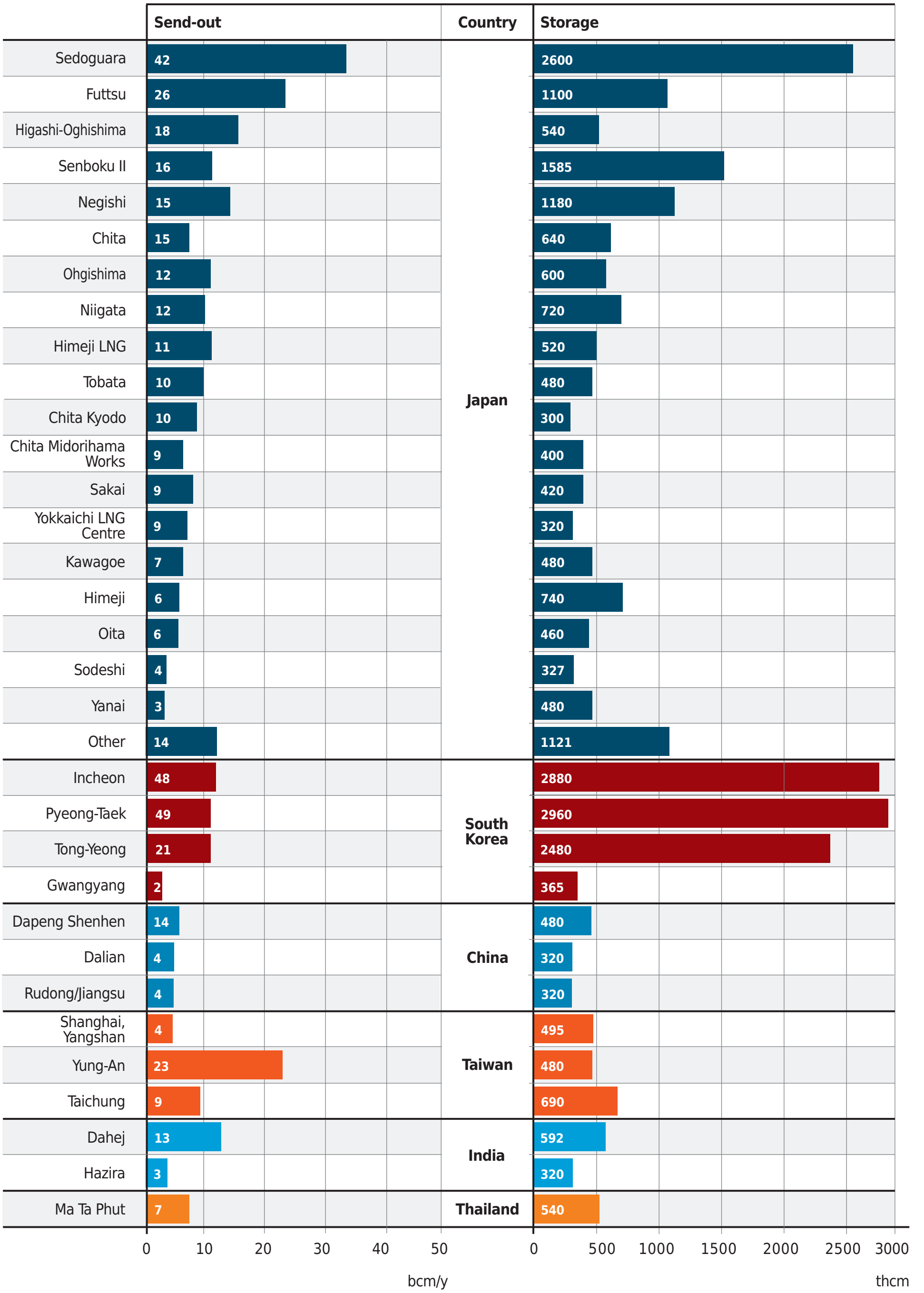
Asia

The growth in demand for energy has resulted in the extensive LNG terminal capacity that in Asia already exists and continues to grow. Since a large majority of natural gas has been traded in the form of LNG, the terminals constructed to receive imports are of great significance for the region. As of 2010, East Asia (China, Japan, Korea, and Taiwan) boasted 51% of the world's regasification capacity[321]. When it comes to storage capacity connected to the import terminals, Japan and Korea alone made up 54% of the global LNG storage capacity. However, as mentioned already, number and capacities of terminals vary depending on energy needs and production capacities of individual countries.

By examining LNG terminals and their capacities on a country-by-country basis we get a clearer picture of the current situation.

The graph below pictures shares of Asian countries in terms of send-out and storage capacities. Deep-dive analysis will be given in each country description. Asian terminals are the biggest in the world in terms of both send-out and storage capacities. For instance, the storage capacity of each of Korean ports is at least 3 times higher than that of the biggest American terminal.

GRAPG 60. **Asian LNG terminals by storage and send-out capabilities.**

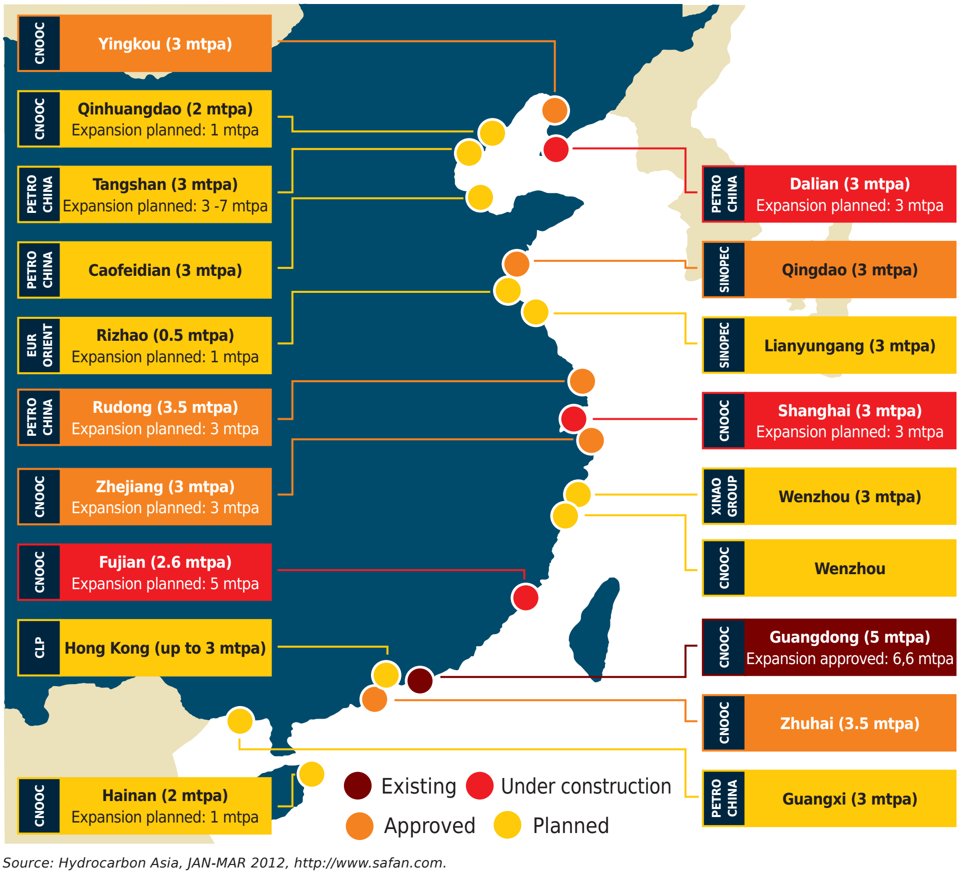


Source: GIIGNL.

China

In the early 21st century, the Guangdong Dapeng LNG terminal was built to increase import capacity in China. It was the first facility built for receipt and regasification of LNG in China. It began operating in 2006 and is designed to process 5 bcm/y of LNG yearly. Expansion projects have now put capacity at 9.2 bcm/y[322]. The terminal is comprised of three storage tanks with individual storage capacities of 160 thcm, and nine vaporization systems[323]. In order to transmit gas from the plant, a transmission pipeline spanning across 400 km was constructed.

GRAPH 61. **Location of China's LNG terminals.**



Source: Hydrocarbon Asia, JAN-MAR 2012, http://www.safan.com.

Since the opening of the terminal in Guangdong, China has approved around ten other LNG facilities and as many as 20 more are in the process of being built or planned[324]. In 2008 and 2009 the completion of four separate projects resulted in an increased capacity 12 bcm/y [325]. In 2010, five projects were underway for a total capacity of 21.5 bcm/y[326].

GRAPH 62. **Chinese LNG terminals in operation as of 2011.**

Existing terminals	Operated From	Import Capacity (bcm/y)	Send-out Capacity (bcm/y)	Storage Capacity (thcm)
Dapeng, Shenzen	2006	9.21	9.00	480
Rudong/Jingsu	2011	4.81	4.20	320
Dalian	2011	4.13	4.20	320
Shanghai, Jangshan	2009	4.13	4.10	495
TOTAL	**-**	**22.28**	**21.50**	**1 615**

Source: The LNG Industry, GIIGNL 2012.

In 2011 Chinese terminals had a total send-out capacity of 21.5 bcm/y, and 9 of them were launched only that year. Storage capacities amounted to 1.6 mcm. China is at its starting point with LNG terminals development, but growing gas consumption will result in further development of LNG projects. Chinese LNG contracts that are much more market-oriented than it is the case of other Asian countries have sparked a number of contract renegotiations. LTC variables will be analysed in a separate chapter.

Japan

Japan is home to the majority of LNG terminals in the world and comes third in terms of the global regasification capacity. As of 2012, there were 32 receiving terminals with a send-out capacity of 253 bcm/y[327]. In 2010, five new or expansion projects were in the construction process for additional 12.3 bcm/y[328].

GRAPH 63. **Japanese LNG terminals in operation as of 2011*.**

Existing terminals	Start-up date	Import Capacity (bcm/y)[76]	Send-out Capacity (NG bcm/y)	Storage Capacity (thcm)
Sedogura	1973	not available	41.60	2 660
Futtsu	1985	not available	26.00	1 110
Higashi - Oghishima	1984	not available	18.00	540
Senboku II	1977	not available	15.70	1 585
Negishi	1969	not available	15.40	1 180
Chita	1983	not available	14.78	640
Ohghishima	1998	not available	12.40	600
Niigata	1984	not available	11.60	720
Himeji LNG	1979	not available	11.00	520
Tobata	1977	not available	10.28	480
Chita Kyodo	1987	not available	15.40	1 180
Chita	2001	not available	9.20	400

Chita	2001	not available	9.20	400
Midorihama Works				
Sakai	2006	not available	8.70	420
Yokkaichi LNG Centre	1988	not available	8.86	320
Kawagoe	1997	not available	6.69	480
Himeji	1984	not available	6.40	740
Oita	1990	not available	6.27	460
Sodeshi	1996	not available	3.90	327.22
Yanai	1990	not available	13.51	480
Others	-	not available	13.51	1 121
TOTAL	**-**	**-**	**252.95**	**15 083.22**

[*]The chart includes LNG terminals that have a send out capacity of 3.00 bcm or higher.
Source: The LNG Industry, GIIGNL 2012.

Due to geographic conditions the only way Japan may import gas is by utilising LNG technology. With the volume of 107 bcm/y in 2011 Japan is the biggest importer of liquefied gas in the world.

India

The constrained domestic supply has led to the construction of LNG import terminals in India. The first, Dahej, was completed in 2004 and has a capacity of 13.8 bcm/y[329]. Since then, several other similar facilities have been built. Two LNG import terminals, recently opened in India, have a total capacity of 6.4 bcm/y and as of the end of 2010 another two for capacity of 6.9 bcm/y were under construction[330]. The new Dabhol LNG terminal is scheduled for opening in the fourth quarter of 2012[331].

GRAPH 64. **Indian LNG terminals in operation as of 2011.**

Existing terminals	Operated From	Import Capacity (bcm/y)	Send-out Capacity (bcm/y)	Storage Capacity (thcm)
Dahej	2004	13.75	12.50	592
Hazira	2005	4.95	3.40	320
TOTAL	**-**	**18.70**	**15.90**	**912**

Source: The LNG Industry, GIIGNL 2012.

South Korea

South Korea is home to four LNG terminals, and their total operational capacity amounts to 118 bcm/y[332]. In 2009, 49.3 bcm/y of LNG was processed at those regasification facilities[333]. Apart from expanding the capacities of the existing facilities, there is also a new LNG terminal being constructed. It is expected to begin the first stage of operation in 2013.

GRAPH 65. **South Korean LNG terminals in operation as of 2011.**

Existing terminals	Operated From	Import Capacity (bcm/y)	Send-out Capacity (bcm/y)	Storage Capacity (thcm)
Incheon	1996	43.62	47.78	2 880
Pyeong-Taek	1986	35.65	47.30	2 960
Tong-Yeong	2002	15.96	20.76	2 480
Gwangyang	2005	3.00	2.30	365
TOTAL	**-**	**98.22**	**118.14**	**8 658**

Source: The LNG Industry, GIIGNL 2012.

Taiwan

In 1990 the first LNG import terminal in Taiwan was completed under the supervision of the CPC Corporation, a state owned petroleum, natural gas, and gasoline company.

The first expansion project which increased capacity to 3.26 bcm was finished six years later[334]. In 2002 a long-distance pipeline of 238 km was completed, which effectively pushed handling capacity up to 10.3 bcm/y[335]. In 2009, the CPC Corporation in Taiwan opened a second LNG receiving terminal designed to process 4.1 bcm/y.

The facility comprises three 160 thcm storage tanks as well as a 135 km pipeline spanning from Taichung Harbor through the Tongxiao distribution station to the Datan measuring station area[336]. In Western Taiwan there are also a distribution and transmission system of pipelines, distribution centres, and loop networks connecting eight different supply locations[337].

GRAPH 66. **Taiwanese LNG terminals in operation as of 2011.**

Existing terminals	Operated From	Import Capacity (bcm/y)	Send-out Capacity (bcm/y)	Storage Capacity (thcm)
Yung-An	1990	10.30	23.00	690
Taichung	2009	4.10	9.00	480
TOTAL	**-**	**14.40**	**32.00**	**1 170**

Source: The LNG Industry, GIIGNL 2012.

Indonesia

Because Indonesia is a major exporter of LNG, some Indonesians have become interested in sending important sources of energy abroad instead of utilising them domestically.

Therefore, apart from expanding its export capabilities, Indonesia is also constructing some regasification terminals to secure its own supply. One such terminal will open in 2012, and eight mini-facilities are planned to be ready by 2015. The building of import facilities is meant to create a more flexible environment for both exports and domestic supply.

January 2010, the government and related companies confirmed their plans to build Indonesia's first series of three floating LNG receiving terminals, to be located in Jakarta Bay, East Java and North Sumatra. The Java terminals will have capacities of about 5.5 bcm/y of LNG. It is expected that the LNG receiving terminal in East Java will be completed in September 2011. The LNG terminal in North Sumatra will have a capacity of about 1.5 bcm/y. LNG supply is expected to come from the LNG plants in Tangguh, Papua, and Bontang, East Kalimantan, LNG imports from Qatar will also be possible.

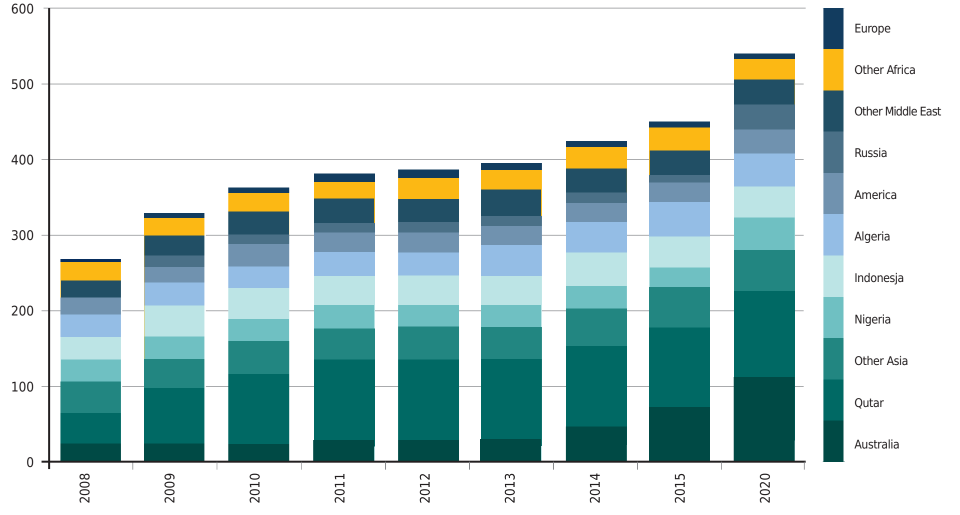
Supply Sources

Sources of LNG imports depend on the region. Some major exporting countries include Algeria, Nigeria, Trinidad and Tobago, Qatar, Australia, Malaysia and Indonesia. It is from those countries that Asia and Europe import LNG. The US Energy Information Administration (EIA) reports that in 2011 the terminals received LNG from Egypt, Nigeria, Norway, Peru, Qatar, Trinidad, and Yemen.[338] The top three US suppliers were Trinidad with 3.8 bcm/y, Qatar with 2.6 bcm/y, and Yemen with 1.7 bcm/y[339].

The supply side of the market has been undergoing constant changes and this trend is expected to continue[340]. Indonesia, which used to be the market biggest supplier of LNG, lost its dominant position to Qatar and the latter will most probably lose its dominance to Australia in the years to come.

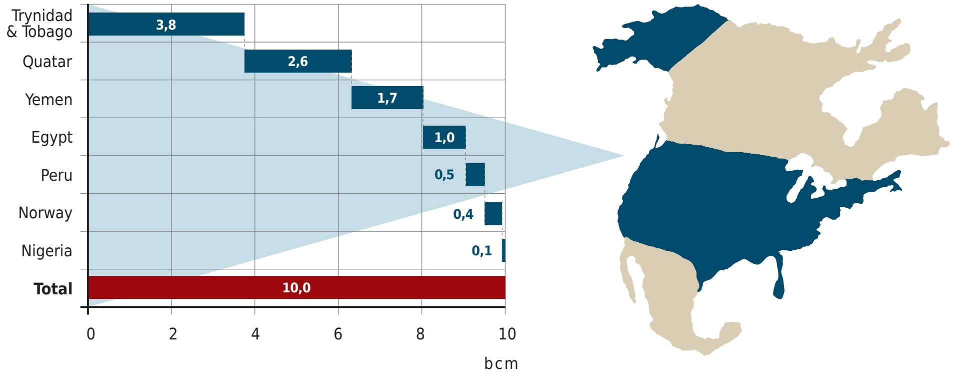
The volume of Australian exports is projected to increase 5 times in the next 7 years, which does not undermine the significance of the Middle East in future. The trends are presented on the graph below.

GRAPH 67. **Projected LNG liquefaction capacity by country.**



Source: *R. Zajdler, Development prospects of price formulas in long-term contracts for natural gas supplies and their significance for the creation of a gas hub in Poland for the countries of Central East Europe, Warsaw 2012.*

GRAPH 68. **US LNG supply sources in 2011.**



Source: *BP Statistical Review, 2012 edition.*

The United States has a diversified supply of gas as compared to countries in Asia-Pacific or Europe, and a long history of exploration, investment, and regulation. Keeping that in mind, we now turn to a pressing question: Can the United States become a net exporter of LNG? Can it harness the advantages of both a large supply of underground reserves and economical production techniques, in order to supply the rest of the world with LNG? To answer these important questions more comprehensively, we should examine historic evolution and role of LNG terminals in the US

The early American import terminals were greatly affected by the changes in demand and supply embedded within the turbulent regulatory history of the natural gas industry. Through the process of deregulation following the natural gas shortages in the 1970s, domestic supply increased, which in turn lessened the need for import of LNG.

The demand for foreign fuel was revived in the 19th century with developments of export capabilities in other countries, especially Trinidad and Tobago, who is one of the predominant exporters of LNG to the United States. In the last decade existing import terminals have been reopened and new ones built[341].

Due to the changes in demand for and supply of natural gas in US terminal had to change to export terminals. In order to convert their facilities into export stations, existing terminals must first be granted permission at the federal level by the DOE to export and by the FERC to site, begin construction, and operate. This is a long process which takes several years.

Additionally, there are certain restrictions. Generally, export may be allowed to countries that hold a Free Trade Agreement (FTA) with the United States. This is mandated in amended section 3(c) of the Natural Gas Act (NGA), which states that applications for export to countries holding FTAs with the US should be considered in the public interest and granted without modification or delay[342]. However, the DOE reserves the right to grant permission to export to countries which are non-FTA countries based on evaluations of whether or not authorization to do so can be deemed aligned with the public interest.[343]

Currently, only one facility has had full approval and ability to export LNG. It is a terminal located in Kenai, Alaska, which in 2008, was granted approval by the DOE to continue the exportation of LNG to Japan and other Asian countries through March 31, 2011 ("DOE Approves Alaska LNG Export Application"). The Alaskan LNG terminal has actually been involved in the exportation of LNG since 1967 when it was first granted authority to do so[344]. From its beginning in the late 1960s through 1994, the plant increased its LNG production capacity from 4.8 bcm/y to over 6.2 bcm/y[345]. Now, the terminal is identified as a 2.1 bcm/y facility[346]. As of now, in April 2012, the Cheniere Energy facility in Sabine Pass LNG in Cameron Parish, Louisiana was granted permission by the FERC to construct and operate export facilities. The DOE has also granted the terminal permission to export to countries that hold a Free Trade Agreement (FTA) with the United States as well as to non-FTA countries. The facility is expected to be able to liquefy and export 16 million tons per annum (mtpa)[347]. The Freeport terminal in Texas is pursuing the same expansion aimed at exporting 13.2 mtpa of LNG[348]. The Freeport LNG project expects to receive approval from the DOE to export to non-FTA countries in 2012, permission to site and begin construction from the FERC in 2013, and also plans to begin operations in 2017[349]. Sempra's LNG terminal in Cameron has also been granted by the DOE permission to export LNG to FTA countries and countries that will enter into FTAs with the United States in future, plans to receive the required permits from the FERC in 2013, and upon completion of the project near the end of 2016 it intends to have the capacity to export 12 mtpa[350]. While Dominion Cove Point has received one approval so far, a final decision whether to pursue the project will not be taken until all permissions have been granted[351]. The remaining companies provide less information on their plans regarding LNG export projects.

An important part of the authority granted by the DOE to export is in the clause regarding FTAs with the United States. Currently, only eighteen countries hold FTAs with the US[352]. Unfortunately, none of them, excluding South Korea, import significant amounts of LNG[353]. To date, the Sabine Pass terminal is the sole project to have received permission to export to non-FTA countries as well. The other LNG terminals also applied for approval to expand their potential target markets by requesting access to non-FTA countries, but the DOE's has not taken any decisions yet. The Department has ordered a study regarding a potential impact on domestic prices for natural gas if other terminals were to begin export in order to determine whether the projects are in the public interest. The main conclusion of a report issued in January was that increased exports of the commodity would result in increased prices for domestic customers[354].

There has also been political pressure against the export of LNG, but for different reasons. For example, some lawmakers such as Edward Markey, a Democrat congressman representing Massachusetts, have proposed bills that would prevent the exportation of natural gas. He stated, "The natural gas industry should reject the proposed trend toward sending our natural gas abroad, which will raise costs to consumers and industry" ("Markey: EPA's New Fracking Safeguards"). Essentially, congressman Markey who holds a seat in the House of Representatives seeks to pass a bill under which gas produced domestically could only be sold to American consumers.

Some members of the Senate have voiced their opposition as well. In March 2012, Ron Wyden, a Democrat senator representing the state of Oregon, presented an argument similar to that of congressman Markey's while participating in a town hall meeting in Astoria, Oregon. A local newspaper reported, *"…US Sen. Ron Wyden, D-Ore., addressed concerns at his annual Clatsop County town hall about exporting liquefied natural gas from Oregon port facilities, saying he believed the proposals could undermine the country's energy independence and drive up costs"* (Graf).

There are many dimensions and opposing angles of this argument. Surely, many others would argue that by eliminating the possibility of selling on international markets American products which are not in high demand domestically the American consumer is harmed rather than protected. For instance, the approved Freeport LNG project estimates that the conversion of its individual terminal will create additional 20000-25000 permanent jobs and that due to the large size of the natural gas market in the United States, impact on the market price of natural gas will be small[355]. Also, the DOE states that in alignment with the projections of the EIA, the benefits of shale gas production include, "reducing the need for imported energy while enhancing US energy security; creating American jobs for drilling, pipelines and production facilities; helping stabilise domestic natural gas prices; increasing royalty and tax receipts for the federal and state governments; and contributing to the US becoming a net exporter of natural gas by 2021" ("Producing Natural Gas From Shale"). According to these projections, the benefits of LNG exports appear to be quite favourable to the American public. The issue whether or not Congressman Markey and Senator Wyden have a valid argument will surely be debated. Nevertheless, it shows that such a form of resistance against facilitation of the export of LNG abroad can be heard as well.

At this point in time it seems the United States is on its way to become a significant exporter of natural gas. With reserve estimates that are only increasing and technology that is only improving, conditions for exportation seem quite favourable. Several large projects aimed at transforming import facilities to function as export stations have also passed through the first stage of application to federal agencies and one has gained full permission to export LNG worldwide. However, most of them have only gained access of exportation to FTA countries, which is a significant limit on the projects' potential.

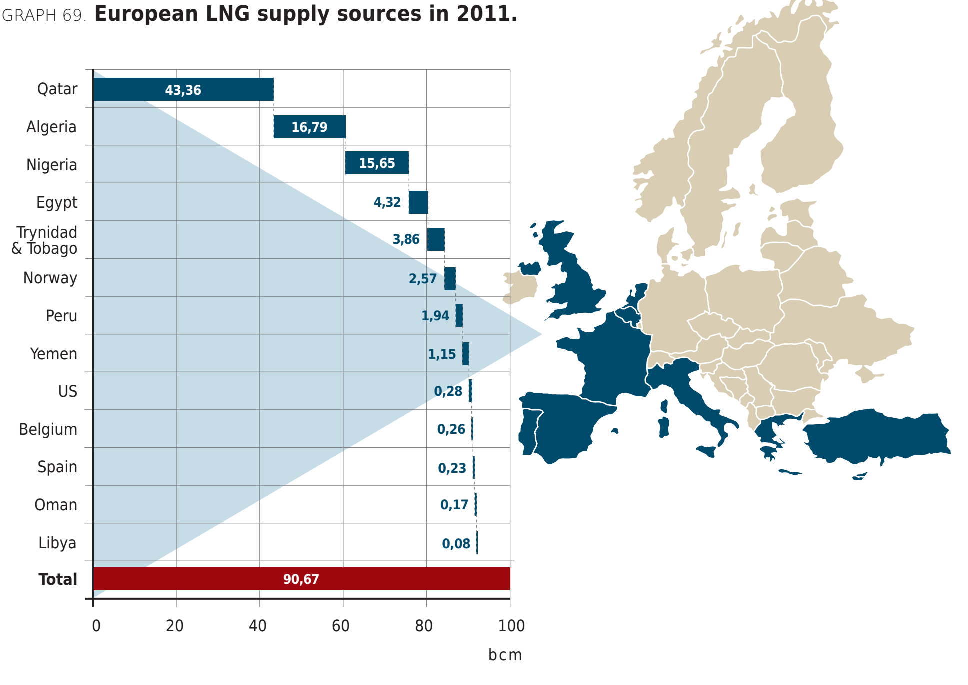
One particular facility, the Freeport LNG terminal in Texas, estimates that its individual capacity to export LNG to global markets will benefit American economy from $4.3 to $6.2 billion per year ("Liquefaction Project Benefits"). Since natural gas in the United States is sold at some of the lowest prices in the world, there is clearly an opportunity to export. However, it remains difficult to make a conclusive judgment on the case of the export of LNG. With two sides fighting against each other, it is difficult to predict which one will prevail. Nevertheless, it is an important subject to explore as natural gas has become an increasingly important energy source worldwide. Since the United States is the world's largest producer of natural gas and one of the top consumers of energy in general, the future of its natural gas market remains an important issue.

Europe

The primary countries exporting LNG to Europe are Algeria, Nigeria, Trinidad and Tobago, and Qatar; smaller quantities come from Egypt, Libya, Oman and Yemen. LNG imports in 2010 accounted for 8.7 bcm, or 12% of total imports into Italy.[356] Algeria is Italy's main LNG supplier, with imports coming through the Enrico Mattei Gasline. Italy also received 0.7 bcm of pipeline LNG from Libya via the Greenstream pipeline.[357] Algeria is also a main supplier of LNG to France (7.7 bcm supplied in 2009[358]), another 1.6 bcm of LNG comes to France from Egypt.

The following graph shows the quantity of LNG received from each exporting country[359]. Countries marked with asterisk indicate re-export in LNG trade.

GRAPH 69. **European LNG supply sources in 2011.**



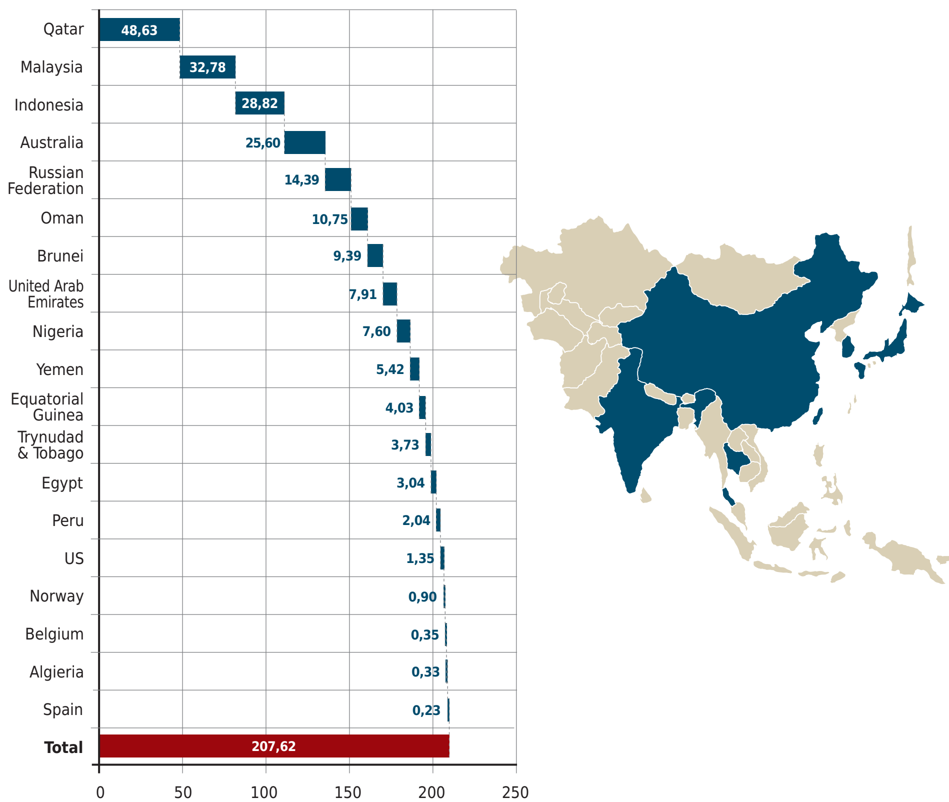
Source: *BP Statistical Review, 2012 edition.*

A new European export terminal has been proposed for construction in Vassilikos, Cyprus, in 2014. It would be the only export terminal in Europe. The terminal would be located on shore and have an export capacity of 6.0 Mt/year.

Asia-Pacific

Widespread differences between supply and demand in Asia constitute an important aspect of the dynamics of the natural gas market in that region, which also has led to significant intra-regional trading. In 2009 for example, 58% of trade could be attributed to trading between the countries of the region.[360]

GRAPH 70. **Asian LNG supply sources in 2011.**



Source: *BP Statistical Review, 2012 edition.*

Again, since there is no developed pipeline infrastructure for transportation and distribution is, natural gas is traded mostly as LNG. In 2010, out of the 186.3 bcm/y of LNG traded between different regions of the world, 112.3 bcm/y was traded within the Asia-Pacific region.[361]

The main importing countries of LNG in Asia are Japan, South Korea, India, China, and Taiwan.[362] Worldwide, they are the 1st, 2nd, 5th, 6th, and 7th, largest importers of LNG. Countries form the Asia-Pacific region that export from them are Australia, Indonesia and Malaysia, while the Middle East (particularly Qatar) and North Africa account for the vast majority of imports from outside the region.[363] Recently Australia in particular has been a significant player in the LNG trade in the Asian region and has the potential to strengthen its position in the upcoming years. In 2010 Australian exports of LNG accounted for 9% of total global exports[364]. Since then, estimates of its reserves have been revised upward as natural gas in the form of coal bed methane (CBM) has become important. A Nomura report expects Australia's gas production to more than quadruple within the next decade from 47 bcm/y to nearly 200 bcm/y[365]. Such projections combined with the extensive demand in the nearby Asian countries give Australia a huge opportunity of exporting LNG. It is believed, that the increase in natural gas production in Australia has been fuelled not by the fear of depleting energy sources, but rather by the potential economic advantages of plugging onto the Asian energy markets[366].

Indonesia serves as another significant exporter within the Asia-Pacific area. In fact, from 1984 to 2005 it was the world's largest exporter of LNG. Now it is the second after Qatar, and 11% of global LNG exports from 2010 came from Indonesia[367].

The following gives a more detailed depiction of each country's source of LNG. The Guangdong Dapeng LNG terminal in China receives gas from Northwest Shelf Australia LNG Venture, which was awarded a 25-year contract with the Guangdong Dapeng LNG terminal. Japan has a rather diverse portfolio of LNG exporters that it deals with; out of total LNG imports, 19% come from Malaysia, 18% from Australia, and 12% from Indonesia[368]. 23% of the LNG received by South Korea was exported from within the Asia Pacific region by Malaysia, 12% by Indonesia, and 5% by Australia[369]. The rest originated from external sources, with the majority coming from Qatar and Oman[370].

To satisfy the Asian region's growing demand, the exporting countries have extensively developed their infrastructure. As the leader in export ability, Australia continues to expand. In 2010, 49.7 bcm/y of liquefaction capacity was under construction and over 166 bcm/y was being proposed or planned in Australia[371]. Also, in 2009 came the final decision for the Gorgon LNG project which, when completed, will have an operating capacity of 20.7 bcm/y[372]. By the end of 2008, Australia's LNG production capacity was 26 bcm/y[373]. As of 2010, two liquefaction plants with a total capacity of 11 bcm/y were opened while another eight with a total capacity of 49.8 bcm/y were under construction[374]. Indonesia, another noteworthy exporter, manages its LNG export business with the support of three liquefaction terminals. The facilities have a combined production capacity of approximately 37 bcm/y[375]. Another liquefaction terminal of 3 bcm/y is expected to be up and running by 2014[376]. Malaysia holds the fourth largest natural gas reserves in the Asia Pacific region, as in 2011 the country's reserves were estimated to be 232.4 bcm[377]. Malaysia's capacity for LNG production stood at 31.3 bcm/year by the end of 2008[378].

Conclusions

There is a close correlation between the availability of LNG on the market and the natural gas pricing. Regions which have flexible gas supply by combining pipeline supply, LNG delivery and national gas production, price natural gas in close correlation with gas hubs prices. The lack of adequate infrastructure for diversification of supply increases dependence from incumbent sources leaving the country (region) as "stranded" from the global gas market perspective. It is also the case with insufficiently developed wholesale gas market mechanisms. The absence of hub pricing mechanisms leads to a greater dependence on LTC and very often on the oil-indexation in LTCs.

CEE region has no direct access to global LNG markets. It is highly dependent on the pipeline gas supply. Its infrastructural development (pipelines, internal interconnections within CEE regions, gas storage facilities) and market developments (gas hubs) are insufficient or non-existent. In the same time other EU regions have either access to global LNG markets or/and are internally highly interconnected. They have also developed hub markets.

These circumstances influence the pricing mechanisms in LTCs in CEE regions. The lack of alternative that the LNG market gives leads to dependence on external suppliers. The perspective development of LNG terminals in the region may change the situation. Presently, EU solidarity requires that CEE regions be supported in order to benefit from the EU internal market rules.

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8. Gas Storage

On the gas market storage facilities are an important infrastructural element. They are used mostly to balance supply and demand in summer and winter; more specifically, excess gas supplied in summer is stored to be used in winter when more energy is needed to meet demand. They are also used to enhance security of supply. In case of supply disruption gas reserves may be used to balance demand. It is particularly important when a country or a region is dependent on supply from sources outside its jurisdiction or/and being supplied from a limited number of external suppliers. Several jurisdictions introduce regulatory requirements to store a certain amount of natural gas in case of emergency. Suppliers also store gas for commercial purposes or as a price arbitration mechanism. The ability to store natural gas affects contractual relations between gas producers and national suppliers. The importance of this relation in case of CEE countries and its influence on pricing mechanisms in LTCs will be presented in this chapter.

Storage at glance

Globally, there are two types of gas storage facilities: underground (salt caverns, mines, aquifers, depleted reservoirs and hard-rock caverns) and surface facilities. The first aquifers were built in 1947 in Kentucky and in 1953 in Germany; the first depleted gas fields were developed in New York in 1916 and in Poland in 1954; and salt caverns were first constructed in Michigan in 1961 and in France and Germany in 1970.[379] Storage facilities were mostly developed after the end of World War II, when pipelines were not large enough to supply seasonal demand.

Each storage facility uses different methods in order to inject and retrieve stored gas. In the depleted fields' technique, gas is re-injected into a porous rock formation and is kept in place thanks to an impermeable cap; in the aquifer technique, water is first injected into pores and later gas needs to be dehydrated before use.[380] Each mechanism requires the use of compressors—motor-driven, turbine-driven, or electric—to transform gas into a proper form before it is injected underground. Each storage mechanism differs in physical characteristics, such as porosity, permeability, and retention capability.[381] Normally, natural gas is compressed and stored in summer and then drawn off during colder seasons.[382] The surface facilities are used to store natural gas in its liquid state—LNG.

The aquifer technique allows for safe storage of large amounts of natural gas in maximum tightness and pressure.[383] However, the depleted gas method is most commonly used for storage of natural gas for a number of reasons. As the name implies, depleted reservoirs have already held volumes of natural gas before being drained, thus these reservoirs provide perfect conditions for storing injected gas. The use of the same field also means that the equipment used for the extraction of locally-produced gas may also be used for storage purposes. Additionally, geological characteristics of depleted reservoirs—such as composition and porosity—are well known, and thus require little research and development. On the other hand, aquifers are not as well understood by scientists and thus require much more investment and development. Moreover, whereas the right pressure for gas storage exists within depleted fields, it is not the case for aquifers. Composition, porosity, and pressure must all be analysed before a storage facility is developed.[384] Most importantly, aquifers require more cushion gas than depleted fields (up to 80% as opposed to 50% of a total storage volume[385]), therefore less gas is available for market consumption. For these reasons, depleted gas fields are the most advantageous for the storage of natural gas.

The salt cavity storage technique differs in that pores for storage are formed through dissolution or extraction of salt, which makes storage mechanism a resilient and watertight.[386] Storage in salt cavities is advantageous because deliverability rates are high in comparison to those of depleted fields or aquifers, yet volume capacity in salt cavities is significantly lower.[387]

GRAPH 71. **Summary of storage facilities.**

Type	Cushion to Working Gas Ratio	Injection Period (Days)	Withdrawal Period (Days)
Aqufer	Cushion 50% to 80%	200 to 250	100 to 150
Depleted Oil/Gas Reservoirs	Cushion 50%	200 to 250	100 to 150
Salt Caven	Cushion 20% to 30%	20 to 40	10 to 20

Source: *Current State of and Issues Concerning Underground Natural Gas Storage Federal Energy Regulatory Commission.*

Natural gas is stored for two main purposes. "Base-load storage" means storage of gas to fulfill the market's demand for this energy source. "Peak-load storage", is a reserve of natural gas stored in case of "unforeseen supply disruptions/shortages."[388] Base-load storage facilities typically include depleted gas reservoirs that can supply gas steadily. Peak-load facilities, on the other hand, are more easily replenished in a shorter period of time due to the function which they serve. For this same reason, gas is more easily injected and drawn off from peak-load storage than from base-load facilities. Each storage facility also has different levels of base gas (also known as cushion gas), which is the volume of gas that must permanently kept in reserve in order to maintain appropriate pressure needed for accurate deliverability rates during withdrawal.[389] The total reserve capacity minus the base gas load is the volume of working gas (also known as "top gas"), or gas available to the market.

Storage facilities globally

The following graph summarizes the number of underground storage (UGS) facilities in each region of the world, as well as UGS capacity per country[390].

GRAPH 72. **Working storage facilities worldwide as of May 2011.**

Europe - Country	Number of UGS facilities in operation	Capacity (bcm)
Russian Federation	26	65.5
Ukraine	13	32.13
Germany	47	20.30
Italy	10	15.60
France	15	12.70
Hungary	6	6.13
Netherlands	3	5.26
Austria	5	7.40
United Kingdom	6	4.37
Czech Republic	8	3.28
Romania	8	2.69
Slovakia	2	2.84
Latvia	1	2.32
Spain	2	4.53
Poland	8	1.83
Denmark	2	1.02
Sweden	1	0.01
Belarus	3	0.85
Belgium	1	0.68
Bulgaria	1	0.45
Croatia	1	0.56
Serbia	1	0.30
Ireland	1	0.22
Portugal	1	0.18
TOTAL Europe	**170**	**191.14**

Asia - Country	Number of UGS facilities in operation	Capacity (bcm)
Uzbekistan	3	4.6
Kazakhstan	3	4.2
Turkey	3	3.1
Azerbaijan	2	2
China	2	1.9
Japan	4	1.7
Armenia	1	0.12
Kyrgystan	1	0.6
Taiwan	1	0.01
TOTAL Asia	**20**	**17.69**

North America - Country	Number of UGS facilities in operation	Capacity (bcm)
United States	401	114.7
Canada	50	20.7
TOTAL North America	**451**	**135.4**

Country	Number of UGS facilities in operation	Capacity (bcm)
Australia	4	0.24
Argentina	1	0.1

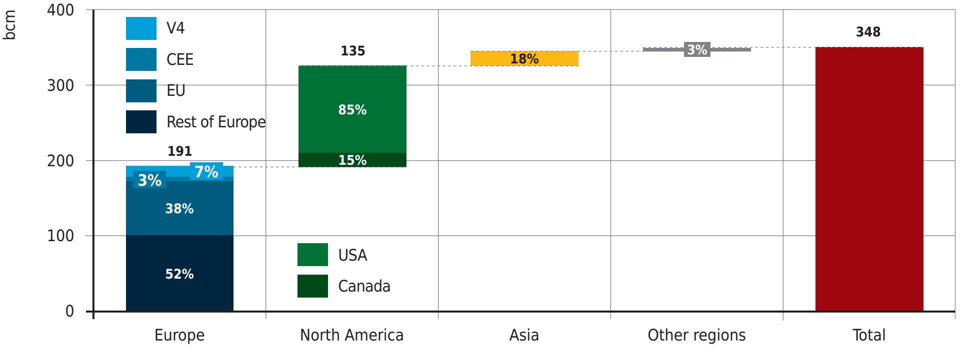
Source: *Number of OGS facilities in operation (May 2011), cedigaz.org, GIE.*

Globally, storage facility capacities are concentrated in two regions: Europe and North America that account for 55% and 39% respectively. Asia's share is about 5% and the rest of the world accounts for only 1%. In Europe, Russia is the biggest country in terms of a total volume as it contributes 1/3 of the total volume. The European Union countries account for 48% of the region and the biggest share can be attributed to Germany, Italy and France.

The position of CEE countries in the EU is not important. Countries of CEE host only 10% of European storage facilities and the V4 countries stand for almost 7.5%. Out of the four countries Polish capacities amounting to 1.8 bcm are the smallest. In North America most storage volume is located in the US (85%). In Asia most capacities have been developed in the CIS countries accounting for over 60%.

China and Japan are both home to approximately 10% of gas storage installations. The regional share is presented on the graph below.

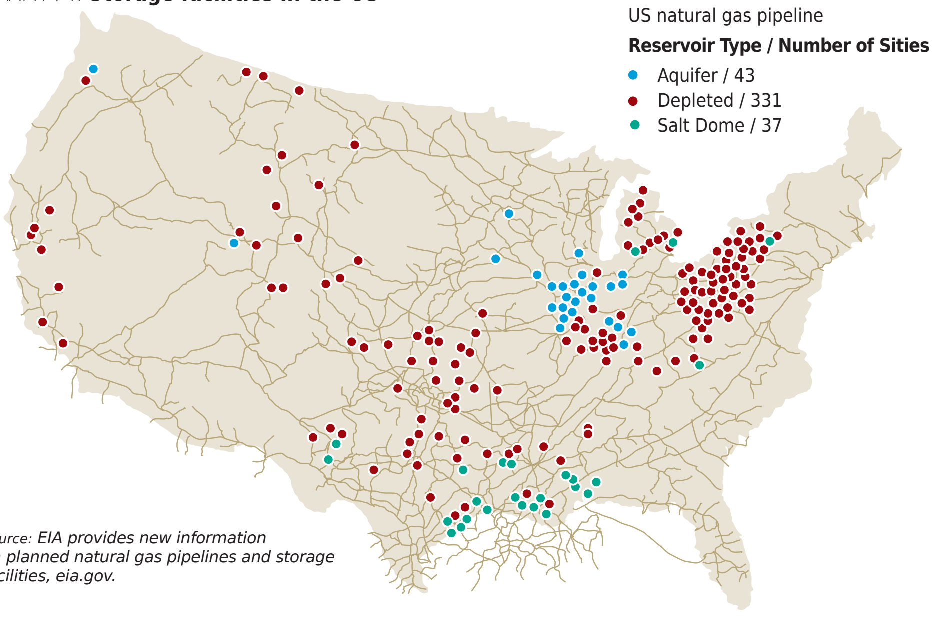
GRAPH 73. **Share in the global storage by region.**



Source: *Author's calculation.*

Since gas supply independence in the US, storage facilities there are generally used by gas suppliers to balance their supply/demand portfolio or for infrastructural balancing purposes. The aim of storage facilities is not other than securing of the country's gas supply. According to the US Energy Information Administration, most of natural gas in the United States is stored in depleted natural gas or oil fields because they are located close to consumption centers.[391] Depleted natural gas and oil fields are also convenient because they take advantage of the existing wells, gathering systems, and pipeline connections in the area. Aquifers are largely used in Midwest America due to the availability of impermeable cap rock under which natural gas is stored.

GRAPH 74. **Storage facilities in the US**



Source: *EIA provides new information on planned natural gas pipelines and storage facilities, eia.gov.*

Currently, there are 411 active underground storage facilities that are being used in 48 states and a total of 120 operating entities that are subsidiaries of 80 corporate entities.[392] Storage facilities that serve interstate interests are either under the jurisdiction of the Federal Energy Regulatory Commission (FERC) or are state-regulated. These entities do not own gas stored in their storage facilities, but they do play an important role in determining how much of the facility's storage capacity is used. There are two main categories of companies that rely on storage facilities: interstate and intrastate pipeline companies.

While the former only relies on storage facilities for load balancing and system management on long-haul transmission lines, the latter uses them for the same purposes as well as to serve end-user customers. According to FERC Order 636, interstate pipeline companies must ensure that their working gas capacities are "available for lease to third parties on a non-discriminatory basis"[393], which opens access to storage capacity.

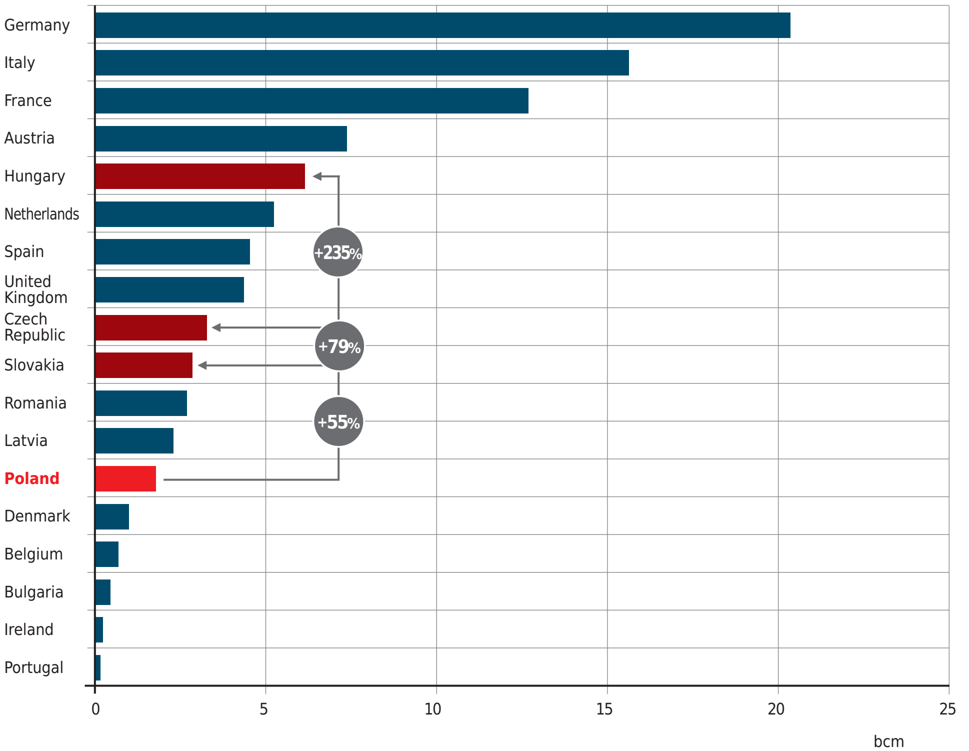
Europe

Storage facilities are crucial in Europe since about half of Europe's natural gas supply is imported. The EU storage facilities serve various purposes. The first is to serve as a backup from any physical and/or political disruption of gas supply; another function is to provide flexible supplies of gas when there is a supply-demand gap in trade; finally, storage facilities provide liquidity to the natural gas market and thus influence gas pricing.[394]

Thus, storage plays a vital role in securing supply. Generally, it differentiates the EU market from its US counterpart. It is especially the case for the EU member states which are dependent on external gas supply, especially if these supplies come from a limited number of counterparts. The projected increase in the EU gas import will be increasingly important as EU gas production continues to decline. CEE countries are particularly dependent on a limited number of external sources of gas supply. Greater storage facilities may enhance their security as in case of supply disruptions they may balance the demand. Considerable volumes of gas stored may also play a role in negotiating supply contracts.

Additionally, storage facilities may also promote competition within the gas market. Flexible gas supplies provided by storage facilities also promote gas trade.

GRAPH 75. **Working gas volumes per country.**



Source: *Gas Infrastructure Europe.*

Altogether, there is a total of 128 storage sites in 19 European countries. The 27 EU member states have an overall working gas volume of 91.8 bcm, with an expected 50 bcm increase by 2025.[395] The biggest countries in terms of volumes are Germany, Italy and France followed by Austria, Hungary and the Netherlands. CEE countries storage facilities range between 0.5-3.3 bcm with the exception of Hungary which has 6.2 bcm and is the 5th biggest gas storage country in the EU. The Czech Republic and Slovakia are in the middle of the stake with capacities of 3.3 and 3.8 bcm respectively.

Compared to V4 peers Poland is far behind. To reach the level of Hungary, Poland would have to increase its capacities by over 200%. Czech capacities are almost 80% higher, whereas Slovak over 50%. Taking into account CEE dependence on external gas supply and infrastructural interconnections with other EU countries, their overall volume of storage facilities is not impressive and Poland still has much room for improvement.

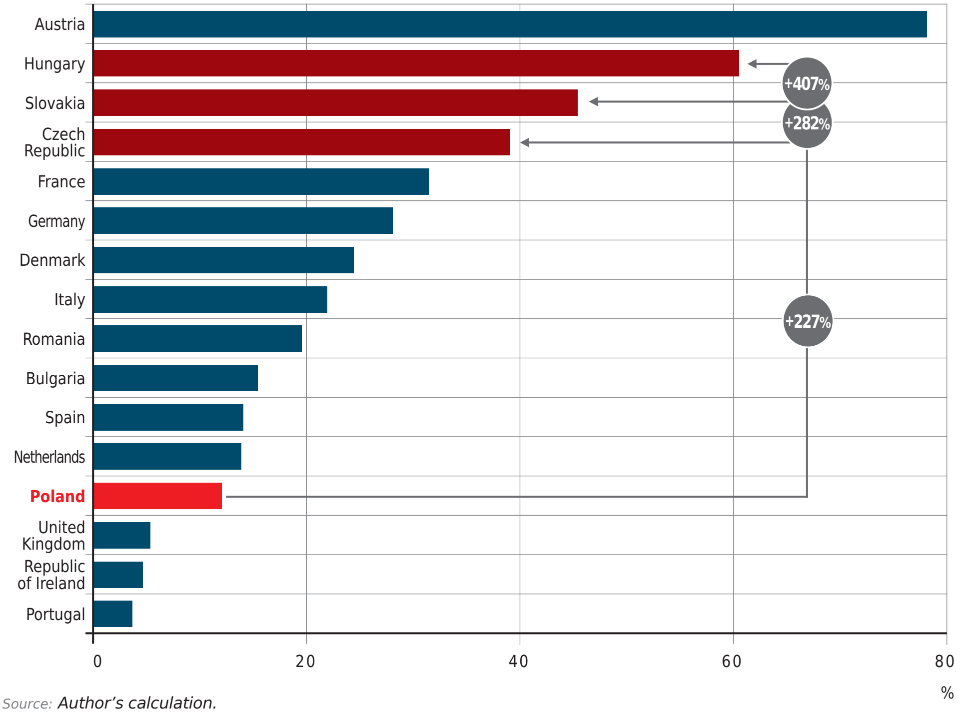
The graph below presents the ratio of storage capacity to domestic consumption of natural gas. It indicates what percentage of annual gas consumption may be covered by stored commodity. Austria can theoretically cover 78% of its natural gas consumption needs from its storage capacities. Remarkably the next three positions are taken by three of four V4 countries.

The ratios for Hungary, Slovakia and the Czech Republic stand at 60%, 45% and 39% respectively while the ratio for Poland equals 12%. Such a low ration puts Poland at the end of the stake and close to gas-producing member states such as the UK, the Netherlands and other countries with diversified fuel sources.

Nevertheless, even one of the biggest gas producing country in the EU – Romania has storage facilities that can cover close to 20% of annual demand.

The percentage values on the graph indicate a gap between Poland and other V4 countries.

GRAPH 76. **Gas storage to domestic gas consumption ratio.**



Source: *Author's calculation.*

Although storage facilities do secure supply to the EU gas market, there is a need for increased competition by improving third-party access (TPA) to such storage facilities. More specifically, there is a need for improvement in the EU market integration, more reliable price transparency, as well as more deeply traded markets for an even more secure supply of natural gas as well as for increased investment in this market.[396]

The shortage of gas storage capacities makes Poland vulnerable to seasonal spikes in demand. It makes Poland vulnerable to gas shortages as the one which was a consequence of Russia-Ukraine gas dispute in 2009. Due to the crisis the Polish wholesaler was forced to cut down supplies to the biggest consumers[397] which would not be the case if storage capabilities where higher. Extended storage facilities also enable potential reactions of traders to short-term price changes on the market when gas can be bought when it is cheaper, for instance due to lower oil prices. Finally gas storage capacity is essential when thinking of development of shale gas exploration. The surplus of commodity must be stored if it is not subject of immediate consumption.

Asia

Underground storage facilities are not crucial for the Asian gas market as they are Europe and in the US. It is so for two main reasons. First, the Asian gas market is almost completely dependent on LNG for its source of energy supply. Thus, when it comes to storage, most LNG is stored in numerous LNG terminals and facilities scattered across each country. Second, lack of extensive pipeline infrastructure means that there is no need for the construction of large, underground storage facilities as a source of gas reserves that may be sent out to neighboring countries.

Japan has 40 oil and gas reserves with a total capacity of 26.5 bcm that have been depleted, yet only 5 out them have been constructed as underground storage facilities.[398] These five fields—Nakajo, Shiunji, Kumoide, Katagai, and Sekihara—are operated by Teikoku Oi, a gas-producing company. Gas stored in these underground storage facilities is used to meet seasonal fluctuations and supply emergency stockpile. They are all depleted gas fields with the following capacities: 2.1 bcm total volume; 1.2 bcm total working gas; and 1 bcm total cushion gas.[399] However, gas demand is beginning to increase, which means that additional storage facilities will need to be constructed in order to meet this demand.

After Japan, China has three storage facilities alongside its storage facilities within its LNG terminals. They are Jintan, Dagang, and Huabei, with a fourth storage center currently under construction between Mainland China and Taiwan. This new storage center will have a total capacity of as much as 2 bcm, with a 1 bcm working gas capacity and a daily delivery rate of 8 mcm. This facility will improve gas supply to Beijing and Tianjin.[400]

The construction of a 4-bcm underground storage facility is planned in northwestern Xinjiang, which would store pipeline gas coming from Central Asia.[401] More specially, the storage facility would be needed for the 30 bcm of gas per year that would be imported from Turkmenistan and later transported to cities such as Shanghai, Guangzhou and Hong Kong.

As a major exporter of natural gas for Asia, Australia also needs underground storage facilities as a part of its natural gas infrastructure. Australia currently has four underground storage facilities, all of which are depleted gas fields.

There are currently no natural gas storage facilities in Korea, Indonesia and Malaysia, although construction of such a facility is planned in Ulleung Basin, Korea.

Conclusions

Gas storage facilities are concentrated in two regions: North America and Europe. The European Union is home to 26% of the global storage volume. Out of that CEE makes 21% which corresponds to a global share of 4%. Gas storage facilities have a number of functions which –affect the domestic and regional gas markets. They are used to balance supply and demand throughout the year and improve a country's security of supply.

The need for investment in storage facilities is particularly crucial in countries with gas supply that is not diversified. The whole CEE region, apart from Romania, is strongly dependent on gas delivery from Russia. This should spark the need for extension of storage capacities in order to make countries little less vulnerable to political decisions that either relate to the country or have negative impact on the country. Poland has one of the smallest storage capacities in the region, outpacing only Bulgaria and Baltic countries. The latter have not developed any storage facilities. Out of V4 countries Poland can store the smallest amount of gas. Taking into account how much of annual consumption can be secured by stored gas, Poland is far behind the EU, CEE and V4 countries.

Together with the necessity for developing storage facilities when investing in shale gas extraction Poland needs to think of its storage capacity strategy. For instance Germany, nowadays having the largest storage capacity in the EU, is still planning multiple investments. The country aims at increasing capacities by 50% in the years to come. Italy wants to reach 19 bcm and the UK 23 bcm[402]. With TPA implementation gas storage may be also strictly commercial enterprise and apart for two main functions there will be another one: generation of profit. Storage capacities also influence relations with gas suppliers. First of all, they serve as a safety buffer in case of disruptions. Vulnerability can be perceived as weakness in a negotiation process undermining a buyers' position. Secondly, big capacities enable decision-taking based on changing market environment – buying when prices are lower, waiting when prices go higher, which results in a more positive balance at the end of the year. Having an alternative of gas delivery from another source, which for instance Poland is about to achieve upon completion of the LNG terminal, gas storage capacities enable playing the competition rule between suppliers taking advantage of lower prices from one of them in a given period. The same applies to the situation in which gas in CEE region can be bought on hubs in significant amounts. Market rules with storage potential strengthen the position of buyer.

379. *R. Sedlacek, W. Rott, W. Rokosz, STUDY ON UNDERGROUND GAS STORAGE IN EUROPE AND CENTRAL ASIA; ÉTUDE SUR LE STOCKAGE SOUTERRAIN DU GAZ EN EUROPE ET EN ASIE CENTRALE, p. 3.*
380. *J.-M. Leroy, Underground Natural Gas Storage: ensuring a secure and flexible gas supply, pp. 5-6.*
381. *The Basics of Underground Natural Gas Storage, eia.gov.*
382. *Adjusting gas demand to fluctuations in demand, total.com.*
383. *Ibid.*
384. *Storage of Natural Gas, naturalgas.org.*
385. *Ibid.*
386. *J.-M. Leroy, Underground Natural Gas Storage: ensuring a secure and flexible gas supply, p. 7.*
387. *Storage of Natural Gas, naturalgas.org.*
388. *Gas Storage Plant, ge-energy.com.*
389. *The Basics of Underground Natural Gas Storage, eia.gov.*
390. *Please keep in mind that the following graph documents UGS facilities as of May 2011, so there have been a number of additions since then. This table, nevertheless, provides insight to volume capacities per region.*
391. *The Basics of Underground Natural Gas Storage, eia.gov.*
392. *Ibid.*
393. *Ibid.*
394. *Gas Storage in Europe; 'Adding security through flexibility', EFET, p. 2.*
395. *Ibid., p. 9.*
396. *http://www.parkiet.com/artykul/689805.html?print=tak&p=0.*
398. *NATURAL GAS STORAGE IN ASIA, LE STOCKAGE DU GAZ NATUREL EN ASIE, International Gas Union.*
399. *GAS STORAGE IN THE APEC REGION; DEVELOPMENT OF COMMERICAL STRUCTURE, Asia Pacific Energy Research Centre, p. 21.*
400. *2010 Annual Report, China National Petroleum Corporation, p. 23.*
401. *PetroChina to build large underground gas storage in Xinjiang, reuters.com.*
402. *K. Hedge, E. Fjeldstad, The future of European Long-Term Natural Gas Contracts, Oslo 2010.*

9. Unconventional gas

Today gas is extracted from a number of sources. With regard to a type of rock from which natural gas is extracted, sources of gas are divided into conventional and unconventional. Unconventional gas is methane which has the same chemical composition as conventional natural gas. The differentiation factor refers to reservoir characteristics that are unusual and more complex to understand for gas companies with the current state-of-the-art technology[403]. It makes the extraction of unconventional gas more expensive.

Unconventional gas is nowadays extracted from shales (shale gas), from isolated rocks (tight gas), and from coalbeds (coalbed methane). The technological progress enables gas exploration from unconventional sources on an industrial scale. Two other sources of methane, whose extraction is being researched, are geopressurized zones – deep underground deposits (3.5 km to 8 km) and methane hydrates – the most recent subject of research – lattice of frozen water which forms a sort of cage around molecules of methane[404]. The two latter sources will not be analysed in this chapter due to no industrial exploration.

Today the vast majority of natural gas comes from conventional sources and accounts for over 85% of the total marketed output. Unconventional gas is expected, however, to increase its market share owing to a dramatic growth of production in the US and potential to secure domestic or regional energy security. Unconventional gas resources are distributed across the world.

Shale gas has a chance to change the natural gas market, but the future of its development is dependent on a number of factors, particularly, on the business case of extraction of the commodity at a relatively high cost. Providing that market players are interested in this source of the commodity, a number of countries might change their position in the value chain.

Global outlook

Industrial exploration of unconventional gas regards mainly operations in the US. The first commercial well was drilled in 1820, and shale gas was first produced in 1926. Although the history is very long, the development of gas production from unconventional reservoirs had remained quite slow until 2006. The factors such as huge reserves of unconventional gas, large non-urbanised spaces enabling drilling, and declining conventional reserves were not sufficient to boost the process. Promotion of unconventional gas required governmental support. The first step was a tax credit for unconventional gas production that was implemented in 1980 by the Crude Oil Windfall Profit Tax Act. The very regulation is known as "Section 29". That triggered interest in a number of shale deposits, and although the tax benefit terminated in 1992, shale gas expansion programs were still continued by operators. The turning point, however, was the market conditions in the 1990s. The drop in conventional gas reserves and insufficient discoveries led to market fears that the demand will not be met by the supply. This resulted in rising gas prices, which in turn caused more expensive unconventional gas extraction to become attractive. The technological breakthrough came in 2005 when hydraulic fracturing techniques were combined with horizontal drilling.

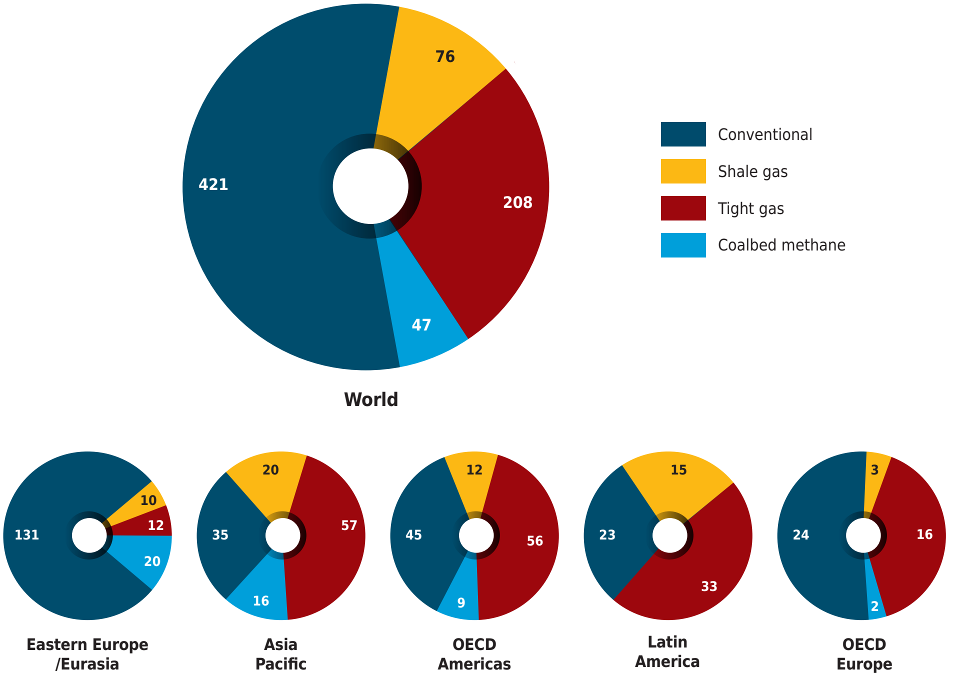
In 2010 the total production of natural gas stood at 3 276 bcm, of which 14% was produced from unconventional gas sources. Over 90% of the total unconventional gas generation originated from two countries: the US and Canada, where the US accounted for 78% and Canada for 14% of the total. Two followers were Russia and China with 4% and 3% respectively. No other country had a share higher than 1%. It is a remarkable fact that the United States is the only country where the share of conventional gas production is lower than the unconventional one[405].

The analysis estimates that recoverable resources of natural gas equal 752 trillion cubic meters (tcm). This volume represents 421 tcm of conventional gas and 331 tcm of unconventional resources. The difference between global conventional and unconventional gas assets equals 90 tcm and proves that the conventional resources pool is 27% higher than the unconventional one.

This disproportion varies from region to region. On the graph below one can see that Eastern Europe[406] has an advantage of having large conventional gas deposits. The picture is quite distorted by Russia, which is one of the richest countries in terms of resource existence. On the other hand, unconventional gas accounts for 72% of Asia-Pacific's gas resources with almost half of it in shale gas. In fact, a similar proportion can be seen in Latin America. The European OECD countries have an estimated balance of conventional and unconventional resources, and in the US there is a visible unconventional gas advantage, though not as significant as in Asia-Pacific.

Additionally, out of the three described sources of unconventional gas, shale gas constitutes 62%. Again there are differences in the regions, but the dominant trend is visible for all the regions apart from Eastern Europe and Eurasia.

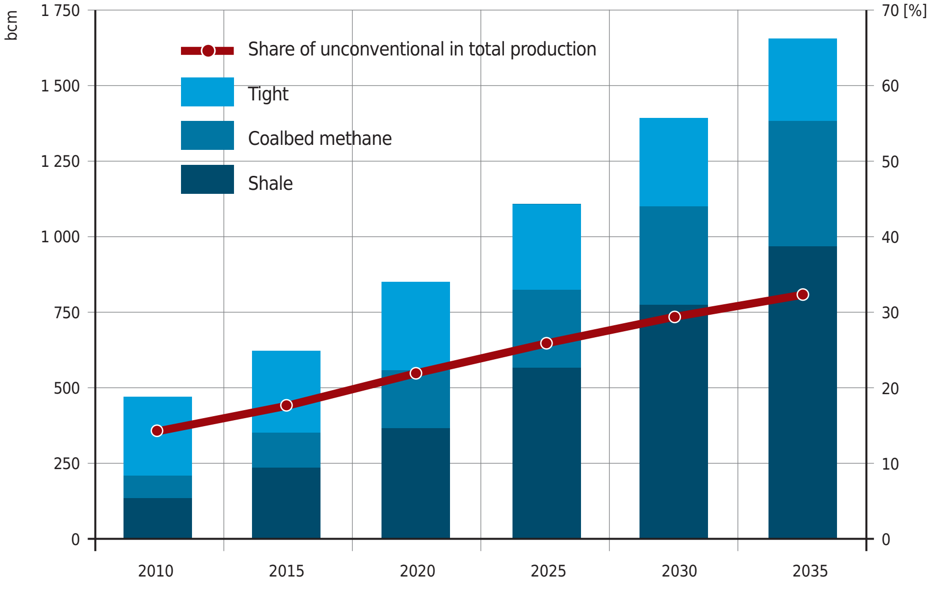
GRAPH 77. **Recoverable natural gas resources by type and region.**



Source: *IEA.*

Globally, most unconventional gas in 2010 was extracted from tight rocks, which was due to its high share in the US unconventional exploration. That year the US extracted 420 bcm and other countries only 70 bcm. Shale gas production contributed almost 30% in unconventional gas production and was also concentrated in the US (140 bcm in the US[407]). Coalbed methane production was estimated at 53 bcm[408] in the US and 10 bcm[409] outside the States, and tight gas at close to 230 bcm[410] and 60 bcm[411] respectively. The graph below describes the current and forecasted production of unconventional gas. Global interest in developing shale-gas-extraction undertakings will result in a growing share of gas from this source, which might exceed 50% in 2025. It will result in much interest and prospect for exploration investments in a number of countries. The world's share of unconventional gas may constitute one third[412] of the world's natural gas consumption in 2035.

GRAPH 78. **Unconventional gas production forecast.**



Source: *IEA.*

The occurrence of unconventional gas in the world was estimated by the International Energy Agency along with local geological institutes.

Tight gas reservoirs originate in the same way as conventional gas. The difference is that the rock is of very limited permeability, which requires special techniques to obtain commercial amounts of the commodity. Their global deposits have not been described in a comprehensive and comparable way.

The occurrence of coalbed methane is linked to coal deposits, and as such it can be found in countries with large coal reserves. The existence of a recoverable resource is also not well described. Globally. the extraction is concentrated in the US and China. Most reservoirs in Europe are located in the UK, Germany, and France[413].

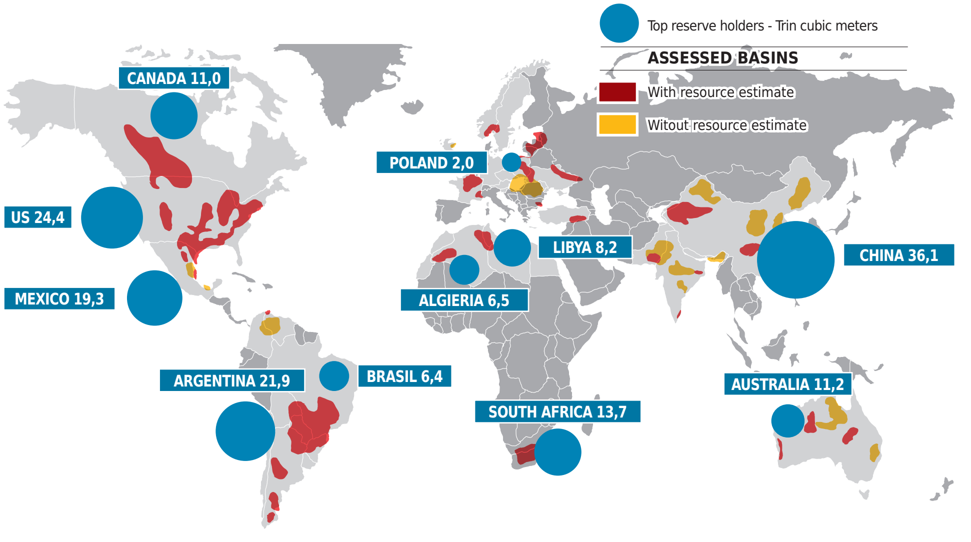
Shale gas has been one of the most discussed topics in the gas industry. Its high deposits may be found on each continent. The biggest potential players include China with the world's richest resources, the US, Argentina, Mexico, South Africa, Australia, and Canada. North American countries, in particular, the US and Canada, have been significant producers of natural gas, which cannot be said of the Latin American region. The latter was the smallest region in terms of the gas production volume in 2011[414]. Vast amounts of shale gas might change this trend. Out of South American countries, Argentina shows the highest interest in developing shale gas extraction in the coming years. Exploration from its deposits (the Neuquen Basin) may change the country's economy. Some drillings have already been carried out, but much more investment is needed in the years to come. A survey carried out in 2011 in Argentina proved that shale gas extraction was believed to start within 3-4 years to come. The projects receive full government support. Relying on imports from Bolivia and Qatar nowadays, the country has prioritised initiatives leading to boost its exploration investments[415].

In Asia-Pacific a significant number of resources is estimated to be located in Australia. Relatively small domestic commodity consumption has already turned the country into a net exporter of gas. The development of shale gas projects will be also linked to a number of obstacles that were not significant issues in the US. Lack of infrastructure on the continent along with shortages of skilled labour might result in a considerable increase in investment outlays, reaching as much as triple the needs in the US. A location remote from urban areas combined with higher transportation costs decreases the competitiveness of shale gas in Australia compared with coal seam gas[416].

China is a country whose gas consumption has been increasing very rapidly in the last few years and domestic production is not sufficient anymore to supply the country's needs. Shale gas is perceived as an option to fulfil its energy needs. Domestic deposits of shale gas were estimated at over 36 tcm[417], which ranks the country as number one in the world. Extraction of shale gas started in 2010, but currently it does not exceed 1 bcm/y. The latest five-year plan aims to cover most of the country's energy needs from non-traditional and alternative sources, one of which is shale gas. In 2012 there were 10-15 wells producing 0.7 bcm of natural gas[418]. The Chinese Ministry of Land's spokesman claims that the country's production of natural gas from shale gas basins could exceed 100 bcm/y by 2020[419].

In the European Union, apart from CEE, shale gas reserves are located mainly in the UK, the Netherlands, Germany, France, and Scandinavian countries. Industrial-scale production has been impeded by a number of economic, environmental, and regulatory obstacles (France banned extraction of shale gas). Moreover, EU countries chose the wait-and-see strategy, observing the development of the US market and its ability to turn shale gas extraction into profitable export flows.

GRAPH 79. **Map of global shale gas basins.**

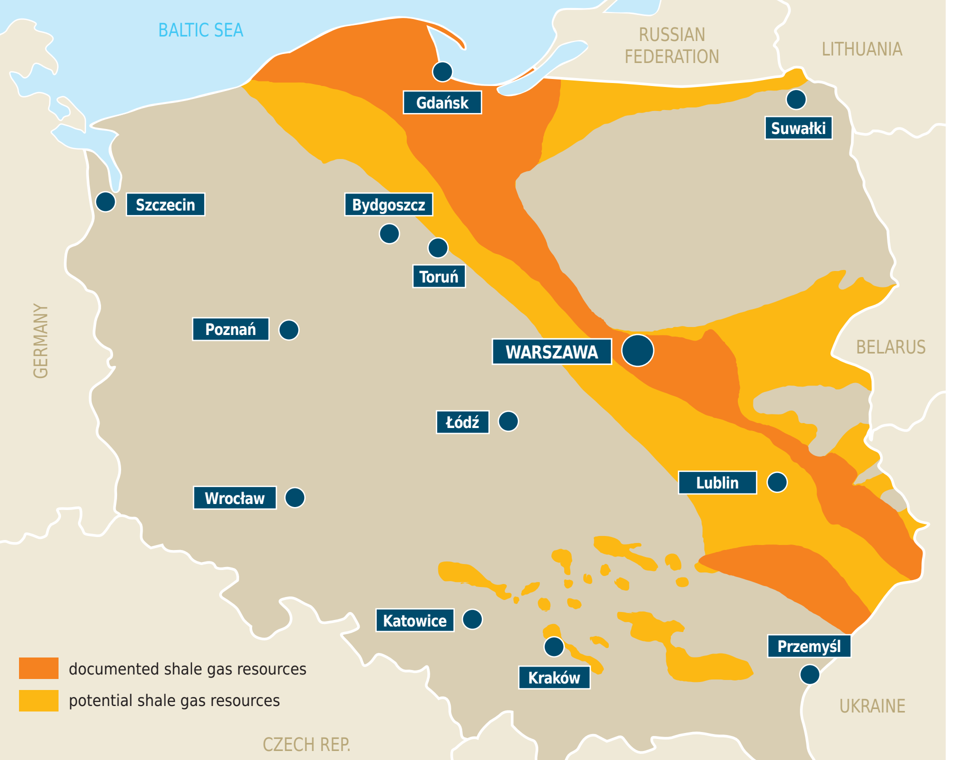


Source: *EIA.*

In Central and Eastern Europe, the initial estimates were very optimistic for Poland and positioned the country in the top locations with regard to the occurrence of shale gas. The volume of reserves was downgraded by Państwowy Instytut Geologiczny (the Polish Geological Institute) according to a report published in March 2012[420]. It shows that in the most optimistic scenario there are 2 tcm at most. Such a volume is still perceived as potentially attractive for global and domestic investors.

The Polish reserves are located in three basins, the Baltic, Podlasie and Lublin Basins, covering the area of 48 thousand sq. km. Recoverable gas is estimated to reach as much as 768 bcm[421]. There are a number of concerns regarding the future of domestic extractions including the country's capability to face large investments as well as manage high costs of drilling operations linked to varying geological conditions. Another issue, which can be perceived as an obstacle, is underdeveloped transmission and storage infrastructure along with limited export connections. There are a number of initiatives that aim to solve infrastructural problems as well as address the required investment outlays. In October 2012 the Polish Minister of Treasury said that the long-term prospective investments would reach as much as PLN 50 billion (approx. EUR 12.5 billion) and 10% of that would be spent by 2016[422]. The goal is to double national natural gas extraction until 2020, which means that some 4 bcm are expected to come from shale gas. The first shale gas concession was granted in 2007[423].

GRAPH 80. **Map of the Polish reserves of shale gas.**



Source: *PIG.*

Romania is also interested in the exploration of shale gas. The country is relatively rich in natural gas resources, and in 2011 approximately 80%[424] of the consumed commodity was supplied from domestic production. Apart from conventional gas in the Black Sea deposits, the country has also access to shale gas that is located in two basins, the Carpatian-Balkanian and Pannonian-Transylvanian Basins. The volume of Romania's resources has been the subject of multiple studies, but it is still uncertain. The EIA estimates the total resources in Romania, Bulgaria, and Hungary at 538 bcm. The initial extraction efforts have proved that costs of shale gas exploration might be too high, but there is still a group of investors interested in exploration in Romania. In June 2012 the Romanian Senate debated on the motion of a memorandum on shale gas extraction, which was finally rejected with a vast majority of votes[425].

Another country that might turn into a shale gas market player is Ukraine with resources estimated at 5.5 tcm, of which almost 1.2 tcm is potentially recoverable. The basins containing the commodity are the Ukrainian parts of the Lublin Basin and Dnieper-Donets Basin in the eastern regions of the country. Compared to EU countries, Ukraine has discouraged foreign investors on account of uncertain legislation. However, a series of changes that took place in 2011 sparked interest of international players that signed memorandums with the government[426].

Shale gas reserves have also been registered in other countries of CEE region. The studies conducted in Lithuania estimate recoverable resources at 120 bcm (downgraded from 480 bcm)[427]. Aiming to gain more independence from Russian gas deliveries, Lithuania sees shale gas extraction as one of its priorities in the National Energy Strategy.

Hungary has access to the same basin as Romania does and the country's biggest oil and energy player, MOL, has undertaken a number of initiatives to explore possibilities linked to shale gas exploration.

Unlike Romania and Hungary, Bulgaria issued a memorandum on exploration of shale gas, which resulted in suspending any exploration activity in the country. Other CEE countries are not considered as potential players in the unconventional gas market in future.

Impact on the EU

Unconventional gas has become a discussion topic in Europe, particularly in the EU, where additional gas supplies could increase energy security of the Union. According to the above graph, Poland is a member state where potentially recoverable resources are the highest[428]. Although the estimates vary from source to source, according to Panstwowy Instytut Geologiczny the initial estimates were much too optimistic, and in fact there is at least 2.5 times less shale gas[429] than there was thought to be. Nevertheless, Poland still counts as regards unconventional gas extraction plans and the recently announced investment outlays will amount to PLN 50 billion in the coming years with a declaration of 5 billion in the next two years[430].

In the European Union there is no single policy concerning unconventional gas, in particular, shale gas. The idea is very much promoted in Poland, where a number of drillings have taken place in the past months, and more and more licenses have been granted, whereas a number of countries like France, Bulgaria, Romania, and the Czech Republic have banned shale gas extraction as environmentally unfriendly[431]. The ban had also been lobbied in the EU institutions, but in September 2012 the Parliament Committee of Environment refused to implement the prohibition claiming that Europe could not afford not to utilise its natural resources that could contribute to lower energy dependence on external deliveries[432].

The Energy Roadmap 2050 sees gas as an important fuel in the energy system transformation, which is aimed to increase demand for the commodity. Shale gas has been perceived as an alternative to imports from Russia and Norway as well as the execution of the gas sources diversification policy. There is, however, no consistent policy with regard to this subject. The latest study of the European Commission found that shale gas development in Europe would not make the continent self-sufficient but would at least make it possible to fill in the gap in declining exploration of conventional gas[433]. Unconventional gas extraction development may change trade flows of natural gas in future. China, a potential, big consumer of this fuel, may turn from a net importer to a net exporter. The same applies to the US, Argentina, and some other countries. On top of that supply of natural gas has a chance to grow, which will result in increased competition on the market, and the latter will consequently influence LTCs and make them more competitive.

Conclusions

Unconventional gas has a chance to change the global gas market in terms of both supply and demand. Nowadays there is one country, the US, which shows the direction to others and dominates in terms of extraction from unconventional sources. A number of countries, however, have showed interest in the matter and are willing to follow the trend. EU countries took the wait-and-see approach, observing the development of the US market.

The development of unconventional gas has been perceived as a huge opportunity for Poland. Even after the amount of gas in its shale deposits has been revised, it may turn out to be a significant player on the market. Shale gas extraction has had much support from the government, which aims to back up shale gas undertakings with multibillion investments. Along with the LNG terminal and extraction of conventional gas, shale gas will lead to diversification of sources and build a negotiating position with Russia. There are also regulatory risks related to possible EU regulatory changes, which may affect shale gas exploration, and it, in turn, may affect the countries producing gas.

There are no regional similarities between CEE countries with reference to physical possibilities and the regulatory approach. However, shale gas development in Poland may affect CEE region by providing an alternative source of gas on the market. Infrastructural integration of the region may make the common approach to regional security of supply feasible. An additional amount of spot gas on the market may lead to a more intense erosion of LTCs. It may also affect pricing mechanisms in LTCs.

Increased unconventional gas exploration boosts the amount of gas on the market. Some potential producers are LNG exporters, which means that gas may reach all global markets making them more competitive and having an impact on agreements in LTCs, making them more dependent on market conditions than on political issues.

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427. *Ibid.*
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10. Moving forward – directions for the CEE countries and V4 members

The Central-Eastern European (CEE) region has certain particularities which influence the gas pricing in LTCs. CEE region has a similar history and geographical proximity. Based on the political and economic environment of the Cold War, CEE countries were part of the Council for Mutual Economic Assistance (COMECON), which created close economic ties with the Former Soviet Union. It influenced the way gas infrastructure and commercial relations in CEE countries were developed.

Until 90s of the 20th century gas supplies to CEE were based on a bilateral monopoly pricing formula, where gas prices were set for a specified amount of time through bilateral government agreements based on a cost-plus calculation method. In the same time the netback formula with indexation to oil and oil derivatives dominated on the European markets. Closer relations between CEE countries and the European Union changed the Former Soviet Union importers' attitude to gas pricing methods in these countries. CEE countries were encouraged to change the pricing formula into the netback one.

CEE region mostly comprises of gas supply corridors from Russian sources to Europe. The gas infrastructure in the region, in particular transmission systems, was built and has been optimized for the transit of gas from the East to the West. In consequence, the demand of the member states in the region is covered to a high extent by supply from one source. No alternative gas supplies to the region were developed under the planned Former Soviet Union economy, which influenced pipeline interconnections between CEE countries and with other external suppliers.

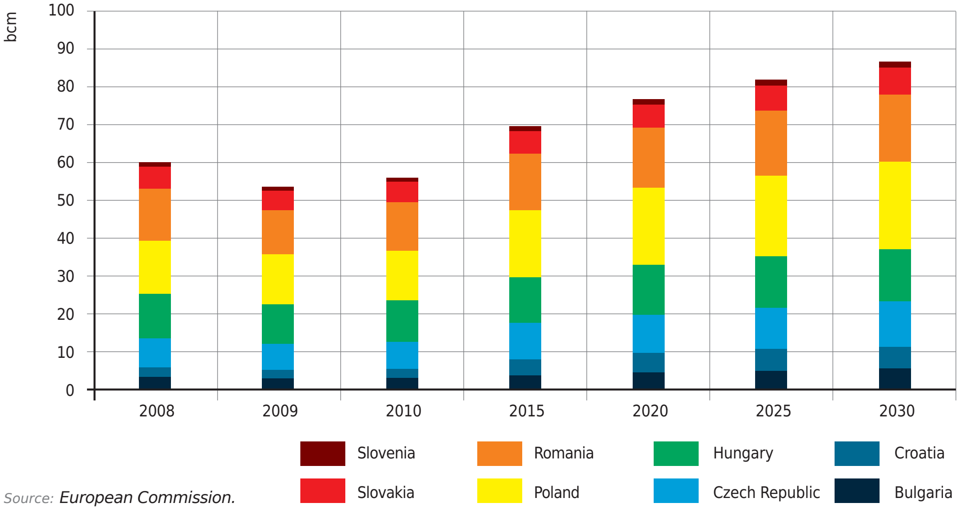
CEE members are aware that new infrastructure needs to be developed in order to enhance security of supply and diversify the gas sources. This need is further stimulated by their membership or close relations with the European Union. The EU funds for infrastructural investments play important role in increasing investments in infrastructure connecting the countries of the region.

This chapter will show in detail the situation of CEE countries and options that they have in negotiating prices for natural gas in LNG adequate to changing market conditions.

Natural gas demand

Based on estimates by the European Commission, the incremental demand in the region (excluding the Baltic states) compared to volumes in 2009 under the base scenario is approximately 23 bcm to 33 bcm by 2020 and 2030, respectively, which represents an average annual growth rate over the entire period (i.e. to 2030) of 2.3%[434]. Demand in the region is dominated by the larger countries, with Poland, Romania and Hungary representing about two-thirds of total consumption. The increase in demand is mainly due to the electricity and industry sectors, although it varies by country.

GRAPH 81. **Gas demand forecasts.**



Source: European Commission.

According to estimates the share of natural gas in CEE electricity production will rise from 9.5% (2010) to 10.6%[435] (2015) and some sources claim that in 2020 it may reach 13-17%[436]. In the EU the share is said to decline from 23% to 21% in 2015 and 19.5% in 2020[437].

CEE region is characterised by a high share of coal in electricity production. The share is estimated at 57% (2010) and is estimated to decline to 48% in 2020. Currently, coal in the EU coal generates 30% of electricity. Germany holds a strong position as its i coal share amounts to 51% of its total electricity generation. The forecasted share of coal in the EU will decline by over 7 percentage points and account for 22.7% in 2020[438]. Several CEE countries hold significant coal reserves, including Poland, Bulgaria, Hungary, the Czech Republic, and Romania. A number of new coal and lignite-based generation units are also planned in Bulgaria, Croatia, Romania and the Baltic countries. Meanwhile Poland, Slovakia and the Czech Republic will decrease their coal-fired capacity.

According to experts, gas demand in CEE region will increase. A part of it will be connected with an increasing importance of gas in the electricity sector. Gas will therefore compete with coal as a stable source of electricity generation. However the pricing formula in gas supply contracts in CEE does not adequately relate to the importance of gas as a netback source to coal in electricity generation.

Natural gas production

Gas production in CEE region in 2010 was 10.8% of gas production within the EU. The biggest producers were Romania (51%), followed by Poland (22%), Hungary (13%), and Croatia (13%). Other countries produce relatively small quantities of natural gas[439]. According to forecasts, the proportion will not change dramatically, however, Poland is expected to increase its production share to 26.7%.

Based on estimation provided by the European Commission[440], a total gas production in the region will decrease considerably in next two decades from more than 20 bcm/year in 2011 to more than 11 bcm/year in 2030. Production in Bulgaria and Slovakia may reach zero after 2020. Production in Croatia, Hungary and Romania is to continue declining at the same average annual rate to that for the period until 2020 and after 2020 production in Poland and the Czech Republic will stabilise at 4 bcm and 0.11 bcm, respectively. Unless unconventional gas is commercially exploited, it leaves CEE countries dependent on imported gas.

Domestic production of natural gas in the Czech Republic is not sufficient to meet national demand. According to the IEA, domestic production could only meet 1.3% of the national demand in 2008.[441] Also Slovakia does not produce enough natural gas to meet national demand. Domestic production currently satisfies less than 2% of the country's demand for natural gas, and it is expected that production will continuously decrease to about one-third of the current production by 2014.[442]Similar level of gas self-sufficiency exists in Bulgaria. Its domestic production covers hardly 2.5% of national consumption[443]. Unlike the Czech Republic, Slovakia or Bulgaria, Poland is quite more stable in terms of domestic production. Its domestic production currently satisfies about 37% of the country's demand for natural gas.[444] Similarly, Hungary's domestic production satisfies about 25% of the country's demand for natural gas.[445] Romania is one of the biggest natural gas producers in the European Union. Its domestic consumption satisfies almost 80% of consumption[446]. Croatia's domestic production positions the country ahead of Romania making it the least dependent on imports.

Currently 82%[447] of the country's domestic consumption is covered from its domestic production[448].

GRAPH 82. **Projected production from conventional sources in the CEE region (bcm).**

Year	Bulgaria	Croatia	Czech Rep.	Hungary	Poland	Romania	Slovakia	Total
2010	0.07	2.30	2.20	2.50	4.30	10.40	0.09	**19.86**
2011	0.46	2.26	0.15	2.57	4.30	10.62	0.16	**20.53**
2012	0.46	2.21	0.14	2.29	4.30	10.33	0.16	**19.89**
2013	0.42	2.30	0.15	2.18	4.30	10.04	0.16	**19.55**
2014	0.38	2.20	0.18	2.14	4.30	9.78	0.16	**19.12**
2015	0.34	2.20	0.22	2.18	4.35	9.52	0.16	**18.96**
2016	0.30	2.10	0.14	2.18	4.35	9.37	0.16	**18.60**
2017	0.27	2.00	0.13	2.10	4.30	9.22	0.16	**18.18**
2018	0.25	1.90	0.13	1.78	4.20	9.05	0.16	**17.47**
2019	0.22	1.90	0.13	1.55	4.00	7.57	0.00	**15.37**
2020	0.20	1.80	0.12	1.50	4.00	7.38	0.00	**15.01**
2021	0.00	1.76	0.11	1.43	4.00	7.13	0.00	**14.32**
2022	0.00	1.71	0.11	1.36	4.00	6.89	0.00	**13.96**
2023	0.00	1.67	0.11	1.29	4.00	6.66	0.00	**13.62**
2024	0.00	1.63	0.11	1.23	4.00	6.43	0.00	**13.29**
2025	0.00	1.59	0.11	1.17	4.00	6.22	0.00	**12.98**
2026	0.00	1.55	0.11	1.11	4.00	6.01	0.00	**12.67**
2027	0.00	1.52	0.11	1.05	4.00	5.81	0.00	**12.38**
2028	0.00	1.48	0.11	1.00	4.00	5.61	0.00	**12.09**
2029	0.00	1.44	0.11	0.95	4.00	5.42	0.00	**11.82**
2030	0.00	1.41	0.11	0.90	4.00	5.24	0.00	**11.55**

Source: *European Commission.*

Import dependency

An important portion of national gas supply comes from external sources out of which import from Russia is the most important. The situation differs depending on a given CEE country; however the general pattern is that these countries are particularly dependent on Russian gas.

GRAPH 83. **Share of exporters in total CEE on natural gas import.**

Exporters	Importers (bcm)										
	CZ	HU	PL	SL	BU	RO	CR	LT	LV	ES	SI
Russia	6.90	5.70	9.30	5.30	2.55	2.56	0.00	2.89	1.50	0.63	0.48
Norway	3.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	1.20	1.00	1.60	0.00	0.00	0.00	0.62	0.00	0.00	0.00	0.25
TOTAL Imports	**12.00**	**6.70**	**10.80**	**5.30**	**2.55**	**2.56**	**0.62**	**2.89**	**1.50**	**0.63**	**0.73**
% Russian imports	57.50%	85.00%	86.00%	100.00%	100.00%	100.00%	0.00%	100.00%	100.00%	100.00%	65.80%

Source: *BP Statistical Review of World Energy June 2012, IEA.*

This pose treats to the security of supply of this region which is not so widely observed in the rest of the EU. Dependence on Russian gas is supplemented with poor storage infrastructure, insufficient domestic production, as well as a lack of interconnections between neighbouring countries which additionally influence these countries possibility of acquiring gas on favourable market conditions.

Infrastructural interconnections

There is still a gap between the level of the region's infrastructural development and the market needs. Given increasing demand for gas and relatively small domestic production in the CEE region gas must be imported in order to secure supply. However, there are no active LNG terminals in the region. The regional interconnections are insufficient. There are plans to build the North-South gas corridor, but presently import is based on interconnections with third countries, with the EU member states and, to a small extent, among CEE countries.

Pipelines

The gas transmission network in CEE is mostly characterized by transit-orientated infrastructure that is used to transport the bulk of Russian gas export to the EU member states. Interconnections generally offer only virtual dual flow.

There is a small number of intra-regional interconnections which disables common approach to secure energy supply. It is also disadvantageous in gas price negotiations, as it does not give sufficient possibility for price arbitration against existing supplier.

Under normal conditions Bulgaria is supplied through Ukraine, Moldova and Romania. In case of disruption of supply from Ukraine, necessary supply goes through Greece and Turkey which routes act as reverse flow only in case of full disruption of Russian gas supplies.

The main supply corridors for Croatia go through Slovenia and Hungary. At the moment both supply corridors are for domestic demand.

Usually Czech Republic is supplied with gas through Ukraine and Slovakia. There is one pipeline that provides gas both for domestic consumption and transit from Russia to Western Europe. This network transports approx. 8.7 bcm/year for the Czech Republic and 30 bcm/year to other end-users.[449] Other supply corridors for the Czech Republic, in case of disruption through Ukraine, run through Germany. There is also a small capacity in Poland which may be used in case of disruption. The Czech Republic also has the best-developed infrastructure in the region, consisting of multiple interconnections between its neighbouring countries.

The main supply corridor for Hungary goes through Ukraine, from which most of gas is imported under normal conditions[450]. The second supply option is through Austria, which has also great relevance. The third option is through Croatia, which would allow for import Croatian and Italian LNG into the country. This option is however available with certain market restrictions. In case of disruption of supply from Ukraine, gas may be imported through Austria[451].

Under normal conditions main gas supply corridors in Poland run through Belarus and Ukraine. Poland is a crucial transit country for natural gas coming from Russia and destined for Western Europe. Russian gas is transited via the Yamal pipeline, with gas coming into the transportation system through four entry points within the country: Lasow (via Germany), Drozdowicze (via Ukraine), Wysokoje (via Belarus), and Kondratki (also via Belarus).[452] Additionally, the gas market in Poland might be supplied through interconnections with Germany and the Czech Republic.

Under normal market conditions, Romania is supplied through Ukraine. In case of disruption in Ukraine, the sole remaining supply possibility is Hungary.

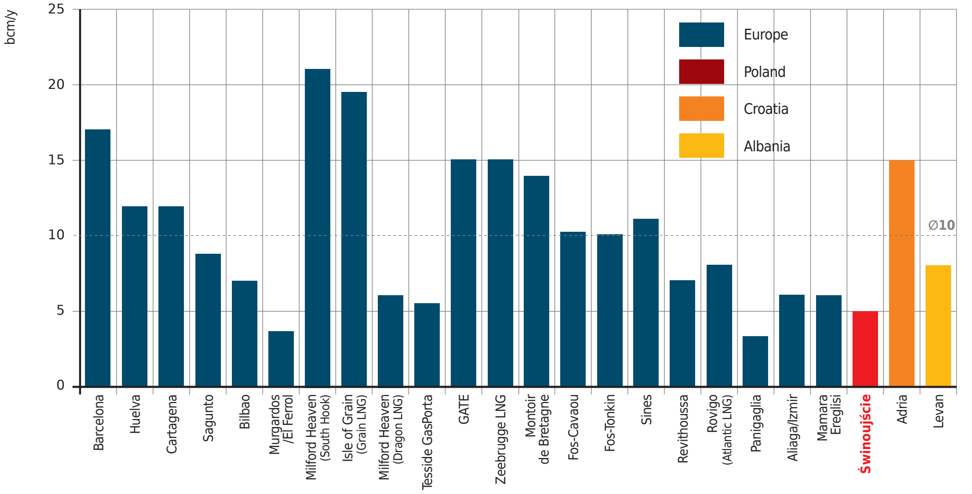
Slovakia is one of the main routes of gas transit from Russia. Slovakia has a domestic and transit pipeline and three interconnection points: Velke Kapusany at the Ukrainian border, Lanzhot at the Czech Republic border and Baumgarten at the Austrian border. Although the total capacity of this pipeline is 90 bcm/year, only 66.4 bcm/year transited by the country and 6.4 bcm was used for domestic consumption in 2009.[453] In the event of disruption in Ukraine reverse flows play an important role for supplying Slovakia. In such case gas supplied through the Czech Republic and Austria.

LNG

Presently there are no LNG terminals in the region. However, recent development plans include the LNG terminal in Świnoujście in Poland which is scheduled for completion in June 2014 as well as terminals planned to be constructed in Croatia. Due to market proximity it is also worth to mention LNG plans in Albania. The initial capacity of Świnoujście terminal is set at 5 bcm/y and at the moment it is the only LNG terminal in the region under construction. The Croatian Adria LNG terminal has been discussed for last years and it seems the country is still interested in developing the investment, particularly given a possible EU investment participation. However, there are some factors slowing down the decision process such as slow decision-making procedures and expected oversupply of the commodity. Croatia's terminal is planned to operate at 15 bcm/y capacity whereas the country's domestic consumption stands at 3 bcm/y only. The disproportion aims at enabling Croatia to become a key transit country for gas transportation. It is planned that the final decision regarding the investment will be taken in 2013. Due to market proximity Albania's LNG plans can also have influence on CEE market. The Levan terminal project was initiated in 2008 and it is still in a planning phase. The projected capacity stands at 8 bcm/y with the option to expand it to 12 bcm/y.

Investments in Poland, Croatia and Albania will open CEE market to a new supply channel of natural gas. Croatia's membership in the European Union as of July 2013 will result in the country's prospect plugging into the EU gas system and as such will ensure additional gas supply once the terminal is completed. CEE region will benefit from an increased amount of resources, which will have impact on regional LTC.

GRAPH 84. **Comparison of the CEE and Albanian LNG terminal projects with the existing European installations with regard to send-out capacity.**



Source: Author's calculation.

Storage facilities

Due to high dependency on imports storage facilities play an important role on European natural gas market. CEE countries have developed a total volume of 19.54 bcm storage capacities which accounts for over 20% of the EU total. The biggest storage capacities in the European Union are located in Germany, Italy and France with 20.3, 15.6 and 12.7 bcm capacities respectively. In CEE there are 34 storage facilities. More specifically, the Czech Republic has eight storage facilities, five of which are depleted gas fields, one of which is an aquifer, and one of which is a granite cavern.[454] Most of these facilities are owned by German RWE Gas Storage. There are plans for construction of additional underground storage facilities. The already existing facilities —Dolni Dunajovice, Haje, Lobodice, Stramberk, Tranovice, Tvrdonice, and Uhrice - have a total working capacity of 3.28 bcm and a total peak capacity of 45.0 mcm/d.[455]

Slovakia has currently two underground storage facilities controlled by Nafta and POZAGAS,[456] and they are used for commercial purposes only. Thus, these depleted gas fields - having a working capacity of 2.84 bcm and a peak capacity of 37,.35 mcm/d[457] - cannot serve as a location for the storage of emergency reserves of gas.

Poland currently has eight storage facilities—Moglino, Wierzchowice, Swarzow, Brzeznica, Husow, Strachocina, Bonikowo and Daszewo—seven of which are depleted gas fields and one of which is a salt cavern. This brings Poland's total underground storage working capacity to 1,83 bcm and peak capacity to 36.4 mcm/d.[458]

There are currently five storage facilities in Hungary—Pusztaederics, Zsana-Nord, Kardoskut-Pusztaszolos, Hajduszoboszio, and Szoreg—all of which are depleted gas fields. E.On Földgaz owns the first five storage facilities of those mentioned, and Hungarian MMBF (72.5% owned by MOL and 27.5% owned by MSZKSZ) owns the last one.[459] Taken together, the facilities have a working capacity of 6.13 bcm and a peak output of 68.0 mcm/d.[460]

Latvia, Bulgaria and Croatia have each one storage facility, out of which the facility in Latvia n is the biggest one with a capacity of 2.3 bcm. Capacities of Bulgarian and Croatian facilities are 0.56 and 0.45 bcm respectively.

GRAPH 85. **Capacity and number of UGS facilities in operation.**

Country	Number of UGS facilities in operation	Capacity (bcm)
Hungary	5	6.13
Czech Republic	8	3.28
Romania	8	2.69
Slovakia	2	2.84
Latvia	1	2.30
Poland	8	1.83
Bulgaria	1	0.45
Croatia	1	0.56
TOTAL EUROPE[463]	**171**	**191.14**

Source: *Author's calculation.*

Extensive storage capacities enable countries to cover a part of their demand from stored volumes in case of seasonal or politically-impacted disruptions. By being able to store much gas countries can play a price game on the market, particularly if they have physical capability to buy from more than one supplier. However, even if sourcing gas from one player, buyers are able to buy fuel when it is cheaper and use it from storage facilities if needed. By being active market players with usage of gas storage capabilities, countries have a chance to impact LTC based on their market operations experience. With regards to consumption Poland has relatively small storage facilities and in terms of ability to cover local demand the country is far behind its regional peers.

Planned infrastructural development

One of the main challenges of CEE is energy security. Regional cooperation is a tool for better integration of the region. Cooperation involves the construction of multiple interconnectors linking the V4 members and the whole CEE region (incl. Romania, Bulgaria, and Croatia). These interconnectors support the ultimate goal of constructing the North-South corridor, integrating the region.[462] This direction is backed by the European Commission financial support on infrastructural projects. Such infrastructural development would also interconnect region with the Italian LNG terminals, the German gas market, reserves in the Caspian Sea, and even North African gas supplies.[463]

There are several initiatives which integrate the EU with the supplying countries from Asia and the Middle East which potentially influence regional security of supply. The most important is the Southern Corridor consisting of: the Trans-Adriatic Pipeline (TAP)[464], the Italy-Turkey-Greece Interconnector (ITGI)[465], the White Stream Project (Georgia-Ukraine-EU pipeline)[466], and the Nabucco pipeline.[467] The basic business target of these projects is to give additional supply of gas mainly to Western Europe. The interconnections with Western Europe could also supply CEE and V4, but CEE and V4 are not their main destination. Their influence on the regional security of supply depends also on the development of internal North-South interconnections.

Wholesale market

The wholesale natural gas market in CEE region is relatively small in comparison with other EU regions. Competition is still limited with the Czech Republic being a leader in gas market development. Because in many respects CEE countries are catching-up with the gas market development in the Netherlands, Germany and the United Kingdom, the regions' development is dynamic and undergoing great changes.

CEE wholesale market is divided and each country has its own local market. Low levels of interconnection among these local markets make the cross-border sale negligible. Gas trading is available at border or domestic points. Local gas trading platforms in some CEE countries enable trading on virtual points. Gas trading is dominated by OTC sale. In countries where the gas market was created, national suppliers holding LTCs lose their maker share but become active market players in the neighbouring countries.

The prices of natural gas in LTCs are heavily linked to prices of oil and oil derivatives. These LTCs include both destination and take-or-pay (TOP) clauses,[468] favouring Russia at the expense of CEE countries. Gazprom almost have monopoly on the sale of gas to CEE, thus leaving little room for l price negotiation.

Conclusions

Regional particularities play important role in conditions of gas supply for CEE countries. Nowadays, they still rely heavily on natural gas supplies from Russia and have no alternative energy source. Any disruption in the region is highly likely to cut-off gas supply, with storage facilities within CEE region being too small to supply enough gas in case of such emergency. In addition to pipeline or supply disruption, CEE countries are also vulnerable to energy coercion by Russian leaders due to little flexibility in price negotiations.

Out of CEE countries, only the Czech Republic has been successful in diversifying energy imports. More specifically, the Czech Republic has access to Norwegian gas, and thus is not as dependent on Russian gas as other CEE countries.

Altogether, outdated pipeline and storage infrastructure put CEE countries at a disadvantage on the natural gas market as compared to Western Europe, and have led to unstable energy security in the region. Thus, improvements in energy security are being given the utmost priority. This mostly refers to developing interconnections within the region and with neighbouring countries - especially with Western Europe. The construction of new natural gas storage facilities, increase in LNG imports, as well as the construction of a north-south gas pipeline would serve as an alternative to Russian natural gas supplies.

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Summary

World economy, despite the current downturns, has been steadily growing, which is accompanied by growth in usage of fuels, in particular natural gas. However, demand for natural gas is satisfied from a wider variety of sources than in was in the past. More flexible supplies integrate so far stranded areas and provide more competition on regional gas markets. These macroeconomic changes concern also CEE countries. Fairly constant GDP growth in the region combined with the close global correlation between this and natural gas consumption lead to further increase in gas demand. Such a pace of growth in CEE region is related to a number of factors such as energy intensity, structure of energy mix, netback value of gas to alternative fuels.

CEE position on the global gas market has been disadvantageous in comparison with the position of the EU in a number of ways: very high dependency on one gas supplier, limited pipeline connections, underdevelopment of infrastructure linking CEE with Western Europe. A growing market, EU single gas market investments, new alternatives and potential shale gas exploration transform the region to less a price-taker than it used to be. High energy intensity of CEE countries, a sound position of gas in energy mix and economy growth, increase the market attractiveness of CEE region for gas exporters. Along with the development of a single gas market in the EU, there appears to be a chance of adjusting LTCs to market conditions.

The way natural gas is priced varies globally. Over time different formulas for determining prices in gas supply contracts, including long-term contracts (LTCs), have emerged, and the world has yet to converge in terms of the models utilised. Although there is some overlap with regard to pricing mechanisms in the three main regional gas markets of North America, Europe, and Asia, contrasting pricing mechanisms are becoming clear. These differences are due to regional characteristics such as regulation, existence or lack of a spot market, a degree of market opening, and transparency, to name only a few. The main identifiable mechanisms include: gas-to-gas competition, oil price escalation, bilateral monopoly, netback, and regulation.

While different pricing mechanisms have been able to coexist for many decades, it is unlikely that the situation will remain the same in future. Several countries traditionally engaged in the below cost pricing have moved to reform the regulatory environment and address price distortions caused by such below the price policies. A huge gap between the prices set by oil indexation in Continental Europe and the spot market prices in the United States and the United Kingdom has opened recently. It reopened LTCs' price negotiations in the EU.

The problems of contrasting price models effectively incited an important debate on best pricing manners, and whether the use of varying methods leading to such huge differences in prices is even sustainable. Many argue that the logic behind oil indexation no longer applies to the current situation, making the transition to gas-to-gas (hub) pricing throughout the world inevitable. However, this prediction has yet to become reality.

The US and the UK have fully liberalised their gas markets and introduced competitive market systems. Continental Europe, especially CEE countries remain a few steps behind. The Asia-Pacific (apart from Australia) seems to be on the beginning of this way. This difference in gas market development among regions requires more caution in comparing different elements of gas markets functioning in these countries. Even a regulatory framework between the US and the EU, which seems similar at the first sight, requires a more in-depth analysis.

The EU, also still not uniform in the regulation of its gas market, observes important regulatory and infrastructural changes which will bring about creating more uniform gas market rules. The entry into force of the so-called 3rd Energy Liberalisation Package and gas market transparency rules, have changed the regulatory framework of the gas market. The EU gas target model is still under discussion. Irrespective of its outcome, the role of LTCs will change based on EU regulatory changes. Existing and future LTCs must be in line with competition law requirements and rules integrating the EU internal gas market. The European Commission in cooperation with the ACER and national energy regulatory authorities (NRA) will force further market integration and application of EU competition rules also with regard to gas pricing mechanisms. All contractual arrangements which fail to meet these objectives will no longer be acceptable. Changes on the gas market make the changes in CEE region inevitable. The recently initiated antitrust procedure by the European Commission against Gazprom and an arbitration case on liability for TOP clause in LTCs recently won by the Czech supplier prove that this part of the EU must change as well.

Gas hubs will play an important role in a new regulatory gas market model. Gas market liquidity and integration will increase, which will make hub prices more reflective of the EU demand/supply balance and less vulnerable to manipulations. The long term EU policy perspective will enhance the role of gas, which may create additional market liquidity forcing the parties to LTCs to make further amendments.

The gas market – apart from the US − still mostly relies on oil-indexed long-term contracts. Until the economic crisis, there was little discussion about renegotiation of price arrangements in LTCs. Recently, the trend to make LTCs more flexible has been observed throughout the EU. Due to stronger negotiating powers the northwestern EU countries have received concessions from producers, while CEE region still tries to follow the market.

Spot price indexation higher than 15% is one of the elements negotiated as an element making LTCs more flexible and in line with market trends. Other concerns such as base price change, volume reduction, destination clause flexibility, minimum bill change or re-opener clause flexibility reduce contractual risks of EU suppliers. CEE suppliers seem to follow this trend, but reaching an agreement with exporters (producers) appears to be far more difficult than for suppliers in Northwestern Europe.

There are several issues which influence the change in a regional gas pricing model, such as hub expansion, LNG development, storage facilities' investments and exploration of unconventional gas sources. They influence, sometimes only indirectly, gas pricing in LTCs.

Prices in hubs, both in Northwestern Europe and in the US, are strongly correlated with each other. The reason for that is the fact that the US as a country and the EU as a union with multiple single-market regulations are local markets where a supply and demand play takes place on a regional and not a local level. It is particularly visible in Europe where hub-developed gas prices in a number of countries are in fact very close to the European average which allows for drawing a conclusion that the European hub gas market is close to a single gas market.

The EU does not have a single reference point such as the Henry Hub in the US, but there is a number of hubs which are more developed than others and might serve as a reference. The first one is the NBP, for the UK market stands out from the EU in terms of the progress of market development when compared to the US. The NBP is the most liquid and most transparent hub as well as the one at which the largest volumes in Europe are traded. The next in line are the Zeebrugge and the TTF. The Dutch government plans to implement a number of actions to make the country a "gas roundabout" of Europe. The TTF is already the biggest continental hub in terms of volume. It is also one of the most liquid hubs competing against the Zeebrugge. The geographical location of the Netherlands enables the country to merge multiple factors important for a gas market: pipelines, extraction, LNG terminals, etc.

CEE region does not have its hub yet, although there have been plans to create a hub in Poland. Nevertheless, European hubs already play a vital role in the region. The EU has been investing in the creation of a single gas market and plans to continue this trend. To some extent the countries of the region already have the opportunity to buy gas at hubs and this will be changing in the years to come. Rapid development in hubs is a result of market ambition for gas to be priced according to market rules. Hubs have created an alternative pricing method that had not existed before and suppliers have to take it into account. Gas exporters have agreed for concessions towards more gas market oriented pricing formulas in LTCs, however they differ regarding the EU region.

There is a close correlation between the availability of LNG on the market and natural gas pricing. Regions which have flexible gas supply by combining pipeline supply, LNG delivery and national gas production, price natural gas in close correlation with gas hubs prices. Lack of adequate infrastructure for diversification of supply increases dependence from incumbent sources leaving a country (region) as “stranded” from the global gas market perspective. It is also the case with insufficiently developed wholesale gas market mechanisms. The absence of hub pricing mechanisms leads to a greater dependence on LTCs and very often on the oil-indexation in LTCs.

CEE region has no direct access to global LNG markets. It is highly dependent on the pipeline gas supply. Its infrastructural development (pipelines, internal interconnections within CEE regions, gas storage facilities) and market developments (gas hubs) are insufficient or non-existent. In the same time other EU regions have either access to global LNG markets or/and are internally highly interconnected. They have also developed hub markets. These circumstances influence the pricing mechanisms in LTCs in CEE regions. Lack of an alternative which the LNG market gives leads to dependence on external suppliers. The perspective development of LNG terminals in the region may change the situation.

Storage capacities influence relations with gas suppliers. First of all, they serve as a safety buffer in case of disruptions. Secondly, big capacities allow decisions to be taken based on changing market environment – buying when cheaper, waiting when more expensive which results in a more positive balance at the end of the year. Gas storage enables price arbitration for gas delivered from different sources for CEE region. The same applies to the situation in which gas in CEE region is bought on hubs in significant amounts.

Gas storage facilities are concentrated in two regions: North America and Europe. The EU is home to 26% of the global storage volume. Out of that CEE makes 21%. CEE countries are not uniform when it comes to amounts of working storage facilities, and gas storage to domestic gas consumption ratios. Poland has however one of the smallest storage capacities in CEE region, outpacing only Bulgaria and the Baltic states. Out of V4 countries Poland can store the smallest amount of gas. Taking into account how much of annual consumption can be secured by stored gas Poland is far behind the EU, CEE and V4 countries. It makes particular countries within the region vulnerable to exporters (producers).

Unconventional gas has a chance to change the global gas market in terms of both supply and demand. Nowadays there is one country, the US, which shows the direction to others and dominates in terms of extraction from unconventional sources. A number of countries, however, have showed interest in the matter and are willing to follow the trend. The EU countries took the wait-and-see approach and are observing the development of the US market. Along with LNG terminals and extraction of conventional gas, shale gas will result in diversification of sources and building of a strong negotiating position with traditional gas suppliers.

There are no regional similarities between CEE countries with reference to physical possibilities and the regulatory approach. However, shale gas development in Poland may affect CEE region by providing an alternative source of gas on the market. Infrastructural integration of the region may make the common approach to regional security of supply feasible. An additional amount of spot gas on the market may lead to a more intense erosion of LTCs. It may also affect pricing mechanisms in LTCs. Increased unconventional gas exploration boosts the amount of gas on the market. Some potential producers are LNG exporters, which means that gas may reach all global markets. On one hand it may make them more competitive and influential in regard to agreements in LTCs, and on the other more dependent on market conditions than on political issues.

The countries of Central Eastern European region share a similar history and are located close to each other. Their cooperation within the Council of Mutual Economic Assistance (COMECON) created close ties with the Former Soviet Union and influenced the way gas infrastructure and commercial relations were developed. Gas infrastructure, in particular transmission systems, storage capacities and gas interconnectors were built to transport gas from the Former Soviet Union to Western Europe. Intra-regional gas infrastructure was not perceived as necessary. As a consequence, the regional demand for gas is covered to a high extent by supply from Russian sources. CEE countries are aware of the need for structural changes in order to enhance competition and security of supply, as well as to diversify gas supply routes. These requirements are further stimulated by membership or close relation of CEE countries with the European Union (EU). The EU funds for infrastructural investments play important role in increasing investments in infrastructure intra-regional connections. Regulatory environment of the EU requires market-oriented changes and further integration towards an internal EU gas market. However, due to insufficiently developed infrastructure and lack of effective gas market mechanisms, CEE countries are more vulnerable to producers' (exporters') market power. Gas market rules should be uniformly applied within the EU, based on solidarity principles, under auspices of the European Commission and the ACER, and in close cooperation with National Regulatory Authorities. It will enhance the negotiating powers of CEE and benefit the EU internal gas market.

Note to the reader

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This analysis aims to show the developments in natural gas pricing in LTCs in Central Eastern Europe, taking into account trends on the global and EU markets. It shows particularities of these markets and the extent to which they are affected by the conditions of geo-political, economic, and legal nature.

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