NEW NATURAL GAS CONTRACTING TRENDS
IN THE EUROPEAN UNION
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INTRODUCTION

Natural gas is the cleanest fossil fuel and has the lowest CO2 emissions of all fossil fuels. It is an enormously important energy source and represents almost a quarter (23.9%) of all energy consumption in the world (BP Statistical Review of World Energy 2013). Its use can vary from power generation, heating and lighting, to cooking and transport (EIA, 2014). As such, it is not indispensable as electricity or oil, but nonetheless remains of the utmost importance for both households and industry in the vast majority of the European Union (EU) Member States.

Europe, however, is not very rich in natural gas. Consequently, its indigenous production is relatively low. According to BP Statistical Review of World Energy 2013, EU-27 natural gas production in 2012 was 149.6 billion cubic meters (bcm), while its consumption was 443.9 bcm. This means that European countries need to rely heavily on imports to satisfy their needs and demand for natural gas. Historically, EU gas imports were not very diversified and countries relied on a couple of major gas producing countries such as Russia, Norway and Algeria. This induced certain risks and meant that buying gas was a kind of negotiation process, in which large producers of natural gas had an upper hand and clear advantages due to their monopolist position coupled with low flexibility of the buyers. With poor infrastructure and almost no competition in the national natural gas markets in the EU, security of supply and stable prices were the two main goals the national incumbents and governments historically pursued. The result of such a situation was the emergence of the so called long term contracts (LTCs), which have been the backbone of EU gas imports for many years and even decades. From the European point of view, LTCs proved to be a reliable instrument for buying and importing gas, as they provided the much needed stability and security of supplies in addition to being an important basis for investments in gas infrastructure across Europe.

With the liberalization of the gas markets in the EU in the late 1990s and early 2000s, however, the playing field has changed dramatically. Unbundling, open markets and the entrance of new market participants provided much needed competition and slowly changed the way gas was being bought and sold, and consequently gas trading, hubs and exchanges soon emerged. Since then, the trend of renegotiating LTCs and making them shorter and especially more flexible, is being observed throughout the EU. Zajdler (2012) states several different factors, such as hub expansion, LNG development, investments in storage facilities and the exploration of unconventional gas sources as the prime causes for this trend. The second trend that is emerging in the aftermath of liberalization of the EU natural gas markets is that not only the duration of supply contracts is changing but also the nature of its pricing. In their report, DNV KEMA (2013) argue that LTCs applied in the EU wholesale gas sector are not only characterized by the length of the contract, but also by pricing terms. Pricing terms, such as indexation to other price benchmarks like crude oil and refined product prices and the volume flexibility are basic elements in any long term gas contract. As the wholesale gas markets are becoming more liquid,
they offer an alternative to the previously more pragmatic approach of the LTCs, oil indexation in the LTCs. Further to this, oil indexation is becoming less and less desirable by the majority of market participants in recent years. Dincerler, Lins and Schmitz (2012) even go as far as to state that even though for decades oil products have been the basis for pricing long term gas contracts, recently this link has broken down in the wholesale spot markets as well as in the forward markets.

On the other hand, the changing nature in the pricing of the LTCs and ever shorter supply contracts have created new issues along the gas chain. Coupled with other factors, this trend has affected the import structure of the EU and created new trade flows. Moreover, it induced changes in the regulation and the way the internal market developed and continues to develop today. It has also had an important effect on capacity issues, security of supply, volatility and risk. As such, Boltz (2013) argues that one of the key challenges in creating an integrated market in Europe is to put effective rules in place to facilitate cross-border trading and market integration between Member States. Sufficient physical cross-border connectivity is thus required to allow effective trading to develop and result in price convergence across different gas hubs (Booz & Company, 2013).

The issue of long term and short term gas contracts can be described as a kind of a trade-off. Hartley (2013) endorses the idea that LTCs between exporters and importers have the advantage of reducing cash flow variability and thereby increasing the debt capacity and capital investments, but on the other hand also limit profitable short term trading opportunities. Moreover, LTCs frequently have anti-competitive foreclosure effects, but nonetheless there exists a growing acceptance that their positive impact on investment makes them desirable as long as spot market competition remains unsatisfactory (De Hauteclocque & Glachant, 2008).

The purpose of this thesis is to thoroughly examine the traditional and latest trends in natural gas contracting and in natural gas trading in the aftermath of the liberalization process. Liberalization of the EU gas markets led to a trend towards shorter supply contract durations as well as to a move from oil-linked to hub-based pricing in these contracts. The aim of the thesis is thus to analyze the role of long term and short term contracts in the EU gas markets. Moreover, it aims to determine what impact the trend toward shorter contracts may have on different aspects of the gas markets, from trading, security of supply, capacity, competition, liquidity, volatility and risk. To achieve this, an analysis of the characteristics of contracts, imports, instruments being traded, infrastructure, capacity and storage will be carried out. The main objectives of the thesis are therefore to analyze the reasons and causes behind the shift towards shorter, more flexible and hub-based pricing of the gas contracts; to examine the effect of such changes on different aspects of the natural gas markets in the EU; to determine whether oil-linked LTCs and shorter hub-based contracts can co-exist and finally, to analyze the future role of LTCs in the European gas markets.

This Master’s thesis is based on a research methodology that provides the theoretical basis for qualitative descriptive parts of the paper. A compilation method, combining relevant literature
such as academic papers, scientific analyses as well as institutional reports and publications, is used to support the descriptions of the problems and any potential new findings. A combination of different existing views, data and facts is used as a tool in comparing and determining any potential advantages or disadvantages of either long term or short term gas contracts in a given situation. Throughout the master’s thesis, statistical methods are used for quantitative research to support the descriptive text and any potential new findings with statistical data and analysis. Statistical data will mainly be used in the analysis of the EU gas sector, the role of hubs in gas pricing and capacity related issues. Most of the statistical data will be obtained from secondary sources such as BP, Eurostat, Comext, ACER, IEA, EIA, ENTSOG, IGU and individual hubs’ and TSOs’ websites.

The thesis is divided into three main parts: the first chapter provides an overview of the EU natural gas markets and places the EU gas markets in the global context. A comparison of the main indicators such as production, consumption and reserves of natural gas between different countries and regions of the world is made. The first chapter also describes different price formation mechanism and lays out the reasons between differences in gas prices across the world.

The second part of the thesis presents the traditional and new gas contracting trends, i.e. the so called long term contracts (LTCs) and the trading markets. History and reasoning of the use of LTCs is described together with the main elements and the typical pricing mechanism of the LTCs. This chapter concludes with the description of the development of European hubs and gas trading. More specifically, it defines the instruments being traded and it analyzes the trading activity and trading volumes within the European hubs.

The third part of the thesis examines the impacts of new natural gas contracting trends on different aspects of the EU gas markets, such as capacity, competition and liquidity, security of supply and last but not least the impact on the existing LTCs and on the future of LTCs in the European gas markets.

Finally, the evolution of new natural gas contracting trends and its impacts is summarized in the conclusion of the thesis, where some estimations and speculations for the future development of the EU gas markets concerning contracts, are also made.

1 OVERVIEW OF THE EU NATURAL GAS MARKETS

1.1 EU in the context of global natural gas markets

1.1.1 Reserves and production of natural gas

The EU is a very important regional gas market, albeit far from being the largest one. In terms of natural gas proven reserves and gas production it is actually the smallest region in the world. Reserves, production and the reserves-to-production ratio (R/P) are important indicators of where the majority of natural gas comes from and thus determine the trade flows, imports and exports as well as, to a certain extent, the prices. It is also very important to determine whether a country or
a region has enough of its own natural gas resources to cover its demand and consumption, or it has to rely on foreign imports and is thus import dependent and to what extent.

Natural gas reserves are difficult to estimate, as they depend not only on actual quantities of gas, but also on technical recoverability and economic viability of extraction and production. That is the reason why these estimates can vary significantly and why they change so significantly over time. As we can see from Figure 1, growing world consumption over the years has not led to diminishing reserves. Proved reserves, meaning that they are technically and economically viable, have in fact remained unchanged or have even increased due to discoveries of new gas fields, namely fields of unconventional natural gas, or due to new technologies.

*Figure 1. Evolution of natural gas proved reserves by region, 1980-2012*

The total proven natural gas reserves in the world were estimated at 187.3 trillion cubic meters (tcm) in 2012, a 0.5 tcm or 0.2% decrease with respect to 2011 (Figure 1). The majority of the world’s proven natural gas reserves are located in the Middle East (42.81%) and countries of the Former Soviet Union (29.02%). Together, these two regions represent 71.83% of the world’s proven gas reserves. The three countries with the largest amount of proven gas reserves are Iran, Russia and Qatar, which are estimated to hold 17.95%, 17.58% and 13.38% of the natural gas reserves respectively. Combined, these three countries hold just under half of the world’s total gas reserves, which indicates that the global gas market is very concentrated and monopolized.

Gas reserves in the European Union\(^1\) are estimated to be the smallest of any region, amounting to only 1.75 tcm and representing merely 0.93% of all proven natural gas reserves in the world (Figure 2). Even taking into account Europe as a geographical area, the picture doesn’t change much, as the reserves then amount to 3.9 tcm or 2.1% of world's reserves.

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\(^1\) EU 27 in 2012
All the other parts of the world combined hold less gas reserves than the countries of former Soviet Union. Namely, Asia Pacific and Africa hold around 8% of all gas reserves, while North America has 6% of all proved gas reserves and South and Central America have 4%.

Figure 2. World map of natural gas reserves in 2012 (tcm)


Appendix 2 presents a list of countries with highest proven gas reserves. As mentioned above, the three countries with the largest proven gas reserves in 2012 were Iran, Russia and Qatar with 33.6, 32.9 and 25.0 tcm respectively. Turkmenistan (17.5 tcm) is the fourth largest country with regards to gas reserves and is followed by USA (8.5), Saudi Arabia (8.2) and UAE (6.1). Interestingly, USA is the only country in the list from the Western Hemisphere and the only one in the top 5 not located in the Middle East or former Soviet Union regions. Venezuela (5.6) is the only country from South or Central America, while Nigeria (5.2) and Algeria (4.5) hold the largest amounts of gas reserves in Africa and conclude the list of top 10 countries of proven natural gas reserves. Again, the table shows how concentrated natural gas reserves actually are, as 91.3% of all reserves are located in twenty countries of the world.

In the last decade, unconventional gas resources such as shale gas, tight gas and coalbed methane, have attracted considerable interest, although in practice the push to develop these resources varies considerably by country, depending on the mix of domestic fuels and imports and perceptions of the risks to energy security and the environment (IEA, 2012).

Unconventional gas reserves are large, but as they are in general much more difficult to extract and produce, they require more complex technology and therefore generally result in higher prices. With new technology such as horizontal wells and hydraulic fracturing, unconventional gas made up nearly 12% of global gas production in 2008, according to IEA (2012). In addition
to the uncertainty and its high price, environmental issues also play an important role in unconventional gas developments.

Eurogas (2014) nevertheless estimates that unconventional gas resources may provide an additional 42.5% of all natural gas reserves in the world. The largest share of such reserves is estimated to be located in Asia Pacific, while the estimations for Russia and Europe are not as optimistic. Europe for example is estimated to have an additional 19 tcm in the form of unconventional natural gas, while Asia Pacific has an estimated 95 tcm of unconventional gas reserves.

Although recoverable resources of unconventional gas in Europe are estimated to be quite large (see Figure 3), especially relative to existing proven gas reserves, they depend on technology and economic, social and environmental viability of production. But unconventional gas resources could still play an important role in the future of the EU, especially considering the latest push from the EU Member States towards diversification of gas supplies and increased security of supply.

Figure 3. Map of major unconventional gas resources in Europe

As yet, there is no large-scale production of unconventional gas in Europe. Medium-term prospects for its production appear brightest in Poland, where exploratory drilling for shale gas is most advanced and the size of its resources is considerable, albeit uncertain. The estimates vary significantly, from 5.3 tcm (EIA, 2011) to somewhere between 346 and 768 bcm (PGI, 2012).

Other largest possible resources of shale gas in Europe can be found in France, UK, Sweden, Germany as well as Austria, Bulgaria and Romania. EIA (2011) estimates that UK could hold as much as 5.7 tcm of technically recoverable gas, Germany up to 230 bcm, while extraction of
unconventional gas in France could reach up to 8 bcm per year in 2035. In line with the above, Deloitte (2013) reports that as far as shale gas is concerned, GECF\(^2\) as well as the IEA\(^3\) remain of the view that the shale gas revolution has not yet occurred. Moreover, the ability to replicate the very favorable conditions under which shale has been developed in North America, elsewhere in the world and especially in Europe, where there are legal constraints for possible development of such resources, is largely unproven.

All in all, new technologies and new findings of gas basins could radically change the European landscape of natural gas markets in the future. At this moment, however, Europe remains dependent on natural gas from other parts of the world. Its shortage of natural gas means that its indigenous production is subsequently rather low and does not cover its demand.

*Figure 4. World map of natural gas production in 2012 (bcm)*

World production of natural gas has been steadily increasing over the last decades and has reached 3,364 bcm in 2012 (BP Statistical Review 2013). The largest producing regions in 2012 were North America and Former Soviet Union with production of 896 bcm and 768 bcm, respectively (Figure 4). Increase from 2011 to 2012 was the largest in the rest of Europe\(^4\), most notably in Norway, where there was a 10.71% increase in gas production. Production of natural gas increased in all the regions, except in the EU-27 and countries of the Former Soviet Union (FSU). In total, world production of natural gas increased by 2.16% with respect to 2011. The two largest gas producing regions, North America (26.65%) and Former Soviet Union (22.82%) accounted for just under half of world’s gas production (49.47%).

\(^2\) GECF – Gas Exporting Countries Forum.
\(^3\) IEA – International Energy Agency.
\(^4\) Countries not part of the EU.
Pacific had around 15% share of total gas production, while all other regions’ shares were less than 5%, except for Africa, whose share was 6.43% (Figure 4). The three largest producing regions - North America, Former Soviet Union and the Middle East have been slowly increasing their share in total world production of gas. EU-27 and Asia Pacific are the only two regions that had decreased their share in total production of gas from 2011 to 2012. EU-27 accounted for only 4.4% of world’s gas production and remains the smallest gas producing region in the world.

Knowing the sources of natural gas is important to understand which countries have strategic advantages and have built their economies around exporting natural gas. The EU, with the exception of Netherlands, is not very rich in natural gas, so it has to rely on imports from countries rich with this natural resource, such as Russia, Qatar, Algeria and Norway. These countries, along with other major gas exporting countries, are very important for European gas supply, its energy security and for setting gas prices and determining the type of gas contracts.

Appendix 3 shows that USA and Russia are by far the two largest gas producing countries, followed by Iran, Qatar, Canada and Norway. In the top 20 list of gas producing countries we also find Netherlands, the only country from the EU in the list. Netherlands has produced 63.9 bcm of natural gas in 2012, which is a significant figure in European terms, but still significantly less than the EU would need to cover its demand.

If we divide the proved reserves with the actual production levels, we get the reserves-to-production ratio or R/P ratio, which is an estimate of number of years of durability of natural gas. In other words, the reserves-to-production ratio tells us for how many years a country can continue to produce natural gas at the current level with respect to its estimated proved reserves. It is an important measure for energy sustainability and energy security which implicitly indicates the future trends and needs for individual countries and regions. The R/P ratio is by far the highest in the Middle East, where relatively low production levels and enormous reserves mean that natural gas can continue to be produced at the current rate for the next 147 years. Clearly, the R/P ratio can change significantly if a new technology transforms economically or technically not viable natural gas to recoverable gas. Not taking into account any possible new unconventional sources of natural gas, the EU’s and USA’s R/P ratio is very low and stands at only 11 and 12 years respectively. In the USA, however, the so called shale gas revolution has already taken place, with shale gas being increasingly extracted and reaching levels that should allow the USA to become completely gas independent. It is a very different story in the EU, though. There is no large-scale production of unconventional gas and at the current pace of production, the reserves will run out in more or less 11 years.

The EU is the region where the R/P ratio is the lowest (Figure 5), making the EU most dependent on external supplies. Zajdler (2012) argues that this ratio indicates the influence that each world region has on gas price formation and can thus affect the prices. As such, the wholesale gas market may be either more seller-oriented, which explains lower prices in gas producing
countries or buyer-oriented, which indicates higher prices in gas importing countries. Gas price formation mechanisms are described in more detail in Chapter 1.1.3.

**Figure 5.** World map of reserves-to-production ratio by region in 2012

![Image of world map with reserves-to-production ratio by region in 2012]


### 1.1.2 Consumption of natural gas

World primary energy consumption has been almost linearly increasing over the last couple of decades and has reached 13,475 bcm in 2012. Similarly, consumption of natural gas in the world has been growing and gaining importance in the energy mix. The share of natural gas in the energy mix has increased from 16% in 1965 to 25% in 2012 to reach the level of 3,314 bcm (BP, 2013). In 2012, the largest gas consuming geographical area was North America with 907 bcm of annual gas consumption, followed by Asia Pacific and countries of former Soviet Union with 625 bcm and 585 bcm, respectively. Annual gas consumption of the EU-27 was 444 bcm and has been somehow stagnating in the last decade, while in the Middle East it has been growing rapidly and has reached 412 bcm in 2012. It is also worth mentioning that the EU and FSU were the only regions of the world where gas consumption decreased with respect to the previous year (2011). In the EU, the decrease was the result of a combination of factors – economic crisis and sluggish recovery on one hand and increased competition from renewables and coal as well as a decrease in electricity demand and consequent decrease in power generation (Eurogas, 2014).

The lowest gas consumption in 2012 can be observed in the developing and third world regions of South and Central America, and Africa, where gas consumption levels have reached 37% and 28% of the EU27 consumption and stood at 165 bcm and 123 bcm, respectively (Figure 6).

Consumption and demand for natural gas are dependent on numerous different factors and are relatively volatile. The most important determinant of the demand, however, remains the
economic development and size of industry (population), as well as the nature of gas consumption in households (IEA, 2012). This fact is supported with the statistics of BP (2013) that reveal the highest gas consumption is in the most developed parts of the world and parts with the most concentrated and largest population. Therefore, it is unsurprising to observe that the USA has by far the highest consumption of natural gas in the world (722.1 bcm), as well as North America as geographical area, which represents 28% of world’s gas consumption. The second largest country in terms of gas consumption is Russia (416.2 bcm), followed by Iran (156.1 bcm), China (143.8 bcm) and Japan (116.7 bcm). In terms of geographical areas, Asia Pacific has overtaken the countries of former Soviet Union and represents 19% of world’s gas consumption compared to 18% of FSU (Figure 7). European Union (13%) is being closely followed by the Middle East, which is expected to consume more gas than the EU in the very near future.

*Figure 6. World map of gas consumption by region in 2012 (bcm)*

The list of top 20 countries in terms of gas consumption (see Appendix 3) reveals that only three countries of the EU27 are present in the list, with the UK, Germany and Italy in the ninth, tenth and eleventh place respectively. Other countries on the list are either very developed countries (Canada), major gas producing countries (Saudi Arabia, Mexico, UAE, Uzbekistan, Egypt), large industry-intensive countries with large and concentrated population (India) or have a mix of all the above mentioned characteristics (Thailand, South Korea, Ukraine, Argentina, Turkey).

Other important drivers for gas demand include environmental policy, energy efficiency, technological changes as well as gas prices and prices of substitute energy sources such as oil, coal and electricity. Nonetheless, it is the weather, which is the single most important factor for
the demand and consumption of natural gas. Natural gas has a strong seasonal component, meaning the demand for natural gas peaks in the cold winter months when additional gas is needed by households for domestic heating. Adversely, the demand for gas is usually at its lowest in the summer. Nevertheless, weather may also cause the demand for gas to swing significantly during short time periods. According to Federal Energy Regulatory Commission (hereinafter FERC, 2012), extreme temperatures or meteorological phenomena can send demand and prices soaring or dropping within the course of a day, sometime unexpectedly.

Figure 7. Percentage share of natural gas consumption by region in 2012


Future trends of gas consumption are also very difficult to estimate. BP Energy Outlook 2030 (2013a) for example predicts that world gas consumption will grow at an annual rate of approximately 1% and will increase by around 15% by 2030. International Energy Outlook 2013 (EIA, 2013) is more optimistic and estimates that gas consumption on the global level will increase by around 24% by 2030, meaning that global gas consumption should rise by at an annual rate of 1.7%. BP (2013) and EIA (2013) estimate that the growth of gas consumption will be the lowest in the EU, increasing merely by 8% and 11% by 2030, respectively. On the contrary, they estimate that gas consumption will grow the fastest in China, Brazil and India, where gas consumption is estimated to grow between 2.5% and 5.5% on average.

1.1.3 Prices and price formation mechanisms of natural gas

Natural gas prices and the basis on which natural gas is sold varies between different regional gas markets in the world. Natural gas market is not as global as the oil market, but rather divided across a couple of interlinked and connected regional markets. Therefore, the world price of natural gas is not a uniform one. There exist numerous different prices, mainly depending on the geographical location and demand but also the aforementioned price drivers. The issue of different gas prices in different regions of the world and different countries is an important one, because it implicitly determines where and to whom the major exporters would rather sell their gas to. To some extent, prices also determine the demand for natural gas. Therefore an analysis of
gas prices in different regions of the world and in different countries is important in order to understand the dynamics of the natural gas trades.

As natural gas is difficult to transport and store, natural gas prices tend to be set locally or regionally. According to EC (2007) the key reason why gas markets have remained regional in character rather than becoming global, is that compared to other primary energy sources, transport costs for gas are high in relation to the price of the commodity. Timera Energy (2013b) describes the reason for pronounced inter-regional gas price spreads and the global price divergence in the gas market as a function of two main drivers:

- it is expensive to liquefy, transport and store gas as LNG, and
- LNG market is relatively immature, with a limited volume of destination flexible supply (flexibility is constrained by source-to-destination restrictions imposed by long term contracts).

This is confirmed by statistical facts that 68% of the traded natural gas in 2012 was transported via pipelines, which may connect a single producer with a single buyer of gas, such as a case of a gas field supplying a power plant, or may consist of a sophisticated grid connecting thousands of individual gas producers and thousands or millions of gas consumers (BP, 2013).

With regard to pricing of the gas, regions may be divided in two major groups; regions where the price of gas is generally linked to the price of oil and regions where the price of gas is generally set based on gas-to-gas competition. The former is based on historical reasons, presented in more detail in the chapter of traditional gas contracting trends, where gas competes with light or heavy oil for heating and steam generation. Such linkage is present and significant in the majority of European gas markets as well as in Asia, namely in Japan and Korea. In other markets, gas-to-gas competition is the prevailing pricing system for natural gas. This means that prices are set and determined through the demand and supply equilibrium mechanism. The markets with mainly gas-to-gas competition pricing mechanism are usually fully liberalized and the most developed, meaning that the majority of gas is traded on spot markets. The markets commonly associated with this type of gas pricing mechanism are the United States, UK and Australia.

In terms of different natural gas markets across the world and the corresponding types of price formation mechanisms, IGU\(^5\) (2014), identifies 5 main price formation mechanisms\(^6\):

- gas-on-gas competition;
- oil price escalation;
- bilateral monopoly;
- netback from fixed product; and
- regulation.

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\(^5\) International Gas Union.
\(^6\) Price formation classification by IGU is explained in the Appendix 7.
Another possible classification of gas markets with different price formation mechanisms would be the following:

- gas on gas markets, where prices are volatile and not linked to other energy sources;
- markets where prices are indexed to substitute energy prices, namely oil and to a lesser extent coal;
- oil-linked price markets where prices are linked directly to oil prices; and
- regulated markets where the government controls and sets the prices.

Broadly half of global gas consumption is priced either on the basis of gas on gas competition or by reference to oil or oil products prices, while most of the remainder is state regulated. Each regional market has developed its own approach to natural gas price formation (Rogers, 2012). In this respect, European gas markets are different from all the other regional markets and have developed their own specifics and characteristics. Of the European peculiarities, two appear to be of critical importance. Namely, an oligopoly of exporting countries outside Europe, which accounts for half of total European supply (and which is likely to grow in the next decade), and the still insufficient network interconnection in various areas of Europe, which is made worse by contractual congestion at some key interconnection points caused by LTCs (Everis and Mercados, 2010).

As the LTCs almost always include confidentiality clauses, it is difficult to estimate what is the actual share of gas prices based on gas-to-gas competition, oil price escalation or other mechanisms. Nevertheless, IGU (2014) estimates that since 2013, gas-on-gas competition in Europe has, for the first time in history, overtaken the oil price escalation and now represents the largest share in Europe, standing at 53 %. Oil price escalation has decreased since 2012 for approximately 9 percentage points and is now estimated to stand at 42 % of total European consumption (IGU, 2014). Regulated prices are still present in some countries, namely in Hungary, Croatia and Bulgaria, and account for about 4 % of all consumption. Similarly, Bros (2013) indicated that 57 % of the total European gas supply was long term contracted under an oil-linked formula in 2012 and estimated to have decreased further to less than 50 % by 2014 (Figure 8).

According to DNV KEMA (2013), however, LNG imports to the EU seem to have retained its own contracting and pricing dynamics. LNG contract prices are traditionally oil-indexed (e.g. Algeria and Qatar). These contracts, however often include an additional transportation element reflecting shipping costs, whilst volume flexibility is believed to be lower than for pipeline gas deliveries. According to Hartley (2013), the proportion of LNG traded spot or under short term contracts has grown substantially since 2000.
Timera Energy (2013b) explains that since the Fukushima disaster\(^7\), the average price of LNG delivered in Asia has been a structural premium to prices in Europe, adjusted for the transport cost differential. This average Asian price premium, however, masks some substantial swings in Asian LNG spot pricing, which are impacting the pricing and flow of gas into Europe. Moreover, Timera Energy (2013c), states that with regard to the European market, the spot market for LNG may still be small relative to the contract (LTC) market, but is nevertheless important because prices at the margin impact the behavior of flexible LNG flows. The spot LNG market is thus driven both by uncontracted LNG supply and LNG under LTCs with flexibility that can be exercised against spot prices (e.g. via cargo diversions, including reloading). Nevertheless, LNG has become one of the most global developments in the convergence of regional gas prices. It represents an influential link between regions and is as such affecting conventional gas prices. Therefore, even if gas prices are at the moment still being set regionally, LNG is the main driver behind the price convergence between regions (Timera Energy, 2013c).

Figure 8. Price formation mechanisms in Europe, 2013 (left), Estimated split of European gas supply in 2012 (right), in percentage

Note: GasTerra, Sonatarch and Gazprom are the largest producers of natural gas in Netherlands, Algeria and Russia, respectively.


According to ACER & CEER (2013), two most important elements impacting the EU price formation are the premium at which East Asian LNG markets (Japan, South Korea and Pacific China) trade above both European and North American prices, and the current US regulatory regime that results in the export of excess coal rather than gas. As a result of these elements,

\(^7\) Fukushima disaster refers to nuclear disaster in Fukushima nuclear power plant that occurred on 11 March 2011 and resulted in nuclear meltdown of nuclear reactors. Consequently, power supply from the respective nuclear reactors plummeted and was largely replaced by LNG.
LNG imports into Europe are decreasing and US gas market is separating from both Asia and Europe, meaning that the US hub price (Henry Hub price) does not really influence EU price formation. The development of Asian prices is especially important for the EU, as the Asian markets can sustain price levels which greatly exceed landed gas costs and for this reason, tend to trigger the diversion of LNG cargoes away from Europe. Sometimes this even gives rise to LNG reloading and reshipment from European LNG terminals. Consequently, this puts an upward pressure on European hub prices (ACER, 2013).

Dickel (2005), however, argues that major determinants of gas pricing in the EU are import dependence, price elasticity of gas demand as well as the downstream and upstream regulation.

All in all, the differences in natural gas prices across the world confirm the hypothesis of existence of multiple regional gas markets. In October 2013, estimated prices of natural gas were by far the lowest in the USA, followed by the EU and significantly higher in Asia and countries of South and Central America. Due to the mainly domestic production, there is no information available for prices of countries of the former Soviet Union and Africa. According to FERC (2013), estimated average price in the US in October 2013 was 8.12 EUR/MWh. Average price in the EU\(^8\) in October 2013 was 27.86 EUR/MWh, while average price in Asia, composed mainly of Japanese, South Korean, Indian and Chinese prices, was significantly higher and reached 37.28 EUR/MWh in October 2013. Similar prices were estimated for Brazil and Mexico, amounting to 38.46 EUR/MWh and 41.34 EUR/MWh in October 2013, respectively (FERC, 2013).

\[\text{Figure 9. International wholesale price evolution, 2008-2012}\]


Gas prices, the pricing structure and price formation mechanisms differ significantly even across different countries of the EU (Figure 9). It is possible to differentiate between Continental and

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\(^8\) Average price in the EU was calculated from different sources; Eurostat Comext database was used for import prices, FERC (2013) for estimated LNG prices and ACER & CEER (2013) for prices of the main European hubs.
Western Europe. Indigenous gas production is very low in Continental Europe and therefore countries rely heavily on imports to satisfy their needs and demand for natural gas. Historically, natural gas imports were not very diversified and relied on couple of major gas producing countries such as Russia, Norway, Algeria and Libya. Davoust (2008) states that in Continental Europe, the pricing is based on the so called replacement value of gas, which corresponds to the value of alternative energies on the final gas markets inside the buyer's country. Continental Europe was and to a large extent still is forced to rely on LTCs with a price based on replacement value, which in most cases refers to oil and oil derivatives. Gas transport option therefore influences price formation mechanisms and importantly, determines from where one country may import the natural gas.

If we dissect the regions of Europe even more, it is possible to group the markets by similar characteristics into Northern European markets, Southern European markets and Eastern European markets. Northern European markets are generally driven by fairly liquid hub prices, based on the NBP, TTF, NCG, Gaspool and Zeebrugge 9 hubs, which, according to EC (2014), amounted to 70% of gas being priced on gas-to-gas basis in 2012. It is nevertheless important to stress that while gas-to-gas is indeed the primary basis for price setting, oil-indexed LTC prices still influence the price dynamics at European hubs, albeit more marginally.

According to the EC (2014), Southern Europe is becoming increasingly influenced by the larger, more mature and developed Northern European markets. In this respect, traditionally more isolated Italian, and especially Spanish and Portuguese gas markets, are increasingly converging with the Northern European hub prices through the new interconnection points. Eastern European markets on the other hand remain the least developed and have not yet developed sufficient liquid gas trading hubs which would allow them to benefit from short term hub based spot contracting complementing the existing LTCs.

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9 NBP – National Balancing Point (UK); TTF - The Tittle Transfer Facility (NL); NCG – NetConnect Germany (DE); Gaspool (DE); Zeebrugge (BE).
Oil-linked prices, represented by the average German import prices, tend to be higher than the prices based on gas-to-gas competition, represented by the average price of the main European hubs (Figure 10). The reasons for the differences in prices lie mostly in different the price formation mechanisms, which will be examined in further detail in the following chapters. Another observation from this figure is that oil-linked prices are much less volatile, even when examining the monthly average prices. Due to inflexibility of the LTCs, which traditionally consist of oil-linked prices, prices in the LTCs do not change daily as opposed to the prices based on gas-to-gas competition based prices, which reflect short term changes.

1.1.4 Global trade flows of natural gas

Trade flows are actually natural gas movements, which describe the trade of natural gas around the world between gas producing countries and countries importing natural gas. Figure 11 presents the gas value chain or, in other words, how gas is transported from the production facility to the end-users.

Pipeline transport is relatively non-complex as the gas may be pumped into the pipeline straight out of the production facility and then transported via the pipeline to either distribution pipeline, large industrial end-users, to other national pipelines or it may be transported to a storage facility. Transportation of LNG, however is more complex as in addition to the production from multiple sources, it includes also liquification and reagascification processes as well as cargo shipping and finally transportation via the pipeline.
Historically, the movement of gas across borders has been predominantly driven by pipelines. Major gas pipelines in the world include the pipelines from Russia and Algeria to Europe, from Canada to the United States, and from Mexico to the United States (Figure 12). Nevertheless, with the expansion of LNG, the demand centers such as Europe, United States and Asia Pacific, are now procuring natural gas from long distance production centers in the form of LNG, transported by special LNG carriers.

Major LNG supply routes include Africa to United States and Europe, and Australia and Middle East to Asia Pacific region. As already mentioned, LNG is much more flexible to transport and is as such more destination-independent. Therefore, LNG destination choice may be driven by prices, which results in the LNG being diverted to locations with the highest margins.

There exist three major gas trading routes – from Russia and countries of former Soviet Union to Europe by pipeline, from Middle East to Europe via LNG, and from Middle East to Asia via LNG (Figure 12). The US gas market is the most developed and with a high level of self-sufficiency which is further supported by the shale gas boom in recent years. Consequently, the US will soon become a net exporter of natural gas and could become an important gas exporter in the near future, depending on their energy policy.
According to the data of BP (2013), 1,033 bcm of natural gas was transported internationally either via pipelines or LNG in 2012. In 2012, Europe (442 bcm) and Asia Pacific (283 bcm) as two regions with low indigenous production and high consumption levels, imported 725 bcm of gas, 70% of all world gas imports. Another important importing region is North America, where the USA, Canada and Mexico imported 141 bcm of natural gas, amounting to 14% of all world imports (BP, 2013).

The export data shows the opposite side. Namely, in 2012, 72% of all natural gas exports arrived from 10 largest exporting countries. By far the largest exporting country is Russia, whose exports of gas amounted to 201 bcm in 2012 (Figure 14). Interestingly, only 15 bcm or 7% of all Russian exports were in form of LNG, while Qatar, the second largest exporting country, exported 126
bcm of natural gas, of which almost 90% was in the form of LNG. Other traditional major exporters of gas include Norway, Canada and Netherlands, while USA, Indonesia, Trinidad and Tobago as well as Nigeria may be described as the new major exporting forces.

The major gas trading routes naturally correspond to the transportation routes from major exporting countries to the countries and regions that require to import large volumes of gas to satisfy their consumption needs. Five out of ten largest gas importing countries are EU Member States (Figure 13). The only two countries that import more gas than Germany are Japan and interestingly the USA that is also one of major exporters of gas. Asia Pacific, which is almost completely dependent on imports of gas is represented in the list by three of its major economies, namely Japan, South Korea and China, while Turkey completes the list of major importing countries with its imports in 2012 amounting to 43 bcm. Demand, supply and imports as well as import dependency of the EU and its Member States are presented in more detail in the following chapters.

**Figure 14. Top 10 export countries of natural gas in 2012**

![Chart showing top 10 export countries of natural gas in 2012](chart.png)


**1.2 Demand and Supply of Natural Gas in the EU**

According to Eurostat (2014), the EU27 gas production stood at 148 bcm in 2012 and the EU27 imported 422 bcm of natural gas, which means that 87% of natural gas in the EU 27 was subject to international trade. Traditionally, two major producers of natural gas in the EU are the Netherlands and the UK, with their production volumes amounting to 64 bcm and 39 bcm in 2012, respectively. These two countries contributed 69% of the total natural gas production in EU 27. With respect to the past, total natural gas production in EU27 has been decreasing rapidly, which is demonstrated by the decrease in production of 16.5% from 2010 to 2012 and astonishing 36.7% with respect to the year 2000 (Eurostat, 2014).
Apart from the Netherlands and the UK, only Germany, Romania, Italy, Denmark and Poland produced more than 4 bcm of natural gas in 2012, while Hungary and Austria were the only two other countries that contributed more than 1% to the total EU27 natural gas production in 2012. The combined production of gas in France, Bulgaria, Czech Republic, Ireland, Slovakia, Spain, Greece and Slovenia reached 1.5 bcm or 1% of total EU27 production in 2012. All the remaining ten countries of the EU27 did not have any production of gas at all or the production of gas was indeed minimal (Figure 15).

According to Eurostat (2014), the gross inland consumption of the EU27, which is the most common measure of demand of natural gas, was 434 bcm in 2012. This shows a continuous decline compared to the pre-crisis levels before 2008, with the exception of 2010. The reason behind this decline may be seen in the economic crisis and instability, coupled with an increase in gas prices. According to IEA (2012), the demand for natural gas is expected to remain below 2010 levels, primarily because of the slow growth in the industrial sector due to weak economic outlook, accompanied with higher gas prices forecasted for the future. Another factor impacting
the gas demand in the EU is the growth in the use of renewable energy sources. The EU also adopted the so-called 2020 Climate and Energy Package in 2009, by which it aims to reduce greenhouse gas emissions, increase the share of renewable energy and to reduce its total primary energy consumption by different energy savings measures (IEA, 2014).

With regard to individual EU Member States, the consumption of gas ranges from less than one bcm in Estonia and Slovenia, to over 60 bcm in Italy and over 70 bcm in UK and Germany. Comparing 2012 consumption levels of individual Member States with those of pre-crisis in 2008, it is obvious that consumption has, in general, declined quite severely (Figure 17). In the UK, Hungary, Finland and Estonia it has declined by more than 20%, while in Germany, Italy, Spain, Romania, Slovakia, Ireland, Denmark, Bulgaria and Slovenia the decrease has been somewhere between 10% and 20%. Only in four countries the gas consumption has increased in 2012 compared to 2008. These countries include Lithuania, Greece, Poland and Sweden (Figure 17).

Figure 17. Gas consumption in individual EU Member States in 2008 and 2012


Global growth in gas demand and supply is in general predicted for the future and thus the future of gas supply to the EU seems rather positive as sufficient volumes of gas should be available from numerous sources. Measures to maximize gas production, use of shale gas as well as biogas production should be taken in order to increase attractiveness of the EU gas markets. The fact remains that in the foreseeable future, EU will remain vastly gas dependent.

1.3 Natural Gas Imports and Import dependency in the EU

There exists a significant gap between the consumption of gas and it production in the EU. The EU thus relies heavily on imports to satisfy its demand for gas. Figure 18 shows how imports correspond perfectly to movements in the demand on one hand and decreasing production on the other. In 2012, the EU gas imports from non-EU countries amounted to 413 bcm, which
corresponds to 88% of the aggregate consumption in the EU. On average, however, import dependency\(^\text{10}\) of individual EU Member States was equal to 73%, in 2012 (Figure 19).

EU imports of gas have been increasing in the last decade (43% between 2000 and 2012, according to Eurostat) and also the EU dependence on imported gas has increased from 74% in 2008. This can be explained by a decrease in EU gas production by 23% in the same period, coupled with a decrease of only 12% in aggregate EU consumption in the same period (Figure 18).

**Figure 18.** Evolution of EU27 natural gas consumption, production and imports (2003-2012)

Majority of EU Member States import all or almost all their gas needs. More specifically, 17 out of 25\(^\text{11}\) EU Member States import more than 90% of their gas needs. Only Netherlands and Denmark are net gas exporters, and UK and Romania are only other two countries that cover significant part of their gas needs through their domestic production (Figure 19). It is also worth mentioning that eight countries import gas from a single source country (Eurostat, 2014).

**Figure 19.** Import dependency\(^\text{12}\) by country, 2012

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\(^\text{10}\) Import dependency is calculated as a ratio of net imports and consumption.

\(^\text{11}\) Cyprus and Malta have no consumption of natural gas.

\(^\text{12}\) Note: Values over 100 % are possible due to changes in stocks.
Import structure of the EU reveals that the most important gas source for EU Member States in 2013 remained Russia. 28% of all the EU gas imports came from Russia, while an additional 56% of all imports came from only three other countries - Norway, Algeria and Qatar. Combined, these four countries represented 73% of all gas imports in the EU. Other important sources of gas in 2013 were Libya and Nigeria, while 21% of all other imports arrived from other countries, which individually represented less than 3% of all imports (Figure 20). According to the EC (2013), the main source of alternative gas for Europe will be the global LNG market which comprises a wide range of countries and shall in the near future most probably include also the USA (Figure 20).

Figure 20. Import structure of the EU 27 in 2013 (left) and breakdown of EU 28 LNG supplies in 2012 (right), in percentage


2 TRADITIONAL AND NEW NATURAL GAS CONTRACTING TRENDS IN THE EUROPEAN UNION

The previous chapters tried to place EU gas in the context of global gas markets as well as present some fundamentals underpinning the EU gas markets. This chapter is a follow-up to the import dependency presented above. With such a high share of gas being imported, it is important to describe how this gas is contracted and transported to the EU. Traditionally, the main form of gas contracting in the EU was the so-called long term contracts (LTCs), which are presented in-depth below.

When discussing natural gas contracts, it is key to distinguish between contracts for the commodity and contracts for capacity. Commodity refers to natural gas as a commodity, and in general we can make a distinction between bilateral negotiated contracts and contracts traded on the gas markets. With respect to capacity contracts, it is possible to differentiate between contracts for transportation of natural gas and contracts for storage of natural gas. According to DNV KEMA (2013), it is nevertheless possible to further distinguish the contracts between
different market parties across the gas value chain, i.e. producers, large importers (wholesalers), small wholesalers (retailers) and end consumers. This thesis is, however, focused exclusively on the contracts for the commodity. In this respect, the main focus of this paper are the wholesale gas markets, namely the contracts and their pricing terms for the wholesale level, i.e. between large producers and large importers.

Pursuant to DNV KEMA (2013), the pricing terms, the length of the contract and volume flexibility are the two basic elements of any gas contract or trade. However, these elements may differ significantly, and their evolution, changes and new trends are the core interest of this paper. Chapter 2.1. presents the traditional gas contracting trends which were characterized by long term contracts, oil-linked pricing mechanisms and low flexibility levels, while in chapter 2.2., new contracting trends and development of gas trading in the aftermath of liberalization, will be discussed and examined in more detail.

2.1 Traditional Natural Gas Contracts in the EU
2.1.1 History and reasoning of the LTCs

Traditionally, state-owned monopolies were the only gas companies in the EU and the so-called long term contracts between these national incumbents and major foreign producers have long been the backbone of EU gas imports. From the 1960s until the energy markets’ liberalization process in the late 1990s, the gas markets in Europe were developed at national level and were generally the domain of national governments. Zajdler (2012) acknowledges that the market was highly integrated within countries' borders and centrally coordinated by public entities. Gas companies enjoyed a certain level of market exclusivity in national markets, and were at the same time entrusted with various public service obligations.

The LTCs were born in the early 1960s in the Netherlands, more specifically in the Groningen gas field. Melling (2010) explains that at the time, end-user gas prices across much of Europe were state controlled and free markets did not exist. Therefore, how to price the gas emerged as an immediate question. Before LTCs, the cost-plus approach, where the sales price is determined by adding the production costs, transport and other charges as well as profit margin, was usually being used for determining the gas prices in Europe. In order to maximize the rent income from the Groningen field, however, the Dutch Government, together with Esso and Shell\textsuperscript{13}, developed the concept of replacement or market value pricing. This pricing mechanism was applied for domestic supplies, while the concept of long term contracts with a minimum pay clause, based on net back pricing or replacement value pricing with regular price review possibilities, was applied to exports (European Parliament, 2006). The concept of LTCs aimed at maximizing the rent income of the exporting state, while keeping the gas marketable. To allow the buyer to pay for the infrastructure and to market the gas, all costs incurred to bring the gas from the delivery point

\textsuperscript{13} Esso and Shell are two of the largest (Anglo-)Dutch gas companies
to the customer would be deducted or netted back from the revenue achievable from the customer.

To sum up, the aim of the replacement value principle was to establish a no-cost related pricing approach, where the so called net-back value would be netted back from this no-cost replacement value. This meant that the gas prices were no longer mainly fixed, as in the case of prices based on production costs, but were now changing over time, with respect to changes in technology, market shares and prices of competing fuels. Using this approach, the exporting country or the seller, was taking risks and reaping rewards from price developments via the replacement value pricing concept, while the buyer was taking the obligation to market a defined volume of gas via the minimum take-or-pay obligation against earning a satisfactory margin. In addition, this approach was an implicit protection against any price arbitrage by the buyer(s). The netback value prices were based on the prices of alternative fuels, gas oil and heavy fuel oil. Indexation to competing fuels was established as a mechanism for softening price fluctuations. As light and heavy fuel oil were key replacement or substitute fuels for gas, it made perfect sense to link the gas price to that of oil.

Moreover, the oil price has always been relatively stable and was at the time, also relatively low. In line with this, Konoplyanik (2011) explains that oil-indexation is a mechanism of softening potential price volatility of key replacement fuels that fully corresponds to replacement value philosophy of that time and is a mechanism that was easy to implement and required rare adjustments.

### 2.1.2 Contract design and pricing mechanism in a typical LTC

A typical net back gas price formula as per Energy Charter Secretariat (2008) is the following:

\[
P_m = P_0 + (0.60 \times 0.80 \times 0.0078 \times (LFO_m - LFO_0)) + (0.40 \times 0.90 \times 0.0076 \times (HFO_m - HFO_0))
\]

In the above formula, the gas price for the relevant month \( m \) is a function of the starting gas price \( P_0 \) in month 0 and the price of competing fuels (light fuel oil – LFO and heavy fuel oil - HFO) in month \( m \) compared to the price of competing fuels in the reference month 0. Moreover, 0.60 and 0.40 factors represent the shares of gas market segments competing with the respective fuels, while 0.80 and 0.90 are the pass through factors that represent sharing risk and reward of the price development between seller and buyer. 0.0078 and 0.0076 are the technical equivalence factors to convert the units of prices for fuel into units of gas price, with reference to the light fuel oil and heavy fuel oil, respectively. The underlined factors are subject to negotiation process, where large monopolistic producers have an upper hand and clear advantages, or at least used to have them due to their position on the gas market.

Melling (2010) also notes that as the Dutch expanded their presence in foreign gas markets, this led to several additional innovations in gas pricing. The export prices for gas were based on the market value of the individual customer country, and were netted back to the Dutch border (by
subtracting the costs to bring the gas to the customer). The Dutch border price would therefore differ between countries depending on the destination country. This is essentially a destination clause that would be included in every long term contract to prevent competition from affecting the prices.

Two other innovations that would impact the future design and structure of the LTCs and the future of gas contracting in general were introduced into the LTCs by the Dutch. Namely, the Dutch introduced the so called price review clauses and the capacity charge (explained in more detail in chapter 2.1.3). The reason for the introduction of the price review clauses into LTCs was that the netback value was changing over time, either because of the change in price of the competing fuels, technology or market shares of the alternative fuels. The changes in the factors included in the LTC price formula needed to be accounted for and therefore periodic reviews (typically over 3 years) of the pricing terms were allowed. The price review clauses thus anticipated the periodic adjustments to the pricing formula in the LTCs. The main price review principles are universally adopted based on changes to economic conditions in the buyer's market for gas, the buyer's ability to profitably sell supplied gas to its own customers, and the tax regime, including environmental taxes, for gas and/or competing fuels (Frisch, 2003). Capacity charge, on the other hand, was and remains to be a special feature of Dutch LTCs and is not usually found in other contracts. The main feature of capacity charge is that contracted gas is payable regardless of the gas actually consumed (Melling, 2010).

A question arises, however, why the long term contract became the norm for more than two decades, especially taking into account that LTCs are not considered to be the most favorable for the importing country or buying entity. This is due to the fact that they constrain competition and do not allow for much flexibility of the buyers. The setbacks of the LTCs will be described in the next subchapters. EU (2006) nevertheless argues that LTCs work well for both sides as they allow exporting countries to maximize their income from selling the gas and to finance the necessary production and transportation infrastructure, while for importers, LTCs ensure secure supply and the marketability of gas.

Similarly, Hedge & Fjeldstad (2010) state that LTCs fulfill two important roles in the gas industry. First, they give a guaranteed source of revenue for companies that make enormous investments in exploration and in the development of infrastructure for the production and transportation of gas. It would be commercially impossible to undertake such large projects without having a buyer for the gas committed by a LTC of large volumes. Secondly, they give gas suppliers and governments a secure source of supply – knowing where your gas will be coming from in 20 years' time is prerequisite for planning. Moreover, Neuhoff & von Hirschhausen (2005) argue that buyers have an incentive to sign LTCs as a barrier to entry for new market entrants, while from the perspective of a gas importing country LTCs increase the security of supply. Therefore, LTCs made perfect sense as they provided producers with certainty of demand on one hand, and provided buyers with security of supply on the other hand.
According to Energy Charter Secretariat (2007), the Dutch export contracts served as a point of reference for most gas export contracts to Continental Europe, which followed over the next four decades; the Russian gas export contracts, Algerian LNG as well as pipeline exports, the Norwegian gas export contracts and Libyan pipeline exports. Over such long period of time, however, some changes are inevitable and with time LTCs have changed as well. Energy Charter Secretariat (2007) observed that this by changing the price formula in the original LTCs. This would allow to better reflect the development in the competitive situation of gas markets, mainly by increasing the share of gas oil, but also by including elements to reflect the changed role of gas in power generation and later the role of gas-to-gas competition. Therefore, changes in market conditions were reflected in the new contracts concluded and by regular price reviews for existing contracts.

Konoplyanik (2011), writes that albeit the Groningen model of LTC has been constantly adapted, it maintained its major characteristic features and remained a fundamental contracting basis in the international gas trade. LTCs have also served as a guaranty of the stable and secure international gas supply.

Another important notion of the LTCs is that they have established a risk sharing mechanism that remained practically intact for more than 30 years. The gas value chain was constructed in a way that enabled the producers to bear only the price risk, while it transferred the volume and credit risk to the buyers (Melling, 2010).

2.1.3 Elements of the LTCs

Traditionally, producers or sellers of natural gas and its buyers entered into supply negotiations bilaterally, which resulted in bilateral long term contracts. The general structure was always the same, while certain individual provisions could be changed, depending on the negotiating power. LTCs were structured, albeit non-standard contracts for large volumes of gas and long term supply periods. DV KEMA (2013) indicates that LTCs applied in the EU are not only characterized by the length of the contract, but also pricing terms and volume flexibility, where all of these elements are interrelated. Hedge and Fjeldstad (2010) describe a typical LTC as an agreement between a supplier and a buyer of delivery of variable daily quantities of gas, between a specified minimum and maximum daily limits, in which the main components are the following:

- Start and end date of delivery,
- Annual Contractual Quantity (ACQ),
- Yearly Take-or-pay (Yearly ToP),
- Daily Take-or-pay (Daily ToP),
- Daily Minimum Quantity (DCQ),
- Daily Maximum Quantity (MOP), and
- Contract Price Formula.
These are just some of the core elements of any LTCs, which are together with some other elements presented in more detail in the following chapter.

- **Length of contracts**

As implicated by their name, LTCs are based on long term contract commitments between producers and buyers. The contractual period is determined as the start and end date of delivery of gas and is agreed upon before signing the contract. The length of LTCs was extremely long at the beginning, usually lasting from 25 to 30 years. According to Hirschhausen & Newmann (2005), however, the duration of LTCs in Europe has diminished from 30 to 15 years in quarter of a century, from 1980 to 2003, while DV KEMA (2013) approximated that upstream side contracts tend to be long term with durations often ranging from 10 to 15 years (Figure 21).

*Figure 21. Distribution of contract length in OECD Europe, 1980-2003*

![Distribution of contract length](image)


- **Contract Quantities**

**Annual Contract Quantity (ACQ)** is the primary reference point for LTCs in Europe around which limits are set over the life of the contract (Melling, 2010). The annual contract quantities can be set to change (increase or decrease) periodically, optionally at predetermined dates or can be reduced over a predetermined time periods due to potential production declines. According to Melling (2010), **Maximum Annual Quantity (MAQ)** is typically expressed as a percentage of ACQ and is often 110 or 115 percent of the ACQ (the percentage being negotiable). MAQ is thus an element for the buyer’s volume flexibility, although the increased flexibility normally leads to a higher price. **Maximum Daily Quantity (MDQ)** is another essential provision in any LTC, as it allows the buyer to form its daily balancing strategy and cover for any potential unexpected increases in daily demand. MDQ is often defined simply as the MAQ divided by 365 but may be higher, by negotiation. On the other hand, minimum quantities in the LTCs are commonly known as the take-or-pay (ToP) provisions that set the boundaries for downward volume flexibility in any single contract year (Melling, 2010).
• **Take-or-pay provision**

According to DNV Kema (2013), one of the main motivations of LTCs in the past, was for parties to agree on risk-sharing or risk-allocation respectively. Under a long term take-or-pay commitment, for instance, the seller puts the volume risk on the buyer of the gas, ensuring for himself that the gas is taken anyway or it is at least paid for. This is a security mechanism that gives the producer certainty regarding the demand. In other words, Hedge & Fjeldstad (2010), consider this clause both as an incentive mechanism to seek compliance in the execution of the contract as well as a means to spread risk. Therefore, the take-or-pay (ToP) provision in a LTC is used to force the buyer to pay for a minimum volume of gas regardless of whether it is actually delivered and consumed by the buyer in the end. Hence, ToP provision is a guarantee for the producer and a kind of fine for non-compliance for the buyer. Melling (2010) agrees that the ToP obligation is effectively a very severe penalty that can lead to a number of companies facing the prospect of losing billions of dollars’ worth of gas for many years in the future.

According to Timera Energy (2013), in addition to setting out the minimum annual contract take (usually defined as a percentage of annual contract quantity), ToP is crucial for defining two other standard key volume flexibility terms. Namely the Make Up and Carry Forward (Timera Energy, 2013). The Make Up is defined as the ability to bank volume of ToP gas that has been paid for but not taken. This means that the respective volumes of gas may be taken in the subsequent year, typically once conditions around the ToP obligation have been met (in that subsequent year). The Carry Forward on the other hand is defined as the ability to offset payments for gas taken above ToP volume in the current year against ToP volumes in subsequent years (Timera Energy, 2013).

DNV KEMA (2013) go as far as to state that a LTC without any take-or-pay provision would in practice not be a long term firm commitment as it would lose its function as a guarantee of demand. Melling (2010) approximates that ToP volumes are typically 85 percent or 90 percent of the annual contract quantity, with adjustments for exceptional items such as sellers’ shortfall, force majeure, etc.

• **Destination clause**

The destination clause is one of the core elements of any LTC and is actually a type of profit-splitting mechanism. It is a clause in a gas supply contract that prevents the buyers from reselling the purchased volumes of gas to other geographical areas. This means that if the destination clause in the contract determines the place of supply as country A, then the buyer is prohibited from selling the contracted amount of gas to any place outside the country A. This mechanism was designed to prevent any arbitrage between high and low price gas markets as well as to maximize the profit of the producer, and it results in a clear price discrimination. Zajdler (2012) confirms that destination clauses help producers to maintain price differentials between national and regional markets. The European Commission (2014) observes that destination clauses together with export bans (or combined clauses), perpetuate market positioning and also
contribute to a lack of fluidity. Konoplyanik (2010) argues that destination clauses were introduced because of the fact that gas exports through the same delivery point destined to different export markets can lead to different contract prices from the same producer or exporter at this point. A destination clause is therefore meant to rule out price arbitration by prohibiting total or partial resale of gas or territorial sale restrictions.

- **Flexibility clause**

The flexibility clause is another integral element of a typical long term contract. According to (Konoplyanik, 2011), it covers deliveries above the obligatory take-or-pay element in the LTCs. The latter typically consisted of 80% of the nominal quantity of the contract, while the flexibility clause provided an optional increase in delivery by 40 percentage points of the nominal quantity of the contract (therefore up to 120% of initial quantity) at a similar price level. In other words, a flexibility clause offered consumers the sought after flexibility within their periodical consumption. It meant predetermined contracted monthly volumes could be increased or decreased by the consumer within the certain limitations (Konoplyanik, 2011).

In addition to the flexibility clause itself, LTCs also contain other implicit elements of flexibility. According to Timera Energy (2013), these include the so called swing provision (which gives the buyer an option to purchase additional quantities of gas), the make-up gas provision (which gives the buyer a right to receive the gas that has been paid for but not yet taken, at a later point in time that was agreed to), and the carry-forward gas provision (which gives the buyer a right to reduce the future amount of delivered gas in case the gas take in recent years exceeded the contractual obligations).

- **Price reviews or price re-openers as price negotiations**

If the circumstances beyond the control of the contract parties change significantly compared to the underlying assumptions in the prevailing price provisions, each party is entitled to an adjustment of the price provisions reflecting such changes. The price provisions shall in any case allow the gas to be economically marketed on sound operation. Either party shall be entitled to request a review of the price provisions for the first time after an ex-ante agreed period and thereafter every three years. Each party shall also provide the necessary information to substantiate its claim. Following a request for a price review, the parties shall meet to examine whether an adjustment of the price provisions is justified. Failing an agreement within 120 days, either party may refer the matter to arbitration in line with the provisions of the contract. As long as no agreement has been reached or no arbitration has been rendered, all rights and obligations regarding price provisions shall remain applicable and unchanged. Unless otherwise agreed or decided by the arbitral award, differences to the newly established price (by agreement or by arbitration) shall be retroactively compensated including interest on the difference calculated at
an interest rate reflecting the conditions on the international financing market (Energy Charter Secretariat, 2008).

2.1.4 Advantages, setbacks and risks of the LTCs

To summarize, the advantages of the LTCs that enabled the LTCs to rule the European gas markets for decades and will probably enable them to be an important part of the gas markets in the future as well. The most important advantages of the LTCs can thus be summarized as the following:

- security of supply and revenues,
- encouragement of investments,
- price stability,
- shock and regulatory resistance,
- transaction costs, and
- low complexity.

All in all, LTCs were shaped and developed long before spot gas markets and trading were developed and established in Europe. As such, the gas prices linked to oil prices, were de facto independent of the supply and demand equilibrium mechanism. The system of LTCs and oil-linked prices proved to be a significant success. It enabled gas to become one of the most important energy sources in Europe, used both by the industry and households. Nevertheless, this system proved to have some major disadvantages compared to the liberalized gas market in the US and later in the UK. The main setbacks and risks of the LTCs can be summarized as the following:

- **Mismatch between gas and oil prices**: Different conditions in the gas markets in the past meant that linking gas prices to those of oil was the best possible choice. However, since the introduction of the LTCs, gas markets have developed separately from oil markets and therefore it would make more sense if the gas prices would be linked to the movements on the gas markets. Moreover, the link to oil prices hinders the development of gas spot markets.

- **Dependency**: Long term commitments result in a buyer being dependent on a single supplier for a number of years or even decades. The buyer is therefore subject to price and volume risks. In case of a cheaper gas being available on the spot markets or in form of LNG, the buyer is nevertheless obliged to take or pay the contracted volume. Similarly, the buyer is obliged to fulfill its contract obligations even in case of a drastic decrease in its anticipated demand. Even if price reviews are possible, they represent a relatively long process and do not provide the buyer with the desired flexibility.

- **Non-flexible pricing formula**: In case of significant changes on the market, the circumstances and the rationale for the pricing formula may change. However, the pricing
formula in a LTC will nevertheless remain the same. Therefore, buyers will be subject to non-optimal, sometimes even unjustified pricing terms under the LTC.

- **Competition hindering**: LTCs present a serious barrier for any possible new market entrants as well as for existing market players that cannot engage in a competitive spot market until they are bound to a LTC.

The above mentioned setbacks and risks of LTCs coupled with structural changes of the gas markets in the EU, such as liberalization, enabled new contracting trends to emerge. In addition to the previously stated setbacks and risks, ACER (2011) recognizes that some other reasons behind the recent shift away from long term, take-or-pay, oil-based priced contracts towards short term, spot-based gas trading and related forwards/derivatives could be:

- Fuel substitution between oil and gas no longer being a price driver;
- Gas demand variability being mainly driven by multi-utility (gas and power) companies; and
- European utilities and traders – now spurred by growing liquidity at some European gas hubs – no longer being willing to take losses on gas trades and being ready to go to arbitration with upstream suppliers on gas pricing issues under LTCs.

### 2.2 New Natural Gas Contracting Trends
#### 2.2.1 Overview and the rationale for the changes in the EU gas markets

A short overview of the legislative and other changes is necessary to help understand what enabled a new market design to develop and the how the corresponding new contracting trends arose.

In the late 1980s, the intention to liberalize the EU energy markets and to create a single EU gas market slowly started to gain momentum. In line with IEA (2008), the main factor behind such radical change was the need to create a more competitive and efficient energy sector in the EU. In times of growing concerns about the competitiveness of European industries in globalizing markets, something needed to be changed, and the liberalization of the energy markets was seen as a possible solution. IEA (2008) acknowledges that the introduction of competition in the gas sector was particularly aimed at creating a more appropriate competitive framework, namely introducing more gas-to-gas competition and consequently increasing efficiency, while also lowering the costs of gas in otherwise monopolistic markets.

Such change was about to radically change the status quo and the landscape of the EU gas markets. In the 1980’s the British government started to pursue a policy of market-driven efficient competitive markets. This of course also included the gas market and energy markets in general. The policy shift coupled with a pursuit to eliminate inefficient government control of the energy sector, resulted in the UK gas sector being privatized and becoming subject to the market principle. The liberalization of the gas market aimed at a more mature gas market with easier
market access for new players and thus increased competition. What followed was the introduction of effective market mechanism for the private entities, which resulted in a more levelled playing field for transmission and distribution facilities and brought benefits for the end-consumers.

The EU soon followed the British example and in this respect it is possible to identify three main trigger points of European energy market liberalization, the main elements of which are the three EU gas Directives (i.e. Directive 98/30/EC, Directive 2003/55/EC and Directive 2009/73/EC), described in Table 1.

Prior to the start of the liberalization process in 1998, gas markets in most EU countries consisted of large national incumbents, which had monopolistic control over the whole gas value chain, from transmission to distribution and sale to final consumers. The only real exception was the UK, where the liberalization had already taken place in the 1980s and early 1990s. This was the biggest barrier to free movement of gas in the EU, as the national monopolies allowed incumbents to block movements of gas across Europe by not allowing competitors on their existing networks and thus denying customers the access to competitive gas supplies.

Table 1. Overview of the EU Gas Directives

<table>
<thead>
<tr>
<th>Directive</th>
<th>Date</th>
<th>Key Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>98/30/EC</td>
<td>January 1998</td>
<td>• Competition to be introduced in stages, starting with large industrial consumers and power plants, then smaller industrial users&lt;br&gt;• Third Party Access (TPA) to be implemented on all transmission pipeline systems (can be negotiated)&lt;br&gt;• Accounting separation of transmission system operators (TSOs) from gas trade</td>
</tr>
<tr>
<td>2003/55/EC</td>
<td>July 2003</td>
<td>• Market opening by July 2004 for all non-household users and complete market opening by July 2007&lt;br&gt;• Regulated TPA to transmission and LNG infrastructure&lt;br&gt;• TPA to gas storage infrastructure&lt;br&gt;• Legal separation TSOs from gas trade</td>
</tr>
<tr>
<td>2009/73/EC</td>
<td>July 2009</td>
<td>• Established common rules for gas transmission, supply and storage&lt;br&gt;• Ownership separation of TSOs from gas trade</td>
</tr>
</tbody>
</table>


An important breakthrough happened in 1994, when the European Court of Justice ruled that electricity is to be considered a good ‘like any other’. This meant that electricity was not considered as a public service anymore and the same definition was soon transposed to natural
The treatment of energy as a commodity opened the doors to development of the Internal Energy Market (IEM) and the subsequent adoption of the above mentioned Gas Directives.

With this, the liberalization process began in the EU. In addition to the three energy Directives, other EU legislative developments played an important role in transforming the EU gas markets in the 2000s. Here, a central piece of the EU energy market legislation is what is commonly known as the Third Energy Package, that has the single goal of strengthening the internal energy market. The Third Energy Package enforced separation of energy supply and generation from transmission ( unbundling), independence of the regulators and cross-border cooperation of TSO’s, designed rules for open and fair retail markets and established the Agency for the Cooperation of Energy Regulators (ACER\textsuperscript{14}).

Also with the liberalization, TPA on gas networks was introduced. Transit gas was unified with transport of gas, meaning that all gas flows, irrespective of being cross-border or within-country, were to be treated equally and therefore TSOs operated under equal conditions for both transit and transport. Moreover, regulated TPA was mandated for all transmission and distribution infrastructures, including LNG facilities, except storage. In line with the TPA provision, operators of infrastructure must grant non-discriminatory access to infrastructure to third parties\textsuperscript{15}. There are, however, exceptions for certain cases, where the TPA may not be applicable. The criteria for the TPA exemptions are set out by Article 36 of the Directive 2009/73/EC:

- The investment must enhance competition in gas supply and enhance security of supply;
- The level of risk attached to the investment is such that the investment would not take place unless an exemption was granted;
- The infrastructure must be owned by a natural or legal person which is separate at least in terms of its legal form from the system operators in whose systems that infrastructure will be built;
- Charges are levied on users of that infrastructure;
- The exemption is not detrimental to competition or the effective functioning of the internal gas market, or the efficient functioning of the regulated system to which the infrastructure is connected.

These exemptions from the TPA provision of the Directive 2009/73/EC were granted in order to facilitate investments, which otherwise would and could not take place.

In general, four main trends with regard to the new market design may be observed since the mid-1990s to the present period. The first is that national incumbents started acquiring assets in other countries in order to compensate the loss of their market share in the national markets.

\textsuperscript{14} ACER – Agency for Cooperation of the Energy Regulators
\textsuperscript{15} Companies other than their related companies.
Second, downstream local utilities merged on a national or regional basis to increase their market position. Third, mergers and acquisitions of gas and power companies became a trend. Fourth, vertical integration of energy companies through mergers and acquisitions took place (IEA, 2008).

2.2.2 History and development of European hubs

EU gas markets were transformed to rely on open access to the network services. According to Vazquez and Hallack (2013), such a market design is based on the implementation of a TSO and characterized by a combination of explicit and implicit allocation of gas transmission. This type of allocation is known in the EU as the entry/exit system of points where the physical network represents only a part of the whole, commercial network. Every EU Member State, with the exception of Cyprus and Malta, which don’t consume natural gas, is required to establish an exit/entry system, where for every entry/exit point, the network users are able to book the corresponding capacities. Combined, are able to book capacities independently for each entry/exit point. The system of individual entry/exit and trading points is comprised of virtual or physical gas hubs or simply hubs. Hubs can be thus be defined as trading locations, which are specified in a contract as a location for selling and buying gas.

According to Heather (2012), however, legislation alone could not and would not effectively deliver the changes to create a successful free and open traded market environment. Gradually, market participants have changed their attitude toward trading and embraced the changed playing field. Heather (2012) also argues that the final contributor to the changing gas market in Europe has been the push by the exchanges to open up the markets by offering new products on easy-to-trade electronic platforms.

The trading locations or hubs can be either physical - real world places, mostly where various gas supply infrastructures from various gas fields intersect, like Zeebrugge in Belgium or Henry hub in the USA, or virtual. A physical hub is an actual location where different pipelines come together and where trading of physical gas occurs. Its purpose is to serve as an actual transit point for the transportation of natural gas, as well as a storage facility (IENE, 2014). Physical hubs are therefore located in specific locations to where gas is transported to or from. Zeebrugge, a physical gas hub in Belgium, for example, is the nexus of different gas sources – it connects the Interconnector pipeline, a pipeline between the UK and Belgium, the LNG terminal as well as the national grid, Zeepipe pipeline (Figure 22).
However, a hub can on the other hand be only a trading platform for the financial transactions of natural gas. A virtual hub as a trading platform can serve a trans-regional zone or an entire country. In such a case, the gas can be injected into any point on the corresponding grid, regardless of the point of extraction (IENE, 2014). Vazquez and Hallack (2013) define the virtual hub as a standard set of delivery points with a simplified representation of the physical characteristics of the network and thus being more than simply a physical junction of pipelines. Virtual hubs have an important advantage over physical hubs. Namely, gas may be traded at virtual hubs irrespective of its location and origin, as long as the prescribed fee for the network access has been paid for. Virtual hubs thus also lead to greater flexibility and diversification of sources and are consequently more suitable for trading operations. DNV KEMA (2013) summarizes that the virtual hubs allow trading to move away from traditional trade at specified physical locations, usually located at the flange of a system entry or exit point.

Both physical or virtual hubs, may offer a wide variety of services to different market participants. In addition to operating and financial services such as storage, parking and exchange, Long, Moore & Venban-Smith (2001) note that hubs have also become gas market trading centers and pricing points, facilitating changes in ownership, promoting price discovery, and offering risk management services. According to Zajdler (2012), the hubs serve as balancing or trading points where shippers trade gas but also offer other related services, such as onward transportation of gas, balancing, portfolio management, trade on the day-ahead, futures, and the OTC\textsuperscript{16} market.

However, the services the hubs offer do not depend only on their physical or virtual nature, but also on their stage of development. In this respect, Heather (2012) classifies the hubs into three categories – trading, transit and transition hubs (Table 2). **Trading hubs** are mature hubs, proven to be reliable markets and are continuously used to manage financial risks in the gas portfolios.

\textsuperscript{16} Over-the-counter refers to non-anonymous standardized bilateral trades between two parties through a broker facilitated by the hub.
They are based on virtual trading points and are also characterized by easy access to trade, high number of participants and high level of transparency.

**Transit hubs** are physical transit points where natural gas is physically traded, the main role of which is to facilitate the onward transportation of large quantities of gas.

**Transition hubs** are virtual hubs which are relatively immature, but have set benchmark prices for natural gas in their national or trans-national regional gas markets. They are also commonly used as ‘balancing markets’ for shippers that deliver or take gas from the corresponding grids.

In the EU, there exist only two strictly virtual trading hubs – NBP in the UK and TTF in The Netherlands. All other existing hubs may be classified as transit or transitional, although it is true that they are constantly evolving and slowly developing into trading hubs. This is also due to the entry-exit system, which has been put in place in order to facilitate the single European gas market. The EU itself is also promoting the development of virtual (regional) trading hubs in order to achieve the integration of the gas market in the EU (IENE, 2014). Due to their maturity and high number of participants, Zeebrugge, CEGH and Gaspool are essentially trading hubs as well. However, due to their physical characteristics they serve as transit points for the onward transportation of gas and can also serve as storage facilities.

The first hub in the EU was the National Balancing Point (NBP), established in the UK in 1994. It soon became the main place for gas trading and it marked the beginning of spot trading with gas in Europe. The NBP became the most important European hub due to its ability to grow consistently. It is supplied with gas by UK’s own gas production, imports from Norway and Continental Europe, storage and LNG. In 2012, trading activity at the NBP accounted for 62% of all continental European gas trading activity. Due to the emergence of other continental European hubs and significant rise of especially the TTF, however, the percentage has lowered from 90% in 2007 (IENE, 2014).

### Table 2. Hub types in Europe

<table>
<thead>
<tr>
<th>Physical hubs</th>
<th>Country</th>
<th>Hub type</th>
</tr>
</thead>
<tbody>
<tr>
<td>Central European Gas Hub (CEGH)</td>
<td>Austria</td>
<td>Transit</td>
</tr>
<tr>
<td>Zeebrugge (ZEE)</td>
<td>Belgium</td>
<td>Transit</td>
</tr>
<tr>
<td><strong>Virtual hubs</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gaspool (GPL)</td>
<td>Germany</td>
<td>Transition</td>
</tr>
<tr>
<td>National Balancing Point (NBP)</td>
<td>UK</td>
<td>Trading</td>
</tr>
<tr>
<td>NetConnect Germany (NCG)</td>
<td>Germany</td>
<td>Transition</td>
</tr>
<tr>
<td>Points d’Echange de Gaz Nord (PEG-Nord)</td>
<td>France</td>
<td>Transition</td>
</tr>
<tr>
<td>Points d’Echange de Gaz Sud (PEG-Sud)</td>
<td>France</td>
<td>Transition</td>
</tr>
</tbody>
</table>
Similarly, spot markets started to develop throughout the EU with the emergence of hubs in different countries. TTF is the second trading hub and is considered to be the most mature, liquid and important for continental Europe. Located in the Netherlands, the TTF has grown significantly in the last couple of year, most notably since 2010. According to IENE (2014), it is the biggest hub in continental Europe in terms of traded volumes. The amount of gas traded at TTF is more than 14 times the amount of gas consumed in the Netherlands. Figure 23 shows that TTF continues to grow relative to the NBP and is in fact drawing financial traders away from NBP. (IENE, 2014)

ACER (2011) reports that in order to become mature, the gas hubs need a large number of suppliers via multiple access routes such as gas-on-gas competition through pipeline supplies, LNG, cross-border interconnection and price responsive storage facilities. Therefore, infrastructure (pipelines, interconnection points, storage, LNG regasification plants, etc.) and supply diversification are two of the most important factors for success of the new market design with fully functional mature and liquid gas hubs.

In this respect, the NBP is considered to be the most mature and liquid European hub. Its prices are a benchmark for the majority of the traded gas in the EU, which is either indexed to the prices of NBP or to prices of other hubs which are strongly correlated to the price of NBP. As it is the most liquid hub, it significantly influences all the other hubs which usually trade against the NBP prices or are linked to the NBP prices via other hubs. Nevertheless, even NBP does not dictate the gas prices in the EU as they are still mainly driven by the prices of LTCs in the continental Europe.
Other European hubs have made slower progress and are lagging behind the NBP and TTF in terms of traded volumes, liquidity and maturity. They are also mostly just physical transit locations and do not represent the whole of the country’s national gas grid as do the NBP and TTF. Other than NBP and TTF, the most important European hubs are Zeebrugge in Belgium and CEGH in Austria. They may be characterized as transit hubs that primarily facilitate the transfer of large volumes of gas from and to other countries of the EU.

The German hubs, Gaspool and NGC, are unique in a sense that the prices at these hubs are established based on the German Border Price, comprised of LTCs with Gazprom that have been negotiated to be linked in 15% to spot indexation prices, rather than based on the spot market (Zajdler, 2012). In terms of traded volumes, NCG is the leading German hub, while Gaspool is operated as a physical rather a virtual hub and is used mostly as a storage area.

Hubs in Italy and France, the PSV and PEGs (PEG Sud, PEG Nord and PEG TIGRF) are considered as transition hubs. They are less developed and mature than the aforementioned hubs in the EU. The main problem of these hubs is the low availability of spot gas due to existing LTCs. For this reason, these hubs have mainly been used as balancing points and for facilitating bilateral, private deals rather than make prices transparent for all market participants.
It is important to stress, however, that the intended EU-wide entry/exit system with hubs at its base, is still in the developing phase. Some countries such as the UK, the Netherlands and Denmark have established virtual points and have no capacity restrictions in place, while in many other Member States either the implementation of virtual points is still missing or the capacities cannot be fully and flexibly used (DNV KEMA, 2013). Figure 25 above presents an overview of the status of implementation of entry/exit systems in individual countries.

**Figure 25. An overview of status of implementation of entry/exit systems**

[Diagram showing entry/exit systems]


### 2.2.3 Gas trading

The liberalization of gas markets in the EU has allowed gas trading to develop and led to a dramatic increase in volumes of gas being traded. As a result, numerous OTC markets as well as energy and gas exchanges have emerged. According to IENE (2014), exchanges, especially those which have created trading platforms for specific hubs, in turn contribute to the growth of the hubs. The new market model is therefore based on trading, where market participants make short and medium-term deals through hubs and exchanges, in addition to the existing bilateral trades.

OTC trading denotes bilaterally negotiated contracts, tailored to specific customer requirements, as opposed to exchange trading, which is more standardized. However, some products traded on an OTC market may also be standardized in order to facilitate standard deals in a quicker and more transparent fashion. An OTC market does not use a centralized trading mechanism, such as shared platforms to auction bids and offers to allocate trades. The performed trades are bilateral non-regulated deals in which buyers and sellers negotiate terms privately, often not aware of the prices currently available from other potential counter parties and with limited knowledge of trades recently negotiated elsewhere in the market (IENE, 2014).
On the other hand, trading on gas exchanges is completely standardized, meaning that it is based on a standard set of products through which deals are performed. The main feature of these products is their time of delivery – it can vary from during a day to couple of years in the future (DNV KEMA, 2013).

Gas exchanges are market operators that bring parties together to facilitate anonymous standardized trading and clearing of energy products. Sometimes gas hubs can be confused with exchanges. However, a gas hub is a place for delivery of the product, whilst an energy exchange is a trading platform where members buy and sell natural gas by submitting bids. According to IENE (2014), the main objective of any energy exchange is to ensure a transparent and reliable wholesale price formation mechanism on the market by matching supply and demand at a fair price to ensure that the trades done at the exchange are finally delivered and paid. An exchange can therefore be defined as a place where gas spot prices are determined. The only difference between the gas exchange and any other commodity exchange is the underlying product – natural gas. Natural gas is also not the only commodity being traded at these exchanges, as majority of European energy exchanges are also active in other commodity markets such as oil, coal and especially electricity.

*Figure 26. European gas hubs and exchanges*

![Map of European gas hubs and exchanges](image)


The large majority of trading activities in Europe is related to the delivery of gas through hubs (Figure 26). While different bilateral deals along with LTCs may result in transfer of title to gas at different pipelines, border inter-connection points (IPs) or LNG terminals, almost all of the gas being traded under standard spot or forward contracts, is physically exchanged at hubs. Yet it is worth mentioning that gas trading occurs not only at hubs and exchanges but also in other
locations. Although relatively small volumes make it insignificant, trading occurs as well in Spanish LNG terminals and Italian border IPs. These trading locations, however, are not organized markets and do not provide required transparency for larger volumes of gas to be traded there (IENE 2014).

2.2.4 Traded instruments

The majority of gas trading is in form of spot trading on day-ahead and intra-day markets, prompt and forward markets as well as a variety of financial derivatives. While spot, prompt and forward markets denote the physical delivery of gas, there also exist the financially settled derivatives such as swaps and options, but such markets are insignificant compared to spot and forward trading, at least as of now.

Spot trading market may be further separated in the day-ahead, intraday and balancing market. Another possible category is the so called within-day market, which serves for balancing but can go as far as offering hourly contracts. In general, however, **spot contracts** for gas may be defined as block contracts for the physical delivery and supply of gas at a constant rate of delivery for daily load (IENE, 2014). The deliveries that correspond to the performed spot trades are always made at a predetermined hub. The most commonly traded contracts are those traded at day T for delivery at the day T+1, the so called day-ahead contracts. They are used for continuous delivery of gas during the day, following the day in which the contract was concluded. They are thus used for the base-load quantity, meaning that the same amount is to be delivered every hour of the agreed period.

**Prompt contracts** are essentially spot contracts that cover delivery of gas for slightly longer periods. Namely, periods from one day to one month in the future. Prompt contracts are thus concluded at day T for delivery of gas on day T+n, where n may equal any given number of days between 1 and 30.

**Forward contracts** are characterized with agreed gas delivery periods that exceed the prompt market horizon, i.e. any period longer than one month. In the EU gas markets, forward contracts are typically being traded for the entire individual calendar months, quarters, seasons (six-month winter or summer season), gas years $^{17}$ or calendar years.

Similar, yet different from the forward contracts are the **futures contracts**. Futures contracts are contracts for forward delivery of gas, where buyer and seller conclude individual transactions with the organized gas exchange. Thus, the futures may only be traded at exchanges and their notable characteristic is anonymity – the buyer and seller remain anonymous to each other as the transaction is concluded via exchange. Futures are not necessarily settled by physical delivery of gas and may also be traded for financial purposes only. The majority of futures trades in Europe are nevertheless settled by physical delivery of gas.

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$^{17}$ Gas year differs from the calendar year and denotes 12 consecutive calendar months, beginning on October 1.
There also exist the financially settled derivatives such as swaps and options, albeit being traded only in small numbers and for small volumes of gas. **Swaps** with gas as an underlying commodity, are, like any other swaps, purely financial transactions that are settled by cash payment. The transactions are carried out in the same way as with any other swaps, while here the commodity is natural gas and the swap is priced against an indexed gas price. Therefore, a seller of the swap offers a fixed price for a certain quantity of gas to be notionally delivered in a specified period in the future, usually priced against a day-ahead gas price. At the time of the notional delivery period, the buyer and the seller settle the financial deal so that the cash payment is required only for the difference between the average of the chosen daily price during the respective period and the originally agreed fixed price.

Similarly, gas **options** are in essence the same as any other options, with the difference that the underlying asset is gas. Options are thus financial derivatives which give the holder of the option the a right, but not an obligation, to buy or sell natural gas at a certain pre-agreed date in the future, at a fixed price. As any other option, gas options may be call options (a right, but not an obligation, to enter into a fixed price purchase of gas in the future) or put options (a right, but not an obligation, to enter into a fixed price sale of gas in the future).

### 2.2.5 Trading activity and volumes

Trading activity is difficult to analyze as the data on OTC trading on hubs is not formally reported. Thus, this thesis uses external sources to estimate the trading activity at different hubs throughout the EU.

*Figure 27. Evolution of traded volumes at main continental EU hubs, 1999-2011*

With regard to trading activity on the gas markets in the EU, it is imperative to stress that OTC trading is significantly predominant over the exchange market trading. Of the 20,000 TWh of aggregated gas trades volumes at main EU hubs in 2012, ACER & CEER (2013) estimates that OTC trades represented more than 90% of the respective trades. ACER & CEER (2013) reasons
that this may be explained by the trust-based trader community, by better counter party knowledge and by clearing fees imposed by exchanges which may constitute as a barrier. A very important factor for the predominance of the OTC trades is also confidentiality that is guaranteed by bilateral contracts and is understandably prized by traders.

As is apparent from the Figure 27, gas trading in Continental Europe really started in the late 2000s. In the last ten years, however, numerous hubs developed and the OTC traded volumes of gas increased dramatically. For the purpose of market integration and development, it is therefore more sensible to analyze only the last couple of years, although the recent financial crisis has definitely negatively affected the further progress of hubs and trading markets in the EU (Figure 28).

\[\text{Figure 28. Traded volumes at main EU hubs in 2013}\]


2.2.6 Hub pricing

Liberalized gas markets together with the development of numerous hubs provided an alternative to traditional oil-linked LTCs. The new trend emerged that linked the contracted gas price to the spot price of gas being traded on a hub at the time being. This new contracting trend that can be observed in the EU for the better part of the last decade, is also known as gas-to-gas competition.

As the name suggests, gas-to-gas competition is based on competition-based pricing mechanisms. In other words, supply and demand for gas is the basis for the hub-pricing. The link to oil and other fuels does therefore no longer exist in a hub-priced gas contracts. This means that gas prices are linked to the fundamentals of the gas markets and react to market signals. Energy Market Secretariat (2007) remark that similarly to all competitive markets, here, the market framework is given by the government and/or regulator, but decisions are not directly influenced by it, as the decisions are made by market participants.
Deloitte (2013) observes that long term, oil-indexed contracts are under serious scrutiny as overall demand for gas decreases in Europe, while new, non-Russian, non-Middle Eastern sources of supply increase. Shale gas in the U.S. has freed up LNG, originally designed for American ports, to address European and Asian spot markets. As a result, spot prices are now lower than the oil-indexed prices of Russian and Middle Eastern contracts, with the result that gas from these sources has become among the most expensive in the world.

Though hub-based or spot-indexed pricing is definitely the new trend in the European gas markets, it is the oil-indexed price levels that remain the basis for the evolution of European hub pricing. According to Timera Energy (2013a), two reasons work together to support the logic of oil-indexation boundaries for gas hub pricing:

- Oil-indexed pipeline contracts represent the dominant tranche of flexible supply driving marginal pricing at hubs (and declining domestic production levels should reinforce this);
- The key producers have a strategic interest in controlling physical flow into Europe to support hub prices at a level broadly in line with oil-indexed pipeline supply.

*Figure 29. Selected LTC prices at national borders vs. NBP day ahead price, 2013*

Price convergence between prices of different hubs is an important indicator of market integration. Price convergence is an important indicator of gas market integration as in fully integrated markets higher prices in one area or country should in principle attract gas supplies from lower priced areas and/or countries that are seeking higher sale and profit margins. Attracting such supplies should then lead to reducing the price differentials and hence price convergence. Adversely, in a sub-optimally integrated markets, such mechanisms are not in place and for different reasons (LTCs, political, capacity issues, etc.), higher prices in one area or country do not attract supplies from lower priced areas and/or countries (Figure 29).
As is evident from Figure 30 above, prices at the main European hubs are relatively similar, except for the French PEG Sud, which stands out with substantially higher prices observed in January 2014. Price differentials between the price in DA product at TTF, Gaspool, NetConnect, NBP, CEGH, Zeebrugge and PEG Nord range to up to 1.01 EUR/MWh, which represents 3.7% of the maximum price observed at PSV. This indicates a relatively high level of price convergence at main European hubs. ACER (2014) argues that increased price convergence across the EU is a result of the renegotiation of LTC conditions, initiated in previous years. Due to the renegotiation of conditions in LTCs, hub prices have been increasingly used as a reference and traditional oil-indexation has been reduced.

The level of price convergence is relatively high when comparing only the prices at major European hubs. Taking into account the EU as a whole and comparing different regions, however, there exist significant price variations, reflecting different degrees of market maturity and stages of development. The role of LTCs is also important in understanding the differences in

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**Figure 30.** Selected hub prices in January 2014

![Diagram showing hub prices](image)

**Source:** ACER & CEER, *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2013*, 2014.

**Figure 31.** Average wholesale gas prices in the EU, 2013

![Diagram showing gas prices](image)

**Note:** Luxembourg, Germany, Finland, Denmark, Netherlands and Poland missing due to no data available

**Source:** Eurostat, 2014; Eurostat Comext, 2014.
price levels of different areas and/or countries. In general, LTCs are much more common in the Central-Eastern and Southern European Member States where hubs are not yet developed, market maturity is lower and the majority of gas is imported from Russia. Oil-indexed and even hub-based LTC prices tend to be higher than hub spot prices and therefore Member States relying mainly on LTCs have in general higher prices. Thus, important differences remain between different areas and Member States in the EU, which may be characterized by comparison of the lowest and highest average wholesale gas price in the EU. Namely, average wholesale price of gas in Sweden in 2013 was more than two times higher than in the UK, which stood at 75% of average EU wholesale gas price (Figure 31).

2.2.7 Legislation and regulatory aspects

In addition to the already described Third Energy Package, legislative and regulatory changes continue to shape the new look of the European gas markets. The primary goal and focus of all regulatory efforts in the EU is to deliver efficient and competitive energy markets with fairer prices to end-consumers.

Gas target model (GTM), presented in 2011 by CEER, envisages sustainable Internal Energy Market in the EU to be formed. GTM was designed to be based on three pillars;

- enabling functioning of wholesale markets;
- tightly connecting different markets; and
- enabling secure supply patterns, all of which shall be achieved by improving effectiveness by realizing economic pipeline investments.

The first pillar deals with enabling functioning wholesale markets. According to Keyaerts & Glachant (2014) this foresees a set of requirements that should be met for a functioning market. The goal of the second pillar is fostering price alignment in Europe, while the third pillar deals with ensuring effective investment signals (Keyaerts & Glachant, 2014).

The GTM envisages liquid hubs with sufficient and efficiently used infrastructure, functioning markets in all of the EU and secure gas flows to the EU and provides a framework for competitive and secure gas flows in Europe.

Another important regulatory effort is the Regulation on Wholesale Energy Markets Integrity and Transparency (REMIT). As energy trading is at the heart of the EU’s liberalized energy markets, preventing market manipulation and market abuse is a crucial element for the functioning of wholesale markets and for promoting the confidence of market participants and final consumers. The purpose of REMIT is to monitor the market with the aim of delivering transparency in the wholesale markets and lowering any chance of market manipulation or falsified pricing.

Lassource (2013) sums up the REMIT regulation by defining it as a consistent EU-wide framework built on three pillars:
• defining market abuse, in the form of market manipulation, attempted market manipulation and insider trading, in wholesale energy markets and introducing the explicit prohibition of market manipulation, attempted market manipulation and insider trading in wholesale energy markets
• establishing a new framework for the monitoring of wholesale energy markets to detect and deter market manipulation and insider trading
• providing the enforcement of the above prohibitions and the sanctioning of breaches of market abuse rules at national level.

As such, REMIT aims to detect and deter market manipulation and thus increase market integrity and transparency which are essential for well-functioning energy trading that is at the heart of EU’s liberalized energy markets.

3 IMPACTS OF NEW NATURAL GAS CONTRACTING TRENDS ON THE EU GAS SECTOR

3.1 Impacts on the Existing LTCs

It is possible to conclude that the EU energy market is somewhat divided between the new competition-oriented regulatory framework and the existence of the LTCs, which will not expire for another twenty years. There is still an ongoing debate whether the oil-linked and hub-priced contracts can co-exist. The current market situation however shows, as confirmed also by IEA (2008), that they can, do and have already coexisted for some time.

The question that arises is how can both actually function in a single market. Liberalized gas markets in Europe, which resulted in market competition, hubs and consequently more liquid markets, have overall reduced LTCs, especially in the downstream part of the gas value chain, whereas LTCs and oil-linked pricing mechanism still play the most important role in the upstream part of the gas value chain. This fact is supported by the data from the database of Cedigaz (2014), from where it is obvious that, even since the liberalization of the EU gas markets, on average five LTCs have been concluded in Europe each year (Figure 32). Importantly, this data does not cover the gas supplies via LNG, which would definitely further increase this number.

The sheer number of existing LTCs mean that they still play an important role in the EU gas markets. Another important aspect is the effect of the new contracting trends on the pricing mechanism in the existing LTCs. In this respect, KEMA DNV (2013), claim that renegotiations of the LTCs are recognized as the main determinant for the reduction of oil-linked gas in Europe. In general, there is undeniable evidence of an accelerating transition to hub indexation. However, not all of the major suppliers of gas are willing to abandon the traditional oil-linked pricing mechanism in their LTCs. According to Timera Energy (2013a), Statoil has been more willing to accept increased levels of hub indexation and its officials have even stated that they expect the
majority of their supplies in the future to be hub indexed. Their intention was further confirmed by signing a 10 year supply contract, worth 1.26 bcm, with German BASF which is primarily based on the hub-index of the German hubs, in 2012.

*Figure 32. Number of gas supply LTCs by pipeline per year of signature*

![Figure 32](image)


Even more interesting is the sheer number and volume of LTCs in force at present. As already mentioned, the LTCs almost always include confidentiality clauses, and it is therefore difficult to estimate what is their exact extent or share in all gas supply contracts. Nevertheless, there exist numerous estimations, none of which is more robust than the one of Cedigaz, the international association for natural gas. Among its unique compilation of long term gas supply contracts information, Cedigaz has compiled a database based on published information on long term supply contracts by pipelines in Europe. Although the data is derived from public sources only, it nevertheless represents the best estimation of the actual state of LTCs in Europe. According to Cedigaz (2014), there were 126 LTCs in force in 2014 in Europe. These 126 LTCs represent supply contracts for gas from 11 exporting countries to 27 importing countries. The breakdown of the LTCs in force in 2014 is presented in more detail in the Table 3, below.

Taking into account the LTCs in force for gas supplied via LNG, it becomes clear that LTCs, either oil-linked or hub-indexed, have a significant presence in the EU gas market and, due to their long term nature, will definitely remain for many years.

The desired model of the European gas market nonetheless consists of predominantly hub-based prices. For this reason, numerous national regulators imposed hub pricing as industry standard for the pricing of gas. As is evident from Appendix 6, at least five European regulators imposed an obligation to sell gas at hubs and/or an obligation to introduce spot component in regulated price, in their respective countries. These state imposed spot component obligations include the requirement to index the price of gas to a specific hub, to sell certain percentage of gas through the exchange and a cap to the oil-indexation of final gas prices.
## Table 3. LTCs by pipeline in Europe

<table>
<thead>
<tr>
<th>Importing country</th>
<th>Number of contracts</th>
<th>Max. volume (bcm/year)</th>
<th>Exporting country</th>
<th>Number of contracts</th>
<th>Max. volume (bcm/year)</th>
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</thead>
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<tr>
<td>Austria</td>
<td>4.00</td>
<td>9.00</td>
<td>Algeria</td>
<td>24.00</td>
<td>61.00</td>
</tr>
<tr>
<td>Belgium</td>
<td>7.00</td>
<td>14.00</td>
<td>Azerbaijan</td>
<td>1.00</td>
<td>7.00</td>
</tr>
<tr>
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<td>1.00</td>
<td>3.00</td>
<td>Denmark</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>3.00</td>
<td>12.00</td>
<td>France</td>
<td>2.00</td>
<td>1.00</td>
</tr>
<tr>
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<td>2.00</td>
<td>Germany</td>
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<td>15.00</td>
</tr>
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<td>6.00</td>
<td>Iran</td>
<td>1.00</td>
<td>10.00</td>
</tr>
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<td>France</td>
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<td>54.00</td>
<td>Libya</td>
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<td>8.00</td>
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<td>104.00</td>
<td>Netherlands</td>
<td>9.00</td>
<td>44.00</td>
</tr>
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<td>3.00</td>
<td>Norway</td>
<td>34.00</td>
<td>98.00</td>
</tr>
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<td>8.00</td>
<td>Russia</td>
<td>37.00</td>
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<td>90.00</td>
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<td>2.00</td>
</tr>
<tr>
<td>Lithuania</td>
<td>1.00</td>
<td>4.00</td>
<td><strong>TOTAL</strong></td>
<td>126.00</td>
<td><strong>449.00</strong></td>
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<tr>
<td>Luxembourg</td>
<td>1.00</td>
<td>0.00</td>
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<tr>
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<td>1.00</td>
<td>0.00</td>
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<td>1.00</td>
<td>1.00</td>
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</tr>
<tr>
<td>Netherlands</td>
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<td>13.00</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Poland</td>
<td>2.00</td>
<td>11.00</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Portugal</td>
<td>1.00</td>
<td>3.00</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Romania</td>
<td>2.00</td>
<td>4.00</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Slovakia</td>
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<td>8.00</td>
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<tr>
<td>Tunisia</td>
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<td>0.00</td>
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<td>22.00</td>
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<td></td>
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</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>126.00</strong></td>
<td><strong>449.00</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Komlev (2014) argues against regulatory enforcement of hub pricing as he believes that it leads to a price mismatch between the hub-based priced and oil-indexed natural gas. Moreover, he argues that implicitly such enforcements also lead to the promotion of unfair competition or free riding. Key gas importers, responsible for national energy security, are deprived of the higher margins as they are forced to sell the gas to end users at usually lower hub-indexed prices. On the other hand, free riders – companies, which do not produce or import gas - do not worry about energy security and do not have costs related to seasonal storage or structured deliveries. They are therefore able to source small volumes of hub gas at a lower price and sell them on for a profit. They speculate on the market - a normal activity in competitive markets - but Komlev (2014) argues enforced hub-pricing may give them unfair advantages.

### 3.1.1 Renegotiations of LTCs

One of the most notable developments or consequences of liberalization, development of gas hubs and trading are definitely the reopening and renegotiation of numerous existing LTCs. These developments are also the main drivers of price convergence in the EU.

Renegotiations of LTCs or contract re-openers as they are usually referred to, most commonly relate to prices and volumes, namely different types of discounts, supply flexibility, ToP reductions, and price-formation mechanism. Renegotiations are normally a result of one party being in a sub-optimal position for an extended period of time and thus wishes to change one or more conditions as set in the LTC. As it is generally difficult for both the buyer and the seller to agree on changing the contract terms, Timera Energy (2013) describes two routes via which these renegotiations are usually initiated:

- Contracts entered into under a Civil Code approach, which typically contain re-opener clauses that specify the conditions under which contract counterparties should come together to resolve a dispute; and
- Contracts entered into in a Common Law context, which typically do not have a formal contractual trigger for renegotiation and it is the commercial incentives that usually bring the two parties to the renegotiation table.

In both cases, renegotiations normally follow a formal re-opener process that may result in either no re-opener (contract terms and conditions are not renegotiated), negotiation or arbitration.

In practice, it has been observed that renegotiations are becoming more and more common, albeit with different end results and consequences. In this respect, ACER for example (2014) reports that price reductions have been granted to several countries by Gazprom as part of its strategy to treat markets separately and establish price discrimination between Member States. Furthermore, ACER (2014) observes that although Sonatarch is still keen to maintain oil-indexed prices in existing LTCs, it is recently showing more flexibility on ToP volume obligations as well as starting to offer some hub-indexed prices in certain contracts.
Similarly, DNV KEMA (2013) observe that while producers Statoil and GasTerra seem to be willing to gradually or fully convert to towards hub indexation, Gazprom, Sonatarch and Qatargas seem to cling to oil indexation in their long term gas export contracts with EU partners.

Although the above are just couple of examples of LTC renegotiations, it may be observed that all major exporters of gas to the EU have slowly but surely started utilizing hubs for physical delivery of gas. In addition, they are also starting to use the hubs as the focus of shorter-term and more flexible contracts.

3.2 Impacts on Capacity Related Issues

Capacity related issues are extremely important in the development of the internal gas market in the EU especially since sufficient cross-border connectivity is required to allow effective trading to develop and result in price convergence across different gas hubs (Booz&Company, 2013). The TPA and restrictions on preferential right to transmission together have definitely had the most significant impact on the capacity related issues.

While the allocation of transmission capacity rights has been implicit for decades before liberalization, meaning that commodity and capacity were traded simultaneously, the desired target model for the single gas market in the EU is based on numerous transmission system operators (TSO’s) that are independent and in charge of all network operations and transmission capacity. Vazquez and Hallack (2013) explain that this enables the simplification of network characteristics into the so-called entry and exit points system. This simplification results in the capacity for the entry and exit points being sold explicitly and separately for each entry and exit point. The shippers therefore need only to define their entry and exit capacity requirements and then purchase the right to enter or exit the market. Once they have obtained the capacity rights, they are able to trade freely with the commodity, within their capacity constraints. Since the shippers need to estimate their capacity requirements in advance, such market design often results in less capacity allocated to the entry-exit points than it is actually available. Vazquez and Hallack (2013) explain that this as the result of entry and exit capacity allocation before the trades take place, so the capacity calculation is made with estimation of the future gas flows and thus the capacity cannot be allocated according to actual market preferences.

The implementation of the entry-exit system in the EU has thus led to significant changes in the shippers’ behavior concerning capacity issues and the underlying contracts for capacity utilization in general. The previous point-to-point capacity contracts, where shippers booked their capacity rights for transport of gas from point A to point B needed to be restructured into entry-exit capacity contracts, which are necessary to execute any trades at the hubs and/or virtual points. The most important characteristic of the new entry-exit capacity contracts is that the requirement of possessing such a contract before being able to trade the commodity. As such, gas may only be delivered into the transmission system if its owner has the corresponding entry capacity and the trading can only take place once the gas has entered the transmission system.
The previous point-to-point system is perfectly described by Yafinova (2013), who explains that in such a system, a shipper, delivered the gas to the designated delivery point, in accordance with his capacity rights, where the gas was then bought by a trader, who did not require any capacity. The gas was later injected into a hub where it was traded further, via OTC or exchange. The gas was eventually bought by another (usually downstream) shipper, who shipped the gas across the transmission system towards the final customer on the basis of its point-to-point capacity contracts concluded with the responsible TSO. The most important characteristic of such a system was that all the trading took place before the gas actually entered the transmission system.

ACER (2013) analyses that EU inter-connection point (IP) capacities are, to a significant extent, fully pre-booked over the longer term, which mirrors traditional commodity LTCs. The report nonetheless concludes that the capacity contracting trend is gradually changing and following the developments in the commodity market described above. ACER (2013) also observes that shippers are starting to contract less cross-border capacity over the long term and rely more on virtual spot trading points for the required capacity, resulting in a trend toward shorter term capacity contracting and the use of secondary markets for capacity trading.

In its inquiry, ACER (2013) acknowledges that access to transmission capacity within the EU is essential in order for a competitive gas market to develop, inasmuch as the development of competition is dependent on the availability of gas. The inquiry also concludes that as TPA conditions within EU Member States, as well as the allocation of capacity rights, often differ substantially between transit and national transportation, traders and shippers continue to experience difficulties in accessing transmission capacity. Moreover, the holders of the LTCs are effectively no longer entitled to preferential access or different tariffs, unless a derogation or exemption from the TPA provisions has been granted to them, based on the special criteria.

Although most capacity at IPs is still fully pre-booked on a long term basis, shorter-term commodity contracting at virtual trading points (VTPs) is having an impact on capacity bookings. In this respect, short term capacity contracting is increasing. According to ACER (2014), the data that confirms this trend can be seen in both the limited demand for long term capacity reveled in the PRISMA\textsuperscript{18} capacity platform yearly auctions, and the proportionally higher demand for short term capacity products.

The increase in short term capacity booking is particularly evident in countries where commodity contracting is available via VTPs, and where trading opportunities between hubs exist. However, this trend does not exceed the overall long term capacity contracted values. Availability of short term capacity contracts is particularly, but not only, important for new entrants and smaller shippers that do not want to commit themselves to longer term capacity contracting if they do not have the matching supply contracts. Short term capacity also allows them to better match supply and demand profiles and reduce the risks of uncertainty. Short term capacity also allows them to better match supply and demand profiles and reduce the risks of uncertainty.

\textsuperscript{18} Online platform for the auctioning and trade of gas transport capacity
Long term capacity contracts are thus still predominant at IPs in the EU, and particularly used by gas producers, large importers and wholesalers with higher availability to predict future capacity needs and absorb changes in larger portfolios. Long term capacity contracted values are usually more predominant in IPs at EU borders.

3.2.1 Capacity trading

With the TPA in force, and with the trend toward shorter term capacity bookings, the development of a European trading platform for capacity was actually just a matter of time as it represented a natural building block in the continuous development of the European gas market. PRISMA is a company set up as an open cooperation which allows all European TSO’s to participate in setting up and managing the trading platform for the European capacity market and thus connects all major European gas markets. By auctioning capacity via PRISMA, TSO’s connect the North-South and East-West regions of the EU by connecting twelve European gas hubs. These include CEGH, Gaspool, NCG, Nord Pool, MS-ATR, PEG North, PEG South, POLPX, PSV, TTF, VHP Portugal and ZTP. Besides the shareholders, 16 other TSOs are also currently marketing their capacity through the platform. Altogether, 319 shippers and more than 970 users use the platform for booking the available transport capacities. Until 2014, more than 36.400 auctions have been concluded and more than 2.40 billion kWh/h have been allocated since the start of the platform.

Capacity may thus be contracted via auctions or via first-come-first-serve bookings. The available trading capacity on the secondary market includes firm and interruptible capacity of all categories supported by the respective TSO. On the secondary market, shippers create trade proposals, which then result in capacity being traded either bilaterally (OTC), through the so called call for orders or on first-come-first-serve basis.

Overall, since PRISMA’s start, platform operations have been secure and stable with a large number of auctions taking place, which is a sign of a well-functioning capacity market in the EU. While ensuring stable operations of the platform, PRISMA also continues further platform development in order to fulfill both European and individual TSO requirements. The expected future developments of the platform include the launch of multi-currency trading the launch of within-day capacity trading option.

The capacity trading platform hence provides a welcome flexibility mechanism for gas transport capacity and is expected to continue developing and increase its offered as well as allocated volumes of capacity.

3.2.2 Existing infrastructure and capacity utilization

As indigenous production of gas in Europe has never been a major source of gas and its further decline means that, even more gas will need to be transported from remote places. Coupled with not really bright prospects of shale gas in the near future, it is evident that majority of gas for
European consumption will need to be transported to Europe either by long distance pipelines or as LNG. This, however, requires sufficient infrastructure and capacities to supply the gas to end customers.

Glachant, Hallack & Vazquez (2013) explain that traditionally, gas was sold by commodity LTCs, which used to be associated with long term capacity rights. In the competitive and liquid markets, any amount supplied by individual producers can be sold on them making LTCs, though still useful, less essential. However, the reduced importance of LTCs raises a problem for the gas transportation industry, whose main source of income is the sale of capacity rights. Unless a reasonable share of the investment costs are covered by the LTCs, new infrastructure is almost impossible to develop and even maintenance of existing infrastructure becomes a substantial problem.

3.2.3 Investments and financing

As already mentioned, the general regulatory conditions for TPA apply to all transport capacity. There are, however, certain exemptions from these requirements, aimed specifically at new infrastructure. Without such exemptions and without the security of long term bookings, the financing of huge infrastructure project would indeed be very difficult. Investments in new pipelines, LNG terminals and other infrastructure incur enormous costs and remain backed by LTCs in order to allow the investors to close the financial structure of the project. This is the reason why many pipelines, LNG terminals and storage have been granted an exemption from TPA requirements.

DNV KEMA (2013) describes the importance of LTCs and/or vertical integration with the example of North Stream project, where only 30% of the whole project was financed by equity of the shareholders, while 70% was financed by banks through numerous loans backed by the expected earnings from transportation contracts. These contracts included long term capacity bookings from major European wholesalers such as Wingas (9bcm/year for 25 years), DONG (2 bcm/year for 20 years), E.ON (4 bcm/year) and Gaz de France (2.5 bcm/year).

The exemption from the TPA provision, however, is not straightforward and unconditioned. DNV KEMA (2013) explains that in general, exempted infrastructure projects are regarded as merchant pipelines, LNG or storage activities for which regulated tariffs, regulated TPA and unbundling will not provide a profitable business case. The exemption from the TPA and other regulatory provisions may thus be limited to only certain aspects or bound to pre-defined conditions. Regulation, for example, may require that part of entry/exit capacity should be short term and thus part of the new capacity available from new infrastructure may be required to be sold on a short term basis.

The primary reason why LTCs have been accepted by the regulatory bodies and have been exempt from certain regulatory provisions is that short term contracts are in many cases unable to secure enough financial resources and revenues for large investments in gas infrastructure.
Even if they may not provide enough resources for the project itself, in some cases short term contracts may help the profitability of potential projects.

Once the gas markets in the EU will become more mature, DNV KEMA (2013) believes that in combination with market-based pricing, demand shall be reasonably secure and sufficiently well predictable, which will in turn make the LTCs almost obscure as in such situation they would no longer provide any added value. Such scenario is nevertheless not close to reality, at least for the next decade, and LTCs will therefore remain an important investment tool for any envisaged new gas infrastructure in the foreseeable future.

3.2.4 Storage

First of all, it is important to understand the role of storage in natural gas markets. Storage is necessary because of the volatile consumption of natural gas – the consumption in winter, for example, is on average six times higher than in the summer. The purpose of storage is thus to store natural gas in times of oversupply in order to secure a steady supply in the times of high consumption, i.e. winter.

There exist different types of natural storage units (Figure 33). First and foremost, it is possible to separate between underground and surface storage. Underground storage units may be further split into aquifers and caverns. An aquifer is a natural storage unit, also called a pore storage, which is usually built in porous sandstone deep below the surface. The precondition of an aquifer is the gas impermeability of the rock layers, necessary to enable the pressing of gas to displace the existing water. The depth of drillings to store and extract the gas in an aquifer may be up to 3000 meters below the surface. Caverns, on the other hand, are artificial storage units, where cavities are created by a lengthy process of washing out of salt. These cavities are then built in up to 300 meters in height and 50 meters in diameter. The so called crystalline structure enables the caverns to be gastight and used as storage.

Gas storage units may also be built on the surface. The two main types of surface storage facilities are tanks and tubes, which are specially designed storage units, similar to pipelines through which gas is transported, albeit in a different form and with different function. They are usually smaller storage facilities, with capacities required for emergency supply of gas.

DNV KEMA (2013) acknowledges that storage may also be distinguished by typical duration of the so-called storage cycle, which can be strategic (year-on-year storage), seasonal, short term (monthly, weekly), diurnal (within day) or peak service storage (withdrawal capacity is much higher than injection capacity).

Regardless of the form and duration of the storage cycle, the storage capacities are important gas sourcing arrangements. Storage was traditionally considered a technical tool enabling the optimization of the gas transmission system and ensuring continuity of the service. With development of the spot markets and hubs in Europe, spot markets and storage are becoming
more and more interrelated. Therefore, storage is nowadays generally considered a natural gas flexibility tool, which enables suppliers to satisfy the demand for gas especially during peak periods. As such, storage now has more than just the traditional function as an investment that enables firms to adjust their supply when demand is uncertain or exposed to cyclical fluctuations. Storage may also be used for speculation, as a precaution and for seasonal production smoothing. Storage makes it possible to rely on inter-temporal fixed prices while the price decisions depend upon actions from previous periods. This allows firms to profit from speculation which influences the market price of gas. In terms of precautionary measures, stored gas reserves allow firms to regulate market supply in response to an uncertain demand. Additionally, storage may act as a safety stock for regulatory authorities and other major suppliers. Storage may also offer firms an option to smooth the cyclical fluctuations in demand (Baranes, 2013).

**Figure 33. Storage types**


Baranes (2013) also highlights that storage has an important impact on the volatility and level of spot and future gas prices. Moreover, storage has a significant influence on strategic decisions made by gas competitors, while storage allocation mechanism improves competition and efficiency in gas markets in general. That is why the EC has underlined the need for their development as the replacement or substitute for LTCs.

Nevertheless, DNV KEMA (2013) argues that large producers such as Gazprom, Statoil, GasTerra and Centrica, have acquired equity stakes in gas storages for purposes of pursuing a strategy of vertical integration into storage. As contract durations entered into by these producers are long term, between 15 to 20 years, it becomes obvious that this is a long term strategy for them. According to the same report, storage contracts for wholesale companies such as E.ON, RWE, Vattenfall, vary between 1 and 10 years, with a focus on contract durations around 5 years. This means that although not as long term as for producers/exporters, storage remains a fairly long term strategy and operation for major European wholesalers as well.
3.3 Impacts on Liquidity

ACER & CEER (2013) define liquidity as the ability to trade, buy or sell a desired commodity or financial instrument without causing a significant change in price of a product and without incurring excessive transaction costs.

Liquidity has a strong bearing on the level of competition and the efficiency of price formation. The most important indicators of the level of liquidity are the number and diversity of market participants, volume of traded gas, churn rate, bid-offer spreads, market depth, pricing mechanisms and indices as well as the extent of derivatives market. It is beyond any doubt that liberalization of the gas markets across the EU has resulted in a much diversified markets in terms of number of market participants and thus increased competition and liquidity (ACER & CEER, 2014).

The continued trend to move away from oil linkage and LTCs coupled with development of trading markets as well as derivatives markets has brought increased liquidity to some hubs, but has also restrained growth on others. This trend can be observed throughout the EU, and has had significantly bigger effect on Norwegian and Dutch producers than the Russian producers, namely Gazprom (ACER & CEER, 2014).

Measuring liquidity and analyzing markets’ efficiency through liquidity measures is important, as liquid markets imply high-level of price transparency and relatively lower transaction costs. Liquidity and market transparency in turn ensure reliability of hubs for portfolio management and optimization increases and also attract higher volumes (European Commission, 2014).

In addition to the number of different products traded at a hub and the bid-offer spread, the two main measures of how liquid an individual gas markets is, are the traded volume of gas and the churn rate. Churn rate or churn factor is a very useful statistic, often used to measure the liquidity of a commodity in a given market. In essence, it is a ratio between trading activity, namely the volume of gas traded at an individual hub or market, and the volume of gas that is produced and exchanged in the country where this trading activity occurs. As such, a higher churn factor implies a more liquid market. The churn ratios of the European hubs vary significantly, but in general, a churn ratio over 8 is considered as producing sustainable price signals, while a hub is considered to be liquid once the churn ratio exceeds 8.

Except for the UK (NBP) and the Netherlands (TTF), liquidity in other hubs is below target churn rate. Although the further evolution of liquidity in these hubs is questionable or at least uncertain, transparent gas trading is undeniable also in countries and market zones where hubs with relatively low liquidity are situated. This is due to other measures of liquidity and factors that need to be taken into account when analyzing the functioning of the markets. However, this is only the case in large Western European gas markets, while in Central and Eastern Europe, most gas markets remain without transparent gas hub trading and are individually too small to develop into competitive wholesale gas markets.
Liquidity may also be measured with indicators like market depth and trading horizon, bid-offer spreads, number and diversity of market participants, extent of derivatives’ market, pricing mechanisms, and different assessment and indices. According to different criteria, the hub or market is also considered to be liquid when the market zone size - consumption of gas by consumers within the market zone – exceeds 20 bcm, and when the supply of gas sources originates from more than three different countries. Additionally, DNV KEMA (2013) consider a market to be liquid when standard transactions can be executed quickly, large volumes per transaction can be treated without causing a significant change in prices (market depth) and when the market has a large number of buyers and sellers willing to transact at all times (market breadth).

New contracting trends – spot contracts, trading and hub-based gas pricing mechanisms, have definitely increased liquidity of the EU gas markets. Higher number of market participants, constantly growing and maturing hubs, increased trading volumes and derivatives’ trading mean that the EU gas markets are much more liquid compared to previous years and especially in comparison with the situation a decade or two ago.

Nevertheless, it is not possible to predict that the liquidity in the EU gas markets will simply continue to increase. With the continuous development of trading, the regulatory context for energy trading in the EU is becoming increasingly important as well. In this respect, European Market Infrastructure Regulation (EMIR) may have an important effect on liquidity in the EU gas markets. EMIR is a response to G20 meeting in 2009 where it was agreed that:

»All standardized OTC derivative contracts should be traded on exchanges or electronic trading platforms, where appropriate, and cleared through central counterparties by end-2012 at the latest. OTC derivative contracts should be reported to trade repositories. Non-centrally cleared contracts should be subject to higher capital requirements«.

Following this, EMIR came into force on 16 August 2012, although many substantive provisions and obligations did not take effect until 2013 or 2014. In essence, EMIR is being implemented for regulation of bilateral OTC derivatives in order to strengthen investor protection throughout the EU, improve transparency and efficiency of financial markets and to provide a framework for regulating penalty provision execution. There are three main components of EMIR, which have direct impact on gas markets and trading:
• Mandatory clearing of specified OTC derivatives contracts (clearing to be provided by central clearing counterparties, while mandatory clearing applies to financial and non-financial counterparties above the clearing threshold),
• Risk mitigation techniques (rules, regulations and techniques to reduce counterparty risk), and
• Reporting obligation.

Reporting obligation requires all OTC and exchange-traded derivatives’ contracts to be reported to a neutral central trading repository, which is a database to provide transparency. Details to be reported include parties and beneficiaries to the contract, type of contract, maturity, notional value, price, settlement date, etc. Whilst the ultimate impact of EMIR is still far from certain, mandatory clearing of physical gas contracts could lead to significant changes in the market. EMIR implementation requires significant effort and resources across the business, which coupled with strict regulation, may result in fewer players in commodity markets, as certain types of market participants may opt to drop out and get involved in different types of transactions. In addition, there is a possibility that standardized products trading will move to the exchanges or even back to bilateral or discretionary contracting. All the above mentioned effects of EMIR may have a negative effect on liquidity in the EU gas markets, which is actually contradictory to the Third Energy Package. Nevertheless, it remains to be seen whether the above mentioned effects will indeed be confirmed or neglected and whether consequently the trading will migrate to the lesser regulated markets.

In general, however, liquidity enhances competition. With the continuous development of competitive gas markets in the EU, the trend toward shorter-term contracts has had a positive effect on liquidity of gas markets and subsequently on competition. In turn, the trend toward shorter-term contracts and development of gas trading and competitive markets has enabled new market participants to enter the market and increased the volume of gas available for trading.

3.4 Impacts on Security of Supply

Security of supply may be defined as the ability of an energy system (national or regional) to meet demand in events of supply disruption, as well as to cope with normal fluctuations in demand patterns, and is as such wider notion than the need to achieve a diversified supply portfolio (Giamouridis & Paleoyannis, 2011).

Security of supply thus implies securing the supply routes as well as the quantities of natural gas to satisfy the needs and demand for gas in the EU. As the indigenous production of gas is low and the EU is thus dependent on imports to cover the demand for gas, security of supply has long been an important issue of the internal energy market in the EU. With the latest developments in the Russian-Ukrainian conflict and its implication on the EU gas imports from Russia, the issue of security of supply has only become more pronounced. This has led the European Commission to
prepare a new Energy Security Strategy in 2014 and put security of supply at the center of the EU's Energy Union.

In the Energy Union Package (2015), the European Commission outlines the most important steps towards securing future gas supplies in the EU. These include:

- Completion of the Internal Energy Market;
- More efficient consumption;
- More transparency, solidarity and trust between Member States;
- Diversification of supply;
- Stronger role of EU in global energy markets; and
- More transparency on gas supply in general.

The biggest fear of the EU is that Russia, one of the major sources of gas for the EU, would cut off or drastically reduce the gas supplies to its Member States. Thus, reducing the dependence on imports from Russia and diversifying the sources of gas in general is one of the priorities of the EU Member States in relation to the completion of the Internal Energy Market. As per DNV KEMA (2013), the most straightforward way to reduce import dependence is to reduce the use of gas and provide room for alternative fuels. On the other hand, diversification may be achieved through diversifying the sources of gas, suppliers of gas and the routes through which the gas is supplied or transported to Europe.

This chapter, however, strives to analyze the impacts of the new contracting trends on the security of supply. As stated in the previous chapters, the LTCs proved to secure the gas from external sources and enhance the security of supply for many years. In general, the LTCs continue to be viewed as if they are the cornerstone of the security of supply of gas in the EU. Consequently, the trend toward shorter term contracts and trading is viewed as decreasing and weakening the security of supply.

Nevertheless, there also exists a view that enhanced competition, shorter term contracts and gas trading actually helps achieve better security of supply. In this respect, two contradictory views exist in the academic and industry sphere. Numerous authors (Wybrew-Bond, Czernie, etc.) argue that new contracting trends in the aftermath of the liberalization threaten the LTCs and their underlying ToP obligations and consequently the supply security in Europe. They believe that the increased price and demand volatility shall put new contracts at risk and undermine the security of supply. The opposite view is that new contracting trends are conducive to security of supply and are indeed enhancing the security of supply. This view is also taken by the European Commission, which claims that a more competitive structure in the European gas market will not undermine supply security of the EU, because ample availability of pipeline gas and the emergence of new LNG markets will lead to a more diversified, rather than a more constrained, supply structure.
It is likely that truth lies somewhere in between. In fully functional and mature liquid markets, gas trading on hubs and exchanges should be able to provide all market participants with the desired volumes and flexibility of gas. Theoretically, competition in a perfect market would increase security of supply. Such a market would also perfectly reflect any supply reductions in the price of gas. As the price would rise, demand for gas would therefore decrease and the use of gas would be substituted by another fuel or type of energy. The problem of course lies in the fact that European gas markets are far from being completely mature and liquid enough to provide for such security of supply and immediate signals in case of drastic supply reductions. This is supported by DNV KEMA (2013), who argue that in order for markets to provide sufficient security of supply, the existence of developed hubs is necessary. In the EU, several traded gas markets and new suppliers are not yet developed properly and cannot provide sufficient security of supply. In the meanwhile, LTCs may therefore still be needed.

Another important aspect of the security of supply is the political or governmental interference. Political interference and lobbying has an important effect and contributes greatly to the security of gas supply. In the previous decades, where large national incumbents relied heavily on LTCs, the role of governments was truly significant. With the trend towards shorter term contracts and gas trading, this influence is diminishing and this cannot be qualified as enhancing or endangering the security of supply.

3.5 Impacts on Volatility

Due to development of spot, forward and derivatives trading as well the continuous push for hub-indexed pricing mechanism and other notable market developments, price relationships between energy products, relationships between market participants and how risk is distributed among them, have all changed.

One of the biggest concerns regarding hub-based prices is the substantial increase in volatility that the hub-based pricing mechanism leads to. In contrast to the LTCs which aimed at price stability and tried to minimize the volatility in prices, the argument for hub-based gas prices’ volatility is that it simply reflects the demand and supply in a given market. As demand and supply of natural gas vary hourly, daily, and most of all seasonally, it is logical that the price that reflects the changes in the demand and supply, varies quite rapidly and is as such much more volatile than the oil-linked price that was in general reset every couple of months based on the average of oil prices in the previous months. However, the increased volatility does not or at least should not represent a major concern, as market participants have a tool to minimize the impact of increased volatility – hedging as a trading strategy. Hedging strategies offer the buyers, as well as the sellers of gas, a way of managing price volatility and smoothening the price differences of the traded gas. In addition, with the development of hubs and trading, gas markets now more resemble the financial markets where similar derivatives and techniques are utilized to manage volatility and optimize portfolios in general. Therefore, swaps, options and other derivatives in addition to other strategies are normal part of every gas trading business.
3.6 Impacts on the Future of LTCs

As natural gas importers are taking a share of producer’s risk by ToP or other commitments in the LTCs to buy large amounts of gas over a long period of time, importing countries and companies may receive some kind of risk compensation in the future for entering into LTCs with natural gas producers. Since the traded markets already offer sufficient supplies of gas, LTCs are becoming less and less important for security of supply. The question arises why importers would have any incentive to enter into a LTC, even if it is indexed to market prices, if they can simply buy the necessary volumes of gas on the traded markets. It would make sense for the producer to sell the gas directly at the hubs or adversely, the importer should get some kind of risk compensation. This would consequently have an effect on the price of the LTCs – if a risk compensation will actually be introduced, it would most probably result in the decrease of the LTC’s price level below the price levels of traded gas on the European hubs. This would mean a major shift in the LTC pricing mechanisms and it remains to be seen whether such compensation and significant pricing changes will indeed come to fruition. As natural gas importers are taking a share of producer’s risk by ToP or other commitments in the LTCs to buy large amounts of gas over a long period of time, importing countries and companies may receive some kind of risk compensation in the future for entering into LTCs with natural gas producers. Since the traded markets already offer sufficient supplies of gas, LTCs are becoming less and less important for security of supply. The question arises why importers would have any incentive to enter into a LTC, even if it is indexed to market prices, if they can simply buy the necessary volumes of gas on the traded markets. It would make sense for the producer to sell the gas directly at the hubs or adversely, the importer should get some kind of risk compensation. This would consequently have an effect on the price of the LTCs – if a risk compensation will actually be introduced, it would most probably result in the decrease of the LTC’s price level below the price levels of traded gas on the European hubs. This would mean a major shift in the LTC pricing mechanisms and it remains to be seen whether such compensation and significant pricing changes will indeed come to fruition.

Even without such compensation, arbitrage opportunities occur between the price of oil-indexed LTCs and the price of traded spot gas. When the price of oil-indexed gas is higher than the hub-based price of gas, the buyers will opt to pay only the minimum ToP quantity in the LTCs and satisfy the remaining need for gas through supplies based on hub-pricing. Arbitrage opportunities arise also in the reverse case, when the price of oil-indexed LTCs is lower than the hub-based spot price. In this case, the traders will buy less spot gas, whilst the demand for oil-indexed gas will be increased.

The use of gas in liquid markets remains subject to short term and longer term competition with substitute fuels, which form price ceilings (like gas oil) and can form a market clearing bottom price where there is enough demand for the substitute fuel. The movement of gas prices continues
to follow the tendency of oil product prices, despite the fact that formal pegging of gas import prices to oil prices has been abolished (Energy Charter, 2007).

While the future is never certain, gas markets in the foreseeable future will most probably continue to accustom both traditional and new contracting designs and pricing mechanisms. Whereas in the long run, neither traditional oil-linked LTCs nor short term hub-indexed contracts will prevail, contract durations will most probably become shorter and consequently short term contracts and spot trading will become increasingly dominant. In this respect, pricing mechanisms play an important role as if pricing would become more short term oriented, overall contract duration would lose significance. Oil-indexed LTCs, however, will not simply disappear. On the contrary, bilateral LTCs will remain by far the most important contract design for gas imports from outside the EU. Major producers like Gazprom, Sonatarch, Statoil and others will continue to rely on contracts with durations of at least 10 years or more, depending on each producer. The LTCs will continue to be based on ToP provisions and at least partially linked to oil prices. With less leverage to assert their influence, these producers will probably revert to stricter policies regarding the price reviews and arbitrages.

The bilateral trades further down the gas value chain, between importers, wholesalers and suppliers, will probably be based on shorter contract durations and will combine the two pricing mechanism to form a hybrid pricing mechanism, which will in part be based on oil indexation and in part on hub indexation or gas-to-gas competition.

Trading will nonetheless continue to increase its share, especially further down the gas value chain. While on the wholesale level, market participants will be trying to resell the long term contracted volumes on the spot and forward markets, only moderate volumes of gas will be made available for trading from major producers.

**CONCLUSION**

On the global level, the importance of EU gas markets is relatively low and will probably further diminish in the future. With practically no indigenous production of natural gas and not really bright prospect for unconventional gas production in the foreseeable future, the EU will continue to depend on imports of natural gas to match its demand. In this respect, the issues will evolve around security of supply and diversification of supply sources.

Diversification of gas supply does not only imply gas being imported from various sources and routes but also different contract characteristics and means through which the gas is bought. After the liberalization of the gas markets in the EU and subsequent development of gas trading, hubs and exchanges, the pricing mechanisms, length of contracts and volume flexibility have been altered significantly. On one hand, there are still numerous LTCs in force, in which the price is indexed to oil and which are further characterized by the take-or-pay obligations and long term contract durations. The so-called LTCs are mainly utilized by the major exporters from Russia,
Norway, Algeria and majority of LNG suppliers. On the other hand, the share of hub-based or gas-indexed prices, in which the main price driver is not the price of oil, but the market value of gas, in spot and forward traded markets has increased significantly in the last decade. With notable success of NBP in the UK, numerous hubs developed in the Continental Europe after the liberalization of gas markets as well. Traded volumes on hubs have been increasing steadily over the years and although the process of gas markets integration has been somewhat slower than expected, the existing hubs and their adjacent market zones are relatively well functioning and efficient. While a general trend toward more flexible and more short term contracts may be observed, especially in the larger markets of Western Europe, the trend is not as evident in the Eastern Member States of the EU, where LTCs are still the predominant form of gas contracting and development of competitive markets and gas trading is lagging behind the western markets.

The current situation on the EU gas markets is therefore a mixture of the traditional and new market designs as well as pricing mechanisms. In such a hybrid system, the two systems are competing against each other and while each design has its own advantages and setbacks, the regulation in the EU is clearly favoring the predominance of competitive market design with gas hubs, exchanges and trading gradually displacing the existing LTCs. LTCs are often viewed as sub-optimal or even harming, but in reality there is nothing fundamentally ‘wrong’ with the LTCs, except the fact that the pricing structure could indeed be deemed as outdated.

As LTCs provide great security of supply as well as great security of demand, this benefits both the buyers and sellers. As such, they are the preferred choice of sellers, namely Russia. They also used to be the preferred choice of large incumbents. However, regulatory provisions coupled with changed behavior and perception of market participants resulted in the transformed behavior of large oligopolistic exporters, which are coming to terms with the new market situation and are now slowly becoming more willing to gradually convert the oil-indexed LTCs to hub indexation. In the last couple of years, many of the existing LTCs have been renegotiated in light of the altered market situation, while many new LTCs have also been concluded in this time, albeit for shorter durations, with different pricing mechanism and other terms as was the case with the traditional LTCs.
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UVOD


Namen magistrske naloge je predstaviti načine, kako so države članice Evropske Unije (EU) velikanske količine plina uvažale oziroma še uvažajo iz omenjenih in drugih držav, predvsem z vidika pogodb o nakupu in dobavi zemeljskega plina. Zgodovinsko gledano viri zemeljskega plina namreč niso bili zelo diverzificirani in posledično so bile države močno odvisne od plina, ki so ga proizvajale posamezne države bogate z zemeljskim plinom. Zaradi navedenega in zaradi slabe infrastrukture ter popolnoma nekonkurenčnega in monopoliziranega trga z zemeljskim plinom, je bila glavna skrb nacionalnih plinskih družb in posameznih držav članic zanesljiva oskrba z zemeljskim plinom ter stabilnost cen plina.

Posledica opisane situacije so bile tako imenovane dolgoročne pogodbe za oskrbo z zemeljskim plinom (LTC), ki so mnoga leta oziroma desetletja predstavljale glavni in edini način uvoza plina v EU. Poleg zanesljive oskrbe in stabilnih cen, so dolgoročne pogodbe namreč omogočale tudi financiranje novega plinskega omrežja in s tem povezane infrastrukture.

Pomemben mejnik v pogodbenih trendih nakupa in dobave zemeljskega plina v EU na sploh je predstavljala liberalizacija trga z zemeljskim plinom v EU v poznih 1990ih in zgodnjih 2000ih. Ločitev dejavnosti, odprtje trgov in posledično vstop novih akterjev na trg z zemeljskim plinom, je povečalo konkurenčnost trgov, kar je vodilo v nastanek prvih plinskih vozlišč in energetskih borz, na katerih so začeli trgovati z zemeljskim plinom. Trgovanje z zemeljskim plinom pa je predstavljalo nove, alternativne možnosti nakupa in oskrbe z zemeljskim plinom. V letih po liberalizaciji trga je bilo močno zaznati nove pogodbene trende pri trgovanju z zemeljskim plinom, in sicer predvsem krajšanje ročnosti dolgoročnih pogodb ter večjo fleksibilnost teh pogodb.

1 PREGLED TRGA Z ZEMELJSKIM PLINOM V EU

Trg z zemeljskim plinom v EU je zelo pomemben regionalni trg tudi v svetovnem merilu, čeprav po količini zalog zemeljskega plina in njegovi proizvodnji sodi med najmanjše na svetu. Količina
zalog ter proizvodnja zemeljskega plina in njuno razmerje (R/P) so pomembne determinante strateških prednosti, ki jih velike zaloge plina prestavljajo za države bogate s plinom. Zaloge zemeljskega plina so v EU kot regiji dejansko najmanjše na svetu, in so ocenjene na zgolj 1,75 bilijone kubičnih metrov (tcm), kar predstavlja manj kot 1% vseh ocenjenih zalog zemeljskega plina na svetu. Podobno tudi proizvodnja zemeljskega plina v EU ni primerljiva z ostalimi, s plinom bogatimi regijami na svetu. Le-ta je namreč v letu 2012 znašala manj od 5% svetovne proizvodnje, kar je v primerjavi s Severno Ameriko (26,65%) in državami bivše Sovjetske Zveze (22,82%) skoraj zanemarljivo.


1.1 Cene zemeljskega plina in njihovo oblikovanje

Zemeljski plin je relativno težko prevažati, zato cena transporta plina močno narašča z razdaljo, ki jo prepotuje. Cene zemeljskega plina posledično niso oblikovane globalno, temveč se po večini oblikujejo regionalno. Različne cene plina v različnih geografskih regijah pa pomembno vplivajo na to, kam največji proizvajalci in izvozniki zemeljskega plina izvažajo plin. Kot najpomembnejši dejavnik zakaj se cene plina oblikujejo regionalno in ne globalno, lahko navedemo dejstvo, da so transportni stroški plina izjemno visoki v primerjavi s ceno samega blaga (European Commission, 2007) ter dejstvo, da je tudi plinifikacija utekočinjenega zemeljskega plina in njegovo skladiščenje zelo drago v primerjavi s samo ceno blaga.

Način, kako se oblikujejo cene zemeljskega plina sicer lahko razdelimo v dve najpomembnejši skupini. Cene plina so lahko neposredno vezane na ceno nafte in/ali naftnih derivatov, ali pa se cene plina oblikujejo tržno, torej na podlagi ponudbe in povpraševanja. Vezava cene plina na ceno nafte in/ali naftnih derivatov je prisotna v večini držav članic EU in v Aziji, predvsem Koreji in Japonski. Tržno oblikovanje cen plina pa je prisotno na razvitejših in liberaliziranih plinskih trgih, predvsem v ZDA, Veliki Britaniji in Avstraliji.

Ker so dolgoročne pogodbe, v katerih je cena plina praviloma vezana na ceno nafte, sklenjene bilateralno, je njihova vsebina zaupne narave in je posledično težko oceniti ali je cena plina v teh pogodbah dejansko vezana na ceno nafte ali se oblikuje tržno. Kljub temu, IGU (2014) ocenjuje, da je po letu 2013, tržno oblikovanje cen zemeljskega plina prvič v zgodovini preseglo vezane cene plina in tako predstavlja osnovo za več kot polovico (53%) vseh cen plina, ki se oblikujejo v EU.
V splošnem so cene plina na podlagi dolgoročnih pogodb, ki so praviloma vezane na ceno nafte, višje kot tiste, ki so oblikujejo tržno. Razlika v cenah primarno izhaja iz samega mehanizma oblikovanja cen. Cene vezane na ceno nafte oziroma naftnih derivatov so mnogo manj volatilne, saj se zaradi dejstva, da je cena plina vezana na ceno nafte in iz tega izhajajočega časovnega zamika, tako oblikovane cene zemeljskega plina ne spreminjajo na dnevni ravni in ne sledijo trenutnim razmeram na trgu. Posledično so tako oblikovane cene mnogo bolj stabilne, kot tržno oblikovane cene, ki odražajo kratkoročne razmere in spremembe na trgu.

2 TRADICIONALNI POGOBDENI TRENDI PRI TRGOVANJU Z ZEMELJSKIM PLINOM

Glede na zgoraj opisano situacijo in dejstvo, da EU uvozi tolikšen del lastnih potreb po zemeljskem plinu, je način kako je zemeljski plin prepeljan oziroma uvožen v EU, izjemnega pomena. To nas pripelje do že omenjenih dolgoročnih pogodb z zemeljskim plinom, ki predstavljajo tradicionalno obliko pogodb za nakup in dobavo zemeljskega plina. Magistrski nalogi so obravnavane zgoraj pogodbe o nakupi in dobavi samega blaga, to je zemeljskega plina, in ne na pogodbe za zakup kapacitet za uporabo prenosnega omrežja zemeljskega plina.

Dolgoročne pogodbe so nastale v 1960ih letih na Nizozemskem. Natančneje, se je koncept dolgoročnih pogodb, ki stremijo k maksimizaciji dobička proizvajalca, razvil na nahajališcu plina v Groningenu. Osnovni namen teh pogodb je bil zagotoviti dovolj sredstev za razvoj plinske infrastrukture, in sicer na način, da se vse stroške transporta, ki nastanejo pri dobavi plina kupcu, odvede od doseženih prihodkov iz tega naslova (EU, 2006). S tem so kupci oziroma države uvoznice plina prevlele kolikošinska tveganja, saj so se zavezale k zakupu določenih količin po bolj ali manj določeni ceni za daljša časovna obdobja. Nadalje so dolgoročne pogodbe zagotavljale tudi implicitni ščit pred kakršenkoli cenovno arbitražo. Primarni namen vezave cene plina na ceno nafte in naftnih derivatov pa je bil zagotoviti cenovno stabilnost in ublažiti nihanja cen. Ker so bili v danem trenutku edini pravi substituti zemeljskemu plinu plinsko olje in nafta, so cene plina vezali na cene teh goriv. Dolgoročne pogodbe so količinska in kreditna tveganja tako prenesla na kupce plina, pri čemer so ponudniki plina prevzeli zgolj cenovno tveganje.


2.1 Sestava in elementi dolgoročnih pogodb

Dolgoročne pogodbe so se tradicionalno sklepale na podlagi bilateralnih pogajanj, kljub temu pa so bili sestava in elementi zadevnih dolgoročnih pogodb venomer enaki. Vsebinsko so se spreminjale zgolj posamezne postavke v pogodbi, kot so cena in odstopanja od zakupljene količine, ki so bile odvisne od pogajalske moči posamezne strani (DNV KEMA, 2013).


Letna zakupljena količina (ACQ) je osnovna postavka vseh dolgoročnih pogodb v Evropi, saj pomeni podlago za zgornjo in spodnjo mejo zakupljenih količin plina. ACQ se navadno spreminja opcijsko, periodično, in ob točno dogovorjenih terminih. Skozi čas se letna zakupljena količina plina lahko tudi zmanjšuje ali povečuje. ACQ je tudi osnova za določitev največje količine odkupa plina (MAQ), ki je določena kot odstotek ACQ, in navadno znaša 110 ali 115% ACQ. Dolgoročne pogodbe pozna tudi največjo dnevno količino odjema plina (MDQ), ki kupcu oziroma uporabniku plina omogoča dnevno uravnavanje porabe plina. Po drugi strani pa je najmanjša količina odjema plina v dolgoročnih pogodbah določena v obliki tako imenovane klavzule vzemi ali plačaj (*ang. take-or-pay, ToP*), ki določa najmanjšo količino plina, ki jo pogodbena stran v danem letu mora odkupiti, saj je v nasprotnem primeru za zadevno količino plina dolžna plačati tudi, če jo dejansko ne porabi.

Vzemi ali plačaj klavzula je tako pravzaprav bistvena sestavina vsake dolgoročne pogodbe, saj kupca prisili v plačilo količine, kot jo določa ToP in posledično ponudniku zagotavlja vir plačila, ne glede na dejansko porabo plina. Glede na navedeno vzemi ali plačaj klavzula predstavlja nekakšno pogodbeno kazen za neizpolnjevanje pogodbenih obveznosti kupca.

Vsaka dolgoročna pogodba vsebuje še vsaj dve klavzuli, in sicer klavzulo o kraju namembnosti (*ang. destination clause*) ter prožnostno klavzulo (*ang. flexibility clause*). Prva preprečuje cenovno arbitražo med trgi zemeljskega plina z višjimi in nižjimi cenami plina, in tako omogoča dobaviteljem plina vzdrževati cenovne razlike med posameznimi državami ali regijami, druga pa
kupcem omogoča odjem dodatnih količin plina (nad MAQ) po praktično enakih pogodbenih cenah. S tem se kupcem omogoči tako željena fleksibilnost količin, čeprav gre še vedno za precej omejeno prožnost, znotraj določenih okvirov.

Če povzamemo, so prednosti dolgoročnih pogodb omogočile, da so le-te prevladovale pri nakupu in dobavi zemeljskega plina skozi več desetletji. Prednosti dolgoročnih pogodb lahko opredelimo kot varnost in zanesljivost oskrbe z zemeljskim plinom, spodbujanje in financiranje investicij in plinske infrastrukture, cenovna stabilnost, odpornost na šoke, nizki transakcijski stroški in relativna preprostost pogodb.

Kljub omenjenim prednostim pa se je izkazalo, da sistem dolgoročnih pogodb močno ovira konkurenco in ni optimalen v primerjavi z liberaliziranimi trgi z zemeljskim plinom v ZDA in tudi v Veliki Britaniji, kjer se cene plina oblikujejo v skladu s tržnimi načeli. Za največje slabosti dolgoročnih pogodb so se tako izkazale velika razlika med cenami plina in nafte ter naftnih derivatov, na katere so bile le-te vezane, velika odvisnost kupcev od posameznih dobaviteljev plina, neprožne formule za oblikovanje cen in zaviranje ter omejevanje konkurence.

3 NOVI POGODBENI TRENDI PRI TRGOVANJU Z ZEMELJSKIM PLINOM

Liberalizacija energetskih, in s tem plinskih trgov v EU, je dramatično spremenila razmere na trgu z zemeljskim plinom. Po mnenju Heather (2012), sama sprememba zakonodaje sicer ne bi zadostovala za razvoj uspešnega, odprtega trga, kjer se prosto trguje z zemeljskim plinom, temveč je k temu pomembno prispevalo tudi spremenjeno dojemanje trga s strani subjektov na trgu in njihova naklonjenost k trgovanju. Heather (2012) tudi trdi, da so k začetku in razvoju trgovanja z zemeljskim plinom pomemben doprinos imele tudi energetske borze, ki so subjektom na trgu ponujale produkte in platforme, s katerimi in na katerih je enostavno trgovati. Jasno pa je, da so tako imenovana plinska vozlišča odigrala najpomembnejšo vlogo, saj predstavljajo osnovo za trgovanje z zemeljskim plinom.

Z nastankom plinskih vozlišč v različnih državah, so se razvili tudi promptni trgi za trgovanje z zemeljskim plinom. ACER (2011) ugotavlja, da je zrelost, razvitost oziroma likvidnost vozlišč odvisna od števila dobaviteljev in kupcev, ki trgujejo s plinom na posameznem vozlišču, čezmejno povezanost vozišča ter cenovno odzivnostjo skladisčnih zmogljivosti vozlišča. Posledično sta plinska infrastruktura (plinovodi, povezovalne točke, skladišča, uplinjevalniki utekočinjenega zemeljskega plina, itd.) ter diverzifikacija virov zemeljskega plina dva izmed najpomembnejših faktorjev za uspešnost novega modela plinskih trgov s polno delujočimi in likvidnimi plinski vozišči.

3.1 Oblikovanje cen na plinskih vozliščih

Liberalizirani trgi z zemeljskim plinom, razvoj plinskih vozlišč ter promptno trgovanje z zemeljskim plinom so subjektom na trgu ponudili alternativno oblikovanje cen zemeljskega
plina. Vezava cene zemeljskega plina na ceno nafte oziroma naftnih derivatov, ki je značilna za dolgoročne pogodbe, tako ni več samoumevna in je v promptni ceni, ki se v danem trenutku oblikuje na zadevnem plinskem vozlišču ali borzi, dobila konkurenčen način oblikovanja cen zemeljskega plina.

Ta način oblikovanja cen temelji na mehanizmu ponudbe in povpraševanja po zemeljskem plinu in predstavlja osnovo za oblikovanje cen zemeljskega plina na plinskih vozliščih. Cena se oblikuje na podlagi trenutnega, promptnega, povpraševanja po zemeljskem plinu in obstoječe ponudbe zemeljskega plina na posameznem vozlišču in tako ni povezana s ceno nafte ali drugih naftnih derivatov. Tako oblikovana cena zemeljskega plina torej odraža trenutno tržno situacijo in tržne spremembe na trgu z zemeljskim plinom.

Konvergenca oziroma poenotenje cen plina med različnimi vozlišči je pomemben indikator povezovanja oziroma integracije plinskih trgov v EU. V visoko integriranih trgih, visoke cene v enem območju namreč privlačijo prodajalce oziroma ponudnike zemeljskega plina iz območij nižjih cen plina, ki zasledujejo višje prodajne marže in višje dobičke. Prihod novih ponudnikov in s tem povečanje ponudbe zemeljskega plina pa posledično privede do znižanja cen in znižanja cenovnih razlik med območjema. Vendar pa v nepopolno integriranih trgih, mehanizem izenačevanja cen ne deluje popolnoma in zaradi različnih dejavnikov (dolgoročne pogodbe, politika, omejitve zmogljivosti, itd.) višje cene v enem območju ne privlačijo dodatnih količin plina iz območij z nižjimi cenami. ACER (2014) opaža, da sta večja integriranost trgov in manjše razlike v cenah med različnimi državami EU posledica spremenjenih (na novo izpogajanih) pogojev v dolgoročnih pogodbah. Novo izpogajani pogoji dolgoročnih pogodb se nanašajo predvsem na oblikovanje cen plina, in največkrat stremičo k ukinitvi vezave cene plina na cene nafte in naftnih derivatov ter uvedbi oblikovanja cen, ki se oblikuje v skladu s povpraševanjem in ponudbo na posameznem ali več plinskih vozliščih.

Ključno vlogo dolgoročnih pogodb ostaja pomembna za razumevanje cenovnih razlik med posameznimi območji oziroma državami EU. V splošnem so dolgoročne pogodbe mnogo bolj pogoste v Centralno-Vzhodni Evropi ter južneje ležiščih državah EU. Razlog za to je tudi to, da se plinska vozlišča na teh območjih še niso razvila, ali pa se niso razvila do takšne mere, kot v razvitejših državah EU. Te trgi tudi sicer veljajo za manj razvite, predvsem pa so mnogo bolj odvisni od uvoza zemeljskega plina predvsem iz Rusije. Ker so cene plina, dogovorjene v dolgoročnih pogodbah, bodisi vezane ali tržno oblikovane, v povprečju višje od promptno oblikovanih cen na plinskih vozliščih, so cene plina v teh območjih oziroma državah EU v povprečju višje. Posledično med državami EU ostajajo pomembne razlike v cenah zemeljskega plina. Tako je bila denimo v letu 2013 povprečna cena plina na Švedskem kar dvakrat višja od primerljive cene plina v Veliki Britaniji, ki pa je bila na ravni 75% povprečne veleprodajne cene zemeljskega plina v EU (Eurostat Comext, 2014).
4 VPLIVI NOVIH POGODBENIH TRENDOV

4.1 Vplivi novih pogodbenih trendov na obstoječe dolgoročne pogodbe

Trg z zemeljskim plinom v EU je torej razdvojen med tradicionalnimi dolgoročnimi pogodbami, ki bodo v veljavi vsaj še nadaljnjih 20 let, ter novim, konkurenčno usmerjenim zakonodajnim okvirom. Pri tem očitno dolgoročne pogodbe in vezava cen plina lahko sobivajo z novimi, promptnimi pogodbami z na vozliščih tržno oblikovani cenami.

Kljud temu, Deloitte (2013) ugotavlja, da dolgoročne pogodbe, ki jih zaznamujejo vezane cene plina, izgubljajo svoj tržni delež in pomen, saj jih počasi, a vztrajno izpodrivajo ponudniki zemeljskega plina, ki ne prihajajo iz Rusije niti iz Bližnjega Vzhoda. Ob tem pa tudi tako imenovana revolucija zemeljskega plina iz skrilavcev, ki se odvija v ZDA, pomeni, da bo v Evropi na voljo več utekočinjenega zemeljskega plina, ki bo po vsej verjetnosti cenejši od tistega, zakupljenega z dolgoročnimi pogodbami. Zemeljski plin iz Rusije in Bližnjega Vzhoda je namreč trenutno med najdražjimi na svetu.

Liberalizacija trgov z zemeljskim plinom v EU, razvoj vozlišč in trgovanja z zemeljskim plinom, ki je pripomogel k nastanku konkurenčnih in tržno oblikovanih trgov v EU, je vplivala predvsem na trgovanje z zemeljskim plinom na koncu prodajne verige (to je od trgovcev, distributerjev in končnih uporabnikov), na začetku proizvodno/prodajne verige pa zaenkrat še vedno prednjačijo dolgoročne pogodbe in vezava cene zemeljskega plina na cene nafte in naftnih derivatov.

Dolgoročne pogodbe tako še vedno igrajajo pomembno vlogo in jo bodo tudi v prihodnje. DNV KEMA (2013) sicer ugotavlja, da so spremembe pogojev dolgoročnih pogodb, predvsem glede oblikovanja cen, glavni dejavnik za zmanjševanje vloge cenovne vezave, kljub temu pa največji dobavitelji plina iz Rusije in drugih držav izvoznik niso naklonjeni tržnemu oblikovanju cen, saj imajo monopolno moč, da se temu uprejo. To dokazuje tudi podatek, da je, kljub upadu števila dolgoročnih pogodb, njihovo število še vedno precejšnje – po podatkih Cedigaz (2014), je bilo v letu 2014 v Evropi veljavnih 126 dolgoročnih pogodb o dobavi zemeljskega plina, sklenjenih med 11 državami izvozniki plina in kar 27 državami uvozniki plina.

4.2 Vplivi novih pogodbenih trendov na prihodnost dolgoročnih pogodb

V skladu z zgornjimi ugotovitvami, bodo dolgoročne pogodbe še kar nekaj časa prisotne na trgi zemeljskega plina v EU. Razen tega, da je opaziti krašanje njihove ročnosti in spreminjanje pogodbenih določil glede oblikovanja cen, pa je njihova prihodnost precej negotova iz določenih ponudnikov in je lahko zgolj predmet ugibanja. Glede na to, da uvozniki plina preko klavzule vzemi-ali-plačaj prevzemajo del ponudnikovih tveganj in so zavezani k odkupu velikih količin plina skozi dolga obdobja, bi se v prihodnosti lahko oblikovalo posebno nadomestilo za zadevne uvoznike, ki sklepajo dolgoročne pogodbe za dobavo zemeljskega plina. Ob dejstvu, da trgovanje z zemeljskim plinom na vozliščih in borzah načeloma zagotavlja zadostne količine plina in so dolgoročne pogodbe manj pomembne za zagotavljanje varne dobave plina, se pojavlja vprašanje, zakaj bi se uvozniki
sploh še odločali za sklepanje dolgoročnih pogodb, ki za njih pomenijo več omejitev kot prednosti. To v prihodnosti lahko pride do uvedbe nekakšnega nadomestila za prevzem tveganj, ki bi se odražal v nižjih cenah plina v dolgoročnih pogodbah. Le-te bi tako verjetno bile celo nižje od tržno oblikovanih cen na vozliščih in borzah, kar pa bi predstavljajo svojevrstno revolucijo pri oblikovanju cen plina v dolgoročnih pogodbah. Vsekakor je to zgolj ena izmed teorij in predvidevanj, kaj bi se lahko zgodilo z dolgoročnimi pogodbami v prihodnosti.

Ne glede na to, da je prihodnost težko napovedovati, pa z veliko verjetnostjo lahko trdimo, da bo trg z zemeljskim plinom v EU tudi v prihodnje deloval tako na podlagi dolgoročnih pogodb, kot tudi trgovanja z zemeljskim plinom na vozliščih in borzah in tržno oblikovanimi cenami zemeljskega plina. Neodvisno od samih tržnih deležev tradicionalnih in novih pogodbenih trendov, bo ročnost dolgoročnih pogodb v prihodnosti, vse bolj se bo uveljavljalo tudi tržno oblikovanje cen plina in trgovanje z zemeljskim plinom na sploh. Vezava cen zemeljskega plina na cene panele in naftnih derivatov pa bo ostala prisotna, vsaj na začetku proizvodno/prodajne verige, kjer bo monopolna moč velikih proizvajalcev oziroma izvoznikov plina omogočala sklepanje novih, sicer krajših, dolgoročnih pogodb.

ZAKLJUČEK

Pomen plinskega trga v EU je na globalni ravni relativno majhen in bo v prihodnosti verjetno še manjši. Praktično brez lastnih virov in ne preveč optimističnih napovedi o možnostih pridobivanja zemeljskega plina iz nekonvencionalnih virov v prihodnje, se bo EU še naprej morala zanašati na uvoz zemeljskega plina. V ospredju bodo tako zlasti vprašanja zanesljive oskrbe in razpršenosti virov dobave plina.

Po liberalizaciji plinskih trgov v EU in nadaljnem razvoju trgovanja z zemeljskim plinom, nastanku plinskih vozlišč in energetskih borz, so se mehanizmi oblikovanja cen, dolžine pogodb in fleksibilnosti dobave bistveno spremenili. Po eni strani so številne dolgoročne pogodbe še vedno v veljavi, kar pomeni, da so cene plina še vedno vezane na cene naftnih kvalitativnih vzemali, ter plačanje dolgo ročnosti samih pogodb. Na dolgoročne pogodbe pristegajo zlasti vseobsevanje zemeljskega plina, kot so Rusija, Norveška, Aļžirija ter prav tako v EU bo večina dobaviteljev utekajoč na globalni trgu zemeljskega plina.

Po drugi strani so se lahko odločili za sklepanje dolgoročnih pogodb v prihodnosti, kjer bi se odražali v nižjih cenah plina v dolgoročnih pogodbah. Le-te bi tako verjetno bile celo nižje od tržno oblikovanih cen na vozliščih in borzah, kar pa bi predstavljalo svojevrstno revolucijo pri oblikovanju cen plina v dolgoročnih pogodbah. Vsekakor je to zgolj ena izmed teorij in predvidevanj, kaj bi se lahko zgodilo z dolgoročnimi pogodbami v prihodnosti.

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Trenutno stanje na trgih z zemeljskim plinom v EU je tako mešanica tradicionalnih dolgoročnih pogodb, katerih glavna značilnost so dolge ročnosti pogodb, vezava cen plina na ceno nafte oziroma naftnih derivatov in klavzula vzemi ali plačaj, in novega načina trgovalja z zemeljskim plinom, ki ga zaznamujejo trgovalje z zemeljskim plinom na plinskih vozliščih ter energetskih borzah. V nekakšnem hibridnem sistemu, tako oba načina trgovalja tekmujeta drug proti drugemu in čeprav ima vsaka oblika svoje prednosti in slabosti, predpisi EU očitno favorizirajo vzpostavitev konkurenčnih trgov, ki bi temeljili na plinskih vozliščih, energetskih borzah in tržni podlagi. S tem pa postopoma izpodrivajo dolgoročne pogodbe, ki jih v zadnjih letih zaradi spremenjenih razmer na trgu, zaznamujejo spremembe pogojev, krajše ročnosti in večja fleksibilnost.
### Appendix B: Proven gas reserves in 2012 ranked by country (tcm)

Table 1. Proven gas reserves in 2012 ranked by country (tcm)

<table>
<thead>
<tr>
<th>Country</th>
<th>Proven Gas Reserves (tcm)</th>
<th>% of World Total</th>
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<tr>
<td>World</td>
<td>187.3</td>
<td>100.0</td>
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<td>Top 20 Countries</td>
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<td>91.3</td>
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<td>17.9</td>
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<td>32.9</td>
<td>17.6</td>
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<td>13.3</td>
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<td>17.5</td>
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<td>4.5</td>
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</tr>
<tr>
<td>17 Canada</td>
<td>2.0</td>
<td>1.1</td>
</tr>
<tr>
<td>18 Kuwait</td>
<td>1.8</td>
<td>1.0</td>
</tr>
<tr>
<td>19 Malaysia</td>
<td>1.3</td>
<td>0.7</td>
</tr>
<tr>
<td>20 Kazakhstan</td>
<td>1.3</td>
<td>0.7</td>
</tr>
</tbody>
</table>

### Appendix C: Natural gas production in 2012 ranked by country (bcm)

Table 2. Natural gas production in 2012 ranked by country ( bcm )

<table>
<thead>
<tr>
<th></th>
<th>World</th>
<th>% of world total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top 20 Countries</td>
<td>2781.1</td>
<td>82.7</td>
</tr>
<tr>
<td>1</td>
<td>USA</td>
<td>681.4</td>
</tr>
<tr>
<td>2</td>
<td>Russia</td>
<td>592.3</td>
</tr>
<tr>
<td>3</td>
<td>Iran</td>
<td>160.5</td>
</tr>
<tr>
<td>4</td>
<td>Qatar</td>
<td>157.0</td>
</tr>
<tr>
<td>5</td>
<td>Canada</td>
<td>156.5</td>
</tr>
<tr>
<td>6</td>
<td>Norway</td>
<td>114.9</td>
</tr>
<tr>
<td>7</td>
<td>China</td>
<td>107.2</td>
</tr>
<tr>
<td>8</td>
<td>Saudi Arabia</td>
<td>102.8</td>
</tr>
<tr>
<td>9</td>
<td>Algeria</td>
<td>81.5</td>
</tr>
<tr>
<td>10</td>
<td>Indonesia</td>
<td>71.1</td>
</tr>
<tr>
<td>11</td>
<td>Malaysia</td>
<td>65.2</td>
</tr>
<tr>
<td>12</td>
<td>Turkmenistan</td>
<td>64.4</td>
</tr>
<tr>
<td>13</td>
<td>Netherlands</td>
<td>63.9</td>
</tr>
<tr>
<td>14</td>
<td>Egypt</td>
<td>60.9</td>
</tr>
<tr>
<td>15</td>
<td>Mexico</td>
<td>58.5</td>
</tr>
<tr>
<td>16</td>
<td>Uzbekistan</td>
<td>56.9</td>
</tr>
<tr>
<td>17</td>
<td>UAE</td>
<td>51.7</td>
</tr>
<tr>
<td>18</td>
<td>Australia</td>
<td>49.0</td>
</tr>
<tr>
<td>19</td>
<td>Nigeria</td>
<td>43.2</td>
</tr>
<tr>
<td>20</td>
<td>Trinidad &amp; Tobago</td>
<td>42.2</td>
</tr>
</tbody>
</table>

Appendix D: Natural gas consumption in 2012 ranked by country (bcm)

Table 3. Natural gas consumption in 2012 ranked by country (bcm)

<table>
<thead>
<tr>
<th></th>
<th>% of world total</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>World</strong></td>
<td><strong>3314.4</strong></td>
</tr>
<tr>
<td><strong>Top 20 Countries</strong></td>
<td><strong>2526.9</strong></td>
</tr>
<tr>
<td>1 USA</td>
<td>722.1</td>
</tr>
<tr>
<td>2 Russia</td>
<td>416.2</td>
</tr>
<tr>
<td>3 Iran</td>
<td>156.1</td>
</tr>
<tr>
<td>4 China</td>
<td>143.8</td>
</tr>
<tr>
<td>5 Japan</td>
<td>116.7</td>
</tr>
<tr>
<td>6 Saudi Arabia</td>
<td>102.8</td>
</tr>
<tr>
<td>7 Canada</td>
<td>100.7</td>
</tr>
<tr>
<td>8 Mexico</td>
<td>83.7</td>
</tr>
<tr>
<td>9 United Kingdom</td>
<td>78.3</td>
</tr>
<tr>
<td>10 Germany</td>
<td>75.2</td>
</tr>
<tr>
<td>11 Italy</td>
<td>68.7</td>
</tr>
<tr>
<td>12 UAE</td>
<td>62.9</td>
</tr>
<tr>
<td>13 India</td>
<td>54.6</td>
</tr>
<tr>
<td>14 Egypt</td>
<td>52.6</td>
</tr>
<tr>
<td>15 Thailand</td>
<td>51.2</td>
</tr>
<tr>
<td>16 South Korea</td>
<td>50.0</td>
</tr>
<tr>
<td>17 Ukraine</td>
<td>49.6</td>
</tr>
<tr>
<td>18 Uzbekistan</td>
<td>47.9</td>
</tr>
<tr>
<td>19 Argentina</td>
<td>47.3</td>
</tr>
<tr>
<td>20 Turkey</td>
<td>46.3</td>
</tr>
</tbody>
</table>

### Appendix E: Characteristics of a gas contract

#### Table 4. Characteristics of a gas contract

<table>
<thead>
<tr>
<th><strong>Underlying</strong></th>
<th>High calorific natural gas (H-gas quality) at 25C (PCS)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Delivery</strong></td>
<td>All contracts are physically settled and delivered on the specified virtual PEG of the gas transport network. Delivery occurs each calendar day of the delivery period. For a given day D of the delivery period, the delivery goes from 06:00 a.m. of day D to 06:00 a.m. of day D+1</td>
</tr>
<tr>
<td><strong>Contract volume units</strong></td>
<td>MWh/day for Spot and Futures contracts</td>
</tr>
<tr>
<td><strong>Contract volume</strong></td>
<td>1 MWh/day</td>
</tr>
<tr>
<td><strong>Minimum lot size</strong></td>
<td>240 contracts (i.e. Minimum Volume = 240 MWh/day)</td>
</tr>
<tr>
<td><strong>Volume increment</strong></td>
<td>10 contracts (i.e. Volume Tick = 10 MWh/day)</td>
</tr>
<tr>
<td><strong>Price unit</strong></td>
<td>€/MWh, 3 decimal digits</td>
</tr>
<tr>
<td><strong>Price tick</strong></td>
<td>0,025 €/MWh</td>
</tr>
<tr>
<td><strong>Negative prices</strong></td>
<td>The use of negative prices is not allowed</td>
</tr>
<tr>
<td><strong>Total contract volume</strong></td>
<td>= Number of contracts x Contract volume (1 MWh/day) x Number of delivery days x</td>
</tr>
<tr>
<td><strong>Maturities</strong></td>
<td>WD: Within-Day</td>
</tr>
<tr>
<td></td>
<td>DA: Day-Ahead</td>
</tr>
<tr>
<td></td>
<td>WE: Week-End</td>
</tr>
<tr>
<td>** Tradable products**</td>
<td>• A WD Product is tradable each trading day for delivery on the same day;</td>
</tr>
<tr>
<td></td>
<td>• A DA Product is tradable each trading day for delivery on the following trading day, or, alternatively, on the day communicated in a Market Notice;</td>
</tr>
<tr>
<td></td>
<td>• A DA Product is tradable each trading day for delivery on the following trading day, or, alternatively, on the day communicated in a Market Notice</td>
</tr>
<tr>
<td><strong>Transformation for clearing purposes</strong></td>
<td>Immediately after the conclusion of the trade, each WE contract is split into the corresponding daily contracts so the covered delivery period remains the same</td>
</tr>
<tr>
<td>** Tradable spreads between products**</td>
<td>Powernext offers a Spread between the PEG Sud / PEG Nord Products. Trading on this Spread results by the buying (respectively the selling) of the first PEG Sud Product and the selling (respectively the buying) on the second PEG Nord Product.</td>
</tr>
<tr>
<td><strong>Trading hours</strong></td>
<td>From 09:00 to 18:00 CET</td>
</tr>
<tr>
<td><strong>Order book opening hours</strong></td>
<td>From 07:00 to 18:00 CET</td>
</tr>
</tbody>
</table>

Appendix F: State-imposed hub pricing obligations

Table 5. State-imposed hub pricing obligations

<table>
<thead>
<tr>
<th>Country</th>
<th>Effective from</th>
<th>Obligation to sell gas at hubs</th>
<th>Obligatory introduction of spot component in regulated price</th>
<th>Way of gas index linkage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poland</td>
<td>11.9.2013</td>
<td>Suppliers to initially sell 30% of the previous year’s volume through the exchange</td>
<td></td>
<td>PCNIG has to consider OTC and GASPOOL prices when putting the offers</td>
</tr>
<tr>
<td></td>
<td>1.1.2014</td>
<td>Suppliers to initially sell 55% of the previous year’s volume through the exchange</td>
<td></td>
<td>PGNIG has to consider OTC and GASPOOL prices when putting offers</td>
</tr>
<tr>
<td>Hungary</td>
<td>1.10.2011</td>
<td>Obligation to sell gas on regulated market at 70% hub-indexed prices</td>
<td></td>
<td>TTF</td>
</tr>
<tr>
<td></td>
<td>1.10.2013</td>
<td>Obligation to sell gas on regulated market at 100% hub-indexed prices</td>
<td></td>
<td>TTF</td>
</tr>
<tr>
<td>Italy</td>
<td>1.4.2013</td>
<td>Regulated gas prices to be 20% linked to spot</td>
<td></td>
<td>TTF</td>
</tr>
<tr>
<td></td>
<td>1.10.2013</td>
<td>Regulated prices to be 100% linked to spot</td>
<td></td>
<td>TTF</td>
</tr>
<tr>
<td>Belgium</td>
<td>1.1.2014</td>
<td>Oil-indexation of final gas prices must be capped at 35%</td>
<td></td>
<td>Zeebrugge</td>
</tr>
<tr>
<td></td>
<td>1.1.2015</td>
<td>Oil-indexation of final gas prices is phased out</td>
<td></td>
<td>Zeebrugge</td>
</tr>
<tr>
<td>France</td>
<td>1.1.2013</td>
<td>Government formula applied to GdF SUEZ prices is 36% spot-linked</td>
<td></td>
<td>TTF</td>
</tr>
</tbody>
</table>

### Appendix G: Price formation classification by IGU

Table 6. Price formation classification by IGU

<table>
<thead>
<tr>
<th><strong>Oil Price Escalation (OPE)</strong></th>
<th>The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases coal prices can be used as can electricity prices.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Gas-on-Gas Competition (GOG)</strong></td>
<td>The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical or notional hubs. There are likely to be developed futures markets. Not all gas is bought and sold on a short term fixed price basis and there will be longer term contracts but these will use gas price indeces to determine the monthly price, for example, rather than competing fuel indeces. Spot LNG is also included in this category, and also bilateral agreements in markets where there are multiple buyers and sellers.</td>
</tr>
<tr>
<td><strong>Bilateral Monopoly (BIM)</strong></td>
<td>The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time, typically longer than one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.</td>
</tr>
<tr>
<td><strong>Netback from Final Product (NET)</strong></td>
<td>The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.</td>
</tr>
<tr>
<td><strong>Regulation (RCS, RSP, RBC)</strong></td>
<td>The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the <code>cost of service</code>, including the recovery of investment and a reasonable rate of return (Cost of Service, RCS). The price is set, on an irregular basis, probably by a Ministry, on apolitical/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise (Social and Political, RSP). The price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to the population (Below Cost, RBC).</td>
</tr>
<tr>
<td><strong>No Price (NP)</strong></td>
<td>The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced may be associated with oil and/or liquids and treated as a by-product.</td>
</tr>
</tbody>
</table>