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RISK MANAGEMENT IN THE NATURAL GAS TRADING

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LIST OF ABBREVIATIONS

de. – German

ACER; Agency for the Cooperation of Energy Regulators

BCM; Billion cubic meters

BGR; (de. Bundesanstalt für Geowissenschaften und Rohstoffe; Federal Institute for Geosciences and Natural Resources

BP; British Petroleum

CEER; Council of European Energy Regulators

CEGH; Central European Gas Hub

EIA; Energy Information Administration

EU; European Union

IEA; International Energy Agency

IENE; Institute of Energy for South-East Europe

IGU; International Gas Union

LNG; Liquefied natural gas

LTCs; Long-term contracts

MTM; Mark to Market

MWH; Megawatt Hours

NBP; National Balancing Point

NCG; NetConnect Germany

OECD; Organisation for Economic Co-operation and Development

OIES; Oxford Institute for Energy Studies

PEG; Powernext Gas Spot

S&P; Standard & Poor's

TCM; Trillion cubic meters

TOP; Take or Pay obligation

TSO; Transmission system operator

TTF; Title Transfer Facility

TWH; Terawatt Hours

VAR; Value at Risk

INTRODUCTION

Rex Tillerson, an American government official and the former chairman and CEO of ExxonMobil, the world's largest publicly traded international Oil and Gas Company stated: *"Natural gas is really well-suited to meet that growing power generation demand, both from the standpoint of its lower environmental impact, but also its capital efficiency and flexibility"* (Inkpen & Moffett, 2011, p. 302).

Natural gas is known and considered to be the most environmental fuel among all fossil fuels, as it has the lowest CO_2 emission per unit of energy and is therefore used in a variety of power applications. It is dominated by three sectors: the residential and commercial consumers, the consumers using natural gas for heating, lightning, cooking and the power generation sector, which uses natural gas to produce electricity (Melling, 2010). According to the World Energy Council (2016), natural gas is the second largest energy source in generating power, representing 22% of the world's generated power and is the only fossil fuel whose consumption is expected to grow and the only one that has the prospective to play a major role in the world's future evolution to a cleaner, more affordable and secure energy. Gilardoni (2008) believes that natural gas is projected to grow because of the economic factor, which is related to the more efficient and cheaper electricity production, and the environmental factor, as natural gas has a lower CO2 emission than other fossil fuels. Furthermore, in December 2015, the Paris Agreement was signed, with a global action to limit global warming to well below 2C, which implicates the reduction of global emissions and is therefore, besides the alternative source of power generation, moving the weight in favour of using natural gas for electricity production (European Commission, 2017a).

Although natural gas usage is on the rise, Europe is not very rich in natural gas reserves. According to the British Petroleum Statistical review of World Energy (2015), Europe only had 1.6% of the world's natural gas reserves in 2015 (3.1 trillion cubic meters), while their production in the same year reached 232 billion cubic meters. Thus, if Europe continues to follow the same production/reserves path, it will have used all of the natural gas reserves in 13 years. On the other hand, Europe's consumption of natural gas reached 444 billion cubic meters in 2015, which indicates that Europe is heavily dependent on imports used to satisfy their demands, as their own production of natural gas is not enough. According to Melling (2010), Europe's imports of natural gas were not diversified, as they were dependent on the major gas producing countries such as Russia and Algeria from abroad, and the Netherlands and Norway from within Europe. Due to the imports' inflexibility and no competition in the natural gas market, they were exposed to certain risks, as the large gas producers held the leverage because of the monopolist position in the negotiation process of buying natural gas, as they could guarantee stable prices and the security of the supply. According to Zajdler (2012), the situation and the historical development in the natural gas market consequently led to the emergence of long-term contracts, containing a natural gas prices index to the prices of crude oil and oil derivatives, which have been the backbone of European natural gas imports for decades and are still present today. Long-term contracts were proved to be reliable contracts for buying natural gas, as they provided security and stability of the natural gas supply due to the indexing prices of natural gas to oil. Furthermore, they were also a vital factor for investments in the natural gas infrastructure across Europe.

However, the liberalization of the natural gas market in Europe in the late 1990s, has had a profound impact on the development of how natural gas is bought and sold across Europe, due to the open market and the emergence of new participants on the market, which provided competition and competitive prices on the natural gas market. According to Zajdler (2012), this was the start of the British model, based on the medium-term supply contracts of natural gas at a price indexed to gas competition, which brought with it the development of natural gas hubs, natural gas trading and exchanges in Europe. The development of the European hubs allowed gas producers, suppliers, and traders to work with each other, to trade for either physical delivery or financial profit and enabled the natural gas prices to reflect the market value of gas, which ultimately resulted in the evolvement from a physical imbalance market to a price risk management market (Long & Moore, 2003).

The risk management's task is to ensure that a company has the necessary funds to make value-enhancing investments. The volatility of the natural gas prices in the last few years (financial crisis, Ukraine crisis etc.) has resulted in natural gas market participants putting increased emphasis on risk management activities. Price volatility of natural gas and the deregulated gas market have presented new challenges and opportunities for natural gas traders, as they can now buy natural gas on a yearly, monthly, daily and even hourly basis with either fixed or floating prices, instead of entering into long-term contractual agreements with fixed pricing, which will minimize the cost and reduce price uncertainty. Natural gas companies choose from different methods of managing risks, either through their investment decisions or financing choices. The use of financial contracts as derivatives, both traded in exchanges and over-the-counter, developed a low-cost method of hedging price risk. There is a wide range of derivative contracts on the natural gas market, including options, forwards, futures, swaps and weather derivatives, which can achieve a wide variety of goals when combined. However, a cost benefit analysis should be performed, so that hedging is applied only when the costs do not overcome benefits. In addition to derivatives, the value-at-risk became the most used control tool for measuring the exposure to short-term financial risks for companies in the natural gas industry during the last decade (Institute and Faculty of Actuaries, 2016). Gas companies are using value at risk to assess the credit and the market risk of their portfolio and their individual positions for the purpose of financial risk management, which allows them to optimize their portfolio and adjust their positions in regard to a risk threshold (Asche, Dahl, & Oglend, 2013).

The purpose of this master thesis is to examine different risk management solutions that companies use on a daily basis to mitigate the risk in natural gas trading. The thesis explores why companies are more inclined to measuring/controlling risk with value at risk nowadays, despite the fact that it is believed to provide overly optimistic risk estimates, especially in the time of crisis.

The objective of this master thesis is therefore to investigate if value at risk really is the appropriate risk management tool for estimating the risk on the natural gas market. This is done by creating a natural gas portfolio of a short-term trader X on the Slovenian natural gas market, and applying three different approaches of value at risk: historical, variance covariance and the Monte Carlo simulation. By doing so, I can shed more light on the assumption that the Monte Carlo simulation is the best method for evaluating the financial risk in natural gas trading (Asche et al., 2013). Moreover, I analyse the pricing and the risk of natural gas trading with the examination of the long-term natural gas contracts and their correlations with hub pricing, which is gaining momentum on the European natural gas market.

The master thesis is based on research that provides an in-depth analytical and theoretical review of the scientific literature, papers and research articles, as well as the institutional reports and publications of the respective topic, in order to support the findings and the details of the problems. Descriptive and compilation methods are used to bring together the knowledge of many authors on the respective topic, especially in the field of risk management in natural gas trading and value at risk. Moreover, the empirical principle is applied for the purpose of calculating value at risk for the imaginary portfolio of the short-term trader X on the Slovenian natural gas market, using three different value at risk methodologies in order to prove or refute the master thesis's' objective.

The master thesis consists of three main sections. The first section starts with the European natural gas market outlook, which familiarizes the reader with the main gas indicators such as production, reserves, consumption and the world trade flow of natural gas. In the first chapter I also present which price mechanisms are globally defining natural gas prices and discuss the outlook of the Slovenian natural gas market.

The second section examines how natural gas was historically traded with the long term contracts, as well as the description of the main elements of the long term contracts and the pricing mechanism of the contracts. In the latter section I describe the development of the short-term natural gas trading and the emergence of European gas hubs. Furthermore, the traded instruments of gas trading, volumes and pricing within the gas hubs are presented.

In the third section I present the risks and the risk management characteristic of the gas sector, how risk management is applied, and which risk management solutions are being used by the companies to mitigate risk. More importantly, I examine the risk and the returns of the monthly gas futures in the portfolio of the short-term natural gas trader, where, additionally, three different methods of the value at risk methodology are calculated, compared and adequately back-tested in order to see which one is the best for demonstrating financial risk. Moreover, I also test the claim set by an analyst at Gazprom, which states that the prices in the long-term natural gas contracts are higher than in the short-term ones, just because they offer the security of the supply and are in fact derived from long-term contracts (Komlev, 2013).

Finally, in the conclusion, I summarize all of my findings and results regarding risk management solutions in natural gas trading and make a few speculations about the future trading of natural gas and the impact of risk management.

1 OVERVIEW OF THE EUROPEAN NATURAL GAS MARKET

1.1 Europe in the context of the world's natural gas market

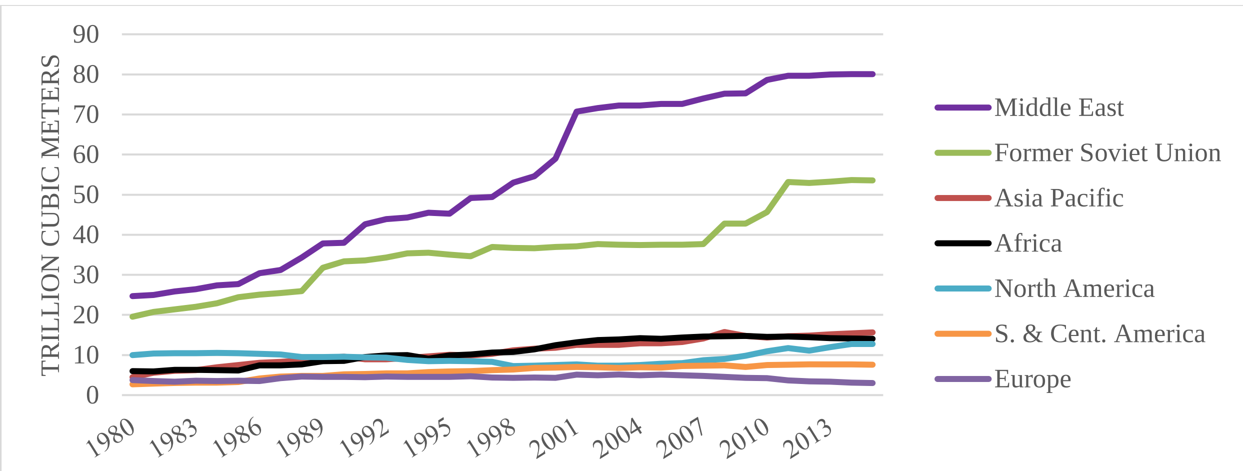
According to Gilardoni (2008), natural gas will be a key energy trajectory for Europe for at least the next 20 years, due to the increase in consumption. From the perspective of the proven reserves and the production of natural gas, Europe is actually the smallest region in the world. Production, reserves and the reserves to production ratio (R/P) are vital indicators that show where a significant amount of natural gas comes from and consequently decide the imports, exports and the trade flows of natural gas. The indicators may also define the prices, to some extent, thus it is essential to determine if a country can satisfy its demand and consumption with its own natural gas resources or if it needs to rely on foreign imports.

Independent Association of Petroleum America (n.d.) defines the natural gas proved reserves as quantities, which can, by analysis of the geosciences and engineering data, be estimated with certainty to be economically producible, meaning, they are technically recoverable and feasible for extraction and production. On the other hand, technically recoverable reserves are, as proved reserves, extracted by using the current technology, but the term does not take the economic profitability into consideration. They are much more expensive, as they include estimates of natural gas that has yet to be discovered, which may not be producible with the current prices, thus the figures are much larger than in proved reserves.

As presented in Figure 1 below, we can see the movement of natural gas proved reserves over the period of 25 years. All of the natural gas proved reserves in the world amounted to 187 trillion cubic meters (tcm) in 2015. With 42.9 % of the natural gas proved reserves in the Middle East and

28.7% in the countries of the former Soviet Union, the two regions combined hold the majority share of the world's gas proved reserves. Iran, Russia and Qatar are the three countries that dominate the world's proved natural gas reserves. According to British Petroleum (BP) (2016), they respectively hold 18.2%, 17.3% and 13.1% shares of the natural gas proved reserves and together had almost 50% of the world's natural gas reserves in 2015. European natural gas reserves are the smallest of any region, with only 3.1tcm, which amounts to 1.6% of the world's proved natural gas reserves. Europe has visibly falling levels of gas, which indicates that it will eventually use up its proved reserves and that the region is highly dependent on the imports of natural gas. Similarly, other continents, namely Africa holding 8%, North America 7%, and Central and South America with 4% of proved reserves, have less of a share of natural gas proved reserves all together than the countries of the Former Soviet Union or the Middle East.

Figure 1: World's natural gas proved reserves by region, 1980 - 2015



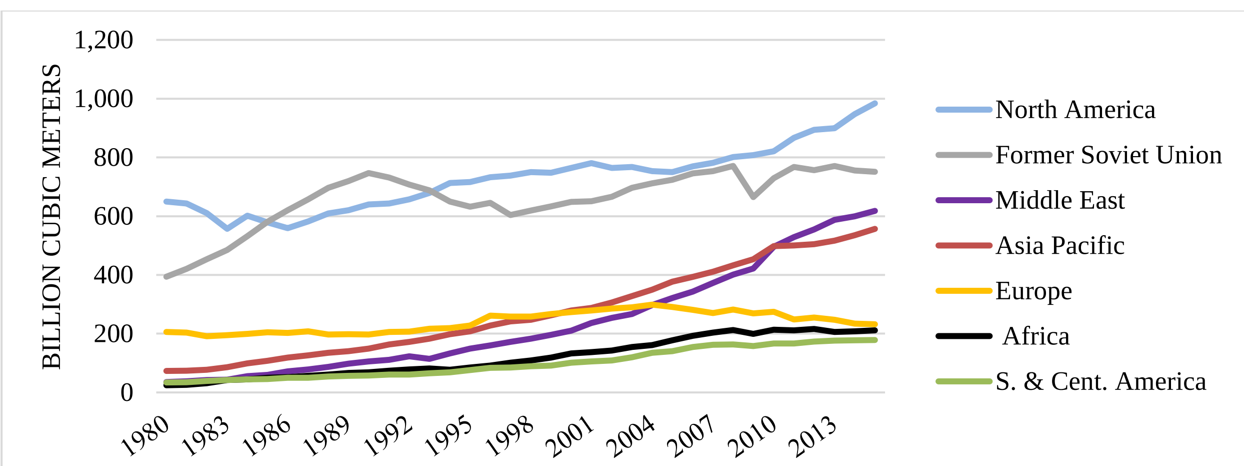
Source: Adapted from BP (2016).

As the demand for energy continues to grow and the traditional, or the so called conventional sources of gas, have become increasingly scarce or costly, the unconventional sources of natural gas are gaining leverage. Unconventional gas (tight gas, shale gas and coal bed methane) is used to describe several different types of gas that have traditionally either been considered too expensive or were lacking the technology to produce it (Society of Petroleum Engineers, 2007). Out of all of the unconventional gases, shale gas, which is basically natural gas trapped in shale, has experienced the most spectacular growth in production over the past decade, especially due to new innovations, such as hydraulic fracturing and horizontal drilling. The new supply of energy has led to the decreasing of the prices of natural gas and the reduction of energy imports and is the fastest growing natural gas resources in the United States and Worldwide today (European Parliament, 2014).

According to the Energy Information Administration (EIA) (2016), only four countries (the United States, China, Canada and Argentina) currently have commercial shale gas production worldwide, but the technological advancements are expected to encourage the development of shale extraction in other countries as well, primarily in Algeria and Mexico. EIA (2016) also believes that shale gas will account for 30% of the world's gas production in 2040, which could radically change the world's energy market and potentially fill the supplies in regions that would otherwise tighten in the following years, such as Central and South America, Asia Pacific, Europe and the United States, which are already becoming self-sufficient. According to the Energy study of 2013, made by BGR, the biggest potential share of shale gas in Europe lies in Poland, France, Romania, Denmark, the Netherlands, Norway and the United Kingdom. Although there is a potential for shale gas production in Europe, it will unlikely achieve the cost and volumes as in the United States. Another problem Europe is facing is that the reserves are spread across several countries, which may limit the economies of scale and means that the European countries have adopted different policies regarding shale gas. For example, both Poland and the United Kingdom are already executing exploratory drilling and hydraulic fracturing tests, while Bulgaria and France have banned hydraulic fracturing due to the potential environmental concerns (European Commission, 2017b).

Overall, new technological innovations and shale gas reserves could potentially change the European natural gas market in the nearby future. However, for now there are too many legal limitations and not enough experience with shale gas exploration in Europe on which to base future potential resources and outlook predictions for the European natural gas market, thus Europe will remain highly dependent on natural gas imports from other worldwide regions for now.

Figure 2: World production of natural gas by region, 1980-2015



Source: Adapted from BP (2016).

As seen in Figure 2, the world production of natural gas has been increasing gradually over the years and has, according to BP (2016), reached 3538.6 billion cubic meters (bcm) in 2015, which is a 2.2% increase in comparison to the year 2014. All regions have increased the production of natural gas in 2015, except the countries of the Former Soviet Union and Europe, which had slightly less production than in 2014, with 0.06% and 0.08% respectively. As observed from Figure 2, the biggest production of natural gas takes place in North America with 984bcm, followed by the Former Soviet Union (751.4bcm), the Middle East (617.9bcm), which has increased the production of natural gas for almost 93% over the past ten years, and Asia Pacific (556.7bcm). On the contrary, the production of natural gas in Europe (232.2bcm), Africa (211.8bcm) and Central and South America (178.5bcm) is more than 2-times smaller when compared to the production of the before mentioned regions. The share of the two largest natural gas producing regions, North America (27.8%) and the Former Soviet Union (21.2%), amounts to almost 50% of the world's natural gas production, tailed by the Middle East (17.4%) and the Asia Pacific Region (15,7%).

Europe, with 232.2bcm production in 2015, has only a 6.5% share or the world's gas production and is, beside Africa (5.9%) and Central and South America (5%), one of the smallest natural gas producing regions in the world. The largest natural gas producing countries in Europe are Norway, with 117.2bcm, the Netherlands (43bcm) and the United Kingdom (39.7bcm), and together they hold an 86% share of all of the natural gas production in Europe.

Due to the increasing production of natural gas and the predictions of bigger natural gas consumptions, it is important to think about the size of natural gas reserves in terms of the reserves to production ratio or R/P. This ratio represents the number of years that the natural gas reserves would last, if the production and the consumption continue at the current rate (Boyle, Everett, Peake, & Ramage, 2012). The R/P ratio is a vital measurement for natural gas sustainability and security, which indicates the future tendency and need for individual countries and regions in terms of natural gas.

Table 1: The reserves to production ratio by regions in 2015

Region	R/P ratio (Years)
Middle East	129.5
Former Soviet Union	71.2
Africa	66.4
South and Central America	42.5
Asia Pacific	28.1
Europe	13.0
North America	13.0

Source: Adapted from BP (2016).

As seen in Table 1, the Middle East has by far the largest R/P ratio, which amounts to almost 130 years. The reason for such a large ratio lies in the huge amount of reserves in the region and a relatively small production of natural gas. The ratio is also very large in the regions of the Former Soviet Union, Africa and South and Central America. On the other hand, Europe and North America have the R/P ratio of only 13, which indicates that the reserves would last only 13 years. However, in North America, we must take into account the unconventional natural gas reserves, especially shale gas, which started the revolution in natural gas and is the fastest growing natural gas resource in the United States today. It is being extracted on a daily basis and already accounts for more than half of the United States' production in 2015 and should allow the US to become gas self-sufficient in the nearby future.

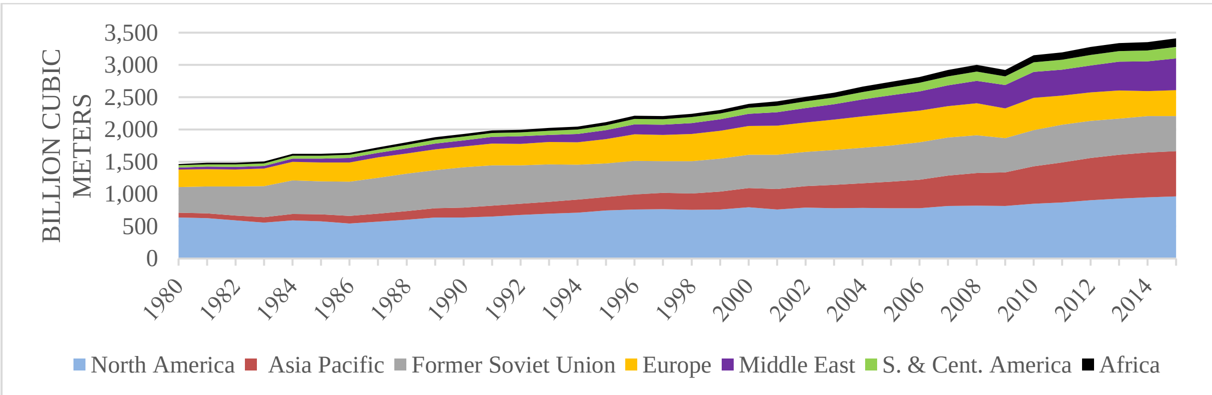
There is a completely different story in Europe, where they also found reserves of shale gas. However, for now, there are too many legal limitations in some parts of Europe and not enough experience with shale gas exploration due to the lack of technological innovation, thus there currently is no extensive production of shale gas and with the current production pace, Europe will run out of natural gas reserves in 13 years.

1.1.1 Consumption of natural gas

The Natural gas industry has been growing rapidly for many years. As detailed in Figure 3, global natural gas consumption has increased from 3410bcm in 2014 to 3468bcm in 2015, which is a 1.7% increase. However, it is still a significant fall from the 10-year average of 2.3%, visible from 2005 to 2015. The consumption of natural gas has increased in all regions except in the Former Soviet Union, where consumption was 3.5% smaller than in the year 2014, due to the reduction in economic activity because of the economic sanctions and the lower prices of natural gas. North America is the largest consumer of natural gas with 963bcm in 2015, tailed by Asia Pacific (701bcm) and the region of the Former Soviet Union (542.8bcm). These three regions combined represent 63.6% of global natural gas consumption with 27.8%, 20.2% and 15.6%, respectively. In regions rich with natural gas reserves, such as the Middle East and North America (taking into account shale gas reserves), the demand continues to grow as a substitute for oil and coal in transport and for power and non-energy use (World Energy Council, 2016). The lowest consumption takes place in the developing and third world countries in the regions of Africa (135.5bcm) and South and Central America (174.8bcm), which together account for 9% of the world's gas demand (BP, 2016).

In Europe, natural gas consumption reached 444bcm in 2015, which amounts to 12.8% of the world's natural gas consumption. This is a 4.3% increase from the previous year and is the first year, after 2010, when the usage of natural gas increased, due to lower import prices of natural gas, although it is still well below the demand before the financial crisis. The decrease in the past years was a result of several factors: the economic-financial crisis and the poor recovery from it on one hand and the bigger competition from the alternative sources of producing energy and coal in a combination with a reduced demand for electricity on the other, which consequently led to the decrease in power generation and the overall reduction of demand for natural gas (Eurogas, 2015).

Figure 3: World consumption of natural gas by region, 1980-2015



Source: Adapted from BP (2016).

The natural gas demand is dominated by four sectors: residential consumers, commercial consumers, the industrial power generation and the transport sector. The power generation sector is the largest user of natural gas and presents a major opportunity for the continuous growth of the natural gas consumption. In 2013, the power sector represented 40.3% of the world's natural gas consumption (World energy council, 2016). However, the demand in the power generation sector is strongly dependent on the available price of natural gas in comparison to other competitive fuels, as well as the policy favourites that affect company operations and investment decisions in a new capacity.

The industry sector is the second largest end user of the world's natural gas (22.1% in 2013), slightly ahead of the residential and commercial sector (21.6%) (World energy council, 2016). The industrial sector is more stable over a span of time, as its use is primarily in heating, melting, feedstock and power generation. However, the industrial sector has more substitutes and optimizes its use and production constantly, thus changes may occur in production or even the production's location in response to gas prices or environmental policies. In the residential and commercial sectors, most of the natural gas is used for space heating. As a result, weather conditions and cycles have a severe impact on the natural gas demand in the residential sector.

The transport sector is the smallest sector of natural gas consumption and represented 3.3% of the world's total use of natural gas in 2013. The use of natural gas for transportation is driven by the discrepancy between gas and oil prices, which indicates switching by the promotion of natural gas vehicles and infrastructure development as well (World energy council, 2016).

Even though there is potential for future demand in all sectors of natural gas, we must take into account the various factors that can affect natural gas consumption. Economic growth and the natural gas price competitiveness will remain crucial elements in the development of natural gas consumption. Gilardoni (2008) believes that the reasons for why natural gas demand is projected to grow, are due to the economic and environmental factors. Therefore, the rising GDP in developed countries has made gas consumption meet stricter environmental regulations, while the emerging countries will try to reduce their use of coal and oil in the long-term and substitute it with natural gas for economic/efficiency reasons, as well as for environmental sustainability. Another reason is the decline of oil in power generation, which is mainly substituted with natural gas, as well as the expansion of emerging countries like China, India and Brazil. Even so, weather is the most significant element affecting the natural gas consumption and demand. As natural gas has a strong seasonal component, meaning that the demand is highest in the winter and lowest in the summer, weather may cause a significant fall in demand due to warmer temperatures. Some meteorological sensations or extreme temperatures can even make the demand and the prices skyrocket or hit rock-bottom within the same day. Therefore, seasonality is an important factor that can directly or indirectly influence the demand and price of natural gas (Rogel-Salzer & Sapsford, 2014).

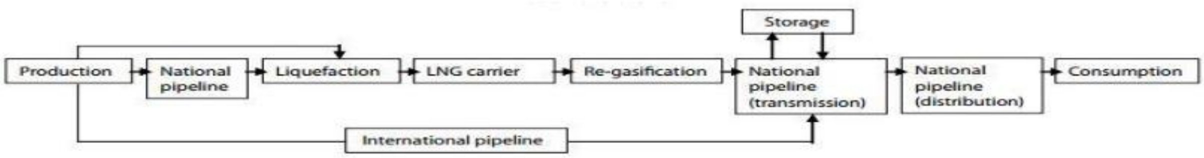
According to the EIA (2016b), the world's gas consumption will increase to 5,756bcm by the year 2040, which is a 65% increase compared to the year 2015. The strongest growth in natural gas consumption is estimated for non-OECD Asia countries (China, India), where economic progress leads to bigger demands. It is expected that the non-OECD region will grow up to 2.5% per year, while OECD countries will grow 1.1% per year. OECD countries' natural gas consumption growth will be the smallest in Europe, where the demand is expected to grow 15% by the year 2040. EIA (2016b) also believes that the industrial and power sectors will together account for 76% of the total natural gas end use in the year 2040.

1.1.2 World trade flows of natural gas

The trade flows of natural gas illustrate the real trade movements of natural gas across the globe, between the natural gas producing countries and countries which import it. Figure 4 below presents the process of the natural gas value chain: how the natural gas is transported from the production plant to the final consumer.

As illustrated in Figure 4, two options of transporting natural gas exist: the first one is the pipeline transport, which is relatively simple as the gas is transmitted worldwide via international high-pressure transmission pipelines. The process starts at the producers' remote pumping stations, where the gas is pumped into the pipeline and then transported via the pipeline to either a large industrial final consumer, a distribution pipeline, to another national pipeline or to a storage facility. On the other hand, liquefied natural gas (LNG) transportation is more complex, as it includes more steps, since natural gas must be liquefied through a cooling process and then transferred in liquid form via special cargo ships to special terminals, where it is re-gasified into natural gas through a heating process. After the re-gasification process, the natural gas is transmitted via national pipelines either to the end consumers or to storage facilities.

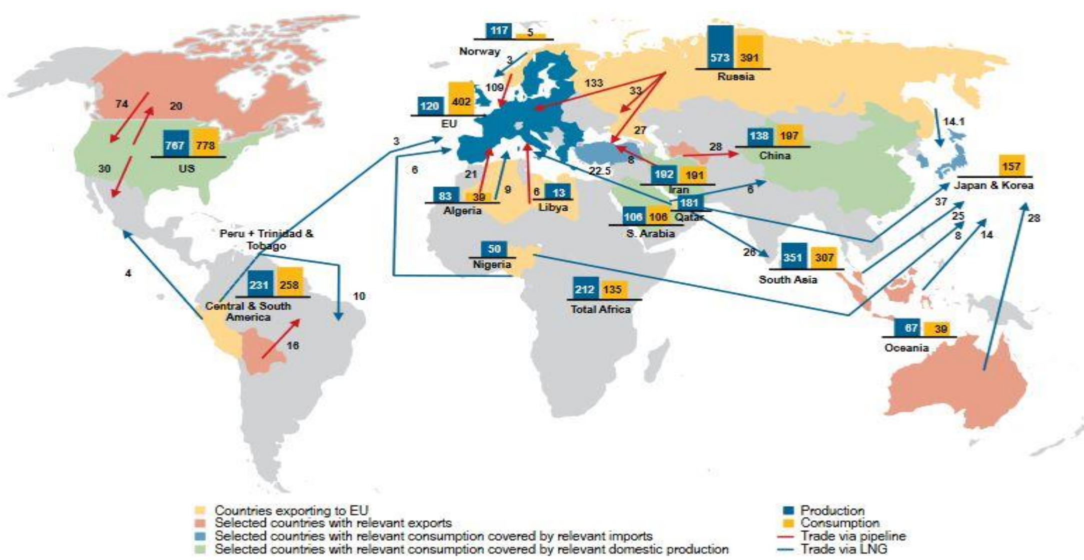
Figure 4: Transportation of natural gas



Source: Energy Charter Secretariat (2007, p. 37).

Most of the natural gas trade has been driven via pipelines. As evident in Figure 5, the major pipeline routes lead from Russia and Algeria to Europe and from Canada to the United States and vice versa. Nonetheless, with the growth of demand for LNG in regions such as Asia Pacific and Europe, they are now acquiring natural gas from long distance production centres in the form of LNG, which is transported by distinctive LNG shippers.

Figure 5: Global trade flow movements of natural gas in 2015 (in bcm)



Source: ACER & CEER (2016, p. 8).

On the other hand, the main LNG routes are from the Middle Eastern region (Qatar) and Africa (Nigeria) to either Europe or Asia and from the Pacific region to Asia. LNG also makes trades from Central America to Europe and to North America. As LNG is more flexible to transport and is not restricted to a certain destination, the final destinations are driven by prices of natural gas, which results in the transportation of LNG to regions/locations with the highest margins/profit.

According to BP (2016) in 2015, 1042.4bcm of natural gas was transported internationally. Most of it was transported via pipelines (68%), while 32% was transferred as LNG with special LNG carriers. Europe and Asia Pacific, regions with low production and high consumption levels, have imported the majority of the world's natural gas either via pipeline or LNG, with 42.5% and 28.8% respectively. The least imports of natural gas were made to the Former Soviet Union and Central and South America, which together account for 9.7% of the world's natural gas imports

1.2 The natural gas price formation mechanism

On the natural gas market, the base for the price formation and the price drivers are set differently across regional gas markets. As opposed to the oil market, which is global, the natural gas market is divided into a couple of connected and interlinked natural gas markets. The price is thus set differently across the markets and there is no worldwide uniform pricing mechanism for natural gas (Rogers, 2012). Natural gas price formation greatly differs between the world's regional markets, depending on several factors such as regulation, spot market existence, liquidity, share of imported gas, type of contracts and the degree of the market opening (Davoust, 2008). Therefore, in order to fully understand the dynamics of the natural gas trade, we first need to analyse the price structure mechanism in different gas regions.

The diversity of the natural gas pricing mechanism on national or regional markets can be found by looking at the specific characteristics of the gas industry. According to Melling (2010), the first one can be found in the transportation costs of natural gas, which are really high compared to other commodities and require a lot of investments in either the pipeline systems or, in case of LNG, investments into either liquefaction, shipping or re-gasification facilities. Another problem lays in the difficulty of storing the gas, due to the required high investments into the storage units and the fact that, in some cases, the storage also requires the availability of the right geology, thus making it more difficult to maintain a necessary security of supply.

Timera Energy (2013) believes that the biggest reason for why the natural gas price mechanism differs is that natural gas as LNG is too expensive to transport, liquefy and store and that LNG is still in an immature phase for now, with limited sources or destinations across the world. This is evident from the fact that almost 68% of the world's natural gas was transported via pipeline in 2015, almost 88 % of which was in Europe. The pipeline can either connect only one supplier and buyer (for example a gas field which supplies a power plant), or it may be united as a grid, connecting hundreds or even thousands of gas producers with a million or more gas consumers (BP, 2016).

According to Atradius (2017), the natural gas market is separated into three markets: North America, Asia and Europe, each region having its own gas pricing and characteristics. In North America, natural gas prices are defined at hubs as the result of a supply and demand dynamics, where the prices of natural gas are based on the spot and futures market, in which a large pool of different buyers and sellers participates in the trading of natural gas (World Energy Council, 2016). Unlike the North American market, the natural gas prices in Asia are dominated by long-term natural gas contracts typically linked to the oil prices. However, Asia is developing regional trading hubs, so that the natural gas prices will better reflect the natural gas supply and demand dynamic, and so, as the largest importer of LNG, they are trading more LNG globally on a short-term basis, which in 2015 accounted for 75% of the LNG imports based on hub pricing (IGU, 2016).

On the other hand, Europe has two different gas pricing systems, one which is based on oil price indexation and the other based on the spot market. Although oil indexation in Europe emerged more than 50 years ago, in today's European two-tier pricing system the oil indexation is losing the battle with the hub base pricing, which is seen as the competitive European strategy and is on the rise (IENE, 2014). According to S&P Global Platts (2015a), gas on gas pricing in Europe represented only 7% of the pipeline gas trade in 2005, but the number significantly increased during the years and more than 50% of all of the natural gas (pipeline and LNG) was priced based on the gas indexed pricing mechanism in 2014.

With regard to the different regional pricings of natural gas across the globe, the gas wholesale prices are, according to the International Gas Union (IGU) (2016), based on five major market pricing mechanisms, of which the oil price escalation and the gas on gas competition will be explained in more detail in the latter section, as it is important for the understanding of the development of the natural gas trading in Europe.

- Oil price escalation /indexation, meaning that the natural gas price is linked to fuels such as gas oil, crude oil or fuel oil through a base price.
- Gas on gas competition or hub pricing, where the price is determined by the supply and demand of natural gas, traded over a course of different periods (day, month, year) at physical or virtual hubs.
- Bilateral Monopoly, where the price is set by a bilateral agreement between a large buyer and a seller, with the fixed price determined over a period of time, which typically lasts one year.
- Net back form final product, whereby the price received by the gas suppliers is the function of the price received by the buyer for the final product the buyer produces.

- Regulation, meaning that the price is set by a governing authority, the ministry. There are different regulations: the cost of service, below cost and social and political regulations.

1.2.1 Oil price escalation

Oil price escalation (also oil indexation or gas-to-oil) was developed in the late 1970s when oil was a leading source of energy and is now a dominant pricing mechanism in Europe, Asia and Asia Pacific. The logic behind this model was that by contractually linking the prices to the competing fuel, the consumer will be provided with the choice between consuming either oil or natural gas. The ultimate goal behind this idea was that the consumers would switch from oil to natural gas consumption in the long run (Kanai, M. 2011).

Oil indexation pricing prevailed on the gas market, because it was thought of as a smart and secure investment for both the producers and the consumers, who were guaranteed the security of supply. The prices set by oil indexation were also considered to be more probable than the prices set by the gas on gas competition. According to IGU (2016), the oil price escalation prevailed in Asia (59%) and in the Asia Pacific region (57.8%), whereas in Europe, oil indexation represented 35% of the price formation for natural gas consumption in 2015.

However, oil escalation is now at risk and under extreme pressure, predominantly due to the liberalization and the competition of the European markets (Hub pricing), the LNG supply surplus and the arrival of shale gas and the substitutes (Hedge & Fjeldstad, 2010). Today, the transition away from oil indexation in contracts has already started, with a major degree of spot gas pricing indexation in long-term contracts, especially due to the increased liquidity of the short-term trade, which has become less risky and more attractive for the customers. The trend is evident in terms of the world's total imports of natural gas (the sum of pipelines and LNG imports), whereas oil escalation represented only 49% of all imports in 2015, while gas on gas (45%) and bilateral monopoly (6%) accounted for the other 51% of the total natural gas imports (IGU, 2016).

1.2.2 Gas on gas competition

Gas on gas competition (also called hub pricing) has been associated with short-term contracts and is the prevailing gas pricing mechanism in North America and the United Kingdom (Atradius, 2017). According to the IGU (2016), 45% of the world's natural gas consumption was made by hub pricing in 2015. Prices within the hub pricing model are set on a basis of natural gas and were determined throughout the trading of future contracts at physical or virtual hubs. The trading and the operations at hubs send signals about the market value of natural gas, thus allowing the supply and demand dynamic to play a major role in the finding of natural gas prices (Zajder, 2012).According to IGU (2016), in terms of the world's natural gas consumption in 2015, the largest gas on gas competition pricing model takes place in North America (99.5%) and Europe (63.8 %), while other regions like the Former Soviet Union (24%), Asia (14%) and Asia Pacific (17%) have significantly less. However, hub pricing can be found in 51 countries across globe and is gaining momentum, especially in terms of LNG imports, where the gas on gas price model represented 31% of all of the world's natural gas imports in 2015.

The main advantage of the gas on gas pricing system is that natural gas prices are comparative and reflect the market value of gas and not oil. On the other hand, the disadvantage of this pricing model is the short-term price volatility that comes with the swift changes in supply or demand. The price spikes or drops can be very painful both for the buyer and the seller. However, this can be managed by utilising forward pricing in contracts and can be done by the buyer or the seller (Zajdler, 2012). Hub pricing is viewed as the best option for natural gas trading, compared to the alternatives, and so gas will be priced by the gas on gas competition more and more. When gas market liquidity and integration will increase across globe, the hub prices will reflect the world's demand and supply of natural gas and will therefore be less susceptible to price manipulation (IENE, 2014).

1.3 The Slovenian natural gas market overview

The Slovenian natural gas market is among the smallest in the EU-28, amounting to around 302sm3 of consumed natural gas in 2015, which is the third highest amount of consumed natural gas after 2004. Industrial consumers consumed 202sm3 (67%) of natural gas, while household consumers used 100sm3 (33%), mainly for cooking, sanitary hot water and heating. If we look at another perspective, the Slovenian natural gas market consist of more than 85% of household consumers and less than 15% of industrial ones. However, industrial consumers consume twice as much. In 2015, Slovenia transferred 20,133GWh of natural gas through its transmission network, to either the Slovenian consumers (8,669) or to other transmission networks (11,264), which is more than the year before and thus ends the multi-annual trend of decreasing the consumption of natural gas (Agency for Energy, 2016).

The Slovenian transmission system operator (TSO) is operated and owned by the company Plinovodi. The natural gas market consists of 946km of high-pressure pipelines and the natural gas is transmitted to Slovenia via high pressure transmission pipelines (Agency for Energy, 2016). The same process is used worldwide, from the remote pumping stations to the end stations via international high-pressure transmission pipelines. Before the transmission, a technological process is used to clean the natural gas of impurities and other unsuitable matter. The transmission and flow of the natural gas via the pipelines is probable due to the compressors which increase the pressure in the pipes and push the gas forward, therefore the major parts of the transmission network are the compression stations in Kidričevo and Ajdovščina (Geoplin, n.d.).

There are 15 different natural gas distribution networks connected to the Slovenian natural gas transmission network, through which the distributors facilitate the distribution of natural gas to 79 Slovenian municipalities. The liberalization of the natural gas market gave the customers the option to choose the supplier of natural gas; meaning the customers will be supplied with gas by the provider of their own choosing. However, the distribution of natural gas will still be supplied by the current distributor of the municipality (Invest Slovenia, n.d.).

Slovenia is also a part of the European gas transmission network, meaning that the Slovenian pipeline system is connected to the neighbouring countries – the Austrian, Croatian and Italian transmission networks, which is a major advantage of Slovenia's geographical position (Invest Slovenia, n.d.). Slovenia is connected to its neighbouring countries' transmission networks at three border points:

- At the Ceršak entry point, where the transmission of natural gas is possible only from Austria to Slovenia ,
- at the Rogatec border point, where the transmission is enabled in the direction from Slovenia to Croatia
- and at the Šempeter entry point, where the transmission is available in both directions, from Italy to Slovenia and vice versa.

Slovenian does not have the production, reserves or storages of natural gas; therefore, the market is highly dependent on the imports of natural gas through the neighbouring countries' transmission network. Slovenia also does not have an organized natural gas market, where systematized trading of standard natural gas products would be executed among buyers and sellers; hence Slovenia's gas market is based on the direct sale or purchase of natural gas between the traders and the suppliers in the combination of short-term and long-term contracts.

Natural gas is supplied to Slovenia by traders who also import it to Italy and the Austrian transmission network, whereas the supply of natural gas from Croatia is only possible through the virtual flows. Traditionally, Russia was the largest source of traditional gas. However, due to the liberalization of the natural gas market, it was replaced by Austria. Market liberalization revolutionized the natural gas market in Europe as well as in Slovenia, hence the long-term contracts, which were signed directly with the Russian producers of natural gas, were replaced by the short-term contracts concluded at gas, where the gas demand and supply are met. This is evident from the structure of imported gas in relation to the contracts' maturity, since, in 2015, most of the

Slovenian natural gas market imports were concluded with short-term contracts (59%), while long-term contracts represented only 41% (Agency for Energy, 2016).

Slovenian suppliers of natural gas buy most of the gas from the Baumgarten gas hub (CEGH-central European gas hub) and the Austrian storages. Therefore, the trading at the border entry point Ceršak accounted for 65% of all subleased energy capacity trading in 2015 (Agency for Energy, 2016). CEGH is Austria's largest reception point and the main distribution hub for imports from Russia, Norway and other countries. Due to its location and the state of the art technology, the Baumgarten gas hub is one of the most important gas hubs in Central Europe. Natural gas is transported to the gas hub via Slovakia and Germany, along several different cross border pipelines. From there on, the gas flows are delivered to domestic and international partners via Austria's 2000km transmission and distribution network (Gas Connect Austria, 2016).

According to the Slovenian Agency for Energy (2016), in the year 2015, the trend of dropping the prices of natural gas continued for the fourth year in the row. The trend of dropping natural gas prices occurred due to the liberalization of the natural gas market, the decrease in the prices for the supply under long-term natural gas contracts and more competition on the market. The logical conclusion would therefore be that the number of new consumers has been growing throughout the years. However, in the period from 2011 to 2015, the number of new connections almost halved on the Slovenian natural gas market, and the explanation can be found in the wide variety of new competitive technology and the local energy concepts, which allow subsidizing technologies in areas which have organized natural gas distribution.

The Slovenian natural gas price consists of 3 elements and has the same structure for both household and industrial consumers:

- the price for the use of the networks,
- the price for natural gas and
- the excise duties, the added tax value and other taxes (the CO2 tax and the contribution to improve the efficiency of energy use).

Even though Slovenia has one of the smallest markets of natural gas in the European Union (EU)-28, the prices are above the average of EU-28, regarding industrial consumers. On the other hand, the prices for household consumers of natural gas in Slovenia are below the average of EU-28 (Agency for Energy, 2016). Slovenia has a trend of falling prices of natural gas in the household sector, which has been lower than the average price of the EU-28 since the second half of 2014. The reason for why the prices of natural gas in the household sectors are lower in Slovenia, can be found in the more competitive offers of Slovenian retailers, which are echoed in the lower cost of the natural gas supply.

As natural gas is known and considered to be the most environmental fuel among all fossil fuels, the demand for natural gas is growing, especially in the household sector, as customers can save money by using natural gas for various purposes, compared to other systems. Natural gas has the shortest period of return as the investment into natural gas for a house returns after three years. However, there are also limitations with this type of heating, especially with the natural gas network and transmission. Hence, some local municipalities will never be part of the pipeline network due to the scattered construction of buildings. Nevertheless, the pipeline system in Slovenia is well developed, efficient and functions in 82 municipalities. Besides, natural gas has a trend of falling prices and the Slovenian natural gas market has become more competitive in terms of offers, thus the future of natural gas consumption in Slovenia looks bright and prosperous.

2 NATURAL GAS MARKET TRADING

In the previous chapter, I tried to position the European and Slovenian natural gas in the context of the world's natural gas and presented the basics of natural gas. The second chapter is a follow up, as the world's natural gas market is going through some major changes due to the liberalization of the natural gas market, so it is important to present how natural gas is being traded and transported to Europe nowadays, and what type of contracts are being conducted between the sellers and the buyers of natural gas. Historically, the natural gas market was traded over the long-term, contracted with long-term contracts (LTCs), which are thoroughly presented below. However, due to market openness and cheaper natural gas prices, hub pricing is gaining momentum and has revolutionized natural gas trading in Europe.

When referring to natural gas contracts, it is important to differentiate between the contracts for natural gas as a commodity and natural gas in capacities. As the name commodity tells us, a commodity contract refers to natural gas as an energy commodity, which can be negotiated either bilaterally or on the natural gas market, while the capacity contracts are conducted for either natural gas transportation or for storage purposes. It is possible to further distinguish the contracts for natural gas between various market parties across the natural gas value chain, such as contracts for the producers, wholesalers, retailers and end consumers (DNV KEMA, 20103). However, this thesis is focused on the trading and risk management of a wholesaler's natural gas. Therefore, in this chapter, I present natural gas contracts, trading instruments and pricing terms intended for the wholesale level.

Chapter 2 starts with the history of natural gas trading and traditional long-term contracts, where I present the length of the contracts, their volume and flexibility, which are the basic elements for any natural gas trade or contract, and other features of the contracts. In subchapters 2.2, 2.3 and 2.4, I discuss the developments and contracting trends of natural gas trading due to liberalization, what kind of traded instruments the wholesalers are negotiating and present the new trend and structure of natural gas trading. In short, I also familiarize the readers with the transport capacities contracts, which are important from the risk management's perspective of a natural gas trader, as they are necessary for the transportation of natural gas and thus needed to be taken into account when trying to mitigate the risk in natural gas trading.

2.1 Long-term natural gas contracts

According to Zajdler (2012), the historic developments on the natural gas market in Europe led to the establishment of two models of the natural gas supply and consequently the pricing in LTCs. The first model - also named the continental model, which was based on LTCs with natural gas prices indexed to the prices of crude oil and oil derivatives. The second model – also called the British model, was formed in the mid-1990s and was based on medium term supply contracts of natural gas at a price indexed to a gas to gas competition (Zajdler, 2012).

Melling (2010) states that the first model began in the 1960s, after the discovery of a large gas field in the Groningen Netherlands and that there was an instant question of how to price the natural gas, as end user prices across Europe were state-controlled and a free market did not exist. Before the introduction of the LTC model, the cost-plus method was used to determine the natural gas prices in Europe. This method is similar to netback pricing. However, instead of setting the price through a subtractive calculation to determine the net back value, the natural gas price here is set by adding the production, the transport costs, the overhead and a profit margin to determine the sale price.

The long-term contracts concept is aimed at maximizing the rent income of the exporting state, while maintaining the natural gas saleable, meaning they allow the buyer to pay for the infrastructure and to market the natural gas, while all cost incurred to bring the gas from the delivery point to the consumer would be netted back from the revenue attainable from the consumer.

2.1.1 The structure and pricing of a long-term natural gas contract

The long-term natural gas contracts have been the backbone of Europe's certainty of supply for years. From the 1970s onwards, long-term contracts have been used to import more than 250bcm/year of natural gas to the EU area (Energy Charter Secreteria, 2007). Long-term natural gas contracts connect buyers and sellers into a bilateral monopoly for a period of 20-30 years, during which both of the parties have explicitly defined obligations.

The long-term contracts are based on oil indexation in order to protect the buyer against price fluctuations to competitive commodities. However, it was proven that this is more advantageous for the producers, because the price of oil was much higher than the price of natural gas, thus the producers have no intention or motivation to shift to hub-based pricing. Furthermore, the producers are questioning and undermining the hubs' ability to provide a dependable price for natural gas commodities and are reluctant to leave the well-established practices, such as long-term natural gas contracts (International Energy Agency, 2013).

Although the pricing mechanism in LTCs is indexed to the price of oil, the price of natural gas varies according to a given region. For example, the prices of natural gas in Continental Europe are linked to a basket of heavy and light fuel oil, while in the Netherlands, Russia and Norway, they are indexed at 80% to fuel oil (Zajdler, 2012). Therefore, it is important to stress that the indexation trend depends heavily on the source of imports in different regions. According to the European Parliament (2006), the pricing formula used in Europe under the net back concept of a long-term natural gas contract, is generally set up in the following way:

$$P_m=P_0+\left(0.6*0.8*0.0078*(LFO_m-LFO_0)\right)+(0.4*0.9*0.076*(HFO_m-HFO_0)) \tag{1}$$

In the formula (1) above, the natural gas price (P) for a relevant month (m) is calculated with the P_0, where P_0 represents the starting gas price in month 0, while LFO (Light Fuel Oil) and HFO (Heavy Fuel Oil) characterize the price of the competing fuels compared to the reference month. 0.60 and 0.40 are the shares of the natural gas market segments competing with the respective fuels, while 0.80 and 0.90 are the pass-through factors, denoting the sharing risk and reward of the price development between the seller and the buyer. The numbers 0.0078 and 0.0076 are the technical equivalence factors that convert the units of fuel prices into units of natural gas prices.

2.1.2 The elements of long-term contracts

The traditional way of conducting business in the natural gas industry, was that buyers and sellers entered into a supply negotiation, which resulted in a bilateral long-term natural gas contract. Even though the contracts of natural gas can either be concluded on a mutual agreement - bilateral or over-the-counter pricing terms, the length of the contract and the volume flexibility are the basic elements in any natural gas contract or trade and are also interrelated. (DNV KEMA, 2013). Furthermore, Long and Moore (2003) believe that the main components in LTCs are, besides the above mentioned, to take or pay provision, the destination clause and the price reviews.

As the name 'long-term natural gas contracts' implies, the contracts are based on a long-term obligation between the sellers and the buyers. The length of the contract is defined by the start and end dates of a natural gas delivery and is set before the contract is signed. According to Melling

(2010), the durations of LTCs were really long in the beginning, lasting from 25 to 30 years, in order to allow for the recovery of exploration and the initial production cost of a new gas field, while the duration of LTCs in Europe diminished nowadays, from approximately 10 to 15years due to the continuous development of the spot market and the gas to gas competitions (DNV KEMA, 2013).

Melling (2010) presented the take or pay (ToP) obligations as minimum quantities that the buyer pays for a minimum volume of natural gas regardless of whether the natural gas is actually delivered and consumed by the buyer. Fundamentally, in this long-term contractual agreement the seller commits to sell a certain amount of natural gas, as well as the natural gas delivery capacity, while on the other hand, the buyer is obligated to take a minimum amount of natural gas via the ToP provision. In general, the ToP volumes take up 80-90% of the annual contract quantity, which is the key point of the European LTCs, over which the natural gas limits are set and can be changed (increase or decrease in quantities) periodically (Melling, 2010). Under the ToP provision, contractual parties agree on risk sharing, meaning that the seller assigns a volume of risk on the buyer who guarantees that the natural gas is paid for and taken, while the seller bears the price risk (DNV KEMA, 2013). LTCs provide a guaranteed source of revenues and security of demand for the producer and the security of a steady supply for the buyer. The seller/producer of natural gas therefore has a certainty of demand and can plan for the necessary investments in the gas extraction and the property infrastructure with a long-term rationale. On the other hand, the buyer has the security of supply and can therefore facilitate a long-term strategy in downstream markets (Talus, 2011). Although the risks in LTCs are allocated between the seller and the buyer of natural gas, Melling (2010) argues that the ToP obligation can be a major penalty for buyers as they pay for gas regardless of whether the gas was actually delivered and consumed, which consequently means that companies may lose billions of Euros worth of natural gas.

Volume flexibility is a basic element in LTCs, as it covers natural gas deliveries above the ToP provision in the natural LTCs and is interrelated with it (Long & Moore, 2003). As said above, typical LTCs contain 80% of ToP obligations of the nominal quantity of the contract, while the flexibility clause offers the buyer up to 40%-point increase in the nominal quantity in the LTCs at a comparable price level of natural gas. According to Konoplyanik (2011), the flexible clause therefore offers the buyer flexibility within the contract period, meaning they can increase or decrease the pre-set monthly volumes of natural gas inside the certain limits.

Another important core element in a natural gas long-term contract is also the destination clause, stating that the buyer is prohibited from redirecting or reselling the natural gas he has purchased onto other national gas markets, where he would become the indirect competition to the seller in the long-term contract (DNV KEMA, 2013). This clause was intended to stop any arbitrage between the high and low price of the natural gas markets and to maximize the profit of the seller, which consequently resulted in price discrimination between regional markets. DNV KEMA (2013) believes that the market parties on the natural gas market will use the price review clause in the LTC in the case where the contractual agreement will move away from the market's conditions. The purpose of the price review clause is that the natural gas price in the LTC reflects the prices on the natural gas market, thus both parties in the contractual agreement are allowed to request a price review after an agreed period and after every three years later on.

2.1.3 The pros and cons of long-term natural gas contracts

As explained above, the main pros of the LTCs are the security of supply, the price stability of natural gas, the low complexity of the contract and the stimulation of investments provided by ToP obligations, which enabled the LTCs to be the main drivers in natural gas trading for the last few decades, while the situation is changing nowadays.

Even though the LTCs were the flagship of the natural gas trade, they were developed before the liberalization of the gas market in the United States and later in the United Kingdom, and brought with them spot gas markets and the trading of natural gas, so they have some disadvantages. The major disadvantages of the LTCs are the discrepancy between the natural gas and oil prices (as the LTCs are indexed to oil prices and not to gas spot markets), the dependence of buyers on a single supplier of natural gas (they have a long-term commitment to buy the contracted volume of natural gas, although cheaper gas is available on the spot market or in LNG form), a rigid pricing formula and the obstruction of the competition as the new market players, as well as existing ones, cannot participate on the natural gas spot market until they are linked to LTCs. The disadvantages of the LTCs, together with the liberalization of the European natural gas market, have created a need for a new contracting trend and for more flexible trading instruments in natural gas, which will replace the LTCs.

2.2 Short-term natural gas contracts

The natural gas market has undergone a major revolution in many countries across the globe, as the government-regulated natural gas market structure has replaced the natural gas supply monopolies, which have existed in many countries. Even though the liberalisation of the natural gas market differs from region to region, the same process is applied around the world and is producing the new competitive market structure for the natural gas supply. The procedure of transformation began in the United States during the 1980s and has now spread to Continental Europe via the United Kingdom, as the result of the European Union Gas Directive (Long & Moore, 2003). All three gas directives are described below:

- The first European Gas Directive came into force on August 10th, 2000 and wants the EU members to open their markets to competition. The vital objective of the Directive is to create a single European natural gas market through opening individual countries' markets to competition (Long & Moore, 2003).
- The second directive was adopted on the 25th of November 2002, with the aim of opening up the competition to all industrial and commercial markets from July 2004 and all household markets from July 2007. The new directive also requires the legal unbundling of gas from entities which sell gas.
- In July 2009, the third directive was signed in order to establish a common rule for gas transmission, supply and storage. In addition to the three energy Directives, the Third Energy package was introduced. The aim of the Third Energy package was to implement the unbundling of the energy supply from transmission, cross border cooperation of the transmission system operator (TSO) and the freedom of the regulators. Furthermore, it established the Agency for the Cooperation of Energy Regulators (ACER), whose mission is to introduce and coordinate the work of state energy regulators at the European level, and to work towards a single European energy market for gas and an electricity market, to the benefit of all European buyers (European Commission, 2013).

The implementation of the European Gas Directive and the Third Energy package is already transforming the European natural gas market, as companies are seeking to mitigate the risk associated with the competition and want to ensure the diversity and security of supply. Energy companies are therefore entering strategic alliances or trying to become integrated into the new marketplace through mergers and takeovers. The liberalization of the natural gas market in Europe has also brought the development of gas trading hubs as the competition is progressing, due to the continuous improvement of connection, releasing pipeline capacity and the enabling of spot trading (Long & Moore, 2003).

During the last decade, the European natural gas market has transformed significantly due to the liberalization and so the development of natural gas hubs in Europe has arisen. Although it has been more than 20 years since the liberalisation of the British market and more than 15 years since the EU published the Gas Directives, there are still a lot of misunderstandings as to what a gas hub actually is. Confusion occurs over whether a gas hub is an actual geographical location (terminal, processing plant, compressor station) or a virtual location within a country's natural gas transmission network. This is what is referred to as an Entry/Exit point or a Market Area (Heather, 2015). Entry/Exit points will have an important role, as places to both balance the physical volumes of gas and to price those volumes, as well as being a place where gas is traded. However, according to Heather (2015), there are several requirements in order to establish a gas hub:

- A liberalized market creates competition between the suppliers and encourages buyers to demand more competitive natural gas prices
- Transparency, because the exchanges in a gas hub must be controlled and regulated and the data must be publicly available
- A large number of suppliers and buyers in order to guarantee efficient competition, sufficient gas flow and liquidity on the natural gas market
- Standardization of contracts as the terms and conditions of the natural gas contracts are harmonized, except the delivery period, quantity and the price of the natural gas market
- Third Party Access: the transit and the transport of natural gas will be united, meaning that all gas flow, regardless of whether it crosses the border or not, will be treated equally and thus, the TSO operates under equal conditions for both the transport and the transit of the gas market

The gas hub model does not include the formation of a single European regulator. On the contrary, the gas hub idea is to work on the existing contractual and operational measures of the national TSOs and regulators and enable the effective use of the cross-border capacity with the transparent natural gas price formation, which will boost greater involvement in gas trading and increase liquidity (IENE, 2014).

According to Heather (2015), a gas hub is a location where several gas pipelines intersect. The interconnection of several gas pipelines therefore represents an opportunity to trade and physically exchange gas between a large pool of sellers and buyers. The first gas hub was established in the United States in the early 1950s in Louisiana, called the Henry Hub, which sets the benchmark price for the entire North American trading region and is the most liquid gas market in the world (IENE, 2014). However, the concept of gas hubs came to Europe much later, due to the later liberalization of the natural gas market, if we do not consider the United Kingdom, where the National Balancing point (NBP) was established in the 1990s. According to Melling (2010), the NBP liquidity, the construction of two gas lines connecting the British market to Continental Europe (the Interconnector and the Balgzand Bacton Line), and the arrival of the LNG, strongly influenced the development of gas hubs in Continental Europe, which have been established in the last 10 years. Today the most significant gas hubs in Europe, according to Kulich (2016), are the Title Transfer Facility (TTF) in the Netherlands, which is the biggest hub in Continental Europe, PEG NORD in France, GASPOOL in Germany, and the Central European Gas Hub (CEGH) in Baumgarten Austria.

The gas hubs are either physical or virtual. Physical hubs are positioned in a specific geographic location, where pipelines physically interconnect and where the entire gas transmission grid is located. To trade natural gas at physical hubs, the seller can only sell to counterparties which have a transport capacity from the gas hubs. Counterparties, which do not have a transport capacity, can also buy the gas at a hub, but they need to simultaneously acquire the gas transport capacity rights from the hub. The necessity to buy the transport capacity can increase the transaction cost. Furthermore, if transport capacities cannot be traded freely they could potentially limit the pool of buyers and sellers, making the market less liquid (Harris, et al., 2013). These types of hubs are more used in the United States than in Europe, where the predominant type of gas hubs are the virtual gas hubs (Kulich, 2016).

Virtual gas hubs also identify as balancing hubs, which cover a wider geographical area and are defined by a national or a trans-regional gas network. The one that operates the gas transmission grid in the virtual hubs can accept natural gas at any location of the geographic area covered by the gas hubs, so the hubs actually represent a balancing point inside a natural gas pipeline system. Although the physical hubs allow for a larger trading volume of natural gas, more participants are able to trade gas in virtual hubs. A clear advantage of virtual gas hubs is that all of the natural gas, for which a fee for the access into the gas network has been paid, can be traded, while at physical hubs, only gas physically passing at an exact location can be traded and this represents higher risks (IENE, 2014). Furthermore, members of the virtual hubs can select between several exit/entry points within the gas transmission and have no commitment to organize the transportation of natural gas, as the transportation of natural gas inside the gas transmission is the responsibility of an independent TSO (Kulich, 2016). Therefore, in virtual gas hubs, counterparties do not have to purchase the transport capacities and this type of trading meaningfully reduces the trading of pipeline capacities (Harris, et al., 2013).

On the other hand, the Oxford Institute for Energy Studies (OIES) uses a different method of classification of the EU hubs, based on their market developments:

- **Trading hubs**: mature hubs, which enables the members to manage natural gas portfolios
- **Transit hubs**: physical gas points, where natural gas is physically traded, and their main job is to enable the transport of gas
- **Transition hubs**: virtual hubs, which are rather undeveloped, but have set the benchmark prices of natural gas in their domestic markets

Heather (2015) believes that it takes 10-15 years for a gas hub to achieve a mature state, as it needs a large pool of suppliers, a cross border interconnection, price responsive storage facilities, bilateral trading and the creation of exchange products (futures). As a result, the natural gas infrastructure supply diversification and trading on future pricing, are the most important elements for a gas hub to become functionally mature and a liquid gas hub. Liquidity in hubs can be measured with the churn rate, which is the volume of natural gas traded, relative to physical volume. The gas hub is considered to be liquid, if it has the churn rate of at least 10-15 (IENE, 2014). In Europe, the most liquid and mature market is NBP in the United Kingdom and TTF in the Netherlands.

The existence of numerous gas pipelines in gas hubs will create a hub pricing competition, which will push down the prices of natural gas. Therefore, the gas hubs are vitally improving the efficiency of the gas markets, as they offer much lower market prices of natural gas than those in the LTCs, are important in guaranteeing energy security in the case of a short-term increase in the demand, especially during the heating season, and play the important role of long-term energy security, as they store huge volumes of natural gas from a large number of suppliers, ensuring that the end users are no longer dependent on the major providers of natural gas. Furthermore, they represent the key factor for the development of further energy integration onto the world's gas market (Heather, 2015).

2.3 Natural Gas Trading

The Liberalization of the gas market in Europe has had a profound impact on the development of gas market trading across Europe, which has resulted in the dramatic increase of the traded volumes of natural gas. As an outcome of the increased trading, several over the counter (OTC) markets, as well as gas exchanges, have arisen. According to FTI Consulting (n.d.), the development of European hubs has allowed the gas producers, suppliers, and traders to transact with each other and for a market-based gas price to emerge. Hence, the new natural market model is based on trading, where market partakers make short and medium-term deals through exchanges and hubs, besides the existing bilateral trades. Furthermore, the natural gas trading and the hub pricing are evolving from a physical imbalance market to a price risk management market (Long & Moore, 2003).

In gas to gas competition, there are two ways of natural gas trading: OTC trading and energy exchange. OTC trading is non-regulated bilateral trading between a buyer and a seller of natural gas, who can be dealt with directly or through brokers. OTC trading can be based on standard as well as customized natural gas products. On the other hand, the energy exchange trading is based on standardized products, where the buyer and sellers of natural gas match bids to facilitate anonymous standardized trading and the clearing of natural gas products (Kulich, 2016). There is a lot of confusion with gas hubs and the energy exchange, as a gas hub is a place for delivery of the natural gas, whereas the energy exchange is where the market operators buy and sell natural gas by giving bids on a trading platform (IENE, 2014). The main goal of any energy exchange is to guarantee reliable and transparent wholesale prices on the market, by achieving market equilibrium at a fair price, to be certain that trades are done and that the exchange is paid for and delivered.

According to IENE (2014) and ACER and CEER (2016), OTC trading is still a preferred trading method in gas to gas competition, due to the lower cost of trading (clearing fees not included) and customized products, while energy exchange requires the liquidity and the standardization in the traded natural gas products, which can reduce the ability of the energy providers to find the customized natural gas products they require in order to mitigate or manage their risk. Additionally, OTC trading is more flexible and therefore, in the case of miss-trades of market partakers, an error can be corrected by a broker in minutes, while on the other hand, the pricing interference from regulators on the energy exchange is common, and the anonymity of the exchange is not always wanted, because some energy trading companies like to know who the counterparty is to reduce the counterparty risk.

Although there are some disadvantages of energy exchanges, they still represent an important role in the development of a traded natural gas market and provide five important functions, which are: price discovery and transparency, supply and pricing flexibility, physical balancing, and financial risk management. Because the exchanges of natural gas are regulated markets, they have a commitment to be fully transparent in everything they do: from volumes to products, as well as the prices at which they were traded. These allow all gas market partakers and outside viewers to know the exact price of gas now and in the future (Heather, 2015)

The capacity contract for natural gas principally comprises of a right and an obligation. The right describes who the owner of the capacity is and has the right to submit the capacity usage to either the TSO or a pipeline. On the other hand, the contractual responsibility is defined by who has to pay either the TSO or the pipeline for the capacity and therefore, according to Harris, Brown, and Massolo (2013), the separation results in several models of capacities for trading:

- **The entire natural gas capacity transfer,** where the capacity owner sells both the right to submit the gas capacity usage, as well as the obligation to pay.
- **The subletting of the natural gas capacity,** where the original capacity owner sustains the right and the obligation. However, the original natural gas capacity owner signs another contract, which allows the third party to submit the capacity to the original owner, which later makes the same nomination to either TSO. It similarly applies for the payment of the capacity.
- **The operational transfer of the natural gas capacity,** where the capacity owner transfers the right to submit natural gas to another party, while the original owner sustains the accountability to pay for the capacity. In this case, the owner must inform the pipeline about the third party, so they will accept their submissions of gas.

Today, all of the European natural gas capacity trading takes place on a trading platform PRISMA, which was developed by a major European TSO and ensures the transparent and easy use of the platform for the gas shippers. Natural gas market players buy/sell transport capacities on the short-term and long-term auctions. The platform is fully automated, thus simplifying capacity trading across the world and helping to promote the competition on the natural gas market (Harris, et al., 2013)

2.4 Traded Instruments

The majority of gas trading for the physical delivery of natural gas in Europe is done in a form of spot trading a day ahead, and intraday, prompt and futures markets. In addition, financially settled derivatives such as swaps, options and weather derivatives also exist, but such markets are minor to the spot and futures trading. All of the above-mentioned instruments are shortly presented below.

A spot market is a market where the market participants buy and sell natural gas on an everyday market, whereas spot prices reflect the daily supply and demand balances and can thus be very volatile (Levine, Carpenter, & Thapa, 2014). The most traded contracts are day (T) or T+1 (day ahead deliveries), which are used for the continuous delivery of natural gas during the day, following the day on which the contract was settled. The spot market can be further divided into the day ahead, intraday and the balancing markets, which offer hourly contracts. However, in that case, there is usually a 3-hour lead time (waiting period) before the delivery of gas can be executed. The delivery usually takes place during 6am and 6pm. Spot contracts are defined as block contracts for the physical delivery and supply of gas at a constant rate of delivery for the daily load (IENE, 2014).

In contrast to spot contracts, prompt contracts refer to all other periods within the month (Heather, 2015), thus prompt contract are in a primary spot contract, which covers the delivery of natural gas for somewhat longer periods than the spot contract. Prompt contracts are settled on day T for the delivery of gas on day T+n, where n is equal to any given number of days between 1 and 30 (IENE, 2014)

In the long term, most of the physical deliveries of gas in Europe are settled via the futures trades. A futures contract is a standardized, exchange-traded contract between the buyer and the seller for the transaction of a certain quantity of an underlying commodity, in our case gas, for a pre-determined price on a future delivery date via the organized gas exchange, which can either be settled physically or financially (Fusaro, 1998). The main advantages of the futures are the elimination of the counterparty credit risk, the reduction of the transaction cost and the simple evaluation of the Mark to Market. The Mark to Market term (MtM) refers to the daily settlement of the futures contract, meaning that the company can see the gains or the losses of a respective futures contract, which are settled through a margin account, at the end of each trading day. Hence, the futures contracts show the profit or the loss during the period of the contract and exhibit the cash flow (Poitras, 2002).The natural gas instruments, such as the futures, can also be seen as a price risk management tool and not just as a source of the natural gas supply. Producers enter into a short hedge to lock a good selling price for the natural gas, while consumers enter into a long hedge to secure a good natural gas buying price.

On the other hand, forward contracts are, similar to the futures agreement, meant to purchase or sell a commodity or financial product for a pre-determined price on a future delivery date specified in the contract term. However, there are, according to Eydeland and Wolyniec (2003), three major differences between the two types. The first difference is that the forward contracts are traded OTC instead of as an exchange, meaning that the forwards do not need to be standardized. The second difference is that even though the forward contract specification is as similarly extensive as the futures, the former allows for a relatively free choice of the characteristic, due to non-standardization. Thus, the structure of the natural gas forwards may be tailored in a way that is most suitable and convenient to the need of the contacting natural gas parties. (Poitras, 2002). The third and the key characteristic, in which forwards differentiate form a future contract, is that forward contracts do not feature daily settlements, which can either be an advantage or a disadvantage. The advantage is that a forward contract holder does not need daily access to cash, in order to satisfy the margin calls, while the disadvantage is the counterparty risk, which becomes significant in the case of the contract being in money at the delivery (Fusaro, 1998).

A swap contract for natural gas is, according to Hull (2006), defined by the so called fixed-price or the fixed-for-floating swaps, which define the contracts where the buying party pays a fixed payment to the selling party for a pre-defined duration of the contract. The fixed payment either stays constant over each period or may vary according to a predetermined schedule. In exchange for a fixed payment, the buying party receives a floating payment from the selling party, which is linked to a specific pre-defined floating index (e.g. a natural gas spot price or a price index). At the time of the delivery, the contractors settle the financial differences, so a cash payment is required only for the difference between the average of the selected daily price during a particular period and the originally pre-determined fixed price. Swap contracts are one of the most popular and frequently used derivatives, because swaps are very flexible financial products, which are traded over the counter and are therefore easily tailored to suit the very specific needs of the contracting party. In addition, they are settled by cash and have an exceptional potential for hedging, as they offer an easy way to transform the floating payment, which is highly volatile due to the fluctuations of the underlying index into a fixed one (Eydeland & Wolyniec, 2003).

Options for natural gas are, in essence, the same as their relatives in other financial markets, except that the underlying asset is gas. Therefore, a call option refers to the right, but not the commitment, to buy gas at a pre-specified strike price. On the contrary, the holder of a put option has the right, but not the commitment, to sell gas at a certain pre-agreed strike price (Fusaro, 1998). To satisfy the needs of the natural gas market, especially to manage the price risks on a daily or even hourly basis, several subtypes of options, such as the fixed strike options and the floating strike options, have developed, and can be exercised daily during the exercise period (Eydeland & Wolyniec, 2003).

Weather derivatives offer buyers the futures or temperature-based options, so they can insure themselves against the falling sales caused by weather patterns that are different than excepted. The main users are the energy companies, which protect their revenues against unexpected warm/cold temperatures. In addition to futures and options, weather swaps also exist, and they are similar to the options based on temperature. Weather derivatives are attractive and have huge potential, as they can be used to hedge unknown quantities and have probable users on both sides, as gas producers may, on one hand, prefer cold winters, while retailers prefer warm ones. Therefore, the weather derivatives are priced against the average outcome and the party who insures itself must pay a risk premium. Although the buyer has to pay the risk premium, the gas producers have used derivatives to hedge against warm winters, as they can be heavily affected by the lower volumes of natural gas, as well as weak prices.

2.5 The trading volumes and the pricing on European gas hubs

Table 2: Traded volumes, market participants and churn rate in European gas hubs

Gas Hub	Traded volumes in TWh			Traded volumes changes over	Active Market Participants	Churn rate
	2011	2014	2015			
National Balancing point (NBP)	18,000	20,505	20,950		>50	26.8
Title Transfer Facility (TTF)	6,295	13,555	17,015		>50	45.8
NetConnect Germany (NCG)	880	1,750	1,790		30	3.3
Gaspool (GPL)	310	1	950		30	
Zeebrugge (ZEE)	870	850	805		15	4.3
Punto Di Scambio Virtuale (PSV)	185	525	720		15	1.0
Points d'Échange de Gaz Nord (PEG)	430	435	500		10	1.7
Central European Gas Hub (CEGH)	170	400	340		15	3.7
Points d'Échange de Gaz Sud (PEG)	40	80	90		5	0.6
Points d'Echange de Gaz TIGR (PEG)	5	5	5		n.d.	n.d.

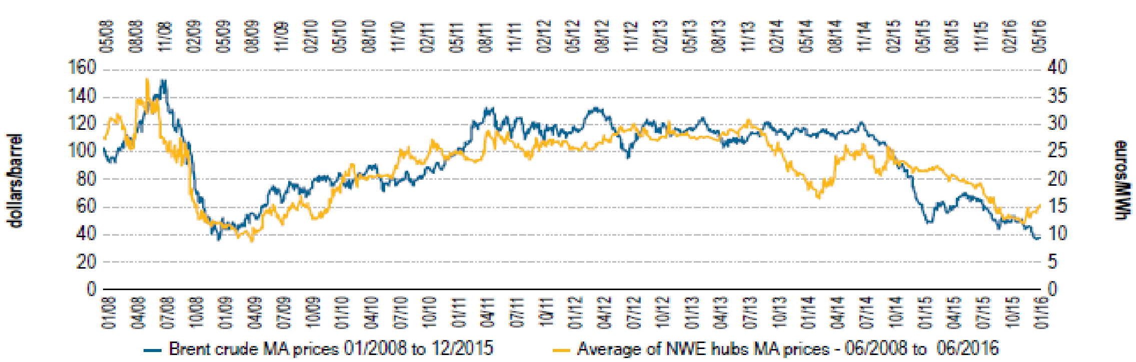
Source: Heather (2016, p. 22).

As seen from Table 2 above, the NBP and TTF hubs are the leading hubs in Europe in terms of the total trading volumes of natural gas and market participants. They have the most developed spot, prompt and forward markets and they act as the gas price reference for the British region and Continental Europe, respectively (ACER & CEER, 2016). Even though, progress can be observed in other parts of Europe as gas hub wholesale markets are beginning to function better over the years.

In addition, the liquidity of the gas hubs is increasing, as total traded volumes at European gas hubs, in 2016, represented 9-times the total European physical natural gas consumption. The TTF gas hub has passed the NBP in 2015, in terms of the churn rate and became the most liquid gas hub in Europe. Other gas hubs are not liquid, as at the gas is considered to be liquid, if it has the churn rate of at least 10 (IENE, 2014). Furthermore, the enhanced hub liquidity in 2015 was connected to an increase in gas volatility, due to oil price movements impacting the natural gas price formation, the Russian Ukraine supply dispute and the reduction of the production cap on the Dutch Groningen field, which engages market participants in price risk management transactions via futures products on gas hubs, in order to mitigate the risk. According to ACER and CEER (2016), the most traded volumes on the European gas hubs are concentrated in spot, prompt and short-term products (from a month ahead to a season ahead) and serve as medium term instruments for the gas portfolio optimization.

As previously discussed in chapter 1.2.2 and in chapter 2.2, hub prices are based on gas to gas competition. However, the gas hub product prices are strongly influenced by the pricing conditions of LTCs via the ToP provision. Therefore, the correlation between the oil and gas hub prices has been historically high, which was also true in 2015, although the LTCs are being gradually replaced by hub ones. The before mentioned trend is very visible in Figure 6 below. The main examination for assessing the level of market integration in Europe is to compare the prices at which the supplier's source of natural gas is in different market regions. The supply cost variances are dependent on the type of supply contracts, the gas supply source and the level of liquidity and competition in Europe. Therefore, all of these factors are impacting the development of the gas hubs and the degree of the European gas market's integration (ACER &CEER, 2016). As a result, in the markets where the gas hubs have an important supply hedging role, meaning that the price formation of natural gas is reflected via the physical buying of natural gas and also the fact that gas indexation is prevalent in contracts, a lower sourcing cost occurs. That is why markets in North-Western Europe (NWE) exhibit lower gas prices, as observed in Figure 6. The narrowing spread between the prices over the last years implies that the regions are benefiting from stronger market competition. Hence the buyers are facilitating the price renegotiations with the suppliers.

Figure 6: The evolution of the oil vs. the gas hub price in Europe



Source: ACER & CEER (2016, p. 34).

3 RISK MANAGEMENT IN NATURAL GAS

3.1 Overview of the risk management in natural gas

According to Walter Wriston, the former chairman of Citicorp, "*All of life is the management of risk not its elimination"* (Jacque, 2010, p.281), meaning that corporations are in the business of managing risk.

Most adopt succeed and other fails. Hence, risk management is nowadays becoming an important tool in mitigating risk. Furthermore, the role of risk management is to ensure that a company has the cash available to make value enhancing investments, because external financing sources, as external equity, are costly and more expensive than internal ones, especially due to the asymmetry of information (adverse selection) or the wrong selection of financing (Froot, Scharfstein & Stein, 1994). The status of risk management on the natural gas market is no exception, as the volatility in natural gas prices in the last few years (financial crisis, Ukraine crisis etc.), has resulted in an increased emphasis on the risk management activities by natural gas market participants.

Risk can be defined as the volatility of the unexpected outcome, which can represent the value of assets, equity or earnings. It can be broadly classified in business and non-business risks. Business risks are the ones that the corporation freely assumes, in order to achieve a competitive advantage and add value to their stockholders. These risks include the business decisions of the corporation and the business environment in which they operate. In addition, the strategic risk (a decision made by the company's board executives), the macroeconomics risk (economics cycle, monetary policies), as well as the competition and the innovation risk, are also included in the business risk classification (Holton, 2004). On the other hand, the non-business risk can be further divided into two groups: the financial risk and other risks. According to Jorion (2006), a financial risk relates to possible losses due to financial market activities. Hence, a market risk, a credit risk and an operational risk (inadequate people, processes or third events) are a part of a financial risk, while other risks include a regulatory/political risk and a reputational risk.

A risk is characterized by two elements: uncertainty and the impact on utility (Holton, 2004), where the risk probability is, according to Berk and DeMarzo (2011), measured with variance and standard deviation. With variance (Var), we mean the excepted square deviation (E[R]) from the mean (R), while standard deviation (SD) is the square root of variance as shown in formulas (2) and (3) below. When there is no risk, the variance is zero. According to Damodaran (2007), the variance and the standard deviation are the most public measures of risk, although they do not differentiate between the upside and downside risk, as risk can be thought of not only as a threat, but also as an opportunity.

$$Var=E\left[R-E[R]\right]^2 \tag{2}$$

$$\sigma(R)=\sqrt{Var(R)} \tag{3}$$

When measuring risk, it is important to differentiate between volatility and variability. The term volatility is used to define the price variation of a commodity, in our case natural gas, and is defined by the day to day changes in the price of natural gas. Volatility, which is a degree of risk, is a degree of unpredicted variation around a mean, and not a degree of variability (level of prices). Since the price is a variation of supply and demand, the volatility in a natural gas price is an outcome of the demand and supply specific (Energy Information Administration, n.d.). In an example where a natural gas contract has a price that differentiates over months (seasonality), according to some predetermined fixed quantities, it is not called volatility but variability, as the contract owner has cost variation over months, which is not an origin of risk or volatility. Hence, it is not volatility if the natural gas contracts, which have the characteristics of seasonality, have the seasonality mirrored in prices. However, if the prices deviate from the expected ones, that is called volatility.

A high level of risk and uncertainty, strengthened by the deregulation of the natural gas market, comes from the natural gas price risk exposure, thus the volatility on the natural gas market refers to the relationship between the price volatility of natural gas and the time of delivery. The relationship commonly declines, as the volatility of near-term gas agreements are inclined to be higher than long-term contracts, which decline to a steady lower long-term level volatility. Hence, the short-term contracts (spot, prompt) have higher volatility than the longer, natural gas contracts as a consequence of a means reversion, which is the inclination of natural gas prices going back to a mean or to a common level of it, after the gas price shockwaves (can be ascending or descending), and originates from short-term circumstances (Graves & Levine, 2010). For instance, in the case of catastrophic events, the supplies of natural gas would be constricted, whereas the demand would be high, and the circumstances may potentially lead to a price spike of natural gas. However, the natural gas price spike would, for example, boost the repairs on the supply production line or the gas would be transported from other parts of the world, and thus the demand would decrease, so that the prices of natural gas would deteriorate to a normal level. There are many potential short-term impacts on the natural gas market that will affect the natural gas prices but are not negligible in the long run. Natural gas prices in the long run are affected by the changes in systems, the technology and the regulations, so they are far less volatile, and it is not uncommon for the short-term volatility of natural gas to be much higher than the one in the long run, which is shown later.

According to EIA (n.d.), the prices of natural gas are more volatile than the prices of other commodities, due to several factors:

- **Weather**: is a strong component, whose unpredicted and major changes (warm winter, cold summer etc.) can heavily impact the end users’ demand and supply component as well.
- **Production and imports**: are a critical component of the natural gas supply, thus their changes have a major impact on the natural gas prices, as the prices for natural gas are uncertain, due to the worldwide natural gas production and imports.
- **Delivery restrictions**: this can happen in the pipeline transmission grid and the consequences can adjust their supply and distribution abilities, which results in the variation of the natural gas quantities
- **Storage**: is an intermediary between the demand and the supply of natural gas and it is very important in the time of the peak of demands (a cold winter). The natural gas market members can therefore use the comparison of storage quantities with a future or a current demand of natural gas, for assessing the natural gas market.
- **The natural gas marketplace information**: if the natural gas market members have miss-information about the before mentioned factors of volatility, the prices of natural gas can change, as they set their trading conclusions on speculation, false information and rumours.

The effect of natural gas price volatility mostly depends on the service and buying practices of consumers and it is why volatility differentiates between the consumers. Natural gas prices for the housing users are more stable than for the industrial and commercial user, as their natural gas receipt reflects monthly average prices of natural gas, which are not so volatile. Industrial and commercial users often rely on a short-term market, buying without fixed price terms, due to the fluctuations in their consumption and are ready to risk the price variation of natural gas in order to save money, as well as shift to other energy commodities if needed (EIA, n.d.). According to Beattie (n.d.), beside the price risk, which is the major issue, other risks that the gas companies face also exist and are interrelated with the price risk of natural gas:

- **The supply and demand risk**: Shocks of supply and demand are also one of the major risks for the gas companies, as natural gas transportations take a lot of investment and time, so they are not easy to mitigate when the prices of natural gas deteriorate or go up. Furthermore, macroeconomic factors and financial crises can additionally affect the investment and the natural gas industry, independently of the usual price risk.
- **The cost risk**: Operational costs in the natural gas industry are really high and depend on the territory (the more difficult to drill, the more expensive the project) and the regulations of the country. If we add the uncertainty of the gas prices due to the natural gas production, the gas companies have a major cost distresses. Additionally, the natural gas companies are struggling to find and keep adequate workers, which they need during the prosperous times and which results in higher salaries. To sum up, the gas industry is a very capital industry with less players over time, as companies cannot afford to cope with the high costs of the industry.

- **The political risk**: Politics affect the natural gas industry with regulations and laws that vary from country to country. However, troubles arise when the political parties or the winds shift and that changes the governing environment. Furthermore, in some cases, the initial agreement can be changed after the money is already capitalized for natural gas drilling or transportation, as a government sees the opportunity to seize more profit for itself. In a natural gas industry, the political risk is more present in the developing countries, where the regulations and laws are still unstable and where the rules are in favour of domestic corporations. Therefore, in order to mitigate this type of risk, the companies have to make a careful analysis of the country and build a sustainable relationship with global gas partners.
- **The geological risk**: This refers to the struggle of natural gas extraction and the probability that the gas reserves are much smaller than estimated. In order to reduce this risk, geologist frequently test the surface to reduce the amount of wrong estimations. Furthermore, as explained in chapter 1, unconventional gas extraction methods significantly helped to extract gas in geographical territories where it would otherwise be impossible.

To cope with the above-mentioned risks, energy players on the natural gas market use risk management processes, tools and control in order to mitigate the risk.

According to Cutis and Carey (2013), value is a function of risk and return and given that risk is an essential part of value, strategic corporations do not try to eliminate risk or even minimize it, but they strive to manage the risk exposure across their organization, so they experience just the right amount of risk to effectively follow the strategic goals of the corporation. Therefore, risk assessment is important and helps the corporation understand how important each risk is to the accomplishment of their strategic goals.

Below, in Figure 7, there is a detailed COSO risk assessment framework. The purpose of the risk framework is to evaluate the height of the risks and to focus board devotion on a significant risk, in favour of designing the basis for a risk response. Risk evaluation is about defining and prioritizing risk, so that the risk degree is dealt with an enterprise determined threshold.

Figure 7: A risk assessment process diagram

Source: Cutis & Carey (2013, p.2).

In the first step of the risk assessment, a corporation must first identify the risk in order to understand it and to prioritize it according to the severity of risk.

The second stage is divided into four stages: the development of the assessment criteria, the assessment of risk and risk interaction and the prioritizing of the risk. The first action of the corporation is to develop some sort of a risk assessment criteria or a scale to measure risk. Most companies define their risk measure/scale in terms of influence (the extent to which a risk affects the corporation's finances, operations, environment etc.) and the possibility or risk. Risks are given a rating from the lowest to the highest magnitudes expected. For instance, a company sets a 5-level rating, from a minor risk, up to dangerous risk, which may affect the company's financials. The same process is applied for the probability of risk, where the company sets a similar scale, from a rare possibility of risk and up to a repeated event or risk. Both scales are illustrated in appendix B and C respectively.

In the later stage, a corporation has to assess the risk, which is generally done in two phases, using qualitative and quantitative analysis. In the first part, the qualitative evaluation is done for an individual risk, according to the before mentioned scales in the form of interviews, surveys, benchmarking and the making of a scenario analysis, which can predict a variety of outcomes and is useful for strategic planning. After that the quantitative analysis is performed, which needs actual values of a risk's influence and the probability of a risk's occurrence in order to allocate assets to business activities with the best risk return and allow the corporation to do a cost-benefit analysis. The value of the analysis depends on the correctness of the data and the validity of the used model.

After the competition of the qualitative and the quantitative analysis, the risk interaction takes place, as it is very important to know the risk of individual factors, as well as their interaction due to the natural hedges and the magnifying risk in order to completely understand the portfolio risk. The easiest way for the corporation to take risk interaction into account, is to group related risks into a wide risk zone (risks related to distribution, marketing etc.) and then appoint the ownership and the oversight for the risk zone. There are three different ways of presenting the risk interactions: a risk interaction map, which is the simplest method (a graphical illustration of risk, where the same risks form x and y axes), correlation matrices and bow-tie diagrams (breaks the risk occurrence into separate components) and is illustrated in appendix D.

In the final stage of the risk assessment, after the conclusion of risk assessments and interactions, the corporation must prioritize the risk. The process is similar to assessing the risk, as risks are first ranked according to several criteria (impact, probability of occurrence). However, the ranked risk order is reviewed due to additional considerations of particular factors alone, and the desired level of the risk threshold. The corporation can achieve this kind of arrangement by organizing risk into a hierarchy or by creating heat maps, which illustrate the risk according to its occurrence and severity. Both possibilities are presented in appendix E and F, respectively.

The outcomes of the risk assessment processes function as the first task of the risk response. According to Cutis and Carey (2013), different options are studied, from accepting risk to reducing it, and different cost benefit analyses and response strategies are formed in order to develop a risk response plan to mitigate the risk according to the company's risk threshold and management strategy. It is highly important that the risk assessments are practical and easy to understand, and that the process is managed by people with the right knowledge and skill, which ensures that the participants feel empowered by their contributions and the monitoring of the risk response. The ultimate goal of a risk assessment is to make sure the managers at every level will use the information to execute decision regarding value.

3.2 The risk management tools in natural gas

According to Froot et.al. (1994), risk management enables the companies to better align their demand for funds with their internal supply of funds. In this way, gas companies can reduce the imbalance of the lack in supply in some periods, with the excess of supply in other periods. This strategy is called hedging. Hedging is a term which, according to Sturm (1997), is used when describing the purpose of entering a transaction with the intent of offsetting risk from another related transaction (for example, buying car insurance is a hedge against the risk of paying for the entire cost of repairing the car). In the case of hedging with insurance products and derivatives, which cost a certain amount in exchange for an uncertain cost, a cost-benefit analysis should be performed, so that hedging is applied only if the costs do not overcome the benefits (Damodaran, 2007).

Natural gas companies have historically used and chosen different methods of managing risk. They have mitigated the risk through their investment decisions and financing choices. Nowadays there are a variety of tools available for the participants on the natural gas market, who want to manage the gas price volatility risk. Tools can generally be divided into physical and financial tools.

3.2.1 Physical tools

According to Graves and Levine (2010), physical tools are further divided into storage, fixed price contracts, changes in production and gas reserves. Storage facilities are an essential physical tool, due to the volatile consumption of natural gas (consumption in the winter is, on average, six-times higher than in the summer), thus their vital role is to store natural gas when there is an oversupply on the natural gas market, in order to guarantee the supply in times of high consumption. According to Levine et al. (2014), there are different types of natural gas storage, which can simply be separated into underground (aquifer, cavern) and surface storage (tanks and tubes). Furthermore, DNV KEMA (2013) explains that storage also differs in terms of duration, as duration can be year on year (strategic storage), seasonal, short-term (monthly/weekly), diurnal (within a day) or peak service storage (where the injection capacity is significantly higher than the withdrawal).

Irrespective of the type or storage duration, storage facilities play an important role in the physical toll heading. The first role is the use of the natural gas storage facilities as a within-a-year hedge, where gas companies purchase large amounts of natural gas in the summer when prices are lower. They inject the gas into the storage, and withdraw it in the winter, when the prices of natural gas are much higher, and thus save money. On the gas market, where the gas companies do not have access to storage facilities, they use LNG peak-shaving facilities in order to satisfy the demand in super-peak periods. They liquefy the natural gas in the summer and re-gasify it in the winter. Another option is short-term storage, which is used on a daily basis for balancing the mismatches between natural gas deliveries and the burn requirements. Apart from these two types, others short-term products also exist, such as parking, loaning services or hourly firm transportation contracts, which allow the buyers to take the gas randomly over specified hours (Graves & Levine, 2010). Overall storage facilities help reduce the risk and improve the supply of natural gas, especially during winter delivers.

Graves and Levine (2010) describe fixed price contracts as an agreement between the buyer and the seller, where the buyer is obligated to pay the seller a fixed price for a predetermined quantity of natural gas, which the seller will deliver to the buyer. The alternative to a fixed contract is an index contract. In an index contract, the price is linked to a monthly spot price of gas, which is reported and published by gas journals.

Apart from the storage facilities and the fixed price contracts, two more physical tools of reducing price volatility exist. One of them is the change in the production of natural gas, where the market producers of natural gas have the flexibility to open or shutdown the production, depending on the gas price levels. The production of natural gas is also dependent on the gas users, who can easily switch to cheaper fuels or buy spot power instead of gas units, so it is sometimes better to buy power than to produce it. With the flexibility of being able to change the production operations, gas user can reduce the gas price volatility. On the other hand, the acquisition of gas reserves, which was considered the longest hedge available on the market, is nowadays not as attractive as it was in the past, due to the deregulation and the unbundling of the European gas market, when the gas companies used vertical integration as a strategy of risk management. (Graves & Levine, 2010).

3.2.2 Financial tools

Financial tools are traded financial instruments, which do not require an actual exchange of natural gas and can be traded on the natural gas market for financial profit. Among these products are futures, swaps, options and weather derivatives, which are explained in detail in chapter 2.4.

3.2.3 The limitations in managing gas price volatility

Like every system, financial risk management has some limitations as well, when managing price risks. Hedging, which is a part of the physical and financial tools, will not remove all of the gas price volatility. Even the most developed hedging plan cannot bear essential changes in the gas industry, due to several reasons. According to Graves and Levine (2010), the major factor is that the available hedges do not take into consideration all of the possible risk factors in the gas industry and that the hedges are also not available for distant periods in the future. Furthermore, hedging is a time, money and people consuming activity, which needs to be balanced against other uses of assets and capacity. As the result of trade-offs, some products in the natural gas portfolio will remain unhedged when forecasting risk, which will result in assessment errors and gaps in the hedge coverage (Kumar & Fisher, 2010). An additional reason is the wrongful perception that the current estimates of risk factors will describe future outcomes, meaning that risk can be predicted, based on the historical volatility of gas prices. According to Graves and Levine (2010), these sorts of limitations can be seen in the below described elements:

- **Liquidity issues** or illiquidity, meaning there is no hedging contract available for a particular period on the natural gas market or no available buyer, which will allow you to leave a natural gas contract, which becomes unattractive (out of money).
- **Credit and collateral costs,** which are the result of the changing conditions on the natural gas market and the excessive hedging, especially for a distant time period on the natural gas market. These fears arise for the natural gas positions which are out of money, and there is a huge likelihood of supplier bankruptcy and the costs of mark to market bookkeeping and cash collateralization commitment. An example is a credit counterparty risk in a rising price environment, when a seller of natural gas, according to the contract, has to deliver the gas to a buyer at a predetermined price, which is lower than the one on the market. In the long term, this can potentially cost the seller a huge amount of money.
- **Regulatory obstacles and risks**, which limit the reduction of risk, and can be achieved with natural gas hedging programs. (Regulators leaving a share of the natural gas portfolio unhedged, so that the end customers will pay the price, which reflects an unstable condition on the natural gas market.)

- **Hedging budgets** can limit the use and effectiveness of particular risk management strategies on the natural gas market. Hence, the strict budgets limit the use of a call, put options and futures on the natural gas market, as well as the insurance product, which needs to be paid up front.

3.3 Risk management control

Kumar and Fisher (2010) believe that when hedging is done well, the benefits of hedging can go beyond avoiding the financial distress by opening up possibilities to save and create value as well. Therefore, it is crucial for a gas company that uses hedging instruments, to have risk management policies, which provide the protocol for the hedging operations and their control, in order to follow the company's overall strategy on the natural gas market. Protocols will generally define all, or some, of the features presented below. However, in this chapter I mainly focus on the metric and the control features, which are the main objective of my master thesis. According to Graves and Levine (2010), the protocol features are: goal, target, metrics/reports and control.

The goal is basically a corporate objective of the gas company, which needs to be achieved by the hedging program. After the goal is set, the gas companies must set a target that requires the creation of a simulation model, which will show open positions and a variety of probable hedges in a company's natural gas portfolio, in order to follow the corporate objective. In the simulation model it is possible to compare the risk mitigating performance of different strategies of hedging, varying on the type and duration, as well as predicting the credit and the collateral exposure of the gas company (Kumar & Fisher, 2010).

The metrics and controls of risk management are interrelated, as the gas companies will have some regulatory reporting of their risk management activities through daily or weekly reports, where they will review their hedged and un-hedged position, which they also have to control. In their reports they will track the forward position and the changes in the position from the previous report (Graves & Levine, 2010). The more developed risk management programs on the natural gas market use statistical techniques to measure and monitor the risk of natural gas portfolios. Over the last year, the value at risk (VaR) became the most used tool for measuring the exposure of the short-term financial risk for the companies in the natural gas industry (Institute and Faculty of Actuaries, 2016).

VaR was developed by JP Morgan in the 1970s, as a risk measurement to show the likely maximum loss over the next trading day in one number, thus VaR is defined as a maximum loss suffered by a given portfolio within a given time period by a given probability (Dowd, 1998). Although the VaR method originates from the banking and the financial industry, companies trading with natural gas are using VaR to assess the market risk of their portfolio and their individual positions on particular gas markets for the purpose of financial risk management, which allows them to optimize their portfolio and adjust their positions with their regards to a risk threshold (Asche et al., 2013).

Simply put, VaR measures the potential loss of the portfolio over a defined period for a given confidence level. The defined period, or the holding period, is referred to at the time in which the assets in the portfolio are constant and thus the portfolio is unchanged (Asche et al., 2013). It is regularly set to be a day or a month, depending on the type of portfolio. However, shorter-defined periods are better for the valuation, as they do not take a long time until the predicted sample is large enough (Dowd, 1998). On the other hand, the confidence level explains how often the portfolio returns will exceed the VaR number. The confidence levels range from 90% to 99%. However, the most used confidence levels are 95% and 99%, meaning that the portfolio return will exceed the estimated VaR one (99%) or five times (95%) on every hundredth observation. Furthermore, one method of VaR assumes normal distribution, which has a high probability that any observation from the sample will have a value that is close to the mean and a low probability of having a value that is far from the mean.

There are 3 used approaches for estimating the VaR: the historical simulation, the variance covariance method and the Monte Carlo simulation (Jorion, 2006), which will be presented below respectively.

According to Jorion (2006), in the basic historical simulation, the historical distribution of the returns also represents the distribution of the future returns. Therefore, to calculate the VaR based on the historical simulation, the time series returns in the portfolio have to be organized from the worst to the best. After the returns of the times series are organized, you have to choose the number that corresponds to the percentile of the distribution, based on the selected confidence level and this is how you get the VaR calculation. Below is the formula (4) for a basic historical simulation where α represents the quintile of empirical distribution of returns (r).

$$VaR_{t+1}=VaR_{\alpha+1}(r_t,r_t\text{-}1\ldots,r_1) \tag{4}$$

In the case where we would have 100 observations, VaRt+1 (0.95) is simply the negative of the 5th lowest return observation in the sorted sample of returns. The advantage of the historical simulation is definitely the easy implementation, calculation and explanation to others. However, it has its disadvantages, since it bases its predictions on past returns and it is highly possible that the future returns will be different (Dowd, 1998).

On the other hand, the variance covariance method assumes a normal distribution, meaning that the asset returns follow a normal pattern. For calculating VaR via the variance covariance method, we only need the average returns and the standard deviations of returns. When using this method, we need to calculate the correlation and covariance between the assets, from which we can get the standard deviation of the portfolio. The following formula (5) is used for the calculation of the portfolio variance, where $\omega_{i/j}$ represents the weights of the assets i or j, ρ_{ij} represents the correlation coefficient between the returns of the asset i/j and $\sigma_{i/j}$ denotes the standard deviations of the assets (Dowd, 1998).

$$\sigma_p^2 = \sum_i \omega_i^2 \sigma_i^2 + \sum_i \sum_{j \neq i} \omega_i \omega_j \rho_{ij} \sigma_i \sigma_j \quad (5)$$

$$Var_{1-\alpha} = P * \sigma_P * Z_\alpha \quad (6)$$

After the calculation of the portfolio variance, the VaR will be given by formula (6) above, where $VaR_{1-\alpha}$ is the estimated VaR at the confidence level 100* (1-α) %, P presents the value of the portfolio, σ_p denotes the standard deviation of the gas portfolio and Z_α represents the number of standard deviations on the left side of the mean, at the required standard deviation. However, since the variance covariance method assumes a normal distribution, we have to test if the sample distribution has skewness and kurtosis that is equal to the normal distribution, which is done by performing the Jarque-Bera test. The formula (7) for the test is presented below, where JB represents the Jarque-Bera test statistic, S represents skewness, K kurtosis and n represents number of the observation. For the normal distribution the skewness is 0 and kurtosis 3.

$$JB = \frac{n}{6}\left(S^2 + \frac{1}{4}(K-3)^2\right) \quad (7)$$

The advantage of using the variance covariance model, is that it is straightforward to implement and that it is easy to retrieve important statistical details from the parameters. However, this method can be hard for someone who is not well-found with normal distribution and will therefore not understand the core concept of the calculation.

The Monte Carlo simulation is, according to Jorion (2006), a parametric method, which generates random movements in risk factors from estimated parametric distributions. In order for the Monte Carlo stimulations to be more efficient, a large number of stimulations needs to be performed. For the calculation of the Monte Carlo simulation, we must first identify the parameters for all risk factors, such as correlation, mean and standard deviation; all derived from historic observation data. After that, we stimulate the hypothetical prices, which depend on the model and the random numbers generated (Dowd, 1998). The simulation in the sample is based on the Geometric Brownian Motion model that is widely used for the stimulation of stock prices. Prices are simulated for the next day, after the last observation in the sample (Jorion, 2006). In the following Geometric Brownian Motion formula (8), how the prices are stimulated is presented, where t denotes time, P represents the price of the assets, μ is the mean return and Wt follows a Wiener process, which is a random number generated from the normal distribution.

$$P_t = P_{t-1}e^{\left(\mu-\frac{1}{2}\sigma^2\right)+\sigma W_t} \tag{8}$$

Once a price path has been stimulated, we build the portfolio distribution at the end of the selected horizon from the lowest to the highest, in order to find the VaR. VaR of the simulation depends on the confidence level and the number of observations in the Monte Carlo simulation, therefore, if we look for a 5% VaR and we have 10000 observations, the 500th lowest value represent the 5% VaR. A clear advantage of the Monte Carlo simulation is that it can be used for any model (financial instruments, portfolios and investments). However, it is very time consuming and computationally intensive to generate all of the needed simulations. If compared to the other two methods of the VaR calculation, we do not need to make improbable assumptions about normality in returns in the Monte Carlo simulation, such as in the covariance variance model. Furthermore, we can bring both particular findings and other information, to improve the forecasted probability distribution, unlike in the historical simulation, which is based solely on historical data (Value at Risk, 2017). Hence, Asche et al. (2013) believe that the Monte Carlo simulation is the best one to present the company exposure to short-term financial risk in the natural gas industry, which is tested in the latter part of the master thesis.

In order to evaluate the accuracy of the VaR model, back-testing is performed, which is essentially a method for predicting a model based on historic data, to measure its correctness and efficiency. In the VaR model, back-testing compares the simulated returns in the portfolio for the specified time horizon. It shows where the VaR is undervalued or where the actual portfolio returns are above the expected VaR. In a case where the actual returns exceed the VaR number, there is a violation. However, if the actual returns are higher than the estimated VaR by only a few times, we need to determine the frequency of the breaches (depending on the confidence level) in order to evaluate whether VaR is accurate and efficient and can therefore be used in a given portfolio (Value at Risk, 2017).

The Kupiec test, introduced in 1995, can be performed for the back-testing of VaR. The test measures whether the number of violations is consistent with the level of confidence or not. By using the binomial distribution in the Kupiec test, we can calculate the portability of the VaR breaks occurring within a specified period of trading days, in order to see if the method can be accepted or rejected. The Kupiec test is calculated by using the formula for the binomial probability (9) below, where x is the number of VaR breaks, p is the level of significance and n is the number of days.

$$P(xn,p)=\binom{n}{x}p^x(1-p)^{n-x} \tag{9}$$

To sum up, the Kupiec test studies whether the amount of VaR breaks significantly differs from the level of significance. In a case where the VaR breaks significantly surpass the anticipated amount, with the respect of the level of confidence, the risk model is rejected.

VaR models are extensively used in risk management in order to keep control over possible losses in a given time interval. The reason why VaR is so popular is because of its simplicity, as it sums up all of the risks in the portfolio into a single number, which is suitable for the purpose of presenting risk to a variety of people, from the board to the regulators. It can measure risk across all types of positions and risk factors, thus providing a financial and probabilistic expression of the loss amounts (Dowd, 2005). However, the VaR model, as any other, has some shortcomings.

One of the major disadvantages of the VaR simulation is that it is only as good as the quality of the inputs, meaning that if the inputs are not a good proxy, then the VaR will be deceptive and the reliance on VaR can therefore lead to bigger loses. Taleb (2008) and Danielsson (2008) believe that VaR also provides estimates that are too optimistic in the times of crisis, as correlation levels are higher, and this can cause problems as natural gas is highly correlated.

Artzner, Delbaaen, Eber and Heath (1999) also discussed that VaR is susceptible to producing biased estimates, as it cannot ensure the diversification benefits in the portfolio theory, because the VaR method does not respect the sub-additivity axiom. This means that if you, for example, add the VaRs of portfolio A and portfolio B, the VaR of both portfolios (A+B) will not be smaller every time. Mathematically speaking, we should have $\text{VaR}\ (A+B) \leq \text{VaR}\ (A) + \text{VaR}\ (B)$. However, the VaR calculation does not always respect that, meaning that the independent risks of assets do not behave as they should in a diversified portfolio.

3.4 The natural gas portfolio

In the last part of my master thesis, I create an imaginary natural gas portfolio of a short-term trader X on the Slovenian natural gas market, where I apply the three different approaches of VaR: historical, variance covariance and the Monte Carlo simulation. I do so in order to investigate if VaR really is the appropriate risk management tool for estimating risk on the natural gas market. This way I am also able to address the belief that the Monte Carlo simulation is the best method to evaluate the financial risk in natural gas trading. In the imaginary natural gas portfolio of the short-term trader X, I calculate the VaR on 1.1.2016 using the above-mentioned approaches, so that I am able to compare them and find the best VaR method for my natural gas portfolio and the natural gas portfolio in general. As the short-term trader X is trading with natural gas for the sole purpose of financial profit, the natural gas is not physically delivered, but is settled financially. As a result, the capacity contracts are unnecessary, and the spot contracts are not viable, thus a natural gas portfolio consist of only a month of futures contracts.

Furthermore, I try to test the claim set by Gazprom's analyst Komlev, which states that the European gas hub prices are not derived from the gas supply and demand equilibrium (short-term contracts), but are actually derived from the long-term ones, which are indexed to oil and play a role of balancing the natural gas market (Komlev, 2013). All of the VaR calculations are adequately back tested.

3.4.1 Natural gas data

The imaginary natural gas portfolio of the short-term trader X consists of monthly TTF futures prices in the period between 3.1.2014 and 1.1.2016, covering a period of two years, and consisting of 104 observations as the prices are observed on a weekly basis. Moreover, the prices of the selected monthly products are expressed in EUR/MWh and were obtained from the Bloomberg Terminal. I have selected weekly prices instead of the daily ones, because there were a lot of missing daily prices for some months, due to the low or zero trading of futures. I could have used different methods to replace the missing values, such as the last price or interpolation. However, I have decided to take the real market data to create a more realistic natural gas portfolio, thus I have chosen the weekly prices. The TTF futures were selected because, according to Heather (2013), the TTF gas hub is the biggest and most liquid gas hub in Continental Europe and has become the clear continental gas price benchmark, while the TTF monthly futures are the most traded products in the gas hub, especially for the financial settlement. Furthermore, monthly futures or similar gas products are sometimes not available at other gas hubs, which are less liquid, meaning that they cannot be purchased or sold at a particular gas hub. Consequently, TTF monthly futures were included in the gas portfolio, which will be traded on the short-term natural gas market.

For the purposes of calculating VaR on 1.1.2016, I took four data series of the moving monthly TTF series: M+1, M+2, M+3 and M+4, where the M represents a month, while the number denotes the specific month. For example, in my case, if we look at the open position of the short-term trader X on 1.1.2016, M+1 represent the price of monthly futures in February on the before mentioned date, M+2 price of monthly TTF futures in March, M+3 price of monthly TTF futures in April and M+4 price of monthly TTF futures in May, respectively.

In Table 3 below, descriptive statistics of the TTF monthly futures are presented. In this master thesis, the analysis and the calculations of VaR are based on the logarithmic returns of the before mentioned returns for the given period.

Table 3: Descriptive statistics of TTF futures

	TTF M+1	TTF M+2	TTF M+3	TTF M+4
Mean	-0.00605	-0.00574	-0.00564	-0.00562

Median	-0.00886	-0.00922	-0.00690	-0.01001
Standard Deviation	0.04282	0.03924	0.03594	0.03129
Sample Variance	0.00183	0.00154	0.00129	0.00098
Kurtosis	0.48473	0.85355	0.97403	1.34920
Skewness	0.41174	0.27279	0.06292	0.52653
Range	0.20895	0.22170	0.20456	0.19063
Minimum	-0.10359	-0.11861	-0.11280	-0.09213
Maximum	0.10536	0.10310	0.09176	0.09850
Sum	-0.62907	-0.59676	-0.58643	-0.58498
Jarque Barquera test	75.008 0.00000	52.523 0.00000	44.123 0.00000	41.057 0.00000

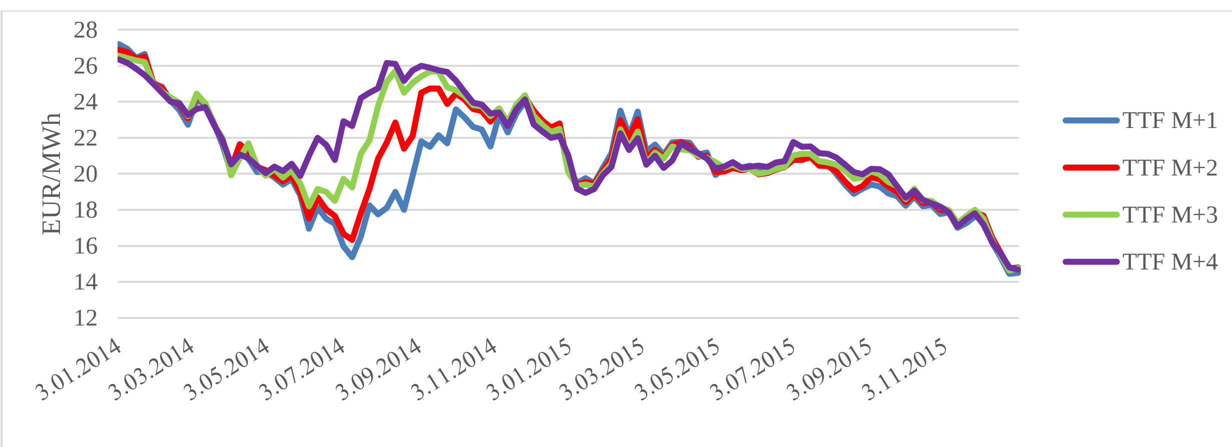
Source: own work.

As shown in Table 3, the means of the four data series are negative and close to zero. This is somewhat expected, as the prices of natural gas deviate over the months due to the seasonality of the product, since natural gas is more used in winter and autumn, for heating purposes, by the household consumers. Hence, the demand and the gas prices are seasonal. If we look at the volatility of the four data series, TTF M+1 returns have the largest standard deviation, meaning they represent the highest risk in the natural gas portfolio, as returns are more volatile. The explanation, as to why the returns of the TTF M+1 series are more volatile, is that the futures will soon expire and the prices on the gas market are more or less going towards the spot prices, which can be higher or lower than the price agreed on the futures contract. Therefore, in order to profit, the traders are trying to close their open position, so the futures trade in high volumes and the prices deviate more. This logic is evident in our sample, as the TTF M+4 futures have the lowest standard deviation, as they are far away from the expiry. In regard to the maximum value, the TTF M+1 futures return have the largest maximum, while, on the other hand, the lowest minimum can be found in the TTF M+3 data series.

Skewness, which measures the asymmetry of data (0 in normal distribution), is positive for all four futures return series in the natural gas portfolio of trader X, as the right tail is longer and there is more data concentrated on the left side of the curve. Furthermore, kurtosis, which presents the distribution of the observed data, is positive for all four returns in the natural gas portfolio, indicating that there are too few cases in the tail of the returns distribution. A higher kurtosis also means that there might be a presence of outliers. In the natural gas portfolio, the highest kurtosis is 1.3, while the kurtosis for the normal distribution is 3, meaning that outliers are not present in the gas portfolio. The normal distributions of the returns were tested with the Jarque-Bera normality test, which has clearly rejected the null hypothesis of the normal distribution of drawing data for all four return series. However, we have to take into consideration that there were only 104 observations, which could significantly impact the Jarque-Bera test, as it is better to have more than 2000 observations in order to have precise results. The histograms in appendix G illustrate the distribution of the returns for all four data series.

From Figure 8 below, it is evident that the TTF futures prices follow more or less the same path in the observed period, meaning that they have similar ups and downs as the gas prices and are therefore highly correlated. It is obvious that the prices in the year 2015 are lower than the prices in the year 2014, and that all TTF futures prices have a downward trend and are in a contango situation. Contango means that the futures prices are above the expected gas spot prices and that their price will gradually fall before expiration. Furthermore, as the prices in the years 2014 and 2015 differ greatly, I have also performed a statistical robust test, in order to test if the variances and the means of monthly TTF future prices of 2014, really are different from the monthly TTF futures of 2015. The T-test (test of equal means) showed that the means of all 4 monthly TTF futures between the years differ significantly, while the F-test (test of equal variances) that was carried out, confirmed that the variances between TTF M+1, TTF M+2 and TTF M+3 differ between the years of 2014 and 2015, while the variances for TTF M+4 are more or less equal in both years. One reason for why the TTF futures prices differ so greatly between the years, is that the winter of 2015 was not as severe as the winter of 2014, and that is why the demand for natural gas was much lower and as a result, the gas prices dropped significantly. Another reason can be that the TTF gas hub was evolving towards becoming the most liquid gas hub in Continental Europe at that time, meaning that the trading of gas futures increased dramatically in the year 2015 and with more supply, the prices of gas dropped. However, there is also a strong possibility that the TTF monthly futures prices dropped because the oil prices dropped significantly in 2015 and there has been a high historical correlation between gas and oil prices

Figure 8: TTF futures prices



Source: Bloomberg Terminal.

3.4.2 Value at risk of a natural gas portfolio

As mentioned above, the prices in 2014 differ greatly in comparison to the year 2015. However, from the risk management's point of view (not to overestimate/underestimate the price risk), and in order to demonstrate how volatile the prices of natural gas can be, I decided to take both years for the calculation of VaR in the natural gas portfolio, since the gas prices through the years are not the same and are heavily dependent on the weather conditions, the demand and supply, along with events such as the ones in Ukraine and the financial crisis, etc, which have a major impact on the gas prices. Moreover, I took two years in order to have more data, as my calculations of VaR and the risk examination are based on the weekly prices of TTF monthly futures, which should, consequently, illustrate a more accurate result of how much a short-term trader of natural gas could potentially lose throughout the years of trading.

Hence, after obtaining the weekly prices of TTF monthly futures for the observed period (3.1.2014 - 1.1.2016) from the Bloomberg Terminal, I had to define the weekly quantities of the monthly futures that were used for the VaR calculations. As the seller X is a short-term trader, who trades solely for financial profit, I have not taken into account the diverse consumptions of end users over the months and have made up quantities, which are exact throughout the whole period and are presented in the table below. From Table 4, it is evident that the quantities in months have a negative sign. The reason why is because I have decided to have a short trading strategy through the observed period, although the natural gas prices stay volatile and respond to any weather-related or gas supply disruption news. I chose a short strategy, because, according to Global Association of Risk Professionals (2016), it is better to have a short position, as the winter will not be as cold as the industry fears for most of the time, the utility buyers will always overpay for the protection and there is enough additional suppliers and the supplies of natural gas to cover a short outage or supply disruptions of the natural gas. However, we have to take into consideration that the strategy can occasionally backfire, especially when there is a severe winter or a political/other gas shortage event, which could skyrocket the gas prices.

Table 4: Weekly quantities of natural gas

	TTF M+1	**TTF M+2**	**TTF M+3**	**TTF M+4**
Quantities in MWh	-500,000	-300,000	-200,000	-100,000

Source: own work.

After defining weekly quantities for different monthly TTF futures, I have all the necessary data to calculate VaR on 1.1.2016, using different VaR approaches: the historical simulation, the covariance variance and the Monte Carlo simulation. However, every VaR calculation needs to be adequately back tested in order to evaluate whether it was calculated correctly. Hence, I calculate

VaR on 1.1.2016 using prior methodologies and then do back-testing in the year 2016, in order to prove or refute different VaR calculations and see which methodology is best suited for presenting the risk in my natural gas portfolio.

3.4.3 Historical VaR

The first VaR calculation on 1.1.2016 for the natural gas portfolio was calculated with the basic historical simulation, which was already explained in detail in subchapter 3.3.3. Hence, to calculate the historical VaR, I have organized the TTF time series returns from worst to best, and then chose the number that corresponds to the percentile of the distribution, based on my selected confidence level. For the confidence level of VaR (α), I chose 99 % and 95%. However, I first needed to calculate the logarithmic returns for the four series, using equation (10).

$$R_t = ln \frac{P_t}{P_{t-1}} \quad (10)$$

In equation (10), R_t presents the returns of the defined week, ln is a natural logarithm, while P_t denotes TTF month futures week gas price and P_{t-1} the TTF month futures gas price of the week before. After obtaining the returns for the period of two years, I have multiplied the weekly returns with the matching quantities and prices, in order to get the profit or loss for the defined week in the observed period. In my example, for instance, the returns on 1.1.2016 for TTF M+1 were multiplied with the quantity 500,000 MWh and TTF M+1 price 14.5 EUR/MWh, returns for TTF M+2 with the quantity 300,0000 MWh and TTF M+2 price 14.8 EUR/MWh, etc. Following the calculations of the profit or loss for all of the weeks in the period of two years, I have arranged them in an ascending order, from the lowest to highest, in order to find my VaR99% and VaR95% using the percentile function in Excel. The percentile function helps you locate the X percentile of values in your data range, which corresponds with your confidence level, thus, in my case, the first and the fifth percentile, respectively. The results of the historical simulation VaR are evident in Table 5. The interpretation of the VaR99% is that we are 99% confident that the assets in a natural gas portfolio of the short-term trader X, will not lose over 3,.099,345 EUR in the natural gas portfolio over the next week. The same interpretation is applicable for the VaR95%, where we are 95% confident that we will not lose over 2.145.332 EUR in the natural gas portfolio over the next week.

Table 5: Historical simulation VaR

In EUR	**VaR 95%**	**VaR 99%**
Weekly VaR	2,145,332	3,099,345

Source: own work.

3.4.4 Covariance Variance VaR

The second VaR was calculated using the covariance variance method. As I have already calculated the weekly logarithmic returns for the drawn data in the historical simulation, I then needed, as the name of the VaR suggests, to the calculate covariance matrix, which can be calculated with the standard deviation of the portfolio, individual logarithmic returns and the correlation matrix. The correlation matrix was calculated in Excel with the correlation function, where I had to select, for example, the returns of the data TTF M+1 and TTF M+2, in order to find the correlation between these two data series. The same procedure was applied for all of the data series. The correlation results can be observed in the correlation matrix Table 6 below.

Table 6: Correlation matrix of TTF monthly returns

	TTF M+1	TTF M+2	TTF M+3	TTF M+4
TTF M+1	1	0.91252	0.74677	0.574782
TTF M+2	0.91252	1	0.86952	0.650868
TTF M+3	0.74677	0.86952	1	0.796104
TTF M+4	0.57478	0.65087	0.7961	1

Source: own work.

Correlation is a statistical measure of how different series or data relate to each other and is used in order to identify a relationship between two different data sets. The correlation of two data series can be between minus one (a strong negative correlation), meaning that, when one data series increases in value, the other decreases, and one (a strong positive correlation), when both series either increase or decrease in value, as they are highly correlated. Furthermore, the closer the correlation is to zero, the less there is of a relationship between assets, whereas a zero correlation indicates that the two data returns have zero relationship. It is evident in portfolio X that the data series are positively correlated, indicating that all of the gas prices of the data series are moving in the same direction. This is an expected result, considering the fact that all monthly futures come from the TTF gas hub and considering the statistical characteristics presented in chapter 3.4.1. In our portfolio, TTF M+1 and TTF M+2 are highly positively correlated (0.91), while on the other hand, TTF M+1 and TTF M+4 are the least correlated (0.57). It is important to note that, combining assets, which do not have a strong positive correlation in a portfolio, will reduce the overall risk. However, reducing the risk by adding assets will also reduce the expected return in the portfolio, as a consequence of risk-return trade-offs. Only in the case where the return series are perfectly and positively correlated (correlation 1), will the risk not be reduced (Mayo, 2011). If we take this into account, the portfolio of the short-term trader X is, due to the high positive correlation of the return series, not as diversified as it could be, were it to contain futures with a low or negative correlation. Hence, in the case where the prices of gas drastically fall, a trader could potentially generate a huge loss due to the low diversification of assets.

After obtaining the correlation matrix, I had all of the necessary data to calculate the covariance matrix, as I already calculated the standard deviations of the TTF monthly futures series, when presenting the descriptive statistics of drawn data. The standard deviations are presented in Table 7 below, from which it is evident that TFF M+1 has the highest standard deviation, as the return series mentioned before are more volatile than others, while the TTF M+4 series has the lowest standard deviation, meaning they represent the lowest risk.

Table 7: Standard deviation of the TTF returns

	TTF M+1	**TTF M+2**	**TTF M+3**	**TTF M+4**
Standard deviation (weekly)	0.04281599	0.039239	0.035937	0.031289

Source: own work.

The covariance matrix is presented in Table 8 below and was calculated by multiplying the correlation of the two specified variables with each respective standard deviation of the before mentioned variables. For example, the TTF M+1 and TTF M+2 covariances were obtained by multiplying the correlation of TTF M+1 and TTF M+2 with the standard deviation of TTF M+1 and TTF M+2. The same procedure was applied to all calculations. The interpretation of the covariance matrix is similar to the correlation, as we can see that the variables have a positive covariance, meaning that the asset returns move up together. This also proves that the portfolio of the short-term trader X is not adequately diversified, because the returns move together, meaning that if one of the TTF returns rises, another will rise and vice versa.

Table 8: Covariance matrix of TTF monthly futures

	TTF M+1	**TTF M+2**	**TTF M+3**	**TTF M+4**
TTF M+1	0.00183	0.001533	0.001149	0.00077
TTF M+2	0.00153	0.00154	0.001226	0.000799
TTF M+3	0.00115	0.001226	0.001291	0.000895
TTF M+4	0.00077	0.000799	0.000895	0.000979

Source: own work.

Following the computation of covariance and the correlation matrix, I have used equation (5) and (6) in subchapter 3.3.3, to determine the standard deviation of the portfolio.

After the calculation of the portfolio variance, the VaR was given by formula (6) above, where $VaR_{1-\alpha}$ is the estimated VaR at the confidence level 100* (1-α) %, the P presents the value of the portfolio, σ denotes the standard deviation of the portfolio and Z_α represents the number of standard deviations on the left side of the mean, at the required standard deviation. In portfolio X, the portfolio value is the total of a weekly quantity of the respective futures, multiplied by the price of the futures on 1.1.2016, whereas, like in the historical simulation, the confidence level is 99% and 95%, respectively. The weekly results are presented in Table 9 below. If we interpret the weekly 99% VaR, we are confident that the short-term trader's loss in the natural gas portfolio X on 1.1.2016 over the next week, will not be over 1,387,750 EUR.

Table 9: Variance Covariance VaR

In EUR	**VaR 95%**	**VaR 99%**
Weekly VaR	1,167,378	1,387,750

Source: own work.

It is evident that the covariance variance VaR is much smaller than the historical simulation, as this model assumes that the returns are normally distributed. However, our returns are not normally distributed, and this may be the reason for why the VaR can be lower. Another possibility for why the covariance variance VaR is lower than the historical one, is because the standard deviation is calculated over a two-year period and does not include the volatilities of certain months, as natural gas is a seasonal commodity, thus some months are more volatile than others, especially April and September, when the prices of natural gas are going down or up respectively. However, I have not adjusted the volatilities in the specified months, because I am using moving monthly futures on a weekly basis in my computation.

3.4.5 The Monte Carlo simulation

The third method, which I used for calculating the VaR of the natural gas portfolio on 1.1.2016, is the Monte Carlo simulation. I have used the weekly prices of natural gas for the futures market TTF M+1, TTF M+2, TTF M+3 and TTF M+4 in the period from 3.1.2014 to 6.1.2016, in order to determine the mean and the standard deviation of the before mentioned futures. In order to calculate the Monte Carlo simulation VaR, I first had to simulate the weekly TTF month futures prices, using the Geometric Brownian Motion equation (8), which was presented in the subchapter 3.3.3.

The difference between this VaR methodology and the other two, is that I have simulated future prices, which may or may not be reached in the future. Hence, I have replicated 1000 weekly prices so that my simulations of TTF month futures prices are more accurate. Before I simulated the prices, I have made an adjustment and put zero mean for all of the futures instead, because the means for all futures are negative and close to zero in the natural gas portfolio. I did this for a better outcome, as the future returns could potentially have a positive mean but would still move around zero. On the other hand, standard deviations for the month TTF futures are the same as in previous calculations and are visible in Table 8 above. Following the modifications, I have simulated 1000 weekly TTF month futures prices from 1.1.2016 onwards, using the Geometric Brownian Motion equation (8), where I have used the Excel function NORMSINV(RAND) for generating random numbers from the normal distribution.

Once I have simulated the price path, I build the portfolio distribution at the end of January first, 2016, from the lowest to the highest weekly prices for all four months TTF futures and multiplied them with the corresponding weekly quantities, defined in Table 5, in order to find VaR. For the purpose of comparing different VaR methodologies, I have used the same confidence level as before, 99 % and 95% respectively. The procedure of calculating the Monte Carlo simulation VaR is very similar to the historical simulation, so to determine the 99%VaR in a natural gas portfolio, where there are 1000 observations, one would look at the 10th lowest value, which represents 99%VaR. Similarly, if we try to identify the 5%VaR, the 50th lowest value represents the 95%VaR.

The results of the Monte Carlo simulation are presented in Table 10, while the interpretation of VaR99% is similar to the previous calculations, since we are 99% confident that the short-term seller will not lose 1,760,644 EUR on 1.1.2016, over the next week.

Table 10: Monte Carlo VaR

In EUR	**VaR 95%**	**VaR 99%**
Weekly VaR	1,069,556	1,760,644

Source: own work.

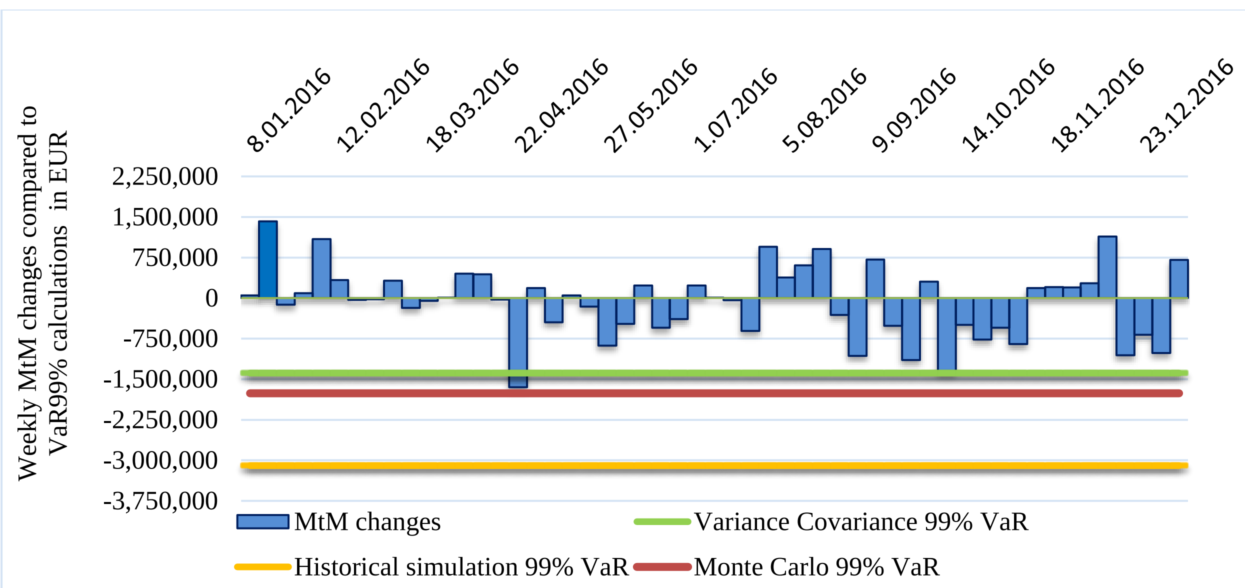
The clear advantage of the Monte Carlo simulation is that we can adjust the calculation according to the gas market, so that it considers the factors, which can influence the losses on the natural gas market and that we can simulate the model until we are satisfied with the distributions and the results. However, if one puts in inaccurate data or false adjustments, VaR can either be undervalued or overvalued, therefore this method is good for using along with other methods, so that you can be certain about the accuracy of the model.

3.4.6 The back-testing of VaR

In order to confirm the accuracy of different VaR models' calculations, back-testing for all of the previously mentioned VaR approaches is performed. I have used back-testing, which measures whether the number of violations is consistent with the level of confidence or not. Back-testing is performed by comparing the weekly Mark to Market (MtM) changes of the portfolio (portfolio losses), with the VaR estimated loses within a specified period. Therefore, I can calculate the portability of the VaR breaks that occurred within a specified period of trading days, in order to distinguish whether the VaR methods can be accepted or rejected.

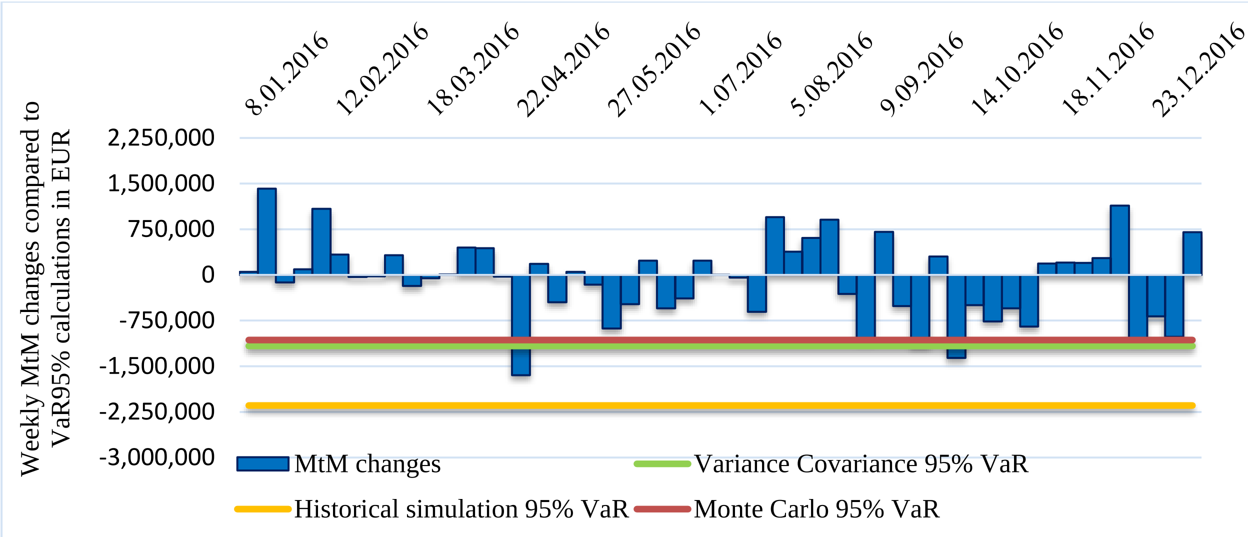
Hence, I have first calculated the weekly MtM changes in the period from 1.1.2016 to 3.1.2017. The MtM changes were obtained by multiplying the weekly prices of particular TTF month futures, with the corresponding weekly TTF quantities and summing them up together (portfolio value). Next, as I have a short-term trading strategy, I have subtracted the portfolio value of the defined week from the portfolio value of the previous week. For instance, the MtM change of 8.1.2016 was obtained from the sum value of weekly TTF month futures on 1.1.2016, multiplied by their corresponding quantities, from which I subtracted the portfolio sum of the weekly TTF month futures on 8.1.2016, multiplied by their corresponding quantities. The same calculations were performed for the whole specified period. Following the calculation of the MtM changes, I have made a decision about whether to accept or reject the 99% and 95% VaR calculations for each model, based on the number of MtM loses that are greater than the weekly 99% VaR and 95% VaR on 1.1.2016. Since we tested the MtM changes over the period of 53 weeks, actual portfolio losses, which are greater than VaR, can occur 0.53 times and 2.7 times in order to accept a 99%VaR and 95%VaR calculation, respectively. In Figures 9 and 10 and in Table 11 below, the results of the 99% and 95% VaR back-testing for all three VaR methodologies are presented, respectively.

Figure 9: VaR99% back-testing



Source: own work.

Figure 10: VaR95% back-testing



Source: own work

Table 11: VaR back-testing

	Historical simulation		**Covariance Variance**		**Monte Carlo simulation**	
	VaR 99%	VaR 95%	VaR 99%	VaR 95%	VaR 99%	VaR 95%
Number of breaks	0	0	1	2	0	3

Source: own work.

From Table 11 and Figures 9 and 10, it is evident that the MtM losses over the observed back-testing period are not higher than in the historical simulation VaR, thus we can conclude that the model is accurate. However, the historical simulation VaR is highly overvalued in this natural gas portfolio in comparison to the other two models, as well as to MtM changes within a specified period of trading days.

One of the reasons why historical VaR is so "conservative" is the Ukraine gas crisis, which happened in the years 2006, 2009 and again in June 2014, when the Russian gas exporter Gazprom cut off the gas supplies to Ukraine, due to non-payment, according to the Russians. In the prospect of avoiding similar incidents in the future, an agreement between the Russian Government and the European Commission was signed, and it expired in March 2015. The agreement states that any disruption of the gas supply should be notified in advance, so that the gas supply can be controlled and be redirect from other areas in case of shortage (Investopedia, 2015). Because of the fear of not renewing the agreement with the above-mentioned parties, the prices of natural gas in the market rose in February 2015, which also had an impact on gas hubs such as the TTF and, consequently, the VaR results. Also, another reason lies in the changes of the gas prices, from one month to another, because the demand in certain months rises and vice versa, due to the seasonality of gas. Therefore, if we would take the above-mentioned outliers from our historical VaR simulation (in our case, two VaR calculations greatly exceed others), we would obtain a weekly 99%VaR and 95%VaR, 2,228,824 and 2,043,419, respectively. These results of VaR are more in line with the calculations of the other two and are still high enough that the MtM losses do not exceed them.

On the other hand, as observed from the Figures above, MtM losses exceed the covariance variance 99%VaR once and the 95%VaR twice. Since we tested MtM changes in the period of 53 weeks, we can say that the 95%VaR is acceptable, while the 99%VaR is not, since the break could occur only 0.53 times. However, we could conditionally accept 99%VaR, due to the short period of the back-testing weeks, because it is possible that, over a longer period of time, the 99%VaR could be accepted.

The third method of VaR that was tested, was the Monte Carlo simulation. As evident in Figures 9 and 10, the break of VaR does not occur in the 99%VaR, while the mark to market losses exceed the 95%VaR three times. Therefore, we can accept the 99%VaR, but have to reject the 95%VaR, since the breaks of VaR occur three times, instead of 2.6 times. However, similar to the covariance variance case, we could conditionally accept the 95%VaR due to the short period of the back-testing weeks and the fact that, if we would round up the VaR break occurrences, the 95%VaR calculations would be accepted.

To conclude, we can see that the historical simulation VaR in the natural gas portfolio of the short-term seller X is the most accurate, since it is not rejected at any confidence level. However, it has quite a few limitations. The most obvious is definitely the reliance on the historical data in which specific onetime events can occur that could potentially never happen again in the nearby future. This is also visible from the calculations and the Figures of the historical simulation VaR, in which the consequences of the Ukraine crisis, which will not happen every year or ever again, are included. Hence, this event, beside the high gas price volatilities over certain months, is marginally worsening the VaR result and is somewhat deceiving the seller about how much he could potentially lose. If we also take into consideration the fact that every gas year is a little bit different, as demand, and hence the supply, relies on several factors (weather, alternative sources, storage, competition on the market, etc.), the historical simulation may not be the best fit for the calculation of VaR in the natural gas portfolio. Although, it is the most accurate model in the natural gas portfolio of short-term trader X.

With that considered, the covariance variance and the Monte Carlo simulation approach are better for demonstrating the risk exposure of the short-term natural gas seller. However, in my natural gas portfolio, both methods, the covariance variance 99%VaR and the Monte Carlo simulation 95%VaR, were once rejected. Nevertheless, we must consider that the back-testing performed in the natural gas portfolio was done in the period of 53 weeks, and that the break of the above-mentioned VaR methods, happened 0.5 times more than allowed. Furthermore, MtM changes are also more aligned to the Monte Carlo and the covariance variance VaR calculations. Hence, we can, in a way, state that the 95%VaR and the 99%Var of both methods are conditionally acceptable.

Keeping that in mind, the only thing left to decide is whether to use the covariance variance or the Monte Carlo simulation approach for the VaR calculations, and if the Monte Carlo simulation, according to Asche et al. (2013) is indeed better for demonstrating the risk exposure in a natural gas portfolio. I believe that we cannot in fact state which of these two methodologies is better for demonstrating the risk exposure in natural gas, since, in our case, they both break VaR at some confidence level and have other shortcomings. For instance, the covariance variance VaR is based on the normality assumptions of the returns and does not consider the volatilities of certain months, which could heavily influence the VaR outcome.

On the other hand, the Monte Carlo simulation is as good as your inputs/assumptions. Thus, if we put in inaccurate data, or the wrong assumptions of the natural gas market, we can strongly influence the results of the simulation. This means that, when generating 1,000 or even 10,000 simulations, we have to choose the right distribution, based on the simulation, which would adequately show us the loss over the period (VaR). However, if we choose the wrong distribution, since our input/market assumptions are not accurate, the results could be catastrophic, particularly in a case where we would undermine the risk. Hence, I am not able to prove or refute the hypothesis that the Monte Carlo simulation is the best methodology for demonstrating VaR on the natural gas market, as the accuracy of the model is strongly dependent on the inputs, assumptions of the market and the correct choosing of the distribution.

Nevertheless, I can confidently stress that the Monte Carlo simulation is a good and accurate method for showing the risk exposure in one number, when you have reliable inputs and good predictions for the future outcome of natural gas. In this situation, I believe that the Monte Carlo simulation is indeed the best methodology for VaR. Yet in a case where the inputs and future predictions/assumptions are not bulletproof, meaning that they can influence simulations and consequently the VaR results in either a positive or a negative way, I strongly believe that the Monte Carlo simulation is not the best option for the VaR calculations, especially on the natural gas market, which is quite a specific market, in terms of price volatility and seasonality. Therefore, I think that the traders on the natural gas market should consider both methods, the Monte Carlo simulation and the covariance variance, for calculating VaR, as this would diminish the possibility of risk underestimation and could take into consideration different factors, which can control the traders' losses.

Considering all of the above, I must stress that we cannot be 100% certain that the Monte Carlo simulation and the covariance variance VaR are the best approaches for calculating VaR and demonstrating the risk exposure in a natural gas portfolio. My conclusion is based on the fact that, if we account for different factors of VaR methodologies into our decision of the best VaR approach on the natural gas market, the conclusion can go either way. Also, in my case, based only on the calculations, the historical VaR is the best fit. Therefore, I am highlighting that these statements regarding the best VaR model, are my conclusions, based on empirical VaR calculations, in-depth analytical and theoretical research of the natural gas market and the risk management solutions used by the natural gas providers and traders on a daily basis.

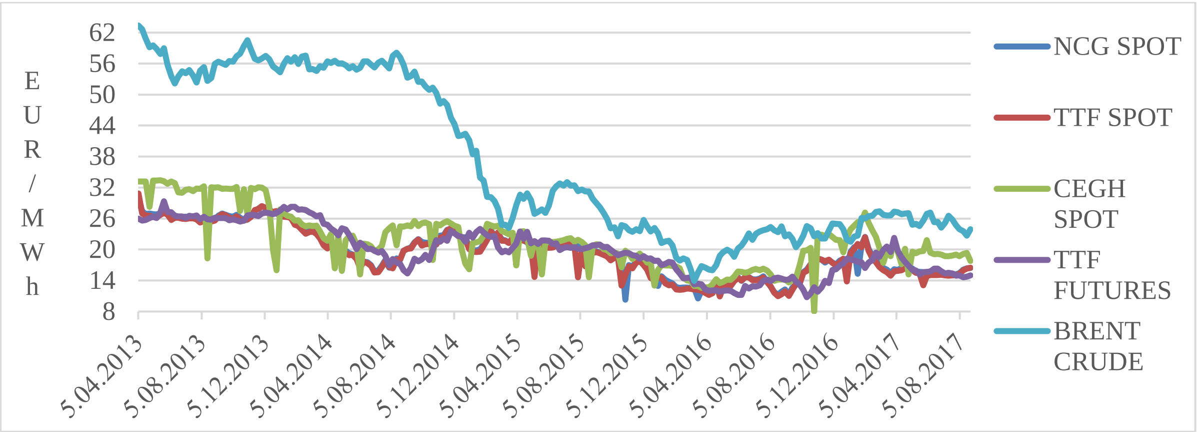
3.5 The testing of the claim set by Gazprom's analyst Komlev

In the last part of my master thesis I compare the European short-term natural gas prices to the long-term natural gas prices, in order to test the claim set by Gazprom's analyst Komlev, asserting that the short-term natural gas prices are derived from the long-term ones and are not the subject of the supply and demand equilibrium. Furthermore, he states that the difference between the gas prices occurs due to the fact that the LTCs guarantee the security of the natural gas supply (Komlev, 2013). In order to test the claim, I chose the average weekly natural gas spot prices, from 3 different natural gas hubs, for the prices of the short-term contracts: the largest gas hub in Continental Europe - TTF, NCG Germany and the CEGH hub in Austria, ranging from April 2013 to August 2017, consisting of a total of 5 years and 230 observations. Furthermore, my analysis includes the monthly TTF future prices on a weekly basis, with the same ranging period, because according to ACER and CEER (2016), the TTF gas hub is widely used as a price benchmark for long-term natural gas contracts and for other gas hubs, thus the monthly TTF futures are a very good proxy for comparison with the long-term prices and spot prices in general.

On the other hand, I chose the monthly Brent Crude oil futures for the representation of the long-term natural gas prices, because in LTC, the price of gas is an index to oil and the Brent Crude futures represent a good benchmark for it. The time period for the Brent Crude futures is the same, as they are presented on a weekly basis. All of the before-mentioned prices were obtained from the Bloomberg Terminal and are presented on a weekly basis in EUR/MWh.

From Figure 11 below, we can see that the prices of the Brent Crude oil in the years 2013 and 2014 are much higher and differ greatly from the gas spot (NCG, TTF and CEGH) and TTF futures prices. However, we must note that in LTCs, they adjust the price of oil with the gas formula, which was described in chapter 2.1. Therefore, the difference between the gas and oil prices can be higher. Furthermore, the Brent Crude futures also have an evident downfall of prices, which started in August 2014 and lasted until April 2015, while this trend is not apparent in spot and TTF futures prices. From then on, the prices of Brent Crude, spot prices and TTF futures, are more or less in a similar proportion and are moving in the same direction, meaning they have similar ups and downs. However, due to the clarity of the price movements, correlations and trends of the above-mentioned gas and oil prices in Figure 9, I have made a correlation matrix, which is presented below.

Figure 11: Five-year comparison between short-term and long-term gas prices



Source: Bloomberg Terminal.

When calculating the correlation, I intentionally took the gas and oil prices and not the returns, as I am interested in this trend over the observed period and the gas/oil prices better represent it. Although all of the financial academics tell us that we can only use returns when calculating correlation, Haber and College (2012) have proved in their paper that the price correlation and the returns correlation of the same series, can significantly differ (the price correlation in the paper is one, while the returns correlation is almost zero), if just one variable is out of the pattern. Hence, I chose to show the correlation using natural gas prices and Brent Crude, especially due to the fact that gas is a seasonal component and the prices can deviate from market to market.

Table 12: Correlation matrix between long-term and short-term natural gas prices for a five-year period

	NCG SPOT	TTF SPOT	CEGH SPOT	TTF FUTURES	BRENT CRUDE
NCG SPOT	1.000	0.981	0.857	0.880	0.768
TTF SPOT	0.981	1.000	0.856	0.868	0.765
CEGH SPOT	0.857	0.856	1.000	0.741	0.719
TTF FUTURES	0.880	0.868	0.741	1.000	0.783
BRENT CRUDE	0.768	0.765	0.719	0.783	1.000

Source: Own work.

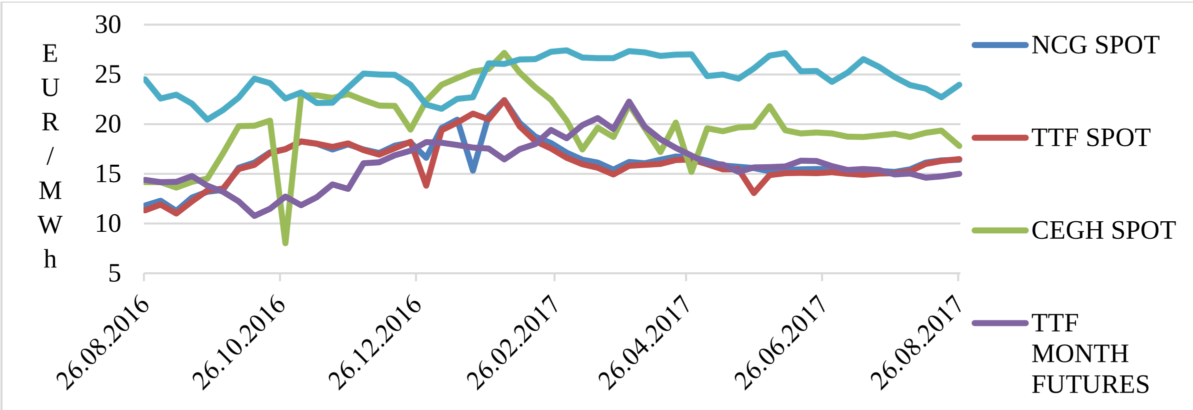
From Table 12 above, it is evident that the spot prices and TTF futures have a very high correlation. However, we are mostly interested in the correlation between the long and short-term gas prices, thus the emphasis is on the comparison between them. It is evident that the highest correlation (0.78) is between Brent Crude oil and the TTF monthly futures. The result is somewhat expected, because, as mentioned above, the TTF futures are used extensively as a price reference for long-term contract indexation. Moreover, other gas prices, such as NCG and TTF, similarly correlated with the Brent Crude futures, with 0.768 and 0.765, respectively. The least correlated are the CEGH spot prices and Brent Crude, with 0.72.

From the results, we could conclude that the correlation between the TTF futures prices and the Brent Crude futures is quite high, and, as the TTF futures presents the benchmark for long-term contracts, we cannot, in good faith, reject the claim that the short-term contract prices are not derived from long-term ones. Furthermore, for the lower correlation with the spot prices, Komlev (2016) argues that the gas spot prices on liquid gas hubs can be based on the supply and demand equilibrium, in some periods, because wholesalers and traders may buy/sell certain amounts of gas in order to balance their shortage or surplus of gas. Nevertheless, the base for the spot prices is still oil indexation and this interpretation could also be plausible and help us understand why the spot prices have a bit of a lower correlation than the TTF futures.

Although there is a lot of evidence that suggests that the short-term natural gas prices are in fact derived from the long-term ones, we cannot be certain that this is the case, especially because 0.78 is not as high a correlation as we would expect in order to be 100% confident, and the fact that spot gas and futures prices were historically strongly influenced by the pricing conditions of long-term contracts, meaning that the correlation between the oil and gas hub prices has been historically high (ACER&CEER, 2016). Thus, in order to be certain that the short-term contracts are in fact derived from the long-term ones and to exclude any historical correlation and trend between them, I take a period of one year, from August 2016 to August 2017, comprised of 54 weeks, for the comparison of the long-term and short-term gas prices. The one-year comparison of prices is presented in Figure 12 below.

From Figure 12, it is evident that the Brent Crude futures prices are still higher than TTF futures, which could be the case because of the supply security offered by the long-term contract. However, in comparison to Figure 11, TTF and Brent Crude futures have a different trend most of the time, meaning that the future prices of oil and gas are, in some periods, moving in opposite directions and thus the TTF futures cannot be fully influenced by them. The same applies for the movement of different gas spot prices in comparison to Brent Crude, while the spot prices still have a similar trend, compared to each other. Nevertheless, I have presented the correlation results of the before-mentioned prices in Table 13 below, for better representation.

Figure 12: One-year comparison between short-term and long-term gas prices



Source: Bloomberg Terminal.

Table 13: Correlation matrix between short-term and long-term natural gas prices for a one-year period

	NCG SPOT	TTF SPOT	CEGH SPOT	TTF FUTURES	BRENT CRUDE
NCG SPOT	1.000	0.909	0.717	0.249	0.199
TTF SPOT	0.909	1.000	0.720	0.199	0.104
CEGH SPOT	0.717	0.720	1.000	0.285	0.179
TTF FUTURES	0.249	0.199	0.285	1.000	0.581
BRENT CRUDE	0.199	0.104	0.179	0.581	1.000

Source: Own work.

The correlation matrix in Table 13 has confirmed that the TTF futures and Brent Crude have a dissimilar trend, as their prices are only 0.58 correlated, which is around 0.3 less than in the period of five years. The difference is even greater if we look at the correlation of spot prices on different gas hubs - NCG, TTF and CEGH, compared to Brent Crude, with 0.2, 0.104 and 0.179, respectively. Therefore, we can see and state that the short-term gas prices nowadays are gradually becoming independent from the long-term prices, meaning that they are no longer derived from the long-term ones, as the prices have their own movement and correlations.

In this respect, I cannot confirm the claim set by Gazprom's analyst Komlev, because it is evident that the short-term gas prices were indeed derived from the long-term ones in the past, which is also obvious in Figure 12 and Table 12. However, with the liberalization of the natural gas market, which brought about a stronger market interconnection and competition along with it, the oil indexation pricing, which affected not just the long-term gas prices, but short-term ones as well, is being gradually substituted by the gas prices. Furthermore, according to ACCER and CEER (2016), even long-term contracts are gradually taking gas fundamentals for the pricing mechanism, which is also evident in the narrowing spread between the long-term and the short-term gas prices, thus many wholesalers are renegotiating their LTCs, in order to obtain a lower gas price. Nevertheless, as I am not able to gather the exact data of how the demand and the supply are affecting the short-term natural gas prices on the before-mentioned European Gas Hubs, I cannot state with certainty that all short-term contracts, or gas spot prices, are based on the supply and demand equilibrium. Although, as seen from the results above, the spot prices on different hubs have their own unique trend, which can be explained with a different demand and supply on the gas hubs. Moreover, even Komlev argues that the spot prices on liquid gas hubs (for example NBP in the United Kingdom and TTF in Netherlands) are the product of the supply and demand equilibrium.

Hence, I can refute the claim set by Komlev, as it was proved that, at a certain period of time, the spot prices at liquid hubs have gas fundamentals, which are derived from supply and demand, not from long-term contracts, but I can say with certainty that the majority of short-term gas prices on liquid hubs are not derived from the long-term ones and are being gradually replaced by gas to gas competition. This statement is confirmed by Gas Pricing (n.d.), which stresses that when buyers and sellers of natural gas on the markets, where oil indexation prevails, will increase, the link to oil prices will decline and will consequently begin to bear a resemblance to a more liberal and open gas to gas market competition.

CONCLUSION

Even though it is believed that natural gas is the cleanest fossil fuel and that it will be a key energy trajectory for Europe for at least the next 20 years, the reduction in the reserves and the ban of shale gas extraction in Europe is not in favour of natural gas consumption, as Europe is one of the smallest regions in terms of gas reserves. This means that Europe will still be strongly dependent on the imports of natural gas from countries with richer reserves, like Russia and Qatar, and will be reliant on the selling conditions from the supplier's side. Nevertheless, the trading process of natural gas has significantly changed over the years with the appearance of new gas players, markets and contracts, due to the liberalization of the European natural gas market.

In the long-term contracts, which prevailed for almost 50 years for the delivery of natural gas, the natural gas prices are an index to oil and have take or pay obligations, in addition to the destination clause. However, they are being gradually replaced by short-term contracts, which are an index to gas prices and supposedly represent the supply and demand equilibrium on the natural gas market. This was also proved when testing the hypothesis by Gazprom's analyst, who stated that the prices on gas hubs are derived from the long-term ones and not from the supply and demand equilibrium, and that the price in long-term contracts is higher, due to the security of the supply. Even though I did not have exact data about how the supply and demand affect the short-term gas prices on particular European Gas hubs, I was able to prove that short-term gas prices were historically influenced by the long-term ones, with the comparison of Brent Crude oil futures with the TTF futures and gas spot prices in different periods (five years and one year). However, they are being replaced by gas to gas competition or the supply and demand equilibrium, where the basis for a gas price is gas and not oil. Thus, I was able to refute the claim set by Komlev. Furthermore, it is evident that the gas prices on some European gas hubs are in fact the factor of supply and demand, such as the NBP in the United Kingdom and the TTF hub in the Netherlands, which actually became the most liquid hub in Continental Europe. On the other hand, a smaller hub like CEGH is still predominantly affected by long-term contracts, as gas is not traded in high quantities there and most of the gas comes from Russia, with slightly adjusted long-term contracts. Nevertheless, short-term contracts are gaining momentum, which is also evident on the Slovenian natural gas market as, according to the Slovenian Agency for Energy (2016), in 2015, 59% of all gas supply came into Slovenian pipelines on a short-term basis.

A new contractual agreement does not only influence the pipeline transportation, but also the LNG transfers, as contracts have lower maturity and are adjusted, so the gas prices resemble the natural gas market situation. All of these changes, from liberalization to the creation of gas hubs on the European natural gas market, brought into gas trading, not just the wholesalers and retailers who want to physically deliver gas in order to satisfy the needs of their consumers, but also the traders who are trading with gas and gas instruments exclusively for financial profit. Although the natural gas market has become more interesting to the variety of traders, there was always a high level of risk and uncertainty present on the natural gas market, which comes from the natural gas price risk. A high level of price risk comes from the fact that natural gas is a seasonal commodity and is reliant on several factors, from the weather and the storage facilities to the production and delivery restrictions. The price risk in natural gas was additionally strengthened by the deregulation of the natural gas market. Beside price risk, other risks are present on the natural gas market, such as the supply and demand risk, which occurs in the times of a crisis or catastrophic events, the political, geological and cost risk, the latter being connected mainly to the operating cost of retrieving the natural gas.

All of the aforementioned risk exposure, accompanied by the increase in gas trading, brought with it a bigger emphasis on the risk management, as the trading parties want to reach the highest return with the lowest risk. Hence, risk management plays an important part as it enables the companies to better align their demand for funds with their internal supply of funds. Companies trading with natural gas are nowadays more inclined to different risk-management solutions, from hedging with different financial instruments like futures, forwards, swaps, options and weather derivatives, to the usage of physical tools, such as gas storage, for the sole purpose of minimizing risk and achieving a higher profit. Nevertheless, when using risk management solutions, a cost benefit analysis should be performed, so that, for example, hedging is applied only if the costs do not overcome the benefits. An important tool, which the gas companies are nowadays using on a daily basis to control the financial and market exposure risk on the natural gas market, is Value at Risk.

In this master thesis it was proven that VaR is a good measurement of risk control in a natural gas portfolio, as it sums up all of the risks in the portfolio into a single number and is therefore suitable for the purpose of presenting risk to a variety of people, from the board to the regulators. Furthermore, VaR has proved to be a good indicator of how much variability can arise in the natural gas portfolio from day to day, and how well risk management is performing the task of keeping the variability within a controllable level, therefore, the people reliable for keeping the company's financial exposure within the limits, can close the open position which loses the most money in a natural gas portfolio on a daily basis.

Moreover, an imaginary example of the short-term trader X showed different possibilities of the VaR calculation, using dissimilar methodologies like the historical simulation, the covariance variance and the Monte Carlo simulation. The calculation in the natural gas portfolio has proved that when only considering calculations, for the before-mentioned case, the historical VaR is the best model. However, when considering that, in 2015, the historical VaR returns were manipulated by the consequences of the Ukraine crisis, which will not happen every year or ever again, the other two models are better. Hence, the covariance variance and the Monte Carlo simulation are superior for representing the financial risk exposure of the company for the natural gas market, especially in the case where history does not repeat itself and when several other factors, like gas monthly price volatility and seasonality, influence the VaR outcome. The example of a natural gas portfolio has failed to clearly prove or refute whether the Monte Carlo simulation is indeed the best for calculating VaR but has proved that it goes well alongside the covariance variance VaR, in the case where you do not take into account all of the relevant futures data and volatilities and is indeed a good tool for calculating VaR. However, in a situation where the one calculating the VaR will have adequate inputs and predictions for the future, the Monte Carlo simulation will be the best method for calculating VaR.

Beside the comparison of different VaR models, it was proven in the natural gas portfolio that gas prices are very volatile and are influenced by the seasonality, weather and other gas supply and demand related news, as gas prices in 2015, compared to 2014, differ greatly. The huge difference between the prices can be explained by the warmer winter of 2015, the fact that, in the same year, the oil prices dropped significantly (oil indexation in long-term contracts) and that on the European natural gas market the TTF gas hub became the most liquid gas hub in Europe, thus gas prices are beginning to reflect the gas prices, instead of being indexed to oil. In particular, this has proved that managing the risk price in natural gas trading is a very important and hard task, as the volatility and risk of natural gas prices changes on a yearly basis. Therefore, the risk management department has to take into consideration not only the historical data, but also the future estimations, meaning the weather, politics, crisis, other regulatory related news, etc., which could affect the natural gas supply and demand and consequently the gas prices, in order to set the right trading strategy and to take the appropriate steps in diminishing the price risk with hedging and the usage of different financial instruments and physical tools, in addition to the VaR control.

Overall, as natural gas trading has been increasing over the years and the future of natural gas looks prosperous worldwide, I think that risk management will gain leverage, as the natural gas market is unpredictable and relies on numerous environmental and economic factors, which cannot be influenced. Therefore, companies will put more effort and emphasis on the use of different risk management solutions, from financial tools to risk control, with measurements like VaR, in order to minimize the risk and have the upper hand in the time of a crisis. With this kind of an approach, they will be able to close any position which is too risky and know exactly how much they are spending for hedging or for insurance purposes. Furthermore, with risk management, they will be able to diminish the counterparty risk and other risks associated with the pools of traders, who are trading just for the sole purpose of profit.

Hence, I am positive that natural gas wholesalers, retailers and traders will start to think more risk aversely and will give more power to the risk management department, as they can be the ones who can prevent a bad or even a catastrophic outcome. My thoughts are perfectly supported by the quote of the Chief Economic advisor to the United States' president Donald Trump and former Chief operating officer of Goldman Sachs, Gary Cohen who said, *"If you don't invest in risk management, it doesn't matter what business you're in, it's a risky business."* (TMS Consulting Pty Ltd, n.d., p. 2)

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APPENDIXES

Appendix 1: Povzetek (Summary in Slovene language)

Zemeljski plin velja za najčistejše fosilno gorivo, saj ima najnižjo emisijo CO2 na enoto energije. Uporablja se v različnih energetskih sektorjih kot so stanovanjski in komercialni, kjer se zemeljski plin večinoma uporablja za ogrevanje in kuhanje ter proizvodni sektor, ki uporablja plin predvsem za proizvodnjo električne energije (Melling, 2010). Po mnenju World Energy Council (2016) je zemeljski plin drugi največji vir v proizvodnji električne energije, saj predstavlja kar 22% proizvedene električne energije in je edino fosilno gorivo, katerega poraba naj bi v prihodnosti rasla, in bo igral pomembno vlogo v razvoju sveta na čistejšo, cenovno dostopnejšo in varnejšo energijo. Poleg tega Gilardoni (2008) meni da bo poraba zemeljskega plina rastla predvsem zaradi ekonomičnega dejavnika, ki je povezan z učinkovitejšo in cenejšo proizvodnjo električne energije.

Čeprav uporaba zemeljskega plina po svetu narašča, Evropa ni preveč bogata z zalogami zemeljskega plina. Po podatkih British Petroleum Statistical review of World Energy (2015) je Evropa imela le 1,6% svetovnih rezerv zemeljskega plina v letu 2015 (3,1 trilijone kubičnih metrov), medtem ko je njihova proizvodnja v istem letu dosegla 232 milijonov kubičnih metrov. V primeru, da bo Evropa sledila isti poti proizvodnje/rezerv zemeljskega plina, bo v 13 letih porabila vse zaloge zemeljskega plina. Po drugi strani pa je evropska poraba zemeljskega plina v letu 2015 znašala 444 milijonov kubičnih metrov, kar kaže na močno odvisnost Evrope na uvoz zemeljskega plina za zadovoljitev povpraševanja, saj sama nima dovolj visokih zalog in lastne proizvodnje zemeljskega plina. Melling (2010) meni, da uvoz zemeljskega plina v Evropo ni dovolj raznolik, saj je odvisen predvsem od velikih proizvodnih držav zemeljskega plina kot so Rusija, Alžirija in Katar iz tujine ter Nizozemske in Norveške znotraj Evrope. Zaradi neprilagojenosti in pomanjkanja konkurence na trgu zemeljskega plina, pa so bili evropski kupci izpostavljeni določenim tveganjem, saj so imeli veliki proizvajalci finančni vzvod zaradi monopolističnega položaja v pogajalskem procesu prodaje zemeljskega plina, ker so lahko zagotovili stabilne cene ter zanesljivost oskrbe s plinom.

Na trgu zemeljskega plina je osnova za oblikovanje cen in cenovnih gonilnikov drugačna po regionalnih trgih. V nasprotju z globalnim naftnim trgom, je trg zemeljskega plina razdeljen na nekaj povezanih trgov z zemeljskim plinom. Ker ne obstaja enoten mehanizem oblikovanja cen za zemeljski plin po vsem svetu (Rogers, 2012), se oblikovanje cen zemeljskega plina močno razlikuje med svetovnimi regionalnimi trgi, odvisna pa je od več dejavnikov, kot so regulacija, obstoj samega plina na trgu, likvidnost, delež uvoženega plina, vrste pogodb in stopnja odprtega trga (Davoust, 2008).

Dolgoročne in kratkoročne pogodbe zemeljskega plina

Po Zajdlerju (2012), je zgodovinski razvoj na trgu zemeljskega plina v Evropi privedel do vzpostavitve dveh modelov oskrbe z zemeljskim plinom in s tem tudi določanja cen v dolgoročnih pogodbah zemeljskega plina. Prvi model - imenovan tudi kontinentalni model, je temeljil na dolgoročnih pogodbah z zemeljskim plinom, kjer so bile cene zemeljskega plina, indeksirane na cene surove nafte in naftnih derivatov. Drugi model, imenovani tudi britanski model, pa je bil ustanovljen sredi devetdesetih let in je temeljil na srednjeročnih pogodbah o dobavi zemeljskega plina po ceni, ki je bila določena glede na ponudbo in povpraševanje (Zajdler, 2012).

Dolgoročne pogodbe o zemeljskem plinu so bile nekaj desetletji glavni temelj oskrbe z zemeljskim plinom v Evropi. Od sedemdesetih let dalje, so bile dolgoročne pogodbe uporabljene za uvoz več kot 250 milijard ameriških dolarjev plina na območje EU (Energy Charter Secreteria, 2007). Dolgoročne pogodbe o zemeljskem plinu povezujejo kupce in prodajalce v dvostranski monopol za obdobje 20-30 let, med katerimi sta obe strani izrecno opredelili svoje obveznosti (obveznost prevzema in plačila zemeljskega plina ter ciljno klavzulo). Dolgoročne pogodbe so se izkazale, kot zanesljive za nakup zemeljskega plina, saj so zagotovile varno in stabilno oskrbo z zemeljskim plinom zaradi indeksiranja cen zemeljskega plina z nafto, poleg tega pa so bile tudi pomemben dejavnik za naložbo v infrastrukturo zemeljskega plina po Evropi. Čeprav so bile dolgoročne pogodbe temelj za trgovanje z zemeljskim plinom, so bile razvite pred liberalizacijo zemeljskega plina, zato so imele tudi nekaj pomanjkljivosti. Glavne pomanjkljivosti dolgoročnih pogodb pa so bile predvsem razlika med ceno zemeljskega plina in nafte, odvisnost kupcev do enega dobavitelja, ter pomankanje in zaviranje konkurence s strani glavnih proizvajalcev zemeljskega plina.

Pomanjkljivosti dolgoročnih pogodb z zemeljskim plinom so skupaj z liberalizacijo evropskega trga zemeljskega plina ustvarile potrebo po novem pogodbenem trendu in bolj prilagodljivim instrumentom trgovanja z zemeljskim plinom, ki bodo nadomestile obstoječe pogodbe. Liberalizacija trga v poznih devetdesetih letih je močno vplivala na razvoj trgovanja z zemeljskim plinom v Evropi kot ga poznamo še danes, predvsem zaradi odprtega trga in navzočnosti novih udeležencev, ki je zagotovila konkurenco in konkurenčne cene zemeljskega plina. Po podatkih Zajdlera (2012) je bil to začetek drugega, britanskega modela, ki temelji na srednjeročnih pogodbah o dobavi zemeljskega plina po ceni, ki je določena glede na ponudbo in povpraševanje z zemeljskim plinom. Nov model pa je s seboj prinesel tudi razvoj centrov za distribucijo zemeljskega plina ter trgovanje z zemeljskim plinom in izmenjavo v Evropi.

Po podatkih Heather (2015) je center za distribucijo zemeljskega plina ali plinsko vozlišče lokacija, kjer se več plinovodov med seboj križa. Medsebojno povezovanje plinovodov torej predstavlja priložnost za trgovino in fizično izmenjavo plina med velikimi skupinami prodajalcev in kupcev.

Prvo plinsko vozlišče je bilo ustanovljeno v ZDA v začetku 50. let prejšnjega stoletja v Louisiani, imenovano Henry Hub, ki tudi določa referenčno ceno za celotno severnoameriško trgovsko regijo in je najbolj likvidni trg z zemeljskim plinom na svetu (IENE, 2014). Kljub temu, pa je koncept plinskih vozlišč prišel v Evropo veliko kasneje, zaradi pozne liberalizacije trga zemeljskega plina, če ne upoštevamo Velike Britanije, kjer je bilo plinsko vozlišče National Balancing point (NBP) ustanovljen že v devetdesetih letih. Danes so najpomembnejša plinska vozlišča v Evropi, po Kulichu (2016), Title Transfer Facility (TTF) na Nizozemskem, ki je največje središče v celinski Evropi, PEG NORD v Franciji, GASPOOL v Nemčiji in Central European Gas Hub (CEGH) v Baumgartnu v Avstriji, ki igra tudi pomembno vlogo pri trgovanju z zemeljskim plinom na slovenskem trgu.

Plinske vozlišča so fizična ali virtualna. Fizična vozlišča so postavljena na določeni geografski lokaciji, kjer se plinovodi med seboj fizično povezujejo in se posledično nahaja celotna prenosna mreža. Pri trgovanju z zemeljskim plinom na fizičnih vozliščih lahko prodajalec proda zemeljski plin samo strankam, ki imajo prenosne zmogljivosti iz plinskih vozlišč. Na drugi strani pa se virtualna plinska vozlišča prav tako opredeljena kot balansirana vozlišča zemeljskega plina, ki pokrivajo širše geografsko območje in jih opredeljuje nacionalno ali med-regionalno plinsko omrežje. Tisti, ki upravlja omrežje za prenos plina v virtualnih vozliščih, lahko sprejme zemeljski plin na katerikoli lokaciji geografskega območja, ki ga pokriva plinsko vozlišče, zato vozlišča dejansko predstavljajo izravnalne točke znotraj sistema plinovodov. Poleg tega pa lahko člani virtualnih vozlišč izbirajo med več izhodnimi / vhodnimi točkami v prenosu plina in se hkrati ne zavezujejo, da bodo organizirali prevoz zemeljskega plina, ker je za prenos zemeljskega plina odgovoren neodvisni operater zemeljskega plina (Kulich, 2016).

Trgovanje z zemeljskim plinom

Kot že omenjeno je liberalizacija trga z zemeljskim plinom v Evropi močno vplivala na razvoj trgovanja po Evropi, kar je povzročilo dramatično povečanje obsega trgovanja. Povečano trgovanje je bila posledica ustanovitve novih trgov kot so Over the Counter (OTC) in izmenjave plina (energy exchange), kjer udeleženci trga opravljajo kratkoročne in srednjeročne posle prek borz in plinskih vozlišč, poleg že obstoječih bilateralnih trgov in dolgoročnih pogodb. Pri kratkoročnih pogodbah »gas to gas competition«, kjer se cena določa glede na ponudbo in povpraševanje sta na voljo dva načina trgovanja z zemeljskim plinom: trgovanje preko OTC in izmenjava energije oziroma v našem primeru zemeljskega plina. Trgovanje z OTC je ne regulirano dvostransko trgovanje med kupcem in prodajalcem zemeljskega plina, ki ga je mogoče obravnavati neposredno ali prek posrednikov. Po drugi strani pa trgovanje z energijo temelji na standardiziranih izdelkih, kjer se ponudba in povpraševanje kupcev in prodajalcev zemeljskega plina ujemata za namen anonimnega standardiziranega trgovanja ter kliringa različnih produktov zemeljskega plina (Kulich, 2016).

Večina trgovanja z zemeljskim plinom za fizično oskrbo v Evropi poteka v obliki, dnevnega, med dnevnega, promptnega in trgovanja s terminskimi produkti. Poleg navedenega pa obstajajo tudi finančno izvedeni instrumentni, kot so zamenjave, opcije in vremensko izvedeni finančni instrumenti, namenjeni za ščitenje oziroma fizično dobavo plina. Sam razvoj evropskih vozlišč in trgovanje z zemeljskim plinom so tako omogočili proizvajalcem, dobaviteljem in trgovcem plina, da trgujejo drug z drugim, bodisi za fizično dobavo ali zgolj za finančni dobiček. Prav tako pa so omogočili da so cene zemeljskega plina začele odražati tržno vrednost plina, ki je v končni fazi povzročila razvoj trga s fizično neravnovesnega in monopolističnega na trg zemeljskega plina, kjer se upravlja s cenovnimi tveganji (Long & Moore, 2003).

Obvladovanje tveganj na trgu zemeljskega plina

Vloga obvladovanja tveganj je zagotoviti, da ima družba na razpolago denar za povečanje naložb, ki povečujejo družbino vrednost, ker so zunanji viri financiranja kot so zunanji kapital dražji od notranjih, zlasti zaradi nesorazmernosti informacij (adverse selection) ali napačne izbire financiranja (Froot, Scharfstein & Stein, 1994). Stanje obvladovanja tveganj na trgu zemeljskega plina ni izjema, saj je nestanovitnost cen zemeljskega plina v zadnjih nekaj letih (finančna kriza, kriza v Ukrajini itd.) povzročila večji poudarek na obvladovanju tveganj s strani prisotnih udeležencev na trgu zemeljskega plina.

Visoka raven tveganja in negotovost, okrepljena z deregulacijo trga zemeljskega plina, izhaja iz visoke izpostavljenosti cenam zemeljskega plina, zato se nestanovitnost na trgu zemeljskega plina nanaša na razmerje med nestanovitnostjo cen zemeljskega plina in časom dobave. Razmerje se pogosto zmanjšuje, saj je nestanovitnost cen kratkoročnih oziroma srednjeročnih plinskih pogodb višja od dolgoročnih pogodb, kar se odraža v relativno stabilni in nižji nestanovitnosti cen plina na dolgi rok. Dolgoročne pogodbe imajo nižjo nestanovitnost cen kot kratkoročne pogodbe z zemeljskem plinom, kot posledica vračanja cen k povprečju (mean reversion), kar je vidno kot nagib cen zemeljskega plina nazaj na srednje ali skupno raven, po udarnih valovih cen plina (lahko se dvigajo ali spuščajo) in izvirajo iz kratkoročnih zunanjih okoliščin (Graves & Levine, 2010).

Obstaja veliko potencialnih kratkoročnih vplivov na trg zemeljskega plina, ki bodo vplivali na cene zemeljskega plina, vendar so na dolgi rok zanemarljivi. Na cene zemeljskega plina na dolgi rok vplivajo predvsem spremembe sistemov, tehnologije in predpisov, zato so veliko manj nestanovitne in ni redkost, da so kratkoročne nestanovitnosti cen zemeljskega plina precej višje, kot je bilo že omenjeno zgoraj. Po podatkih EIA (nd) so cene zemeljskega plina bolj nestanovitne od cen drugih proizvodov zaradi več dejavnikov kot so: vreme, proizvodnja in uvoz, omejitve dobave, skladiščenje in informacije o trgu zemeljskega plina. Poleg cenovnega tveganja pa so na trgu zemeljskega plina prisotna tudi tveganja ponudbe in povpraševanja, stroškovna, politična in geološka tveganja, ki pa se večinoma odražajo v spremembi cen zemeljskega plina in so tako del cenovnega tveganja. Da bi obvladali zgoraj omenjena tveganja, energetski akterji na trgu zemeljskega plina uporabljajo procese obvladovanja tveganj, svoja orodja in kontrole, da bi s tem ublažili tveganje in nestanovitnost cen zemeljskega plina.

Namen procesa obvladovanja tveganja je tako ovrednotiti višino tveganj in osredotočiti predanost vodij podjetja na velika tveganje za oblikovanja osnove za odziv na prej omenjena tveganja. Ocena tveganj je opredelitev in določanje prednostnih tveganj, tako da se stopnje tveganja obravnava glede na določen prag tveganja podjetja. Zelo je pomembno, da so ocene tveganja praktične in enostavne za razumevanje ter da proces vodijo ljudje z ustreznim znanjem in spretnostmi, kar zagotavlja, da se udeleženci počutijo opolnomočene s svojimi prispevki in s spremljanjem odzivov na tveganja. Končni cilj ocene tveganja je tako zagotoviti, da bodo upravljavci na vseh ravneh uporabili informacije za izvršitev odločitve o minimiziranju tveganja v korist podjetja.

Orodja za obvladovanje tveganja v zemeljskem plinu

Proces obvladovanja tveganj po mnenju Froot, Scharfstein & Stein (1994) družbam omogoča, da bolje uskladijo svoje povpraševanje po sredstvih s svojo notranjo ponudbo sredstev. Na ta način lahko plinska podjetja v določenih obdobjih zmanjšajo neravnovesje pri pomanjkanju dobave s presežkom dobave plina v drugih obdobjih. Ta strategija se imenuje hedging. Hedging je izraz, ki se po Sturmu (1997) uporablja pri opisovanju namena vstopa v transakcijo z namenom izravnave tveganja z drugo povezano transakcijo (na primer, nakup avtomobilskega zavarovanja je varovanje pred tveganjem plačila celotnih stroškov popravila avtomobila). V primeru zavarovanja z zavarovalnimi produkti in izvedenimi finančnimi instrumenti, ki krijejo določen znesek v zameno za negotove stroške, je potrebno opraviti analizo stroškov in koristi, tako da se varovanje uporablja le v primerih, kjer stroški ne presegajo koristi (Damodaran, 2007).

Podjetja v industriji zemeljskega plina so v preteklosti uporabljala in izbrala različne načine obvladovanja tveganja in so tako s svojimi naložbenimi odločitvami in možnostmi financiranja zmanjšala tveganje. Danes obstajajo različna orodja za udeležence na trgu zemeljskega plina, ki želijo obvladovati tveganje nihanja cen zemeljskega plina. Orodja na splošno lahko razdelimo na fizična in finančna orodja. Po mnenju Graves & Levine (2010) so fizična orodja nadalje razdeljena na skladiščenje, pogodbe s fiksno ceno zemeljskega plina, spremembe v proizvodnji in zalogah plina ter skladiščih. Po drugi strani pa so finančna orodja izvedeni finančni instrumenti, ki ne zahtevajo dejanske dobave zemeljskega plina in se lahko z njimi trguje zgolj za finančni dobiček. Med ta orodja sodijo terminske pogodbe, zamenjave, opcije in vremenski derivati. Poleg procesov za obvladovanje tveganj ter fizičnih in finančnih orodij, bolj razviti programi in družbe za obvladovanje tveganj na trgu zemeljskega plina uporabljajo statistične tehnike za merjenje in spremljanje tveganja portfeljev. V zadnjih letih je tvegana vrednost (Value at Risk - VaR) bilo najpogosteje uporabljeno orodje za merjenje finančnega tveganje za podjetja v industriji zemeljskega plina (Institute and Faculty of Actuaries, 2016).

Tvegana Vrednost – Value at Risk

VaR je razvila banka JP Morgan v sedemdesetih letih prejšnjega stoletja kot meritev tveganja, ki je pokazala največjo verjetno izgubo v naslednjem trgovalnem dnevu v eni številki, zato je VaR opredeljen kot največja izguba, ki jo lahko določen portfelj doseže v določenem časovnem obdobju glede na dano verjetnost (Dowd, 1998). Čeprav metoda VaR izvira iz bančne in finančne industrije, podjetja, ki trgujejo z zemeljskim plinom, uporabljajo VaR za oceno tveganja njihovega portfelja in njihovih posameznih položajev na določenih trgih s plinom za namene obvladovanja finančnih tveganj, kar jim omogoča optimizacijo svojega portfelja in prilagoditve svoje trgovalne pozicije glede na prag tveganja (Asche, Dahl & Oglend, 2013)

Obstajajo trije uporabljeni pristopi za ocenjevanje VaR-a: zgodovinska simulacija, variančno-kovariančni model in simulacija Monte Carlo (Jorion, 2006). VaR modeli se obširno uporabljajo pri obvladovanju tveganj, za namen ohranitve nadzora nad morebitnimi izgubami v določenem časovnem intervalu. Razlog za priljubljenost VaR modela je zaradi njegove preprostosti, saj so vsa tveganja v portfelju povzeta v eni sami številki. VaR lahko meri tveganje pri vseh vrstah pozicij in dejavnikih tveganja v podjetju, s čimer zagotavlja finančno in verjetnostno izražanje zneskov izgube (Dowd, 2005). Vendar ima model VaR, kot vsi finančni modeli tudi nekaj pomanjkljivosti.

Ena od glavnih pomanjkljivosti modela VaR je, da je model enako dober kot kakovost njegovih podatkov. To pomeni, da če vhodni podatki niso dober približek realnega stanja, bo VaR izračun zavajajoč in bo samo zanašanje na VaR lahko vodilo k še večji izgubi. Taleb (2008) in Danielsson (2008) menita, da VaR zagotavlja preveč optimistične ocene izgube v kriznih razmerah, saj so ravni korelacije tedaj višje, kar lahko povzroči težave in napačno oceno izgub, saj so produkti med seboj močno korelirani.

Izmišljen kratkoročni portfelj zemeljskega plina

S tem namenom sem na slovenskem trgu zemeljskega plina ustvaril portfelj zemeljskega plina kratkoročnega trgovca X, kjer bom uporabil in predstavil tri različne pristope VaR izračuna: zgodovinski, variančno-kovariančni model in Monte Carlo simulacijo. Portfelj je bil kreiran za namen raziskave, ali je VaR res primerno orodje za obvladovanje tveganja ter oceno tveganja na trgu zemeljskega plina. Na ta način pa lahko obravnavam tudi prepričanje, da je simulacija Monte Carlo najboljša metoda za predstavitev tveganja/izgube pri trgovanju z zemeljskim plinom.

Izmišljen portfelj zemeljskega plina kratkoročnega trgovca X sestavljajo gibljive mesečne terminske pogodbe plinskega vozlišča TTF v obdobju od 3.1.2014 do 1.1.2016, ki zajemajo obdobje dveh let in obsegajo 104 opazovanja, saj so cene predstavljene na tedenski bazi za namene izračuna tvegane vrednosti na dan 1.1.2016. Ker je prodajalec X kratkoročni trgovec, ki trguje izključno za finančni dobiček, nisem upošteval raznolike porabe končnih uporabnikov v mesecih. Zato sem si tudi izmislil količine trgovalnega zemeljskega plina po mesecih, ki so enake v celotnem obdobju. Za namen trgovanje sem izbral kratko strategijo, ker je po mnenju Global Association of Risk Professionals (2016) bolje imeti kratko pozicijo, ker zima ne bo tako mrzla, kot se industrija večinoma boji, kupci vedno preplačajo za zaščito in obstaja dovolj dodatnih dobaviteljev in zalog zemeljskega plina za kritje kratkih izpadov ali oskrbe z zemeljskim plinom. Po opredelitvi in pridobitvi vseh potrebnih podatkov sem izračunal VaR na 1.1.2016 z uporabo predhodnih metodologij in nato opravil testiranje v letu 2016, da bi dokazal ali zavrnil različne izračune VaR modelov ter ugotovil, katera metodologija je najbolj primerna za predstavitev tveganja v mojem portfelju zemeljskega plina.

Preizkus trditve analitika Komleva iz podjetja Gazprom

Poleg izračunov različnih VaR modelov sem v zadnjem delu svojega magistrskega dela primerjal evropske kratkoročne cene zemeljskega plina z dolgoročnimi cenami zemeljskega plina, da bi preizkusil trditev analitika Komleva, ki trdi, da so kratkoročne cene zemeljskega plina izpeljane iz dolgoročnih in niso predmet ravnovesja med ponudbo in povpraševanjem. Poleg tega tudi navaja, da razlika med cenami plina nastane zaradi dejstva, da dolgoročne pogodbe zagotavljajo zanesljivost oskrbe z zemeljskim plinom ter so zato dolgoročne cene zemeljskega plina višje (Komlev, 2013).

Za preizkus trditve sem za cene kratkoročnih pogodb izbral povprečne tedenske cene zemeljskega plina iz treh različnih vozlišč: največje plinsko vozlišče v celinski Evropi - TTF, NCG Nemčija in CEGH v Avstriji, od aprila 2013 do avgusta 2017, kar je sestavljalo skupno 5 let in 230 opazovanj.

Moja analiza vključuje tudi terminske mesečne TTF pogodbe s povprečnimi cenami na tedenski ravni v že prej omenjenem obdobju, saj se po mnenju ACER & CEER (2016) plinsko vozlišče TTF pogosto uporablja kot referenčna vrednost za določanje cene v dolgoročnih pogodbah zemeljskega plina in za druga plinska vozlišča. Na drugi strani pa sem izbral za dolgoročne pogodbe mesečne terminske naftne pogodbe Brent Crude na tedenski ravni, ki predstavljajo dolgoročno ceno zemeljskega plina, saj so v dolgoročnih pogodbah cene plina indeksirane na nafto. Poleg 5 letne primerjave pa sem naredil tudi primerjavo kratkoročnih in dolgoročnih cen zemeljskega plina za obdobje od avgusta 2016 do avgusta 2017, z namenom izključitve zgodovinskih korelacij in trendov cen.

Zaključek

Čeprav se domneva, da je zemeljski plin najčistejše fosilno gorivo in da bo za Evropo vsaj še 20 let ključna energetska pot, zmanjšanje zalog in prepoved pridobivanja plina iz skrilavca v Evropi, ni naklonjeno porabi in uporabi zemeljskega plina, predvsem zaradi dejstva, da je Evropa ena od najmanjših regij glede na zalogo in proizvodnjo zemeljskega plina. To pomeni, da bo Evropa še vedno močno odvisna od uvoza zemeljskega plina iz držav z bogatimi rezervami, kot sta Rusija in Katar, ter bo odvisna od prodajnih pogojev monopolističnih dobaviteljev. Kljub temu pa se je proces trgovanja z zemeljskim plinom v preteklih letih bistveno spremenil s pojavom novih udeležencev na trgu zemeljskega plina in pogodb zaradi liberalizacije evropskega trga.

V dolgoročnih pogodbah ki so bile temelj dobave zemeljskega plina in so v Evropi prevladovale skoraj 30 let, so cene zemeljskega plina vezane na indeks nafte in imajo poleg ciljne klavzule tudi obveznosti za prevzem ali plačilo. Vendar so le te postopoma nadomestili s kratkoročnimi pogodbami, kjer ceno plina predstavlja ravnovesje med ponudbo in povpraševanjem na trgu z zemeljskim plinom. To je bilo dokazano tudi pri preizkušanju trditve analitika Gazproma Komleva, ki je navedel, da so cene na plinskih vozliščih vezane na indeks nafte in ne ravnovesja med ponudbo in povpraševanjem, ter da je cena v dolgoročnih pogodbah višja zaradi varnosti oskrbe. Čeprav nisem imel natančnih podatkov o tem, kako ponudba in povpraševanje vplivata na cene kratkoročnega plina na določenih evropskih plinskih vozliščih, sem lahko dokazal, da so dolgoročne cene historično vplivale na kratkoročne cene zemeljskega plina s primerjavo terminskih pogodb za nafto Brent Crude s terminskimi pogodbami plinskega vozlišča TTF ter s tedenskimi cenami plinskih vozišč NCG in CEGH in TTF v različnih obdobjih (pet let in eno leto). Kljub temu pa se je izkazalo med primerjavo enoletnega obdobja, da cene plina v kratkoročnih pogodbah niso več vezane na indeks nafte, saj imajo drugačen trend in korelacijo kot dolgoročne pogodbe, ter so tako počasi prevzele drugačen način formiranja cen, pri čemer osnova za ceno plina ni več nafta temveč je rezultat ravnovesja med ponudbo in povpraševanjem. Tako sem tudi lahko zavrnil trditev analitika Komleva, ki pa je tudi sam priznal, da so cene zemeljskega plina na likvidnih plinskih vozliščih (na primer NBP v Veliki Britaniji in TTF na Nizozemske) rezultat ravnovesja med ponudbo in povpraševanjem.

Uporaba kratkoročnih pogodb se po Evropi povišuje, kar je očitno tudi na slovenskem trgu zemeljskega plina, saj je po podatkih Agencije za energijo (2016) leta 2015 59% celotne oskrbe s plinom prišlo v slovenske plinovode na kratkoročni osnovi. Novi pogodbeni sporazumi pa ne vplivajo samo na transport po plinovodih, temveč tudi na prenose utekočinjenega zemeljskega plina, saj imajo pogodbe nižji rok dospelosti in se prilagajajo, tako da cene plina odražajo stanje na trgu zemeljskega plina. Vse te spremembe, od liberalizacije do ustvarjanja plinskih vozlišč na evropskem trgu zemeljskega plina, so prinesle povečano trgovanje s plinom ne samo s strani trgovcev na debelo in drobno, ki želijo fizično dobavljati plin, da bi zadovoljili potrebe svojih potrošnikov, ampak tudi trgovcev, ki trgujejo s plinom in plinskimi instrumenti izključno za finančni dobiček. Čeprav je trg z zemeljskim plinom postal bolj raznolik, je na trgu z zemeljskim plinom prisotna visoka raven tveganja in negotovosti, ki izhaja iz cenovnega tveganja zemeljskega plin. Visoka stopnja cenovnega tveganja pa izhaja iz dejstva, da je zemeljski plin sezonsko blago, ki je odvisno od več dejavnikov, kot so vreme, skladiščenje in same omejitve proizvodnje in dobave zemeljskega plina.

Vsa zgoraj omenjena izpostavljenost tveganju, skupaj s povečanjem trgovanja s plinom, je prinesla večji poudarek na področju obvladovanja tveganj, saj trgovci želijo doseči najvišji donos z najnižjim tveganjem. Zato ima obvladovanje tveganj pomembno vlogo, saj omogoča podjetjem, da bolje uskladijo svoje povpraševanje po sredstvih s svojo notranjo ponudbo sredstev. Podjetja, ki se ukvarjajo z zemeljskim plinom, so zato zdaj bolj nagnjena k različnim rešitvam za obvladovanje tveganj, od varovanja z različnimi finančnimi instrumenti, kot so terminske pogodbe, zamenjave, opcije in vremenski derivati, do uporabe fizičnih orodij, kot je skladiščenje plina z namenom minimiziranja tveganja in doseganja višjega dobička.

V tej magistrski nalogi je bilo dokazano, da je VaR dobra meritev nadzora tveganj v portfelju zemeljskega plina, saj povzema vsa tveganja v portfelju v eno samo številko in je zato primerna za predstavitev tveganja za različno sorto ljudi, od odbora do regulatorjev. Poleg tega pa se je VaR izkazal kot dober pokazatelj, koliko spremenljivk lahko pride iz portfelja zemeljskega plina iz dneva v dan, in kako dobro upravljanje tveganj opravlja nalogo ohranjanja variabilnosti na nadzorovani ravni. Zato lahko zaposleni v oddelku upravljanja tveganja zaprejo odprto pozicijo, ki dnevno izgublja največ denarja v portfelju zemeljskega plina, ter s tem ohranjajo finančno izpostavljenost znotraj praga tveganja družbe.

Poleg tega je izmišljen portfelj kratkoročnega trgovca X, sestavljen iz različnih mesečnih terminskih pogodb TTF, pokazal različne možnosti izračuna VaR z uporabo različnih metodologij, kot so zgodovinska simulacija, variančno-kovariančni model in Monte Carlo simulacija. Izračuni v portfelju zemeljskega plina so pokazali, da je zgodovinski VaR najboljši model le ob upoštevanju izračunov za prej omenjeni primer. Vendar, če upoštevamo, da so bili podatki leta 2015 v modelu VaR manipulirani zaradi posledic ukrajinske krize, ki se ne bodo zgodile vsako leto ali kadarkoli, sta druga dva modela boljša za prikaz realne slike izgube. Zato sta variančno-kovariančni model in simulacija Monte Carlo boljša za predstavitev izpostavljenosti finančnemu tveganju podjetja na trg zemeljskega plina, zlasti v primeru, ko se zgodovina ne ponavlja in na izračun tvegane vrednosti vpliva več drugih dejavnikov, kot so mesečna nestanovitnost cen in sezonska nihanja zemeljskega plina. Primer portfelja zemeljskega plina ni jasno dokazal ali ovrgel, ali je simulacija Monte Carlo dejansko najboljša za izračun VaR, vendar je dokazal, da ga je dobro uporabiti poleg variančno-kovariančnega modela VaR, če pri izračunu ne upoštevamo vseh ustreznih podatkov o nestanovitnosti cen zemeljskega plina in prihodnje porabe zemeljskega plina. Toda v primeru, ko bo tisti, ki bo izračunaval VaR, imel ustrezne podatke in napovedi o prihodnost trga zemeljskega plina, nestanovitnosti cen in porabi potrošnikov, bo simulacija Monte Carlo najboljša metoda za izračun tvegane vrednosti.

Poleg primerjave različnih modelov VaR je bilo v portfelju zemeljskega plina dokazano, da so cene zemeljskega plina zelo nestanovitne, ker na njih vplivajo različna obdobja v letu (sezone), vremenske in druge informacije o oskrbi s plinom in povpraševanjem. To je lepo vidno med primerjavo cen zemeljskega plina med leti 2014 in 2015, saj se cene v omenjenem obdobju zelo razlikujejo. Veliko razliko med cenami je mogoče pojasniti s toplejšo zimo leta 2015, dejstvom, da so se istega leta bistveno znižale cene nafte (indeksacija nafte v dolgoročnih pogodbah), in da je na evropskem trgu zemeljskega plina plinsko vozlišče TTF postalo najbolj likvidno središče plina v Evropi. Zato so cene plina v nekaterih pogodbah že začele odražati ravnovesje med povpraševanjem in ponudbo, namesto da bi bile indeksirane z nafto. Zlasti pa je to dokazalo, da je upravljanje cenovnega tveganja pri trgovanju z zemeljskim plinom zelo pomembna in težka naloga, saj se nestanovitnost cen zemeljskega plina letno spreminja. Zato mora oddelek za obvladovanje tveganj upoštevati ne le zgodovinske podatke, ampak tudi prihodnje ocene, kar pomeni vreme, politiko, krizo, druge novice, povezane s predpisi idr., kar bi lahko vplivalo na ponudbo in povpraševanje po zemeljskem plinu in posledično na ceno plina, da bi lahko določili pravo trgovalno strategijo in sprejeli ustrezne ukrepe za zmanjšanje cenovnega tveganja s hedgingom in uporabo različnih finančnih instrumentov in fizičnih orodij poleg nadzora tveganja z VaR modelom.

Appendix 2: Example of an impact scale

Figure 1: Example of an impact scale

Rating	Descriptor	Definition
5	Extreme	• Financial loss of $X million or more[3] • International long-term negative media coverage; game-changing loss of market share • Significant prosecution and fines, litigation including class actions, incarceration of leadership • Significant injuries or fatalities to employees or third parties, such as customers or vendors • Multiple senior leaders leave
4	Major	• Financial loss of $X million up to $X million • National long-term negative media coverage; significant loss of market share • Report to regulator requiring major project for corrective action • Limited in-patient care required for employees or third parties, such as customers or vendors • Some senior managers leave, high turnover of experienced staff, not perceived as employer of choice
3	Moderate	• Financial loss of $X million up to $X million • National short-term negative media coverage • Report of breach to regulator with immediate correction to be implemented • Out-patient medical treatment required for employees or third parties, such as customers or vendors • Widespread staff morale problems and high turnover
2	Minor	• Financial loss of $X million up to $X million • Local reputational damage • Reportable incident to regulator, no follow up • No or minor injuries to employees or third parties, such as customers or vendors • General staff morale problems and increase in turnover
1	Incidental	• Financial loss up to $X million • Local media attention quickly remedied • Not reportable to regulator • No injuries to employees or third parties, such as customers or vendors • Isolated staff dissatisfaction

Source: Cutis& Carey (2013, p.4).

Appendix 3: Example of a risk probability scale

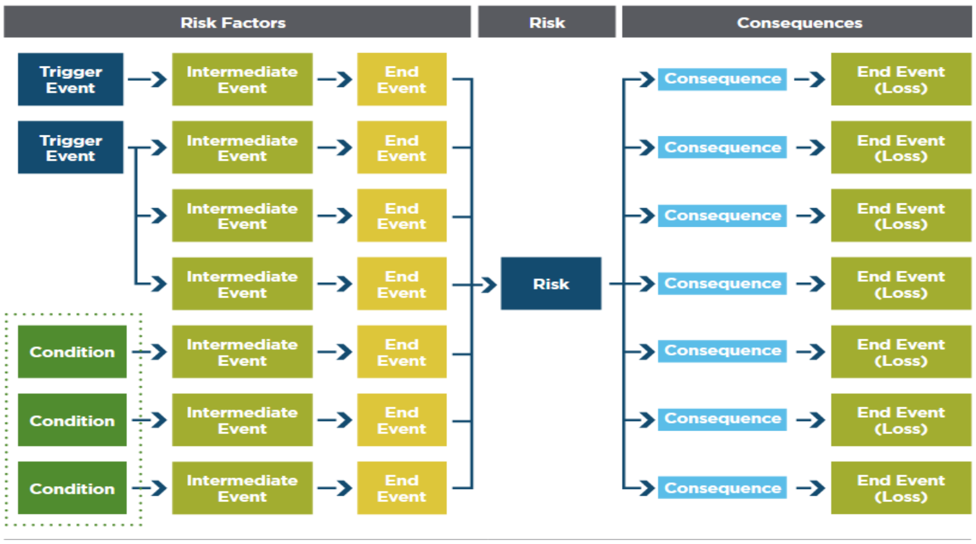
Figure 2: Example of a risk probability scale

Rating	Annual Frequency		Probability	
	Descriptor	Definition	Descriptor	Definition
5	Frequent	Up to once in 2 years or more	Almost certain	90% or greater chance of occurrence over life of asset or project
4	Likely	Once in 2 years up to once in 25 years	Likely	65% up to 90% chance of occurrence over life of asset or project
3	Possible	Once in 25 years up to once in 50 years	Possible	35% up to 65% chance of occurrence over life of asset or project
2	Unlikely	Once in 50 years up to once in 100 years	Unlikely	10% up to 35% chance of occurrence over life of asset or project
1	Rare	Once in 100 years or less	Rare	<10% chance of occurrence over life of asset or project

Source: Cutis& Carey (2013, p. 5).

Appendix 4: Example of a Bow tie diagram

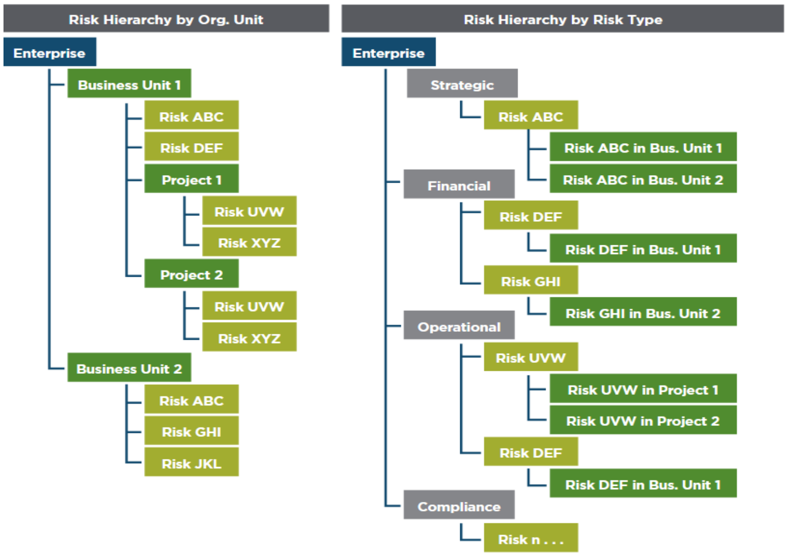
Figure 3: Example of a Bow tie diagram



Source: Cutis& Carey (2013, p. 13).

Appendix 5: Example of a risk hierarchy

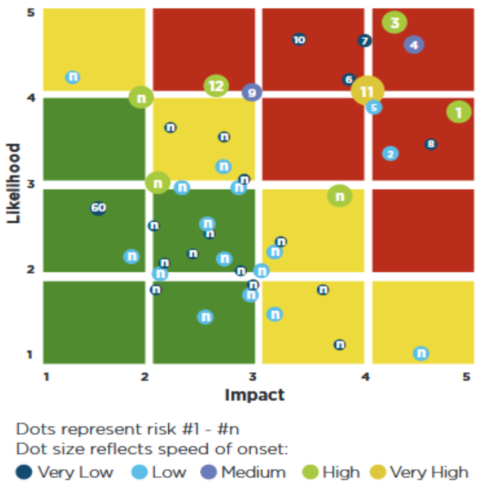
Figure 4: Example of a risk hierarchy



Source: Cutis& Carey (2013, p. 14).

Appendix 6: Example of a heat map

Figure 5: Example of a heat map



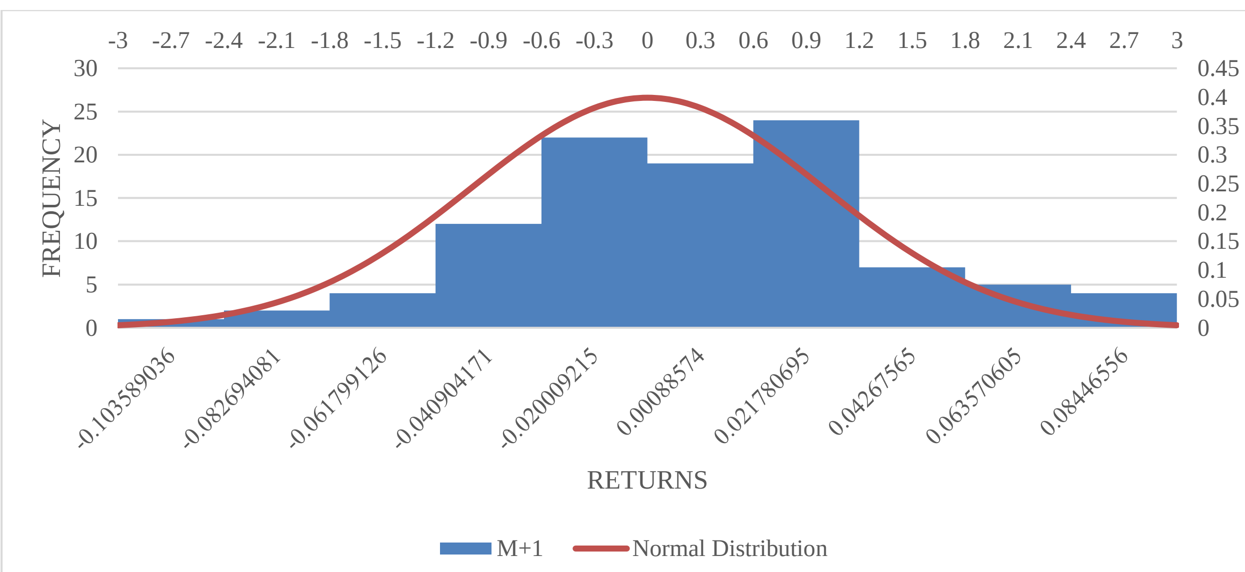
ID	Risk	I	L	V	S
1	Supply chain disruption	4.8	3.7	3.8	4
2	Customer preference shift	4.1	3.3	3.5	2
3	Copper price rise >10%	4.3	4.7	2.3	4
4	Work stoppage > 1 week	4.4	4.5	4.1	3
5	Economic downturn	4.0	3.7	3.5	2
6	Supplier consolidation	3.8	4.2	3.2	1
7	Local competitors enter	3.9	4.5	3.6	1
8	New substitutes available	4.5	3.6	4.2	1
9	Cost of capital rise >5%	2.9	4.0	2.9	3
10	Tighter emission standards	3.4	4.6	2.9	1
11	FCPA violation	4.0	4.0	3.3	5
12	Exchange rate fluctuations	2.7	4.1	2.7	4
n	. . .	...	...	...	...
60	Impairment of assets	1.6	2.7	1.6	1

I = Impact L = Likelihood V = Vulnerability S = Speed of onset

Source: Cutis& Carey (2013, p. 16).

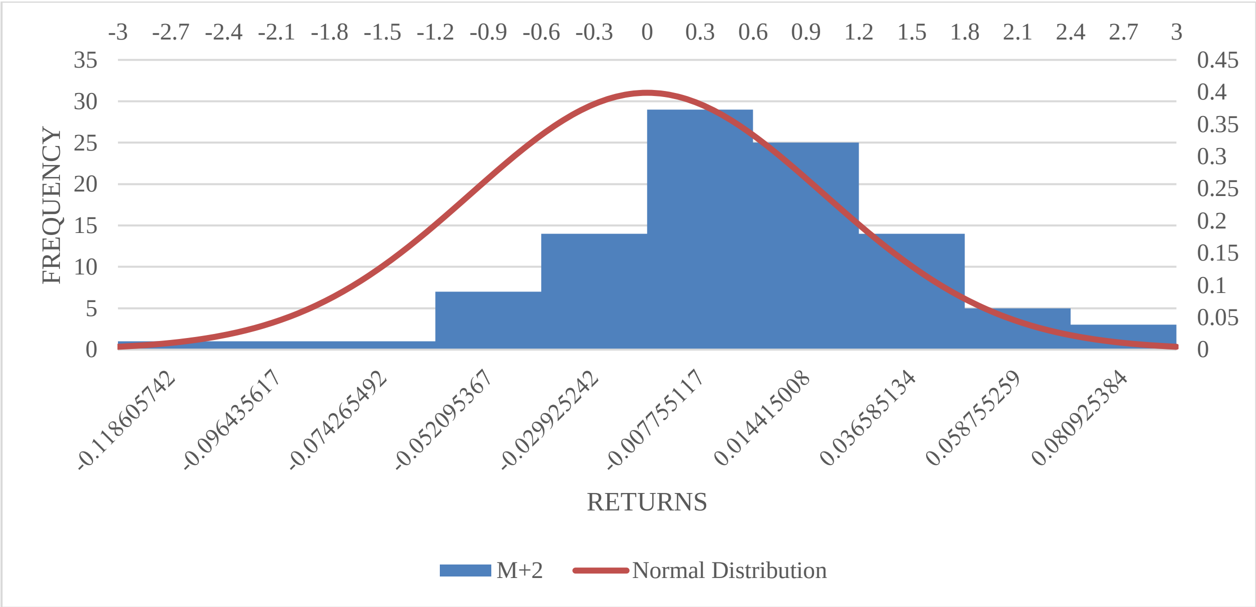
Appendix 7: Histogram of TTF return series

Figure 6: TTF M+1 histogram



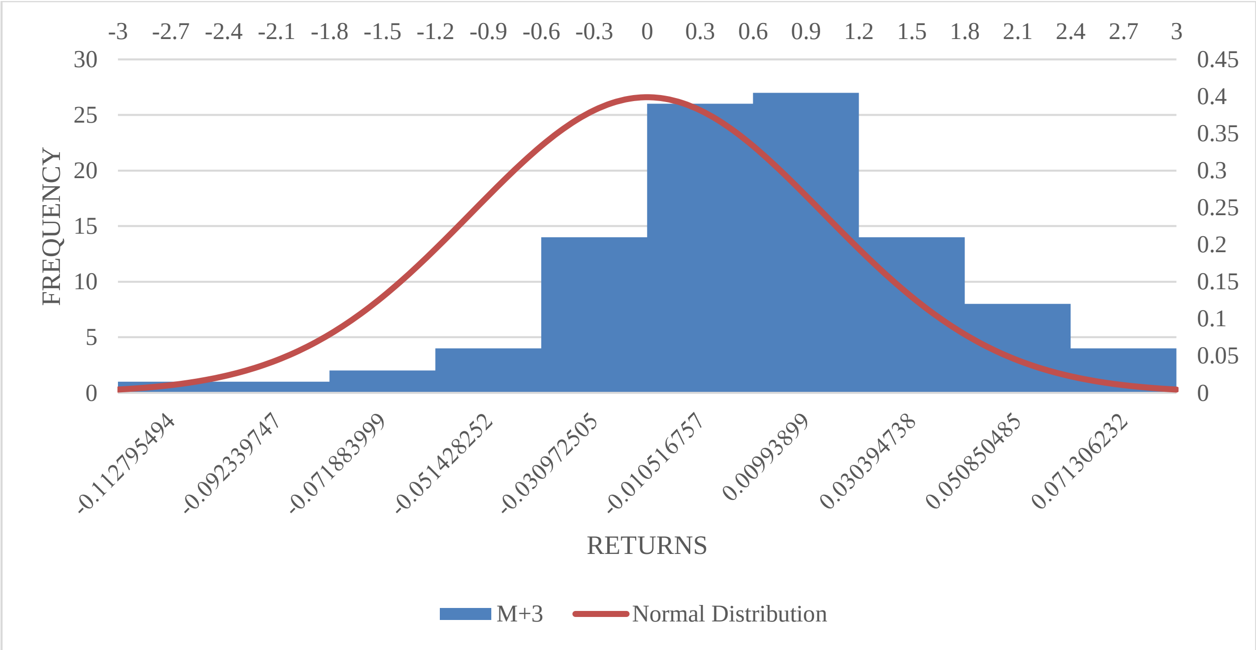
Source: Bloomberg Terminal.

Figure 7: TTF M+2 histogram



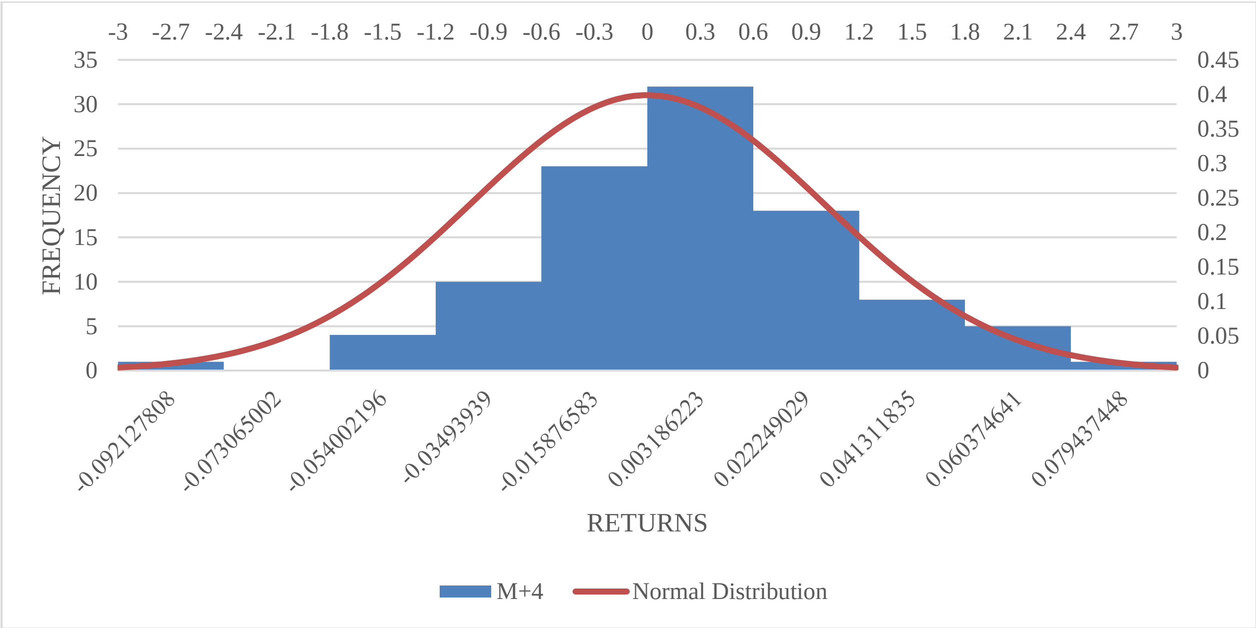
Source: Bloomberg Terminal.

Figure 8: TTF M+3 histogram



Source: Bloomberg Terminal.

Figure 9: TTF M+4 histogram



Source: Bloomberg Terminal.