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"MODELING THE EUROPEAN NATURAL GAS MARKET"

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ΔΗΛΩΣΗ ΓΡΑΦΟΝΤΑ

Ο υπογράφων Σκαράκης Αλέξιος βεβαιώνω ότι το έργο που εκπονήθηκε και παρουσιάζεται στην υποβαλλόμενη διπλωματική εργασία είναι αποκλειστικά ατομικό δικό μου. Όποιες πληροφορίες και υλικό που περιέχονται έχουν αντληθεί από άλλες πηγές, έχουν καταλλήλως αναφερθεί στην παρούσα διπλωματική εργασία. Επιπλέον τελώ εν γνώσει ότι σε περίπτωση διαπίστωσης ότι δεν συντρέχουν όσα βεβαιώνονται από μέρους μου, μου αφαιρείται ανά πάσα στιγμή αμέσως ο τίτλος.

Dedicated to my one and only best friend Dimitris,

whose integrity of opinion underpinned the realization of this project.

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Modeling the European Natural Gas Market

Keywords: natural gas, E.U. gas system, global markets, integration, oversupply, energy security, static equilibrium model, cost minimization

Abstract

Even though E.U.'s natural gas markets are in a transitional stage towards liberalization, there are huge differences between North-Western and South-Eastern markets, which eventually prevent integration. Without complete integration, energy security considerations are not to be taken lightly. The dynamic character of natural gas trade allows policy-makers to implement energy policies on trade patterns, which could mitigate import dependency on a single supplier. While E.U. can never be completely independent from Russian natural gas imports, it is possible to differentiate its trading routes and sources. In the current thesis, I study in detail the E.U. natural gas market and system, and of lesser extent the markets of external suppliers, which affect the most E.U.'s gas market. I also deploy a static equilibrium model, based on the economic and trade theory, to quantify results of import dependency, in respect to production and transportation costs. The equilibrium that arises, focuses in maximizing consumers' benefits, by minimizing the final cost of natural gas import. Through non-linear programming, the minimization problem produces interesting results and insights to "whether" and "how much" an E.U. Member-State is dependent on a single supplier. It is also a simple but useful tool for any policy-maker who wants to minimize the final import costs, while increasing energy security. Furthermore, the user is able to implement energy policy scenarios based on the initial structure of the model and calculate their additional opportunity costs or benefits. The model can improve the performance of natural gas trade by computing optimal and feasible solutions, and addressing market failures, such as excessive market power, externalities, and price discrimination. However, when such market failures arise, they must be addressed through corrective regulation, but without reducing critical benefits from the markets, such as consumers' welfare.

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INTRODUCTION

The global natural gas market has experienced many significant changes during the past decade. North America becomes from a net importer of natural gas to a "game-changer" exporter, altering the global LNG trade "order". Its "emergence" of shale gas development drastically changed the global outlook of LNG markets. Oversupply lead from the U.S., Australia and the Gulf States is creating increased competition for Russia and Caspian regions in the global market. According to (Stern & Rogers, 2014), the period with the highest risk of LNG oversupply will be between 2018 and 2023, but there is difficulty in predicting the future equilibrium between supply and demand because of six "key" uncertainties: the Asian, especially Chinese, gas and LNG demand; the transition away from J.C.C. (Japan Customs Cleared Crude Oil Price) pricing in Asian markets; the U.S. shale gas performance that defines the scale and pace of U.S. LNG export volumes; the impact of shale gas development outside the U.S.; the volume and timing of LNG supply from new projects outside the U.S.; Russia's response to increased competition, which could lead to "overspill" of excess LNG into the European market. Besides, it is also stated that "The only major supplier with significant upstream spare capacity is Russia, which will increasingly emerge as a 'buffer' or shock absorber in the new global order". While Russia is still a dominant "traditional" supplier of natural gas to Europe, its ability to influence the global natural gas markets is decreasing in the long-term by competition from alternative "emerging" suppliers. However, the anticipated rising demand in China can lead to more infrastructure developments in Eurasian regions, which will help them differentiate their exports and decrease their dependency on European demand, which growth is slower in comparison to China's. But, these investments entail some profound risks due to low oil and gas prices. In the contrary, higher and stable oil prices could help Russia exploit its output ratio to its maximum, and expand its supply network without fearing a collapse in its federal budget. Russia keeps its eyes fixed on the "emerging" Asian gas markets and is very decisive to aggressively hold a dominant position there, by exploiting its huge reserves and investing in new infrastructure. If the Eurasian neighbors align with this strategy also, it is highly probable that we are going to witness a 2nd Cold War, this time though, in the global natural gas markets (Aling, 2014).

The state of oversupply raises concerns about the trajectory of future LNG prices and demand-supply balances. It is highly probable that oversupply, will cancel any prospect of shortages, as it is already narrowing the existing wide price differentials between various world markets. This state has serious implications in turning natural gas into the most competitive geopolitical resource of energy of our time. Moreover, natural gas will become an increasingly important source of fuel in the next years as its conventional use expands to include new applications in power generation and transportation sectors. The use of coal as a dominant fuel source for power generation in the OECD economies has fallen off in recent years, due to environmental and climate policies for lower greenhouse gas emissions. Besides, tightening environmental regulations can have a large positive impact on gas usage. Furthermore, the abundance of cheap and strategically diverse global gas reserves, and its nature as a more environmental friendly fuel are making gas a vital energy source as the world moves on to a “cleaner” and more efficient energy mix. In fact, by measuring the amount of Carbon Dioxide (CO_2) emissions in relation to the energy they produce when they are burned: coal from anthracite emits 228.6 pounds of CO_2/MMBtu, coal from lignite emits 215.4 pounds of CO_2/MMBtu, whereas natural gas emits only 117 pounds of CO_2/MMBtu. That is because natural gas is primarily content of methane (CH_4), which has higher energy content relative to other fuels, and so it has a relatively lower CO_2-to-energy content[1].

As natural gas trade becomes more globalized and new producing and consuming markets emerge, so do regional prices adjust to new market balances (MacAvoy, 2000). Since “globalization” started in 2007, changes in prices of natural gas in one regional market, lead to much more immediate impacts on supply-demand equilibrium in other markets[2]. That happens due to the dynamic character of global natural gas markets. A contributing factor to the period of adjustment is the “wholesale price formation mechanisms” of the regional markets we investigate: it depends on how much the wholesale price of natural gas in each market is linked or indexed with the price of oil. However, some fundamental reforms during the mid and late 2000s have altered the pricing schemes in which natural gas had been traded. We are going to see that, EU’s energy regulations and competition law have initiated the momentum towards natural gas markets’ integration, and along with the “emergence” of trading Hubs, they have changed the regulatory and pricing context of natural gas in Europe. But, integration still remains far from completion at a Union level.

New producers have emerged over the past decade with the ability to produce and export huge quantities of natural gas to whatever destination. However, the very reason for the incentive of export to exist, is because there is a consumer in a foreign market that is willing to pay a certain margin above the domestic price, which covers the cost of the trade (Medlock, et al., 2012). Those are called “arbitrage opportunities” for the producer/exporter and are presented as differences between regional prices. In the contrary, oversupply and globalization of markets may well lead to international integration and therefore to narrowing of these price

[1] https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

[2] For example, shale gas developments in North America and changes in the energy mix of Asia have impacts on Europe and vice versa.

differentials in long-term. But, how fast and to what extent regions will be affected, is currently unclear. Currently, global natural gas markets are not integrated and their nature could change significantly in response to changes in natural gas trading patterns, such as technological breakthroughs, supply disruptions and energy policy changes.

Furthermore, we are going to see that there are plenty of new projects of LNG coming online, both for exporting and importing regions. These developments are showing that there is going to be a significant expansion in global natural gas trade. In fact, according to I.G.U. (2016), LNG global trade in 1990 was at 50 MTPA and in 2015 reached 244.8 MTPA; Global nominal regasification capacity of 757 MTPA in January 2015 and proposed liquefaction capacity at 890 MTPA. United States and Australia are holding the "king's crown" on these developments, also helping in diversification of imports for Asian, Japanese, and European gas markets. Let us have in mind that until the mid-2000s, when the potential of U.S. exports started growing, there has been limited availability of regasification and liquefaction infrastructures, as well as prohibitive costs that constrained the flow of LNG from one region of the world to another. Although LNG was accounted only for 4% of global natural gas supply in 1990, in 2014 global LNG consumption was up to 9.8% with an average growth rate increase by 6.6% per year in LNG demand since 2000. Regarding energy security, diversification of LNG supplies from countries such as Australia and the U.S. provide major supply security benefits for huge consumers. On the other hand, natural gas supply risks remain substantial yet: close to 15% of global LNG capacity is estimated by I.E.A., to be unavailable due to outages and lack of feed gas. In combination with the current low-price environment, the possibility of supply instability in countries dependent on oil and gas revenues is likely to occur. Moreover, the sharp cutback in upstream investments could exacerbate feed gas issues. In the end, the following six driving factors are going to have a significant impact in the future of LNG industry in midst of a more globalized and interconnected world system (Stern & Rogers, 2014):

- The level of U.S. domestic gas production and LNG exports
- The level of non-U.S. LNG supply after 2015
- Shale gas development outside North America
- The direction of future supplies from Russia
- Asian natural gas and LNG demand
- More flexible pricing formations

The main subject of my thesis is the development of an international natural gas trade model that focuses in the gas trade patterns between E.U. and external suppliers. The model is called ENGTM (European Natural Gas Trade Model) and is designed to compute market-clearing prices and quantities based on production and transportation costs of each supplier. The objective function minimizes these costs and then computes the most feasible solution per given data of production and transportation costs, maximum supply quantities (proportional to total proved reserves of each supplier), maximum pipeline technical capacities on the interconnection points between trade regions, and finally demand quantities. The “ENGTM” has been modeled in “GAMS” (General Algebraic Modeling System) and it is a simple market equilibrium model, which allows interdependence between gas prices and quantities traded between producing and consuming regions in a single point in time. However, the model is static and it cannot be used to assess the optimal timing of resource extraction. In the third chapter of my thesis, I present the mathematical formulation of the model and describe its use by developing three different scenarios: the first “reference case”, the two alternative scenarios “Norway’s complete liberalization” and “Energy security”. The first scenario describes the natural gas trade between the E.U., eight internal (i.e. Norway, Denmark, Germany, Italy, the Netherlands, Poland, Romania, and the U.K.) and seven external suppliers (i.e. North America, Qatar, Russia, Algeria, Azerbaijan, Libya, and Nigeria), by computing market-clearing prices for 2015 period. In the second scenario, I assume that Norway’s costs are highly reduced due to complete liberalization of its market and try to quantify the competition process that takes place between Norway and the other suppliers in terms of supply-demand equilibrium. In the final and third scenario, I induce into the model an index called “energy security”. The index is separately applied to the previous two scenarios and give insights about the demand/supply equilibrium, when energy security regulation takes place and sets constraints on the trade capacities between the E.U. and the chosen suppliers. I believe that the model is a simple but useful tool for any researcher, company and/or policy-maker, who wants to have a clear insight on the European natural gas trade patterns.

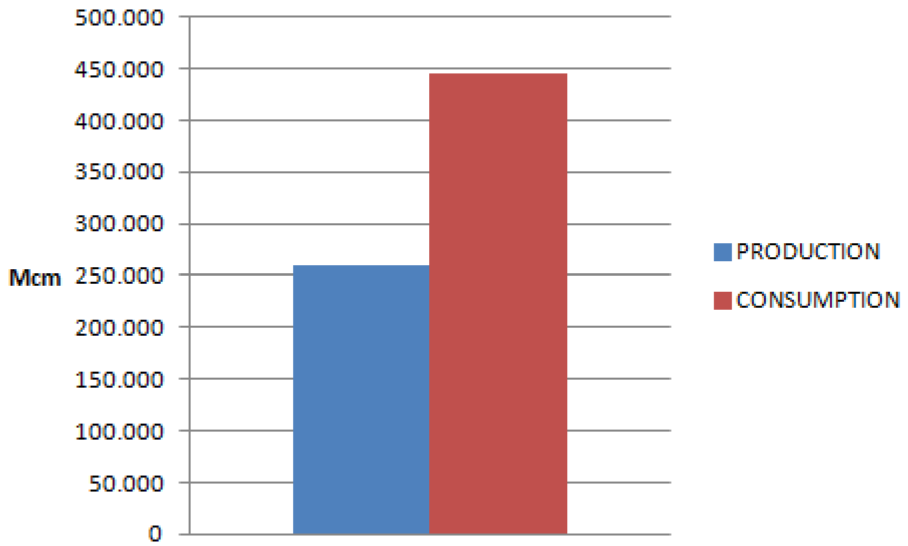
CHAPTER 1: EUROPEAN NATURAL GAS ANALYSIS

When someone thinks of E.U.'s energy status, the first sentences that come to his mind are: "highly energy consuming region", "extremely dependent on fuel imports", and "energy security". In **Figure 1** we can see the comparison of E.U.'s production and consumption, and in **Figure 2** the comparison of E.U.'s exports and imports. It is true, that in 2012 E.U. imported 90% of its oil, 66% of its gas, 62% of its hard coal and 95% of its uranium according to E.C. (2014). However, the rate of growth has been slowed down the past few years due to economic recession, improved energy efficiency of buildings, and increase of home-produced renewable energy. But let us not confuse the terms "energy security" and "import dependency". Import dependency may occasionally have a side effect on energy security under one condition only: if the major share of sources belong to a single supplier and the routes are not flexible. Oil import dependency may be high and Russia is a major supplier, but E.U. also has flexible access to crude oil and refined products by ship, roads and railways from a variety of other suppliers. Regarding coal, E.U. imports around a quarter of its total demand from Russia, but also has access to a wide variety of other sources for coal, which is transported around the world mainly by ships and railways. Therefore, oil and coal import dependency, at the moment, does not affect really energy security. In the contrary, most of natural gas imports depend on Russian pipelines, and many eastern and Baltic States depend on Russia for around 100% of their gas consumption (Buchan, 2014). In fact, Europe as a continent relies on Russia for about one-quarter of its natural gas supply[3]. So, if we consider the Ukraine gas crisis, we can conclude that Europe's natural gas imports are more vulnerable than coal and/or oil, and that natural gas is still more correlated to energy security issues than other energy commodities.

On the other hand, E.U. has other sources than Russia that can import natural gas, though these are not without problems. For example, Norway is already a substantial provider, but holds its output at a given quantity and does not raise it due to high production costs caused of high natural gas prices. North Africa has also become an unreliable supplier due to political turmoil. Buying extra LNG capacities is always a feasible solution, but that means E.U. must outbid the high import prices of Asian markets **(Figure 31)**. Finally, Azerbaijan is the only region that has responded to E.U.'s Southern Corridor initiative to bring Caspian gas to European markets through "TANAP" (Trans-Anatolian Pipeline), which will be connected to "TAP" (Trans-Adriatic Pipeline) passing onshore through Greece, Albania, and then offshore to Italy.

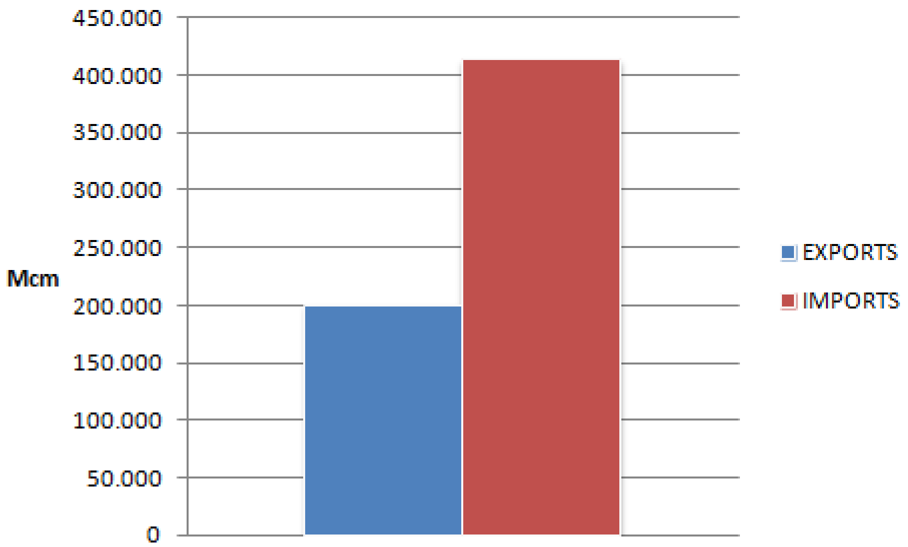
[3] Russia, supplies over one-third (66%) of Germany's requirements, and East and Baltic countries, which were closely integrated with Russia in the Communist era, are even more dependent.

Figure 1 E.U. Total production & consumption comparison in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

Figure 2 E.U. Total imports & exports comparison in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

From the early 80s to the early 2000s, European gas demand expanded robustly due to the continuous increase of oil prices, and high economic and environmental cost of coal plants. None has ever expected that natural gas would have so much success in replacing oil for space heating and power generation, and to become one of the most important fuels in E.U.'s primary energy source balances. As I have discussed in the introduction, we live in a period where LNG is "flooding" the global natural gas markets and it will continue to do so for at least the next four years, when there will be enough regasification capacity, and the demand will reach a level that can absorb the most of the existing supply volumes. However, oversupply is not an absolute term: oversupply of U.S. LNG in the world market created the conditions for Europe to diversify its flows and sources of natural gas from Russian and Algerian pipelines, thus, aiding in the energy security and giving additional leverage for the pricing terms in existing and future supplies. Because in the past many E.U. Member-States have experienced negative effects from the Russia-Ukraine gas price disputes, in 2006 and 2009, this diversification of sources can be seen as an "insurance policy" to future possible supply disruptions (Ratner, et al., 2013). Besides, E.U. leaders have long called for a comprehensive plan to reduce energy independence, which should reflect the fact that E.U. needs to accelerate further the diversification of its energy supply, increase its bargaining power and energy efficiency, continue to develop renewable and other indigenous energy sources and coordinate the development of infrastructures to support this diversification (away from Russia) in a sustainable manner, through the development of interconnections with third countries[4]. Additionally, to energy security, the Crimean crisis made E.U. leaders to normalize relations with Iran, to achieve a more diversified network of natural gas suppliers. In the contrary, someone would argue that energy independence from Russia could risk one of the primary long-term goals of E.U. that refer to the decarbonization of the Union's economy by lowering greenhouse gas emissions. In 2014 E.U.'s Member-States carried out energy security stress tests simulating two scenarios about possible Russian supply disruptions: a complete halt of Russian gas imports to the E.U., and a disruption of Russian gas imports through the Ukrainian transit route[5]. According to the European Commission's "European Energy Strategy (2014)" it is clear that "The E.U. is the only major economic actor producing more than 50% (23% renewable and 28% nuclear) of its electricity without greenhouse gas emissions. This trend must continue. In the long-term, the Union's energy security is inseparable from environmental policies and significantly fostered by its need to move to a competitive, low-carbon economy that reduces the use of imported fossil fuels"[6]. It seems that E.U.'s Member-States are determined to stick to their energy and environmental goals (i.e. energy affordability, CO_2 emission reduction) no matter what happens in the short-term.

In 2014, natural gas import dependency of the **OECD Europe** was at 23.89% representing 18.94% of total energy demand; crude oil dependency was at 60.88% representing 48.26% of total energy demand; coal import dependency falls at 11.87% representing 9.41% of total energy demand; finally, renewable import dependency was at 3.33% representing 2.64% of total energy demand. According to (I.E.A., 2016), total energy demand by fuel was 1,883.63 Mtoe and total imports at 1,493.3 Mtoe. It

[4] "European Council Conclusions March 2014", available from: https://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/141749.pdf.
[5] https://ec.europa.eu/energy/en/topics/energy-strategy/energy-security-strategy.
[6] European Energy Security Strategy, COM (2014) 330, May 2014, Brussels, available from: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014DC0330&from=EN.

seems that the total import dependency in 2014 was at 79.27%[7]. However, in the long-term, one must consider the possible development of shale gas in Europe that is going to rebalance the decreasing domestic production of conventional gas in countries like the Netherlands. That rebalance may also help in the diversification of gas imports, yet it entails side effects in the climate change. Shale gas production was abandoned in the E.U. by legislative work for many years in the past, due to the harmful effects that its production and exploration activities have in the environment. The German government in 2014 brought to the surface legislative proposals for shale gas exploration, while "Total" was allowed to do exploration tests for shale gas in Denmark. Operations have also been occurred to Poland, the U.K. and Romania, where possible reserves may exist (Buchan, 2014). In my opinion, legislation must adapt to the long-term state of the market, through corrective action, and never comes as an obstacle. When problems of energy security, and import dependency arise one should do well to consider shale gas as an alternative possible solution.

There is a current trend in Europe: demand needs for natural gas are increasing, while oil and gas prices are extremely low, thus, raising significant barriers in the future natural gas exploration and production outputs, especially for the three-main internal E.U. suppliers (i.e. Norway, the U.K., and the Netherlands). I believe that such issues raise important concerns, regarding the future of internal energy supply in the E.U. In 2015, production from the "North Sea" was at around 120,000 Mcm, of which the 60% belonged to Norway, 30% to the U.K., and the remaining 10% to the Netherlands. Due to falling oil and gas prices, the upstream activities in the North Sea has been decreased, following the same trend of upstream investments in the region. It seems that production from the continental shelves of the Netherlands and the U.K. will continue declining, thus, creating huge issues of increased decommissioning of essential infrastructure. Moreover, maintenance costs are going to increase in the near future and lead to a higher break-even price. In the end, North Sea's states governments have been trying to mitigate the impact of low oil and gas prices, by introducing tax reductions. According to I.E.A. (2016), "In the United Kingdom and the Netherlands, the upstream offshore sector operating in the North Sea has been advocating tax concessions to maintain both production and exploration".

In the end, an important question that has been raised was: "What does Europe really gains from this oversupply of LNG?" The real profit for Europe is the high pressure on the status quo of O.P.E. price formations. In fact, Russia has already accepted lower prices for its natural gas, and is even allowing a portion of its sales in Europe to follow hub based pricing schemes (Medlock, et al., 2011). Because of the failures of European utilities to meet take-or-pay levels during 2009-2011 in the

[7] To calculate import dependency of region we divide total imports of fuels by the total energy demand of fuels.

Russian contracts, renegotiations between Gazprom and its buyers were, and will be, inevitable. In 2010, several importing companies had demanded both for reductions in contractual prices and take-or-pay quantities. Thus, Gazprom had agreed that a 15% share of the oil indexed price would be moved to hub-based prices for 3 years, beginning in October 2009 (Stern & Rogers, 2011). That change signaled the transition from an "Eastern Regulated Pricing Formation" to a more "Western Spot Pricing Mechanism" for Europe, where natural gas pricing will be mainly driven by supply and demand forces. Moreover, (Stern & Rogers, 2013) have also pointed out that hybrid pricing[8] is just a transitional stage that will lead to full market-based pricing of long-term contracts. Besides, as the volume of global natural gas trade increases, so does the impact of oil price indexation decreases, leading to the reduction of global price spreads. Finally, Asian gas prices will continue to remain influenced by the price of oil, but oversupply along with emerging flexible LNG markets is expected to mitigate that oil-linkage.

Key E.U. metrics in 2015:

- **Total production**: 258,964 Mcm
- **Total consumption**: 444,966 Mcm
- **Total imports**: 414,961 Mcm
  - **From pipelines**: 366,769 Mcm (89% of total imports)
  - **LNG terminal entries**: 47,427 Mcm (11% of total imports)
- **Total share of imports in total consumption**: 93.08%
  - **Of which from pipeline:** 82.43%
  - **Of which in the form of LNG:** 10.66%
- **Total exports**: 200,387 Mcm
  - **From pipelines**: 177,907 Mcm (89% of total exports)
  - **LNG terminal exits**: 22,480 Mcm (11% of total exports)
- **Total share of exports in total production:** 77.38%
  - **Of which from pipeline:** 68.7%
  - **Of which in the form of LNG:** 8.68%
- **Total proved reserves**: 3,058,560 Mcm
- **Total RPR ratio**: 86 years
- **Total share of production in total proved reserves**: 8.47%

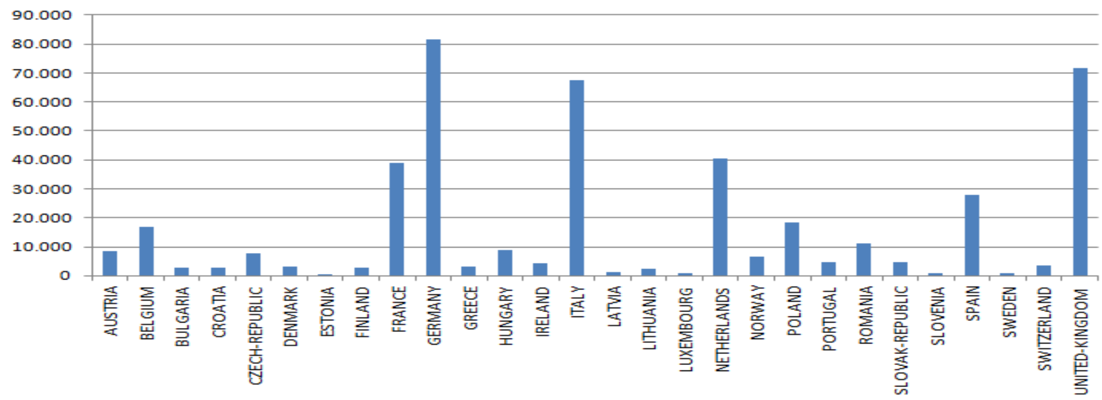
[8] Hybrid pricing is when the base price of a contract is lowered but the oil indexation of the final price is retained, or when there is co-existence of oil-linked

1.1 Demand

Consumption

In **Figure 3** we see that Germany accounts to the highest consumption among the E.U.'s Member-States reaching 81,370 Mcm, which represents 18.29% of total consumption. The U.K. has the second largest consumption at 71,770 Mcm (16.13%), then follows Italy (67,523 Mcm), the Netherlands (40,297 Mcm), and France (39,087 Mcm). Additionally, Italy's consumption rose by 5,600 Mcm from 2014 and was the highest increase among Germany (2,200 Mcm) and France (2,300 Mcm). On the other hand, the lowest consumption in 2015 observed in Estonia at 471 Mcm (0.11%). As I.E.A. (2016) states, the main reason behind this low consumption is that in 2014 Estonia's main company in the chemical and petrochemical sector ceased activity, resulting in no non-energy use of natural gas. Finally, the highest consuming states accounts to 67.43% of total consumption reaching 300,047 Mcm.

Figure 3 E.U. 2015 consumption by country (Mcm)

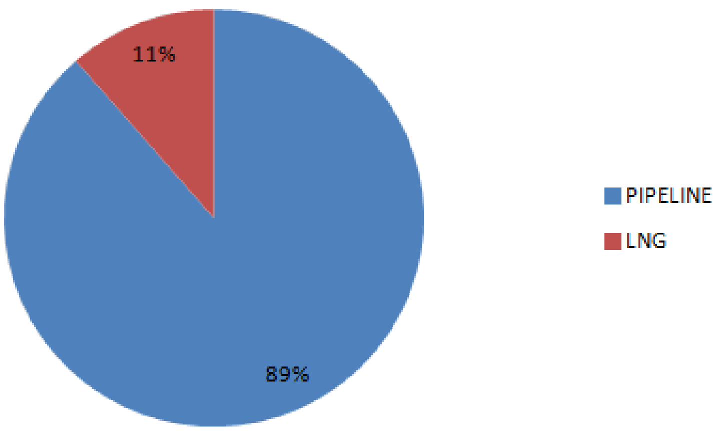


Source: I.E.A. (2016), Natural Gas Information 2016

Imports

In 2015, imports of natural gas in the E.U. from pipeline entries reached the amount of 88.55% of total imports and the rest 11.45% belonged to LNG imports **(Figure 4)**. We observe that E.U. is dependent on natural gas imports by pipelines, especially the Baltic and Eastern states that are closer to Russia. Besides, the most part of the continent is interconnected by pipelines both for internal players and external (i.e. Russia, Algeria). Furthermore, there is significant lack of LNG infrastructure across coast states that cannot displace pipeline import dependency, except from the U.K., Spain and Italy. So, increase in demand means increase in pipeline imports, until sufficient LNG applications offset pipeline import dependency.

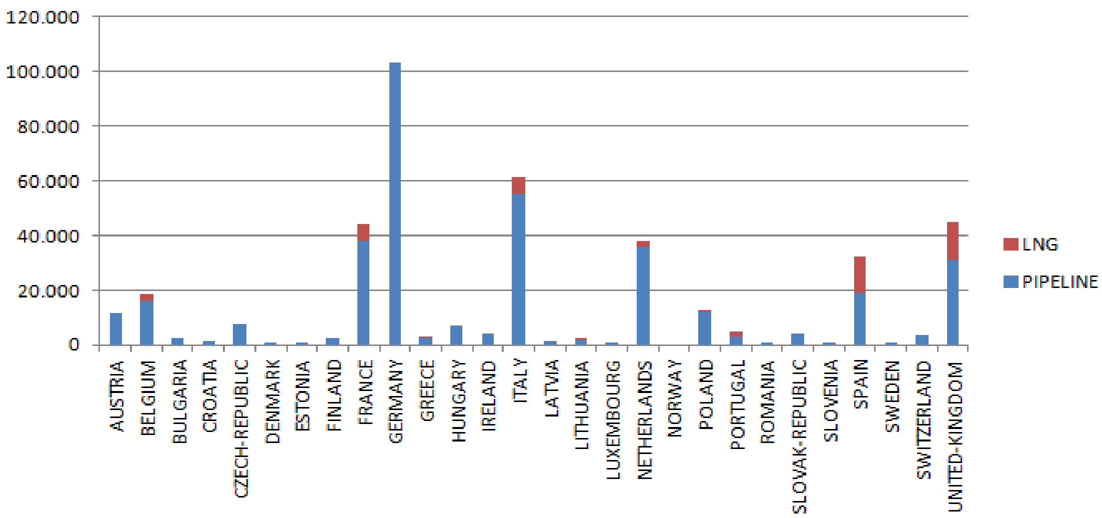
Figure 4 E.U. Share of pipeline & LNG imports on total imports in 2015



Source: I.E.A. (2016), Natural Gas Information 2016

In **Figure 5** we see that the imported quantities are driven by the trends of consumption: Germany had the highest total import score of 103,055 Mcm followed by Italy (61,201 Mcm), the U.K. (44,702 Mcm), France (44,383 Mcm), the Netherlands (37,888 Mcm), and finally Spain (32,428 Mcm).

Figure 5 E.U. LNG & pipeline import quantities in 2015 (Mcm)

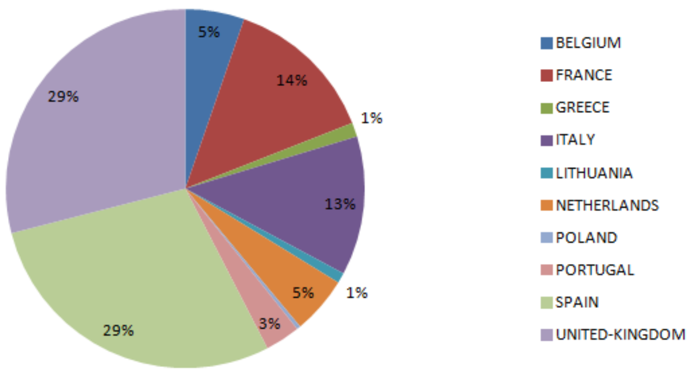


Source: I.E.A. (2016), Natural Gas Information 2016

We also see from **Figure 6** that LNG imports are mainly concentrated in the U.K. and Spain at 13,751 Mcm (28.57% of total LNG imports) and 13,550 Mcm (28.99% of total LNG imports) respectively. While Italy accounts for 5,942 Mcm (12.53%) and France for 6,504 Mcm (13.71%). In fact, the dynamics of the British and Spanish LNG markets are vast, both in technology applications and market fundamentals. Reasons for that concentration in U.K. and Spain are:

- U.K. NBP has become an international destination hub for physical and virtual trade the last ten years, due to its liquidity, the spot price mechanism it offers to buyers, and because it is a huge interconnector point to the rest of North and Central Europe.
- Spain however, has the most developed system of LNG terminals across the continent. In fact, it has seven LNG terminals already operational and plans for other five LNG capacity expansions, and two new facilities starting in 2017.

Figure 6 E.U. Member-States LNG share in total LNG imports

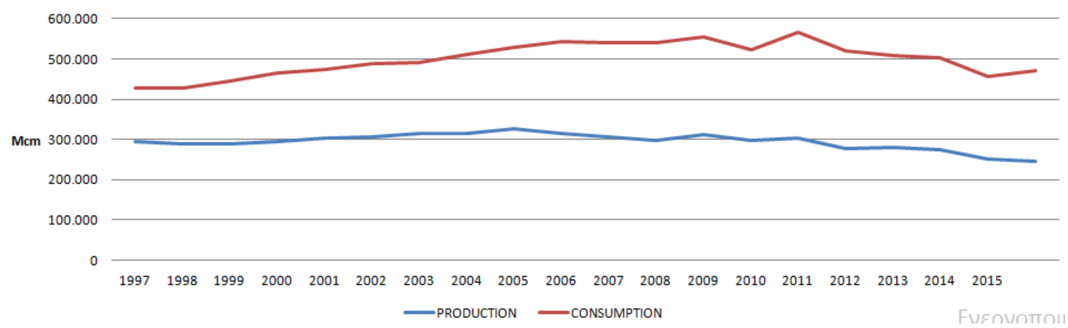


Source: I.E.A. (2016), Natural Gas Information 2016

Consumption by sector

As we observe in **Figure 7**, E.U.'s demand growth from 2011 to 2015 was negative, due to low coal price that made coal plants more competitive than gas plants. This can also be seen in **Figure 8**, where final natural gas consumption is broken down to the various sectors, in which natural gas can be used. In the contrary, for the next five years there is going to be an increase of 10 Bcm and the power generation sector is going to play a very important role in the stabilization of European natural gas demand. Additionally, there will be small increases in the industrial sector, balancing the small loses from the residential and commercial sectors. While prices for coal remain low, the price differential between gas and coal is weakening due to decreasing gas prices. That leaves space for gas to come back to competitiveness, especially in the U.K., where there is a floor on coal price (I.E.A., 2016).

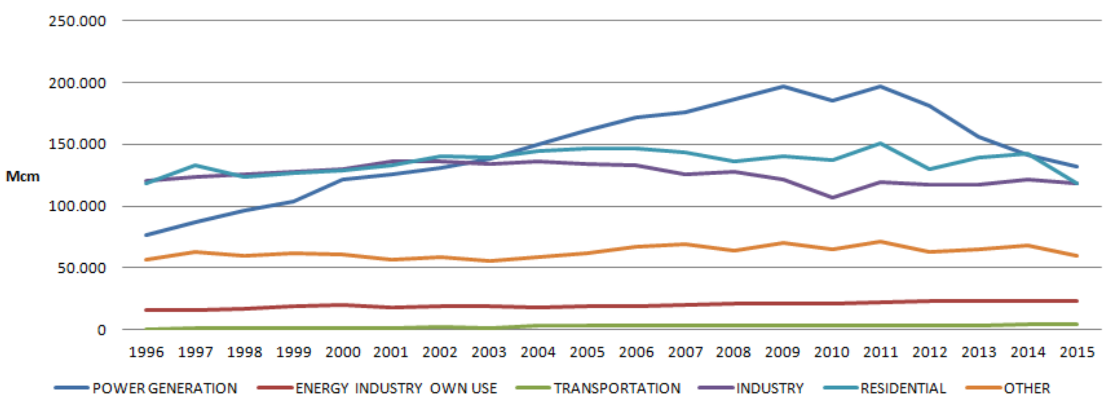
Figure 7 O.E.C.D. Europe's production & consumption from 1996 to 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

In the following **Figure 8** we observe that in the transportation sector and in energy industry's own use, natural gas demand has been stable during the whole period from 1996 to 2015. However, the use of natural gas in the power generation sector has been falling from 2011 onwards, the same as in the residential sector. That decrease is the result of extremely low coal prices, even lower than gas, which makes coal use more competitive than gas in the aforementioned sectors.

Figure 8 Gas Demand by sector in O.E.C.D. Europe 1996-2015



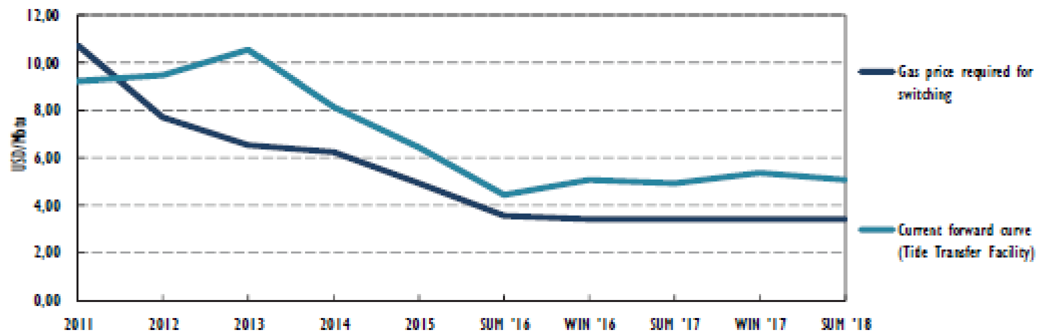
Source: I.E.A. (2016), Natural Gas Information 2016

Fuel switching

A measure to decrease Russian import dependency of gas is "fuel-switching". However, in the short-term, this will not be very effective, especially in the residential sector that consumes most of E.U.'s gas. The shale boom in the U.S., and changes in its energy mix has driven much of the coal supplies into Europe, where coal price is well below than that of the imported Russian natural gas[9]. According to I.E.A. (mid-term gas report, 2016), while gas prices are in a historically low level, they have not yet reached a level that would lead to a broad substitution of coal, except from occasional circumstances. **Figure 9** represents the indicative gas prices needed to fuel switch from coal-to-gas from 2011 to 2018. Besides, the growth rate of fuel-switching is driven by three forces (Aling, 2014):

- The rate at which coal-fired generation is replaced by natural gas combined-cycle generators.
- The access of long-term contracted supplies at competitive prices between other fuels.
- The rate at which natural gas can displace oil-based transport fuel, either directly or through natural gas-based substitutes.

Figure 9 Indicative gas prices required to trigger coal-to-gas switching in continental Europe



Source: I.E.A., Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021.

1.2 Supply

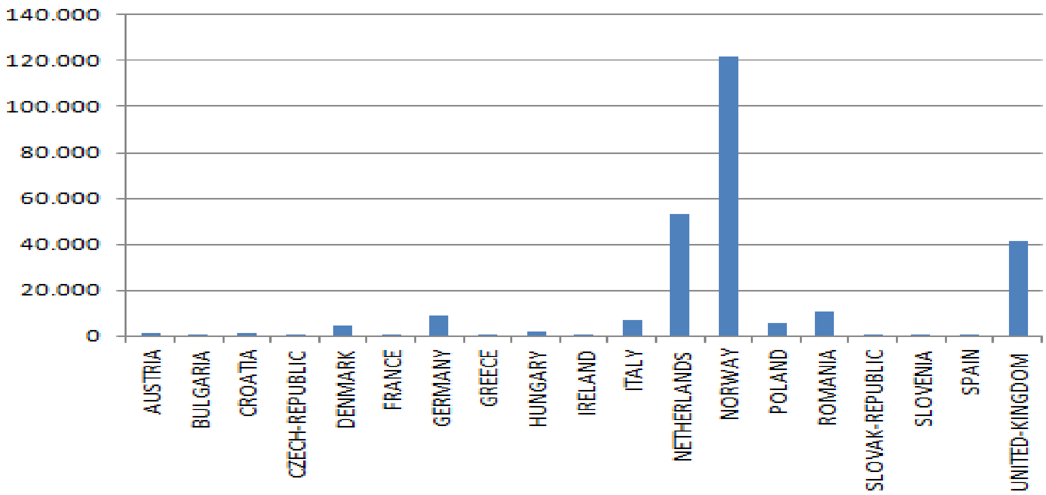
Production

It is a fact that E.U.'s consumption surpasses its internal production and that exactly is what makes Europe import dependent. It is true that there is no sufficient network of internal natural gas producers to satisfy Europe's demand needs. From **Figure 10** we observe that the only large producer of natural gas in E.U. is Norway, but again its production rates are low to its reserves and not sufficient. In fact, its production in 2015 was at 121,646 Mcm which accounts for 27.34% of total E.U.'s consumption. We also observe that the second largest producer is the Netherlands with production at 53,296 Mcm in 2015, which accounts for 20.58% of total E.U. production. Finally, the third largest producer is the U.K. at 41,286 Mcm, which

[9] Russian gas is more expensive because of its oil-indexation.

represents 15.94% of total E.U. production. According to I.E.A. (2016) Norwegian gas production augmented by 8.1% after two years of stability, mainly due to new fields' developments; in the Netherlands production decreased by 23.8% in comparison to 2014, due to a production cap[10] in Groningen field imposed by the government in order to avoid earth-quakes that started to worsen as the field started to deplete; and production in the U.K. increased by 7% due to developments of the two new fields "jasmine" and "Kew". Finally, the absence of any significant price response to the Dutch supply sock is a good paradigm of the magnitude, in which global oversupply has affected current market fundamentals.

Figure 10 E.U. natural gas production in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

Regarding Norway, the historically largest internal supplier of natural gas in E.U.'s vicinity, its production increased from 112,580 Mcm in 2014 to 121,650 Mcm in 2015. That caused by the increase in E.U.'s gas demand and was underpinned by the completion of three large field developments and the start-up of Valemon field in January 2015[11]. However, low oil and gas prices will probably start affecting production rates in the near future, causing a decrease in investments for exploration and production. Besides, I.E.A. (2016) stated that "while cost deflation will help cushion some of the impact of lower prices, Norwegian gas production could start drifting lower early next decade unless investments recover".

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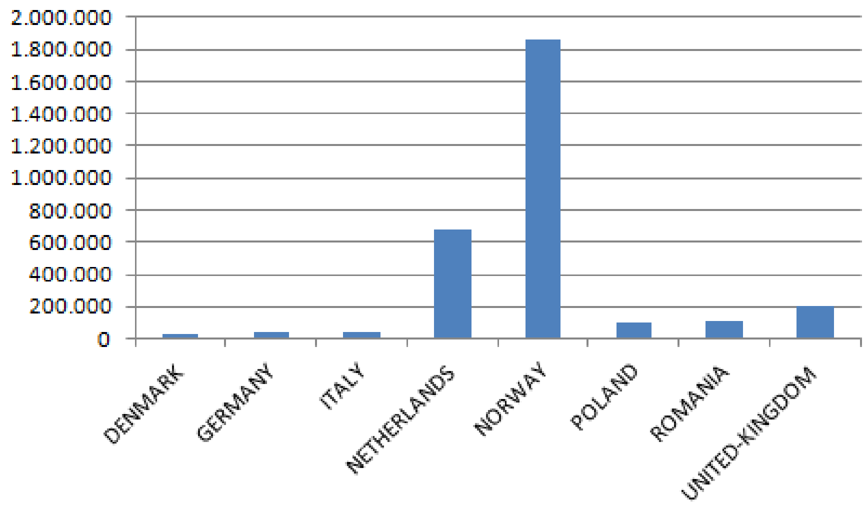
[10] The most recent cap is set at 24 Bcm, which is half the level of Groningen production in 2013 and at 27 Bcm in from October 2015 to September 2016.

[11] N.P.D. (2016), "The Shelf in 2015-Field Developments", available from: http://www.npd.no/en/news/News/2016/Summary/Field-developments/.

Reserves[12]

When someone investigates the natural gas supply dynamics of a region, I believe that is essential to include that region's reserves in his analysis and compare them to production, in order to make forecasts about the future availability of a resource. Moreover, by comparing the remaining reserves at the end of a year to the production quantity of that year, we come by the "RPR" (Reserves-to-Production Ratio): the length of time, in years, that those remaining reserves would last if production were to continue at that particular rate. RPR is usually used by companies and governments to determine the life of a project, future income and whether more exploration must be undertaken to ensure continued resource supply. The ratio's magnitude is inversely related to the annual rate of production, which may depend on geological features and the stage of the resource development[13]. New discoveries, regulations, changes in technology and economy can significantly affect the outcome of the ratio[14]. According to **Figure 11,** Norway's reserves amount to 1,857,792 Mcm and are the largest among the Union's (60.74% of total reserves); second is the Netherlands with 674,016 Mcm (22.04%); the third largest is the U.K. with 206,736 Mcm (6.76%). Romania and Poland also have their own reserves of 110,448 Mcm (3.61%) and 93,456 Mcm (3.06%) respectively.

Figure 11 E.U. natural gas reserves at the end of 2015

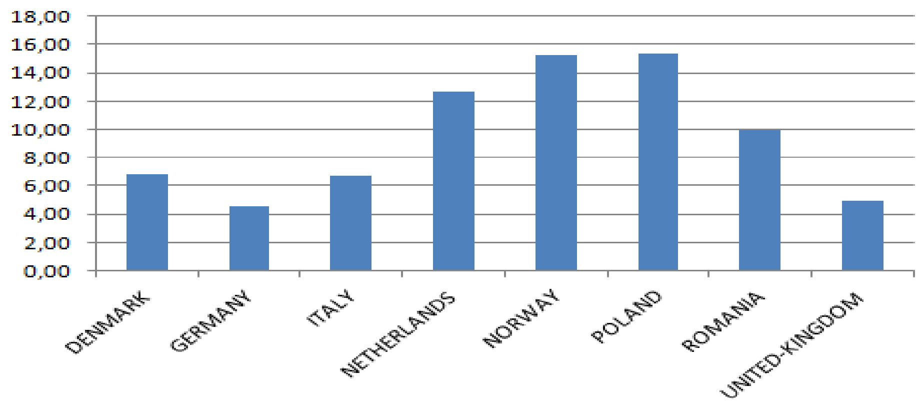


Source: B.P. (2016), Statistical Review of World Energy 2016

[12] Reserves are the amount of a resource known to exist in an area and to be economically recoverable under the existing conditions.
[13] Typically, there is high initial RPR during the early phases of development, and then the RPR sharply declines towards the maximum level of production.
[14] Government policies may deliberately slow production, thereby increasing the RPR in the interests of prolonging reserve life, whereas a company may inject water and/or gases into a reservoir to increase production, thus decreasing the RPR.

Figure 12 represents the RPR of each producing region in the E.U. in 2015. According to the existing conditions of production, we observe that Norway's and Poland's reserves are going to long for at least fourteen years with both production reaching 6.5% of total proved reserves. Norway's reserves are far too vast than those of Poland's, but their production rates are the same. Additionally, the Netherlands' production has decreased due to governmet's regulations on Groningen field[10], which is its major supply field, causing the RPR to rise almost at thirteen years with own production representing 7.91% of total proved reserves at the end of 2015. Romania's RPR is at ten years and its production rates at 10% of total reserves. Denmark's and Italy's RPRs are for both almost at seven years with production to reserves rates at around 15%. Finally, German and Britsh RPR are close to five years with production rates at around 20% of total reserves.

Figure 12 E.U. RPR in 2015

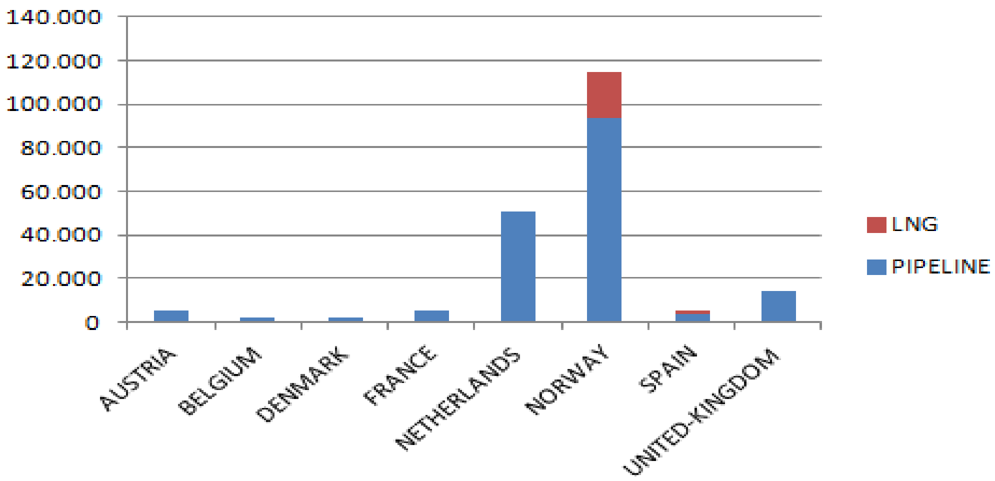


Source: B.P. (2016), Statistical Review of World Energy 2016

Exports

Figure 13 shows us that most of the exports in 2015 were from Norway at 114,767 Mcm, both from pipeline (93,975 Mcm) and in the form of LNG (20,792 Mcm). The Netherlands are following at 50,962 Mcm only from pipeline and then comes the U.K. at 14,088 Mcm. We also see that Spain had some exports of LNG at 1,688 Mcm, which account to 7.51% of total LNG exports. On the other hand, Norway's LNG exports account to 92.49% of total E.U. LNG exports. Although Spain and U.K. have an extremely developed system of LNG facilities, comparing to other E.U.'s Member-States, these are used mainly for regasification purposes and not as exit points of LNG. Additionally, due to their low production rates and high demand needs they cannot export large quantities. Finally, Spain's few exports do not come from its own production: it mainly imports natural gas and then exports it in the form of LNG instead.

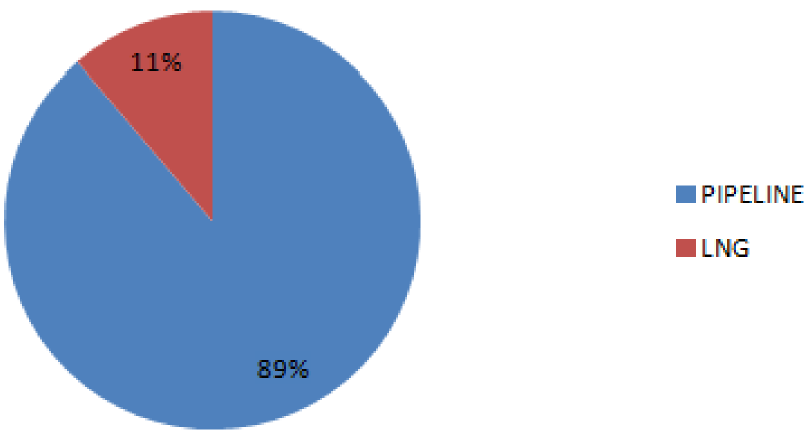
Figure 13 E.U. exports pipeline & LNG exports in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

According to **Figure 14** LNG has a share of 11.22% in total exports, whereas exports by pipelines have a share of 88.78%. Combining exports and imports shares of LNG and pipelines, we can conclude that Europe is terribly lacking the infrastructure of LNG facilities in comparison to China, which is the second largest consumer of natural gas worldwide. That can easily raise concerns of energy security and diversification of imports, because the majority of pipelines connected to E.U.'s borders belong to Russia.

Figure 14 E.U. Share of pipeline & LNG exports in total exports 2015



Source: I.E.A. (2016), Natural Gas Information 2016

1.3 Market

1.3.1 Hubs

Oversupply goes along with increased liquidity (physical or virtual) in the market. So, it was necessary for a highly consuming region like E.U. to develop a way to absorb the new available excess capacity. Technological advancements in natural gas transportation and storage facilities, and the oversupplied environment from the mid of the past decade, have led to the rapid growth of the British Hub market. As a consequence, this has led to the creation of many "physical" and/or "virtual" hubs within the E.U. By 2013, the transition to hub-based pricing was well-developed in North-Western E.U. and made it a dominant parameter when it comes to pricing formulas. The U.K. was a leading force in LNG trading and has ever been a major physical interconnector point of natural gas in North-Western E.U. for many years[15]. In fact, much of the traded quantities in hubs (contracted or not) are being adjusted to include a spot price mechanism with reference to the N.B.P. (National Balancing Point) price. The N.B.P. hub in the U.K. has the perfect throughput to turn it into a central destination point for global gas flows. **Figure 15** shows the quarterly traded volumes of each European trading hub from 2014Q1 to 2015Q3. In 2015Q1, NBP's quarterly traded throughput reached the amount of 6,300 TWh on first quarter with the churn ratio[16] close to 23. That is exactly what made the British gas market a leading "force" in the development of most of the trading hubs that exist today in Central and North-Western E.U. (i.e. T.T.F., Zeebruge, N.C.G., Gaspool etc.). In South-Eastern E.U., hubs do not play any significant role due to the lack in liquidity, and because prices are mostly regulated. Yet, South-Eastern E.U. is in dire need of a liquid trading hub like that of North-Western E.U., to be integrated with the rest of E.U.'s transmission system. Bruegel (2014)[17] suggested that Ukraine could form that hub to take advantage of its large storage capacity, but investors and traders would first want to be sure that Russian gas transition to "South Stream" would not be lost. Besides, the experience of natural gas markets in North America has shown to us that in order for hubs and/or futures markets to be developed in a region, they need a strong underlying physical market with much liquidity. So, the current partly illiberalized energy market of South-Eastern E.U. creates physical barriers for the creation of hubs.

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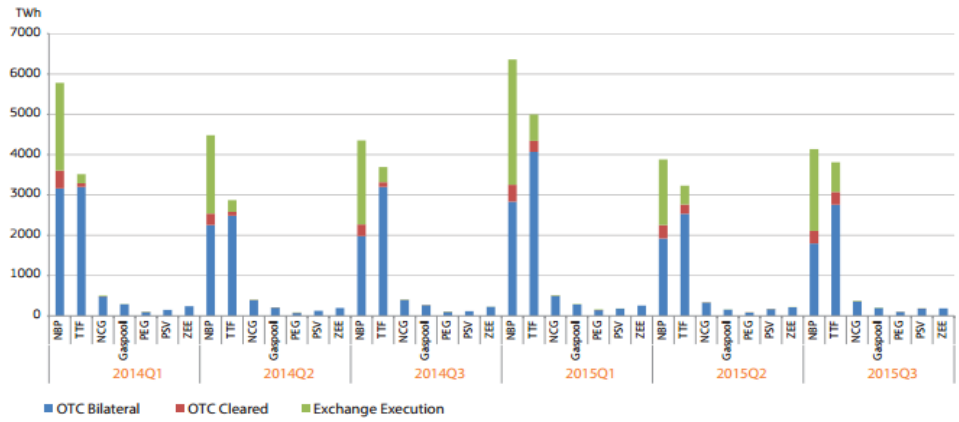
[15] The very first step for a pan-European network of spot trading market was the construction of an interconnector between two hubs: the U.K. (NBP) and Belgium (Zeebruge) in 1998.

[16] The "churn ratio" represents the number of trade transactions related to physical amount of gas exchanged.

[17] A. Loskot, G. Zachmann (2014), "Rebalancing the E.U.-Russia-Ukraine Gas Relationship", *Bruegel Policy Contribution,* available from: http://bruegel.org/wp-content/uploads/imported/publications/Rebalancing_the_EU-Russia-Ukraine_gas_relationship.pdf.

Figure 15 Quarterly traded volumes in European hubs in 2014-2015



Source: European Commission (2015), "Quarterly Report on European Gas Markets".

As these new markets (i.e. hubs) evolve, so does the contracting system of natural gas changes. Spot pricing and shorter contracts has come to the surface. Besides, the deeper the hubs, the shorter the contracts and vice versa. So, as the liquidity has risen in the European gas markets, LTCs have become more flexible (Neumann & Hirschhausen, 2007):

- Re-export to third countries is allowed
- Take-or-pay limit has been reduced to 60%
- Time for adjusting price formulas has been shortened
- Contract's maturity between ten to twenty years

1.3.2 Long-Term Contracts

Most of the capacity traded worldwide, is still conducted on the form of long-term contracts (up to 20 years) with complex price clauses. The main drivers of these clauses are: the "base price" and the "index"[18]. Additionally, many of these contracts include a "take-or-pay" clause that "traps" the buyer to pay for a specified minimum quantity of the annual contractual quantity at the contract price[19], whether or not such volume of gas is taken. Long-term contracts may seem to be in favor of large producing countries against highly consuming regions considering their duration, but that assumption will change fundamentally if we investigate it from the point of view of huge exporting countries. Globalized gas trade has given the opportunity to industries to expand and develop their infrastructure with new large-scale investments. So, the contractual supplies need to be long enough for both importing

[18] The index determines how the base price is adjusted over time. Generally, prices are adjusted quarterly based on the average of oil prices in the preceding 6-9 months, with a lag of three months.

[19] Usually, the take-or-pay percentage on gas supply agreements is at between 75%-95% of the contracted quantity.

and exporting countries to recover the huge costs and safeguard their cash flows to assist the financing of these investments. However, in the late 2000s E.U.'s regulation and competition law changed the overall scene of the terms, under which the existing contracts were operating (i.e. eradication of destination clauses). For example, the emergence of hubs (particularly in the North-Western E.U.) with more transparent transaction mechanisms and easier methods of access via online platforms, have increased competition among large customers, and the consumers could choose from a variety of suppliers (virtually and/or physically). The aftermath of the hub emergence and the continuously rising liquidity in the North-Western E.U., was that the trading hubs could be used as a tool of leverage power between E.U. and Russia's trade terms. Due to oversupplied markets that eliminated shortages and increased liquidity, E.U. could easily turn to other more flexible (contractual or not) producers than Russia. So, Russia knowing that will lose its dominant position over the European markets, something that would be catastrophic in short and mid-term decided to succumb on these pressures and opted for a strategy that would bring balance between its contractual pricing terms and the hub-based pricing levels. In 2012, Gazprom[20] agreed that the base price in their long-term contracts would be reduced by 7%-10%, and take-or-pay levels would be reduced to 60%. That was a very smart move because Russia managed to mitigate the gap[21] between its long-term contract price and the hub price, without requiring Gazprom to agree to hub price indexation, and thus retaining the oil indexation. In the end, the progressive transition from oil-indexed prices with rigid adjustment terms to a full hub-based (spot) pricing mechanism with rapid adjustments to market conditions, such as these of North America and the U.K., in the whole Europe is unlikely to occur for the time being.

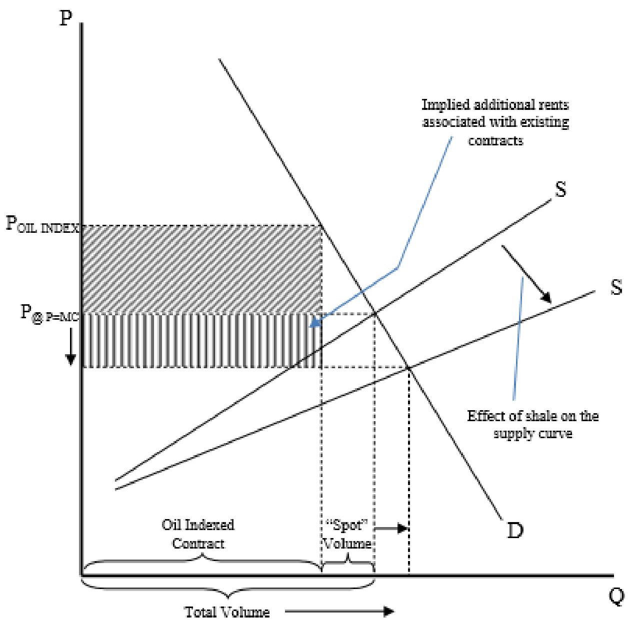
It is worth mentioning that an advantage of oversupply is that E.U. is shifting to a more "spot price" based environment, thus, decoupling the prices between Hubs and LTCs. While LTCs are generally based on O.P.E. formulas, the short-term and spot gas traded in hubs, both virtual and physical, has led to the increase of G.O.G. competition formulas. Besides, the most influential factor of this radical change in the system is oversupply (Stern & Rogers, 2011)**.** In fact, the abundance of shale gas in North America makes the supply curve more elastic and pricing above marginal cost is becoming quite difficult: as the elasticity of supply increases, the rents associated with oil-indexed contracts also increase, leading to renegotiations of the final price. That means, "oil-indexation" is losing some of its ground. **Figure 16** shows how the effect of the Shale boom in the U.S. affect the trading contracts of natural gas. However,

[20] Gazprom produces more than 80% of Russia's natural gas and controls access to Russia's domestic natural gas pipeline system.

[21] If the gap between the contract and the hub price becomes too great, the buyer receives a rebate at the end of the price period.

most of the gas traded is still under the scope of ad hoc formulas[22] that are linked to O.P.E. mechanisms (Konoplyanik, 2010). Moreover, a critical assumption to begin the above argument is that the increased elasticity of supply is directly related to the increased number of export capacity due to new different exporters in the global market, so as to avoid discriminatory pricing from a single huge producer. For example, Qatar due to its geographical power position and its huge contractual volumes of LNG can easily exercise pricing power towards E.U. and Asia: by selling LNG to the E.U., Qatar can keep prices in Asia high, thereby acting as a "discriminating monopolist" (Allsopp & Stern, 2012). Besides, oil-indexation is a form of price discrimination because firms distinguish consumers and prevent resale, while different consumers have different elasticity of demand. According to (Hartley & Brito, 2007) both conditions are met in Europe[23] and Asia, but not in North America. On the contrary, as the global LNG trade expands to more regions, so does the regional physical liquidity increases, thus, eliminating the prospects of price discrimination and excessive market power. That leads to the conclusion that only when E.U. becomes integrated and thus completely liberalized, then price discrimination will end[24].

Figure 16 The Supply Curve Effect of Shale and Implications for Price



<u>Source:</u> Kenneth B. Medlock (2012), "U.S. LNG Exports: Truth and Consequence", James A. Baker III Institute for Public Policy, Rice University.

[22] Ad hoc arrangements allow for adjustment of the pricing formulas by changing the variables that determine the base price or through the weighting of petroleum products to include some reference to hub prices.
[23] The Lack of transport differentials in Europe is evidence of discrimination.
[24] Recent changes in the contractual terms are showing that price discrimination in Europe tends to decrease.

Meanwhile, global supply capacities remain higher than ever before in history even in a low-price environment. We know from the economic theory that when the supply capacity is increasing so does the price and vice versa, due to the positive analogous relationship that comes from the structure of the supply function itself. So, the current global state seems quite paradoxical. The only “truth” behind this paradox is time (future expectations), and surely past time decisions affect current market fundamentals: lower production rates now, ceteris paribus, distribute cash flows more into the future, thus lowering the NPV (Net Present Value) of current foreign investment decisions. But what should happen to prices when someone applies this trend to the prime model of U.S. shale gas industry? We know that the domestic production of the U.S. has increased due to the expansion of shale and coal bed methane deposits. These unconventional deposits have higher upstream costs. Thus, when the production of unconventional reserves increases, should the prices increase too, in order to cover the capital expenditures. At least that should happen to domestic wholesale prices, until technological advances come into play and facilitate the production activities from unconventional deposits, by lowering the associated production costs. However, today’s oversupply is the aftermath of investment decisions made in the past, when major exporting and storage facilities started developing[25], in a time when natural gas and crude oil prices were much higher. Because of the long-term character of these investment decisions, and because the price of natural gas that was agreed upon by the trading countries was in long-term contractual form, the supplies from these investment decisions taken in the past are going to be price-inelastic today. Moreover, most of the producing countries have high production costs and cannot follow the example of the U.S. shale industry, thus, making it impossible to low their contractual gas prices[26] that has been made in the past and it will continue for over a decade. That means, supply prices respond too slowly to changes of supply quantities, and today’s prices cannot satisfy the supply glut, neither follow supply’s pace. Overall, price-inelasticity along with structural changes in the power generation sector makes the demand responsiveness to low prices inelastic, and unable to absorb the excess capacity for the time being, thus enabling issues of feed gas.

Demand and supply factors of a region can easily affect the price trajectory of natural gas in another region, due the dynamic global character of natural gas trade. According to (Stern, 2014), the most influential factors of the past few years that affected price movements were the following:

- The increase in crude oil prices above 100 $/bbl on a sustained basis.

[25] While these investments provide a supply buffer through temporary excess supplies, they are not the result of energy supply security policies.
[26] They need to cover the loss of the high production costs.

- The nuclear disaster that happened in Fukushima in 2011, significantly increased the demand for short-term LNG supplies and thus, tightening the global LNG market.
- The emergence of new LNG markets in China, India and the Middle East, affecting supply and demand capacities.
- The robust development of shale gas plays in North America that caused increasing production and a sharp fall in Henry Hub prices. Along with the capability to export worldwide, North America "contaminated" the global market with historically low price levels of LNG.
- The fluctuations of global coal prices, which are still very low, have clearly impacted gas demand in the power generation sector in a negative way.
- The increased use of renewable sources in power generation due to energy policies.
- The short-term power and carbon price movements have caused changes both in the "spark spread"[27] and "dark spread"[28].
- Political developments are always on the scene, but with outmost significance these in North Africa (Arab Spring), causing high concerns of Energy Security problems[29].
- Finally, is the economic recession in Europe, impacting energy and natural gas demand.

Even though natural gas total final consumption in 2014 reached 15.1%[30], there is not adequate literature on gas pricing. That is because in most countries, except North America, gas pricing is not very transparent and most of the times is regulated by governments, which make it harder to obtain accurate information on the subject. So, in order to have a clearer image on natural gas pricing formations that exist around the globe, I present below **Table 1Error! Reference source not found.**, where the different wholesale price formation mechanisms are described, according to IGU's "Wholesale Gas Price Survey" (2016). In the end, as natural gas market has been more and more globalized over the past decade, so has its pricing formation mechanisms been affected: recent regulatory changes combined with oversupply and muted demands, appear to have put high pressure on E.U.'s oil-linked contract gas prices. On the other hand, in support of oil-linked LTCs, it is well-known that they provide an element of price certainty, between the contracting members, for huge traded

[27] Spark spread is determined as the difference between the selling price and the cost of electricity, when it is generated by natural gas.
[28] Dark spread is determined as the difference between the selling price and the cost of electricity, when it is generated by coal.
[29] The "Arab Spring" curtailed gas exports from Libya for most of 2011.
[30] I.E.A. (2016), "Key World Energy Statistics 2016", available from: https://www.iea.org/publications/freepublications/publication/KeyWorld2016.pdf.

quantities when there is absent storage and physical liquidity, an absence that exists highly in South-Eastern E.U.

Table 1 Types of natural gas wholesale price formation mechanisms

WHOLESALE PRICE FORMATION TYPE	DESCRIPTION
Oil Price Escalation (O.P.E.)	The price is linked, usually through a base price and escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices can be used as well as electricity prices.
Gas-on-Gas Competition (G.O.G.)	The price is determined by the interplay of supply and demand and is traded over a variety of different periods (i.e. daily, monthy, and annually). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP). Also incuded in this category is "spot LNG", any pricing that is linked to hub or spot prices, and also bilateral agreements in markets where are multiple buyers and sellers.
Bilateral Monopoly (B.I.M.)	The price is determined by bilateral discussions and agreements between a large seeler and a large buyer, with the price being fixed for a period of time - typically one year. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from G.OG.
Netback from Final Product (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, and is the major variable cost in producing the product.
Regulation: Cost of Service (R.C.S.)	The price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.
Regulation: Social and Political (R.S.P.)	The price is set on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise.
Regulation: Below Cost (R.B.C.)	The price is knowngly set below the average cost of producing and transporting the gas, often as a form of state subsidy to the population.
No Price (N.P.)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced may be associated with oil and/or liquids, and treaded as a by-product.

Source: I.G.U. (2016), Wholesale Gas Price Survey 2016

1.4 Regulation towards liberalization

For the past ten years E.U., has been the epicenter of reforms and changes in the natural gas sector. A numerous set of changes, including the "E.U. reform agenda"[31], has been affecting the structure of E.U. gas markets. Some of the most important

[31] Official Journal of the European Union (2009), "Directive 2009/73/EC of the European Parliament and of the Council", L211/94, 14 August.

features of these changes are: the diversification of imports (energy security); CO_2 emissions reduction; increased competition in domestic natural gas markets; energy efficiency; promotion of spot and short-term contracts; promotion of a new pricing mechanism based on G.O.G. formations; and the liberalization of the domestic national gas markets. By these reforms, E.U. goes towards a more liberalized market model like that of the U.K. and the U.S.A., which would improve the pricing and competitiveness of natural gas sector. It is true that the transformation to a more spot-based, integrated market with short-term contracts and G.O.G. mechanisms requires first the liberalization of the domestic markets. In fact, since the 90s, domestic markets have started liberalizing by the separation of management in the upstream, midstream and downstream activities of state-owned physical monopolies, which controlled the largest share of the market. That means exploration and production, transportation and distribution, wholesale and retail marketing of natural gas will behave as three different markets, exposed to greater competition. European Commission created directives that forced national governments to implement policies such as the unbundling of vertically integrated companies, workable third party access in investment of infrastructure and the free choice of gas providers by the consumers to increase competition and decrease the market power of large national companies. All the aforementioned changes are instructed under a common goal of E.U.'s energy policy: the integration of the European natural gas markets. According to the "E.U. gas target model", these steps should gradually lead to a progressive connection between national markets, in order to create an integrated European gas market. However, the key to achieve this goal is investment in infrastructure (LNG terminals, storage facilities, pipelines, hubs, interconnector points).

Finally, the incentives for these changes were the following:

- Technology advances in LNG infrastructure that reduced regasification costs (Jong, et al., 2010).
- Increased number of combined cycle power plants that promoted the use of natural gas as a cleaner source of energy and reduce CO_2 emissions (I.E.A., 2011).
- The gas transmission disruption due to disputes between Russia, Ukraine and Belarus, which created the notions for "import diversification" and "energy security of supply" (Goldthau, 2008).
- The creation of virtual and physical hubs in the continental Europe, where natural gas can be traded like a financial derivative (i.e. gas futures, gas options). "Paper gas", as it is called, helped the entrance of new players and therefore the expansion of a common energy market (Heather, 2010).

However, one can ask "How well-integrated is the European gas market today?" The answer is only at a sub-regional level and not at a "Union" level. Only the North-Western E.U. (sub-region) helps in the creation of a regional integrated market, while the South-Eastern part is still behind development due to national market dynamics and limited bilateral relations between one or two major exporting countries (Haase, 2008). Generally, gas flows within E.U. as a whole remain relatively scarce and there are no common rules and regulations for the organization of the domestic national markets. Additionally, there is also controversy between western and eastern member states about the decarbonization of the economy. While western states propose that E.U. should accelerate its decarbonization strategy, eastern Member-States believe that this would be unaffordable for their economies and a factor that would destabilize E.U.'s electricity grid. It is true that the European Commission sees the decarbonization strategy as a mean to reduce Europe's dependency on Russia for fossil fuels, because its energy needs will be covered by the development of indigenous renewable energy[32]. Yet, coal has been the solid foundation of energy security for many of the eastern States. I believe that the most feasible solution for energy security is investment in new infrastructure such as new interconnectors and LNG terminals and/or the expansion of the already existing.

Energy Union Strategy

E.U.'s energy strategy of an integrated "Energy Union" is based on five pillars (E.C., 2015):

- Energy security, solidarity, and trust
- A fully integrated European energy market
- Energy efficiency contributing to moderation of demand
- Decarbonization of the economy
- Research, innovation, and competitiveness

In addition to those pillars, which are greatly interrelated to one another, there have also been regulations and legislations about the European "Energy Security Strategy", which is of outmost significance for the Union to be completely integrated (E.C., 2014). That strategy aims at the integration of the internal energy market by implementing European network codes, and target models for both natural gas and electricity markets. Furthermore, there is the regulation 994/2010, which repeals the Council Directive 2004/76/EC, concerning measures to safeguard security of gas supply, and also management of supply disruptions, by initializing stress tests and protection of infrastructure schemes, as well as the management of oil stocks

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[32] European Energy Security Strategy, COM (2014) 330, May 2014, Brussels, available from: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52014DC0330&from=EN

(O.J.E.U., 2010). According to (O.J.E.U., 2013), the E.U. regulation 347/2013 provides guidelines for the trans-European development of energy infrastructure along with the development of PCIs (Projects of Common Interest). Another measure of the “Energy Security Strategy”, which contributes to E.U.’s energy integration and liberalization, is the differentiation of sources and flows by managing the internal production and mitigating the import dependency on Russian gas imports, and by upgrading the energy efficiency of the Member-States’ households and the residential sector.

The creation of interconnectors between Member-States is part of the E.U.’s “Energy Union”[33] strategy, where E.U. is committed to build missing energy infrastructure links and ensure that every Member-State has access to at least three different sources of gas. According to the European Council Conclusions of the 22nd of May in 2013[34], the European Council called for particular priority to be given to “Reaffirming the objectives of completing the internal energy market by 2014 and developing interconnections so as to end any isolation of the Member-States from the European gas and electricity networks by 2015”. Towards this direction, one of E.U.’s priorities is to integrate the Baltic Sea sub-region with the rest of the continental Europe. That is because, Finland and the other three Baltic States (i.e. Estonia, Latvia and Lithuania) are heavily dependent on gas imports from a single producer and that is Russia. Under the scope of supply diversification of the Baltic States, in October 2016 we saw the signing of a new project: the “Baltic Connector” pipeline between Finland and Estonia, which alongside with the “GIPL” (Gas Interconnector Poland-Lithuania) will allow these Baltic Sea states to diversify their gas sources and routes and thus contributing to the energy security of the sub-region. Just as the Prime Minister of Estonia Taavi Roivas mentioned “Baltic Connector signifies a key development for Nordic-Baltic energy market integration, for region’s security and diversity of supply and for consumer benefit”[35]. In the end, it is worth mentioning that these ambitious programs are realized under the scope of B.E.M.I.P. (Baltic Energy Market Interconnection Plan)[36], which is part of the E.E.R.P. (European Economic Recovery Plan)[37]. B.E.M.I.P. aims to further integrate the Baltic States’ energy markets by

[33] European Commission (2015), “Energy Union Package”, COM (2015) 80, Feb 25, available from: http://eur-lex.europa.eu/resource.html?uri=cellar:1bd46c90-bdd4-11e4-bbe1-01aa75ed71a1.0001.03/DOC_1&format=PDF.

[34] Available from: https://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/137197.pdf

[35] European Commission (2016), “Investing in Infrastructure that Unites: First Gas Interconnector between Finland and Estonia Ends Energy Isolation”, *Press Release*, available from: http://europa.eu/rapid/press-release_IP-16-3470_en.htm.

[36] BEMIP Action Plan 2015, available from: https://ec.europa.eu/energy/sites/ener/files/documents/BEMIP_Action_Plan_2015.pdf.

[37] European Commission (2008), “A European Economic Recovery Plan”, COM (2008) 800, Nov 26, available from: http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52008DC0800&from=EN.

building more infrastructures. In fact, B.E.M.I.P. projects concerning gas internal market and infrastructure include[38]:

- New interconnections such as the "Baltic Connector" pipeline
- Implementation of reverse flows such as through the proposed "Amber PolLit" pipeline between Poland and Lithuania
- LNG facilities in Estonia and Latvia
- Gas storage facilities in Latvia

The internal market should have been completed by 2014, so as to allow natural gas and electricity to flow freely. Besides, according to the European Council Conclusions of the 4th of February in 2011[39], "The E.U. needs a fully functioning, interconnected and integrated internal energy market. Legislation on the internal energy market must therefore be speedily and fully implemented by the Member-States in full respect of the agreed deadlines". Looking at the broader picture, by building more interconnectors and agreeing on pan-European trading arrangements, bottlenecks and congestion can be easily removed from the gas markets, thus, allowing gas to flow where it is most needed. It is those markets of South-Eastern E.U. that are most vulnerable to supply disruptions and least attractive for suppliers (European Commission, 2014). In the end, for all the above-mentioned measures and developments to be realized, E.U. must become an Energy Union "speaking" with "one voice" (full integration).

European Gas target model

The need of a pan-European gas target model has been envisioned by the C.E.E.R. (Council of European Energy Regulators), in its published document of the 1st of December in 2011[40]. Initially, the Regulators see a competitive European gas market as a combination of entry-exit zones with "virtual" hubs. The Council's vision suggests that the development of competition should be based on the development of liquid hubs across E.U., at which gas can be traded. Additionally, market integration should be served by efficient use of infrastructures, allowing market players to freely ship natural gas between market areas, and by responding to price signals to help gas flowing to where it is valued more. Finally, the target model must allow for sufficient and efficient levels of infrastructure investment, where physical congestions hinder

[38] BEMIP 6th Progress Report (2014), available from:
http://ec.europa.eu/energy/sites/ener/files/documents/20142711_6th_bemip_progress_report.pdf.
[39] Available from:
https://www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/ec/119175.pdf.
[40] CEER (2011), "CEER Vision for a European Gas Target Model", *Conclusion Paper,* available from:
http://www.ceer.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/GAS/Gas_Target_Model/CD/C11-GWG-82-03_GTM%20vision_Final.pdf.

market integration. According to C.E.E.R., the three pillars that will underpin its vision are:

- Enable functioning wholesale markets by establishing an entry-exit system and a "virtual" trading point at a national or regional level, while increasing liquidity through market-based balancing and gas release contracts.
- Connection of these functioning wholesale markets (market integration), with efficient use of the already existing interconnection capacity. That means the development and application of European network codes, and regulations on capacity allocation and congestion management, in order to develop hub-to-hub competition (linearization of the energy market).
- Ensure the energy security of supply, along with economic investment, by coordinated, market-based infrastructure development, based on price signals from the hubs.

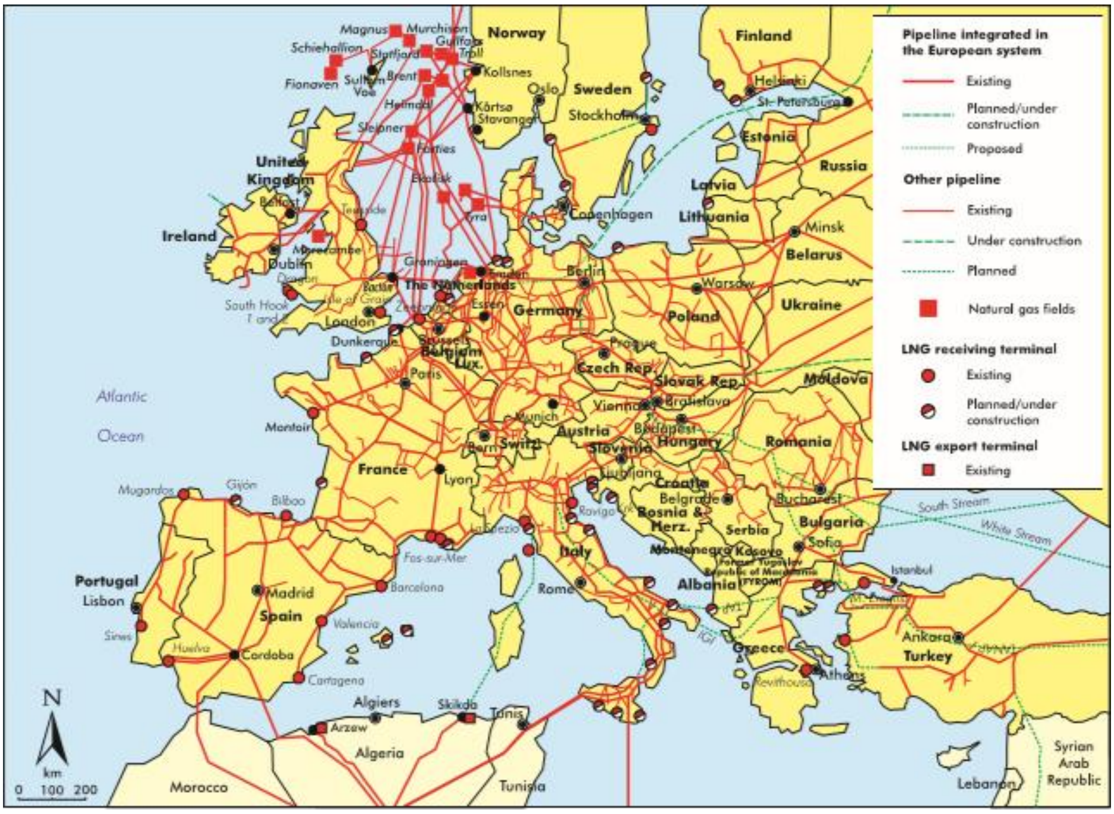
In the end, according to A.C.E.R. (Agency for the Cooperation of Energy Regulators), the launch of the updated Gas Target Model[41] includes five key objectives:

- Establishment of liquid, competitive and integrated wholesale energy market.
- Enhancement of Europe's security of energy supply and channeling of the external element of the Internal Energy Market.
- Movement to a low carbon society with increased penetration of renewable sources, and smart, flexible and responsive energy supply.
- Development of a functioning retail market that benefits end-users.
- Building a stakeholder dialogue, along with cooperation and new governance arrangements.

[41] Available from: http://www.acer.europa.eu/Events/Presentation-of-ACER-Gas-Target-Model-/Documents/Launch%20of%20ACER%20updated%20Gas%20Target%20Model%20Presentations.pdf.

1.5 System[42]

Map 1 Integrated European pipeline infrastructure of existing, planned & proposed projects



Source: I.E.A. (2016), Natural Gas Information 2016

Map 1 shows the European natural gas system of pipelines. E.U. has been developing many plans, especially infrastructure developments, towards the path to energy market integration under the conduction of PCIs: "To help create an integrated E.U. energy market, the European Commission has drawn up a list of 195 key energy infrastructure projects known as projects of common interest (PCIs). These are essential for completing the European internal energy market and for reaching the E.U.'s energy policy objectives of affordable, secure and sustainable energy"[43]. Some of these projects of pipeline, LNG, and storage infrastructure developments are going to be analyzed in the current section. E.U.'s natural gas system analysis includes the following clusters:

- Transmission pipelines for the transport of natural gas and bio gas that form part of a network, which mainly contains high pressure pipelines used for upstream and local distribution of natural gas.
- Reception, storage and regasification or decompression facilities for LNG or CNG.

[42] http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/.
[43] https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest.

- Underground storage facilities connected to the above-mentioned high-pressure natural gas pipelines
- Any equipment or installation essential for the system to operate safely, securely and efficiently or to enable bi-directional capacity, including compressor stations.

1.5.1 Pipeline transmission system

Completed PCIs

Map 2 Completed pipeline PCIs

Source:
http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/

The above **Map 2** shows the completed PCIs that were before 2017 in the color of dark red and in bright red appear to be the completed PCIs that are between 2017 and 2020:

- The upgrade of the entry points on the “Yamal-Europe” pipeline in Poland: “Lwowek” from 6.46 Mcm/day up to 9.8 Mcm/day, and of “Wlocawlek” from 8.38 Mcm/day to 25.2 Mcm/day entry points. Thereby, the total daily capacity will be at 35Mcm/day.
- The capacity enhancement by 5.5 Mcm/day of the onshore “Klaipeda to Kursenai” gas transmission on a distance of 110 Km in Lithuania.
- The pipeline between France (Pitgam) and Belgium (Maldegem) with a daily capacity at 24 Mcm/day, and a gas compressor in France.
- The reinforcement of the French internal network from South to North on the Arc de Dierrey pipeline between “Cuvilly”, “Dierrey” and “Voisines” on a distance of 308 Km.

- The reverse flow at "Passo Gries" interconnection point towards Germany and France via Switzerland with new onshore pipelines of around 80 Km and with a daily capacity of 421 GWh/day as overall reverse flow capacity increment, along with a compressor station of 95 MW.

Ongoing PCIs

Map 3 Ongoing pipeline PCIs

<u>**Source:**</u>
http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/

The main purposes of ongoing PCIs that were before 2017 have to do with; building infrastructures and applications to allow bidirectional flows from Northern Ireland to Great Britain and also from Ireland to the United-Kingdom; building interconnections between Poland and Slovakia, and related internal reinforcements in Eastern Poland, which are required to ensure an effective and efficient cross-border network expansion; building infrastructure to bring new gas to the Central and South-European region, with the aim of diversification; building applications between Austria, Croatia and Slovenia at Rogatec. **Map 3** shows the ongoing PCIs to be committed before 2017:

- Physical reverse flow at "Moffat" interconnection point between Ireland and the U.K. with capacity at 433 GWh/day.

- Transmission infrastructure projects between Rembelszczyzna and Strachocina in Poland.
- A gas compressor station and a pipeline system from Bulgaria to Slovakia currently known as "Eastring".
- Compressor stations and a pipeline system from Greece to Austria currently known as "Tesla".
- A pipeline in Greece from Komotini to Thesprotia, with length of 613 Km, diameter at 42'', along with two compressors.
- Compressor stations at the Croatian transmission system.

The ongoing PCIs between 2017 and 2020 **(Map 3)** include; the reinforcement of the French network from South to North in order to create a single market zone; interconnections between Croatia, Slovenia and Austria at Rogatec; an interconnection between the Hungarian and Slovenian transmission systems, enabling access to underground storages in Hungary for Slovenian gas suppliers, enabling access to LNG terminals in northern Adriatic and other gas sources for Hungarian gas suppliers; phased capacity increase on the Bulgaria-Romania-Hungary-Austria bidirectional transmission corridor "ROHUAT/BRUA", in order to enable 1.75 Bcm/year in the first phase and 4.4 Bcm/year in the second, including new resources from the Black Sea; the first bidirectional Austrian-Czech interconnection "BACI"; Czech-Polish interconnection "STORK II" upgrade and related internal reinforcements in Western Poland; infrastructure upgrade in the Eastern Baltic Sea region, along with the diversification of gas supply; Poland to Slovakia interconnection and related internal reinforcements in Eastern Poland; interconnections between Greece-Bulgaria and Bulgaria-Serbia, and necessary reinforcements in Bulgaria. These PCIs are listed below:

- The 60 Km long "Gascogne-Midi" pipeline in France with 5.5 MW compressor station in Barbaira, in order to reduce bottlenecks between North and South French areas.
- The new onshore "Val de Saone" pipeline of 190 Km in France between Etrez and Voisines, and a new compressor station of 9 MW at Etrez.
- Changes at the existing "TENP" pipeline system[44], including block valve and compression stations, in order to allow physical firm, reverse flow at Walbach from Switzerland into Germany, with a capacity of 10 GWh/hour with the possibility to upscale in the future. However, this reversal requires the construction of a new deodorization facility at the German-Swiss border.
- A gas pipeline Interconnection between Croatia and Slovenia at Rogatec.
- Upgrade of Rogatec interconnection so as to provide reverse flow.

[44] TENP is a pipeline in Germany from the interconnection point at Walbach to Boltcholtz.

- First phase of the GCA Mosonmagyarovar CS development on the Austrian side.
- New onshore bidirectional Austria to Czech-Republic interconnection with length of 12 Km on the Czech side and 496 Km on the Austrian side, planned capacity of 18 Mcm/day, and expected power at of the compressor station in Austria of 14 MW.
- Tvrdonice-Libhost pipeline, including upgrade of compressor station of Breclav in Czech-Republic.
- New onshore pipeline with a length of 112.4 km and a maximum capacity 13.7 Mcm/day in the direction Poland to Czech-Republic and that of 19.6 Mcm/day in the opposite direction.
- Upgrade of onshore pipelines in Greater Poland and Silesia regions. The total length of the lines in the PCI amounts to 404 Km.
- An interconnection between Hungary and Slovenia of 114 Km length, with non-interruptible capacity at 1.14 Mcm/day and interruptible at 2.28 Mcm/day and the power of the compressor station at 8.1 MW.
- New onshore bidirectional pipeline between Poland and Lithuania known as "GIPL" with total length of 534 Km[45] and capacity of 2.4 Bcm/year[46] in the direction of Poland to Lithuania, and up to 1.7 Bcm/year in the opposite direction. Additionally, with two power compressors at 6.8 MW and 6.7 MW.
- Construction of a 93 Km pipeline from Riga-Lecava and Lecava-Lithuanian border with total capacity at 12 Mcm/day. Additionally, the upgrade of gas metering station in Lithuania.
- Enhancement of the onshore Estonia-Latvia pipeline to a daily capacity of 10 Mcm/day. The power of the compressor station is of 35 MW.
- The new bidirectional "Balti connector" pipeline between Estonia and Finland, with total length of 150 Km[47], including metering and compressor stations at both ends of daily nominal capacity at 7.2 Mcm/day[48]. The power of its compressor is about 10 MW.
- New onshore pipeline of approximately 164 Km and with maximum capacity at 15.6 Mcm/day in the direction from Slovakia to Poland and 12.9 Mcm/day in the opposite direction.

[45] 177 Km in the territory of Lithuania and 357 in the territory of Poland

[46] The capacity from Poland to Lithuania may be extended up to 4.1 Bcm/year in the second stage of the project development.

[47] Offshore part of 80 Km, onshore part in Estonia of 50 Km, and onshore part in Finland of 20 Km. Estimated share of offshore pipeline is expected to be 50-40 km as a part of Finnish transmission system and 30-40 Km as a part of the Estonian transmission system.

[48] Capacity can be increased to 11 Mcm/day if the network capacity in Estonia and Finland is increased.

- Interconnection of the national transmission system with the international gas transmission pipelines and reverse flow applications at Isaccea in Romania.
- New onshore pipeline with length of 307 Km from the Black Sea Shore to Podisor in Romania, and total capacity of 6 Bcm/year.
- The new offshore "Poseidon" pipeline of approximately 216 Km, with capacity of 329.4 GWh/day and diameter at 808 mm. The total power of the compressor station in Thesprotia will be at 120 MW. Additionally, the total capacity could be upgraded to 20 Bcm/year with minimal modification of the basic configuration, mainly regarding increased power of the compressor station.
- The new onshore pipeline "IGB" between Greece and Bulgaria, with length of 182 Km and technical forward capacity at 9 Mcm/day, capable to be increased at the second stage up to 15 Mcm/day with additional installation of a compressor station of 10 to 15 MW.
- Upgrade and extension of onshore pipelines in Bulgaria, including projects for rehabilitation, modernization and expansion of the existing national transmission system[49].
- The new onshore "IBS" pipeline between Bulgaria and Serbia, with a length of 150 Km and capacity at 4.93 Mcm/day, interconnecting the Bulgarian and Serbian gas systems between Sofia and Nis through Dimitrovgrad.
- The new onshore pipeline "Posidor-Horia GMS" in Romania, with a length of 528 Km and capacity at 4.5 Bcm/year, along with three new compressor stations with total power of 43.5 MW.
- Expansion of the transmission capacity in Romania towards Hungary up to 4.4 Bcm/year (second phase).

Furthermore, there are planned ongoing PCIs for the period beyond 2020 such as; the third interconnection point between Portugal and Spain; the development of the Eastern Axis between France and Spain; reinforcement of the French network from South to North, and reverse flow from France to Germany at Obergailbach/Medelsheim interconnection point; bidirectional flows from Northern Ireland to Great Britain and Ireland, and also from Ireland to the U.K.; the connection of Malta to the European gas network; evacuation pipelines towards Hungary, Slovenia and Italy; interconnection between Greece and Bulgaria, and necessary reinforcements in Bulgaria. These PCIs, per **Map 3,** are listed below:

[49] Modernization and rehabilitation of compressor stations, intelligent pig inspections, expansion and replacement of sections of the existing transmission system, and implementation of systems for optimization of the management process of the network technical condition.

- The creation of a new pipeline between Portugal and Spain, of total length at 314 Km (229 Km in Portugal and 85 Km in Spain) and total bidirectional capacity of 11.8 Mcm/day for the full development of the project.
- The new onshore “Midcat” pipeline of 580 Km, interconnecting Spain and France (432 Km in Spain and 148 Km in France), and with total capacity at 230 GWh/day from Spain to France and 80 GWh/day in the opposite direction. There will also be three compressor station of total power at 76 MW.
- The reinforcement of the pipeline between Saint Martin de Crau and Saint-Avit, in France, on a distance of 220 km.
- Reinforcement of the pipeline between Saint-Avit and Etrez, in France, on a distance of 170 Km.
- Adaptation of the odorisation practices, reinforcement of compressor stations in three locations in France, reinforcement of the North-East pipeline between Morelmaison and Laneuvelotte in France, and change of the metering facility in Medelsheim. The planned capacity from France to Germany is at 100 GWh/day.
- Upgrade of the “SNIP” (Scotland to Northern Ireland) pipeline to accommodate physical reverse flow between Ballylumford and Twynholm. The upgrade involves three components: install compression, reversal of a metering stream and flow control, and removing upstream gas odorisation equipment and installing at downstream point.
- The new bidirectional offshore “Baltic Pipe” pipeline, connecting Poland and Denmark through the Baltic Sea with estimated capacity at 6 Bcm/year and length of 200 to 290 Km. Furthermore, there will be related auxiliary installations, the required onshore pipelines connecting the offshore parts with national grids, the receiving terminals, and compressor stations in both countries.
- The development of a gas pipeline interconnection between Sicily and Malta, including terminal stations with an approximate length of 155 Km of annual and daily capacity at 2 Bcm/year and 49 GWh/day respectively[50].
- A new onshore pipeline in Italy of approximately 425 Km and with a daily capacity of 264 GWh/day, along with the installation of a compressor station of 33 MW power.
- A new offshore pipeline with total length of 220 Km between the island of KrK in Hungary and the Casal Borsetti in Italy (146 Km to the epicontinental zone border in the Hungarian part and 74 Km in Italy). Total daily capacity will be at 46 Mcm/day.

[50] Primarily intended for the importation of natural gas from the Italian gas network.

- The interconnection of the Northern ring of the Bulgarian gas transmission system with the "Posidor-Horia" pipeline, and expansion of the capacity on "Hurezani-Horia-Csanadpalota" section. The project is meant to link the new planned "IP3" between Bulgaria and Romania.

Pipeline PCIs between the E.U. and third party countries

Of outmost importance for the E.U., according to its "Energy Union" strategy, are the following PCIs of cross-border interconnection points between the E.U. and third countries such as Azerbaijan and Algeria, in order for the E.U. to diversify further from the Russian natural gas pipeline import dependency, and to safeguard its energy security. Additionally, these PCIs will offer; new interconnection between Algeria and Italy; natural gas infrastructures and associated equipment for the transportation of new resources of gas from the offshore fields in the East Mediterranean; integrated, dedicated and scalable transport infrastructure and associated equipment for the transportation of a minimum 10 Bcm/year of new sources of gas from the Caspian region, crossing Azerbaijan, Georgia and Turkey, and finally reaching the E.U. markets in Greece and Italy. According to **Map 3**, these PCIs are listed below:

- The new transcontinental gas pipeline "Galsi" of 851 Km[51] connecting Algeria and Italy via Sardinia. The capacity is 7.6 Bcm/year and the power of the compressor stations in Algeria and in Sardinia are of 3.33 MW and 2.26 MW respectively.
- The new "EastMed" pipeline of approximately 1,900 Km that will directly connect the East Mediterranean gas resources to the European Gas system. Pipeline's estimated capacity will be at 320-350 GWh/day with the option to be upgraded to 510 GWh/day, if relevant reserves would be discovered in the offshore of Crete. The total compressor power will be at 225 MW or at 275 MW in the case of 510 GWh/day capacity from Crete. Pipe diameters will be at 610-810 mm for the offshore section and 1070-1170 mm for the onshore section.
- The new onshore and offshore "TAP" pipeline between Greece/Turkey and Italy via Albania with a total length of 878 Km (773 Km onshore and 105 Km offshore), with a normal capacity of 28.6 Mcm/day and a maximum capacity of 31.8 Mcm/day; initial throughput capacity of 10 Bcm/year; and the power of the compressor station at 90 MW.
- The gas pipeline to the E.U. from Turkmenistan and Azerbaijan via Georgia and Turkey. That particular PCI is a combination of three other projects:

[51] The project can be divided into two sections: international offshore section of 288 Km from Algeria to Sardinia, and a national section of 563 Km (285 Km onshore crossing Sardinia, 275 Km offshore from Sardinia to Tuscany, and 3 Km onshore in Tuscany).

the "TCP" (Trans-Caspian Pipeline), and the expansion of "SCP-(F) X" (South-Caucasus Pipeline) and "TANAP" (Trans Anatolia Pipeline).

- TCP: The offshore pipeline in the Caspian Sea with a length of 300 Km and capacity at 32 Bcm/year will branch-off at a connection with the "East-West" pipeline in Turkmenistan, and it will feed into "SCP-(F)X" in Azerbaijan.
- SCP-F(X): Upgrade of the existing pipeline system between Azerbaijan and Turkey via Georgia system, with throughput capacity upgrades of 5 Bcm/year by 2022.
- TANAP: New onshore and offshore pipeline between the Eastern and Western borders of Turkey and crossing Anatolia, with a length of 1,900 Km and an initial throughput capacity of 16 Bcm/year.

- The new onshore "ITB" pipeline between Turkey and Bulgaria of about 200 Km[52], and with capacity at 9 Mcm/day.

Table 2 Pipeline capacities from LNG entry points (Mcm/day)

COUNTRY	CAPACITY (Mcm/day)
BELGIUM	48.44
SPAIN	199.12
FRANCE	73.32
ITALY	54.22
LITHUANIA	11.50
NETHERLANDS	37.47
POLAND	23.91
PORTUGAL	63.15
GREECE	14.09
UNITED-KINGDOM	172.61

Source: ENTSO-G, http://www.entsog.eu/maps/transmission-capacity-map.

[52] The Bulgarian section is approximately 75 Km and the Turkish 130 Km.

1.5.2 LNG facilities system

Operational regasification terminals and capacities:

- **Number of existing facilities:** 26
- **Total maximum hourly capacity:** 26.09 Mcm/hour
- **Total maximum nominal annual capacity:** 196,410 Mcm/year
- **Total LNG storage capacity:** 8.71 Mcm

Under construction regasification terminals and capacities:

- **Number of new facilities and expansions:** 12
- **Total maximum hourly capacity:** 7.46 Mcm/hour
- **Total maximum nominal annual capacity:** 52,710 Mcm/year
- **Total LNG storage capacity:** 2.63 Mcm

Planned regasification terminals and capacities:

- **Number of new facilities and expansions:** 39
- **Total maximum hourly capacity:** 31.73 Mcm/hour
- **Total maximum nominal annual capacity:** 243,800 Mcm/year
- **Total LNG storage capacity:** 12.24 Mcm

Operational LNG liquefaction terminals and capacities:

- **Number of existing facilities:** 5
- **Total maximum annual capacity:** 6,704.1 Mcm/year

Planned LNG liquefaction terminal and capacities:

- **Number of new terminals:** 1
- **Total maximum annual capacity:** 6,897.22 Mcm/year

LNG is one of the best ways for E.U. to differentiate its import dependency on "traditional" pipeline suppliers such as Russia and Algeria. Although the plans for LNG facilities are quite promising, their development is of an earlier stage, and of fewer number than that of the pipeline PCIs, taking into account the higher initial cost to build LNG terminals than pipeline interconnections. However, the most developed LNG markets in the E.U. are placed in the Western and North part of the continent (U.K. and Spain), whereas the South-Eastern part is quite left behind, except that of Italy's. **Map 4** shows the European PCIs of LNG facilities. Europe expands its demand capacity in order to achieve the target "energy security" by diversifying its sources from traditional suppliers. Poland's annual consumption amounts to 15 Bcm/year and imports 10 Bcm/year from Russia. In fact, the "Swinoujscie LNG" project came online in late 2015 and reduced the Russian share, which accounted at about 60%, by Qatari LNG, and Poland can now draw Russian gas from Germany. In addition, Poland has signed a 20-year long-term contract with Qatar for 1.2 Bcm/year that covers the 24.5% of the project's total capacity: "Swinoujscie LNG" has a total capacity of 4.9Bcm/year, almost equal to the one third of Poland's annual consumption. Some other projects that will help in that directive of diversification started developing in 2016: the "Dunkirk LNG" in France with capacity at 13 Bcm/year, in Finland the "Pori LNG" at 0.3 and the "Revithousa" capacity expansion that will add 2 Bcm/year. In the end, an upcoming small scale project will start developing in 2018: the "Manga LNG" in Finland of 0.5 Bcm/year (I.E.A., 2016).

Map 4 PCIs for LNG facilities

Source:
http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/

LNG projects to be commissioned between 2017 and 2019

Currently, South-Eastern Europe has a major problem of liquidity because of the lack of interconnection pipelines and sufficient LNG infrastructure **(Map 4)**. That is also one of the reasons why Greece had not become a trading hub yet. Although Greece is placed in a very good spot, in terms of geopolitics, and has already a LNG terminal in Revithousa Island, it is not an adequate facility to solve the liquidity problem of South-Eastern Europe, or to make Greece a trading hub yet. To that end, we see that many new projects are coming online in the region the upcoming years, not only pipeline projects but also an ambitious LNG terminal. In 2018 there is going to be commissioned a new offshore LNG terminal near Alexandroupolis, and a system of subsea and an onshore pipeline of 28 km (4 Km onshore and 24 Km subsea), with a capacity of 16.8 Mcm/day. One of the planed PCIs is the extension of the Zeebruge LNG terminal in Belgium, which will be commissioned in 2019. There will be an extension of the LNG/CNG terminal with additional send-out capacity of 3 Bcm/year, an additional storage tank of 180,000 m^3 and a maximum ship size of 266,000 m^3. The new LNG tank and the new jetty will increase the capacity of the LNG supply to Belgium and to North-Western Europe by about 25%. Another ongoing project to be commissioned in 2019 is the "Shanon" LNG regasification terminal and a connecting pipeline in Ireland. Shanon LNG will deliver gas into the existing Ireland's national gas transmission network near Foynes via a 26 Km high pressure onshore pipeline, with a design pressure of 98 bars. The planned initial send-out capacity of the project is at 191.1 GWh/day. The terminal will have up to four LNG tanks of total capacity at 800,000 m^3 and a high efficiency CHP plant providing heat to regassify the LNG. Furthermore, the terminal's ultimate capacity will be at 318.5 GWh/day. Moreover, in 2019, in Hungary there is going to be commissioned a very ambitious project: the phased development of a LNG regasification vessel in the KrK Island, and evacuation pipelines towards Hungary, Slovenia and Italy. The development is currently focused on an onshore type of LNG terminal with a corresponding send-out capacity of 4-6 Bcm/year. Depending on the Open Season results, before FID, the project promoter (LNG Croatia LLC) will decide whether to proceed with the construction of the onshore LNG terminal or to introduce the FSRU as an intermediate technical solution. One project of big importance to the Union's Baltic States energy security is the "Tallinn" LNG in Estonia. The three Baltic States are around 90% dependent on Russian pipeline gas imports. So, the aforementioned project will help in diversifying gas supply in the Eastern Baltic sub-region.

Table 3 E.U. LNG regasification maximum capacities in Mcm per hour & Mcm per year as of May 2015

COUNTRY	FACILITIES			HOURLY MAX CAPACITY (Mcm/hour)			NOMINAL ANNUAL CAPACITY (Mcm/year)		
	OPERATIONAL	UNDER CONSTRUCTION	PLANNED	OPERATIONAL	UNDER CONSTRUCTION	PLANNED	OPERATIONAL	UNDER CONSTRUCTION	PLANNED
BELGIUM	1	1	1	1,7	1,7	2,15	9.000	9.000	12.000
CROATIA			3			1,26			
ESTONIA			2			0,62			6.500
FINLAND		4	2			0,8		110	2.600
FRANCE	3	1	3	3,47	1,9	5,97	21.650	13.000	41.000
GERMANY			1						
GREECE	1	1	2	0,57	0,80	1,28	5.000	7.000	11.100
IRELAND			3			2,46			9.000
ITALY	3		5	2,12		5,33	14.710		40.000
LATVIA			1						5.000
LITHUANIA	1	1		0,46	0,46		4.000	4.000	
MALTA			1			0,23			2.000
NETHERLANDS	1	1	1	1,65	1,65	2,2	12.000	12.000	16.000
NORAWY	2						150		
POLAND		1	1		0,66	0,86		5.000	7.500
PORTUGAL	1			1,35			7.900		
ROMANIA			1						
SPAIN	7	2	7	7,86	0,3	5,1	68.900	2.600	44.800
SWEDEN	2		2	0,01		0,83	800		800
UNITED-KINGDOM	4		3	6,9		2,65	52.300		45.500
TOTAL	26	12	39	26,09	7,46	31,73	196.410	52.710	243.800

Table 4 E.U. Natural gas liquefaction capacities in Mcm/year as of May 2015

COUNTRY	FACILITIES			ANNUALL CAPACITY (Mcm/year)		
	OPERATIONAL	UNDER CONSTRUCTION	PLANNED	OPERATIONAL	UNDER CONSTRUCTION	PLANNED
CYPRUS			1			6.897,22
NORWAY	5			6.704,1		
TOTAL	5		1	6.704,10		6.897,22

Source: G.I.E. (Gas infrastructure Europe), http://www.gie.eu/index.php/maps-data/lng-map.

Table 5 E.U. LNG storage capacities in Mcm as of May 2015

COUNTRY	FACILITIES			LNG STORAGE CAPACITY (Mcm)		
	OPERATIONAL	UNDER CONSTRUCTION	PLANNED	OPERATIONAL	UNDER CONSTRUCTION	PLANNED
BELGIUM	1	1	1	0,38	0,38	0,56
CROATIA			3			0,36
ESTONIA			2			0,25
FINLAND		4	2		0,12	0,18
FRANCE	3	1	3	0,84	0,57	1,46
GERMANY			1			
GREECE	1	1	2	0,13	0,23	0,34
IRELAND			3			1,2
ITALY	3		5	0,49		1,63
LATVIA			1			0,18
LITHUANIA	1	1		0,17	0,17	
MALTA			1			0,18
NETHERLANDS	1	1	1	0,54	0,54	0,72
NORAWY	2			0,01		
POLAND		1	1		0,32	0,48
PORTUGAL	1			0,39		
ROMANIA			1			
SPAIN	7	2	7	3,62	0,3	3,25
SWEDEN	2		2	0,05		0,06
UNITED-KINGDOM	4		3	2,10		1,38
TOTAL	**26**	**12**	**39**	**8,71**	**2,63**	**12,24**

Source: G.I.E. (Gas infrastructure Europe), http://www.gie.eu/index.php/maps-data/lng-map.

LNG projects to be commissioned in 2020

According to **Map 4**, there will be a send-out capacity extension up to 7.5 Bcm/year on the “Swinoujscie” LNG terminal in Poland, which is going to be commissioned in 2020. Another project that is going to be commissioned in 2020 is the “Gothenburg” LNG terminal in Sweden. The new onshore terminal will have a send-out capacity of 0.5 Bcm/year and a LNG storage capacity of 25,000 m^3, and the maximum ship size is at 75,000 m^3 of LNG. As I said before, the Baltic States have a major problem because of their dependency on the Russian imports for natural gas by pipelines. In addition to the new LNG terminal “Tallinn” in Estonia to be commissioned in 2019, there is also another LNG project to be commissioned in 2020 towards the aim of diversification of gas supply in the Eastern Baltic Sea region. The new onshore LNG terminal near Paldiski, including a reloading facility for bunkering or small scale distribution, will have an annual send-out capacity of 2.5 Bcm/year. The LNG storage capacity in the first stage will be 160,000 m^3 with the possibility to be increased up to 320,000 m^3, and the maximum ship size will be of 165,000 m^3 or any standard LNG tanker capable to pass through the Danish Straits.

LNG projects to be commissioned after 2020

There are two very ambitious LNG projects in plans after 2020: one in Cyprus and the other in Malta **(Map 4)**. These two islands are currently isolated from E.U.’s gas network due to the lack of internal network and infrastructure as well as lack of LNG terminals. However, the new fields that have been discovered the last seven years in the shores of South-Eastern Mediterranean are one of the possible solutions in the problem of gas liquidity and energy security of the sub-region and to the Union as a whole in the long-term. So, E.U. initially aims to build gas infrastructures and associated equipment for the transmission of new sources of gas from the offshore fields in the Eastern Mediterranean by involving Cyprus in the game, which is going to be the connector from the gas reserves to Europe through pipeline, or regional supplier of LNG. The LNG project in Cyprus is to be commissioned in 2024 and is going to remove internal bottlenecks, end the gas isolation of the island, and will allow the transmission of gas from the Eastern Mediterranean region. Additionally, the LNG project in Malta along with its connection to the Italian network by pipeline is going to connect the Island to the rest of the European gas network. The project will be commissioned in 2026, following the completion of the first stage, which is the pipeline interconnection with Italy. The second phase will allow bidirectional flow of gas through the pipeline interconnection by installing a floating LNG storage and regasification unit (FSRU).

1.5.3 Storage facilities system

Operational storage facilities and capacities:

- **Number of existing operational facilities:** 153
- **Total technical working gas capacity:** 108,337 Mcm
- **Total withdrawal technical capacity:** 2,117.24 Mcm/day
- **Total injection technical capacity:** 1,171.32 Mcm/day

Under construction storage facilities and capacities:

- **Number of new facilities and capacities:** 27
- **Total technical working gas capacity:** 7,362.91 Mcm
- **Total withdrawal technical capacity:** 96.61 Mcm/day
- **Total injection technical capacity:** 49.21 Mcm/day

Planned storage facilities and capacities:

- **Number of new facilities and capacities:** 49
- **Total technical working gas capacity:** 29,278.69 Mcm
- **Total withdrawal technical capacity:** 339.67 Mcm/day
- **Total injection technical capacity:** 247.17 Mcm/day

Total operational underground storage capacity: 108.5 Mcm

Total under construction underground storage capacity: 7.4 Mcm

Total planned underground storage capacity: 29.5 Mcm

Romania storage developments

There have been signed projects for storage facilities to increase the storage capacity of the South-Eastern E.U. Member-States, because of the existing reserves of natural gas in these parts. **Map 5** shows the European PCIs of natural gas storage. **Table 6** represents the technical working capacities of E.U.'s operational, under construction, and planned storage facilities. **Table 7** the withdrawal and injection technical capacities of the same facilities. Whereas, **Table 8** represents E.U.'s operational, under construction, and planned underground storage capacities Romania is a Member-State of the E.U. that has its own production of natural gas, and it is also placed in a geostrategic position in the Eastern E.U. because it is surrounded by many states that satisfy their own needs by importing gas from third countries. Although Romania uses its production mainly for its own domestic needs, by developing gas storage facilities in the country, E.U. can safeguard the continuous provision of energy, and the continuing flow of natural gas to the surrounding

Member-States that are heavily dependent on gas imports from Russia. Thus, the storage facility developments in that state are of major importance to the energy integration of the Union. To that directive there is going to be new underground gas storage in a depleted field in the Northern part of Romania (Suceava) with the following technical characteristics:

- Working gas capacity: 200 Mcm
- Withdraw capacity: 2 Mcm/day
- Injection capacity: 1.4 Mcm/day
- Cycling rate: 1 times/year

There is also the extension and upgrade of the storage facility in the depleted field Sarmasel in Romania, with the following characteristics:

- Working gas volume: 1,550 Mcm (800 Mcm of existing, plus 100 Mcm in progress, plus 650 Mcm of new capacity).
- Withdraw capacity: 10 Mcm (4.75 Mcm of existing, plus 2 Mcm in progress, plus 3.25 Mcm of new capacity).
- Injection capacity: 10 Mcm (6 Mcm in progress, plus 4 Mcm of new capacity).
- Cycling rate: 1 times/year.

Additionally, in Romania there is going to be commissioned in 2019the revamping and extension of the storage facility in a depleted field in Depomures, with the following technical characteristics:

- Working gas volume: 600 Mcm (300 Mcm of existing capacity, plus 300 Mcm of new capacity).
- Withdraw capacity: 5 Mcm (2 Mcm of existing capacity, plus 3 Mcm of new capacity).
- Injection capacity: 5 Mcm (2 Mcm of existing capacity, plus 3 Mcm of new capacity).
- Cycling rate: 1 times/year.

Latvia storage developments

Additionally, for reasons of energy security in the Eastern parts of the Union, especially in the Eastern Baltic Sea region, which import dependency on Russian gas is at around 90%, in 2025 there is going to be a major infrastructure upgrade in Latvia: the enhancement of the Incukalns underground gas storage **(Map 5)**. In fact, there is going to be an upgrade and extension of an aquifer storage facility with the following technical characteristics:

- Current working gas volume: 2,300 Mcm

    - After extension: 2,635-2,835 Mcm
- Current withdrawal capacity: 28-30 Mcm
    - After modernization expected: 34-35 Mcm/day
- Current injection capacity: 17 Mcm/day
    - After modernization: 21-22 Mcm/day
- Cycling rate: 1 times/year (seasonal storage)

Ireland storage developments

In the developments of bidirectional flows from Northern Ireland to Great Britain and Ireland, and from Ireland to the U.K., there is also going to be a development of an underground storage facility at Larne in Northern Ireland **(Map 5)**. The project will be commissioned in 2021 and will provide a working gas volume of 420 Mcm/day. It will also be connected to the Northern Ireland gas transmission system at Ballylumford. The works so far have included permitting and consenting activities, technical surface and subsurface design, well planning and design, procurement for salt testing well, stakeholder management, and finally financing activities including a market study and successful application for CEF funding.

Map 5 PCIs for gas storage facilities in E.U.

Source: http://ec.europa.eu/energy/infrastructure/transparency_platform/map-viewer/

Table 6 E.U. Storage facilities and their technical working gas capacities (Mcm) as of May 2015

COUNTRY	FACILITIES			TECHNICAL WORKING GAS CAPACITY (Mcm)		
	EXISTING OPERATIONAL	UNDER CONSTRUCTION	PLANNED	EXISTING OPERATIONAL	UNDER CONSTRUCTION	PLANNED
AUSTRIA	10			8.250		
BELGIUM	1			700		
BULGARIA	1		3	550		1.650
CROATIA	1	1		553	25	
CZECH-REPUBLIC	8	4	1	3.507	505	180
DENMARK	2		3	998		
FRANCE	17	1		12.008,2	60	675
GERMANY	58	6	4	24.566,45	2.043	679
GREECE			1			360
HUNGARY	5			6.330		
IRELAND	1		1	230		174
ITALY	10	6	12	16.582	3.405	7.074
LATVIA	1		3	2.320		2.800
LITHUANIA			1			500
NETHERLANDS	5			12.900		
POLAND	9	4	2	2.754,09	776	
PORTUGAL	1	1		300		
ROMANIA	7		4	3.050		1.600
SERBIA	1	1		450	350	
SLOVAK-REPUBLIC	2		2	3.135		890
SPAIN	4		1	4.103		240
SWEDEN	1			10		
UNITED-KINGDOM	8	3	11	5.040,27	199	12.456,69
TOTAL	153	27	49	108.337	7.362,91	29.278,69

Source : G.I.E. (Gas Infrastructure Europe), http://www.gie.eu/index.php/maps-data/gse-storage-map.

Table 7 E.U. withdrawal and injection technical capacities (Mcm/day) in storage facilities as of May 2015

COUNTRY	WITHDRAWAL TECHNICAL CAPACITY (Mcm/day)			INJECTION TECHNICAL CAPACITY (Mcm/day)		
	EXISTING OPERATIONAL	UNDER CONSTRUCTION	PLANNED	EXISTING OPERATIONAL	UNDER CONSTRUCTION	PLANNED
AUSTRIA	94,38			76,06		
BELGIUM	15			7,8		
BULGARIA	3,4		4,6	3,16		4,48
CROATIA	5,76	2,4		3,84	1,4	
CZECH-REPUBLIC	56,89	10,9	7	39,1	0,9	2
DENMARK	16,2			8,4		
FRANCE	331,9	4	43,6	188,4	4,8	14
GERMANY	597,56	10,8	27,5	316,35	27,2	3,6
GREECE			4			5
HUNGARY	78,6			44,65		
IRELAND	2,6		1,1	2		0,8
ITALY	291,35	27,2	92,34	135,85	1,71	81,14
LATVIA	30		5	17		
LITHUANIA			8			3
NETHERLANDS	274,2			128		
POLAND	46,23	16,11	5,28	27,44	2	3,6
PORTUGAL	7,2			2,04		
ROMANIA	27,2		13,3	22,7		13,3
SERBIA	5	5		3,5	0,7	
SLOVAK-REPUBLIC	45,11		13,75	38,77		11,75
SPAIN	31,6		14	22,4		9
SWEDEN	0,9			0,36		
UNITED-KINGDOM	156,16	20,2	100,2	83,5	10,5	95,5
TOTAL	**2.117,24**	**96,61**	**339,67**	**1.171,32**	**49,21**	**247,17**

Source : G.I.E. (Gas Infrastructure Europe), http://www.gie.eu/index.php/maps-data/gse-storage-map.

Table 8 E.U. underground storage capacities (Mcm) as of May 2015

COUNTRY	OPERATIONAL	UNDER CONSTRUCTION	PLANNED
AUSTRIA	8,3		
BELGIUM	0,7		
BULGARIA	0,6		1,7
CROATIA	0,6		
CZECH-REPUBLIC	3,5	0,5	0,2
DENMARK	1		
FRANCE	12	0,1	0,7
GERMANY	24,6	2	0,7
GREECE			0,4
HUNGARY	6,3		
IRELAND	0,2		0,2
ITALY	16,6	3,4	7,1
LATVIA	2,3		2,8
LITHUANIA			0,5
NETHERLANDS	12,9		
POLAND	2,8	0,8	
PORTUGAL	0,3		
ROMANIA	3,1		1,6
SERBIA	0,5	0,4	
SLOVAK-REPUBLIC	3,1		0,9
SPAIN	4,1		0,2
SWEDEN			
UNITED-KINGDOM	5	0,2	12,5
TOTAL	108,5	7,4	29,5

Source : G.I.E. (Gas Infrastructure Europe), http://www.gie.eu/index.php/maps-data/gse-storage-map.

CHAPTER 2: REST OF THE WORLD'S NATURAL GAS ANALYSIS

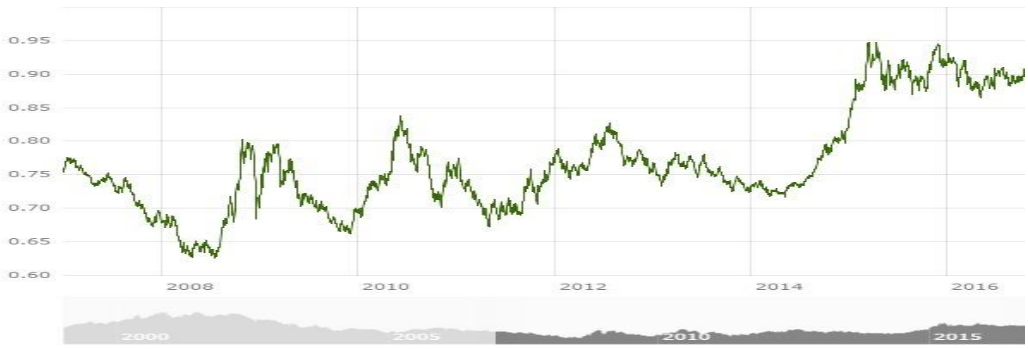
On the long-term, one of the greatest advantages that oversupply has to offer to E.U. is increased competition between "emerging" and "traditional" suppliers of natural gas. Oversupply of LNG has led to increased competition activities among "traditional" pipeline producers (i.e. Russia) and new LNG exporters (i.e. U.S.A.): more flexible U.S. and Qatari LNG volumes are cutting off share of the Russian pipeline imports into Europe. In fact, the shale gas boom in the U.S. redirected to Europe a significant volume of LNG (mainly from Qatar) that had been produced for export in the North American market. As a result of this sudden oversupply, was the robust decrease of hub prices below the level of LTCs (Honore, 2011). That means, increased spare import capacity allows E.U. to arbitrage between pipeline and LNG prices. For example, the exceptionally low price of U.S. LNG can easily compete and eventually cut share from Russia, which is a "traditional" pipeline gas supplier to E.U. and Asia.

On the short-term, demand shocks and other transitory factors may be profitable arbitrage opportunities that will see export volumes increase on occasion, but they won't support large-scale capital investments (Medlock, et al., 2012). How does one evaluate an arbitrage opportunity as "profitable" or not? The answer to the previous question is the "exchange rate". We can see that there is an exogenous factor that affects the trajectory of trade between foreign markets. Consequently, that factor also plays an important role in the number of FIDs that will take place during the current market conditions. So, eventually is a factor that also affects the total export and/or import capacity of a producing and/or consuming country respectively. For example, according to (Medlock, et al., 2008), in order to evaluate an arbitrage opportunity between U.S. exports to France, first we need a link between "prices" (P_x, x= (U.S., FR)) of the trading countries and the "exchange rate" $\boldsymbol{XR}$ of the two different currencies (i.e. $/€). **Figure 17** represents the exchange rates between the US$ and the € from 2007 to 2016. The "unit conversion factor" $\boldsymbol{HC}$ represents the heating conversion, when you transform KWh to MMBtu. So, the equation goes as follows:

$$\boldsymbol{AV = P_{US} - P_{FR} * XR * HC}$$

Where, $\boldsymbol{AV}$ represents the "arbitrage value", which is measured in $/MMBtu. So, it is quite clear from the above simple linear equation that the product of $\boldsymbol{HC}$ and $\boldsymbol{XR}$ represents the "slope" of the line curve $\boldsymbol{AV}$. The coefficient $\boldsymbol{P_{US}}$, which is measured in $/MMBtu, represents the intercept of the line curve. The slope of a line curve depicts the percentage in which the dependent variable $\boldsymbol{AV}$ is dependent on the variable $\boldsymbol{P_x}$ (Ayacloglou & Benos, 2007). In our case, because the sign of the slope is negative, there is an opposite trajectory effect in the $\boldsymbol{AV}$ for every change of the price of natural gas in France $\boldsymbol{P_{FR}}$, which is measured in €/KWh, ceteris paribus. That means, if the dollar weakens against the euro, $\boldsymbol{XR}$ will decrease and $\boldsymbol{AV}$ will increase and the opposite, all else equal. Thus, the risk of exchange rate movements is very crucial for LNG exporters. Finally, future opportunities for the U.S. to profitably export depend on the future of global natural gas markets and on the inclusion of relevant terms in specific contracts to export natural gas.

Figure 17 Exchange rates US$ vs. € from 2007 until today



Source: ECB, US$ exchange rates vs €, http://www.ecb.europa.eu/stats/exchange/eurofxref/html/eurofxref-graph-usd.en.html

Weaker demand growth and historically low gas and oil prices that cause a sharp cutback in upstream investments are the main reasons of a slower global natural gas production. Lower production rates, ceteris paribus, distribute cash flows more into the future, thus lowering the NPV of these investments. Additionally, slower power generation growth, extremely low coal prices and the rapid development of renewable sources, are making natural gas's growth slower. According to projections made by the I.E.A. (2016), the production growth will increase by 1.5% on average for the next five years, which is lower by 1% from that of the previous six years. Most of the increase will be led by North American and Australian production. In addition, U.S.'s production is forecasted to increase by more than 100 Bcm, which accounts to the one-third of global incremental production. That shows us the great effort of the U.S. shale gas industry to remain in the "game" and continue to be a leading producer.

The downturn in global oil and gas prices has caused a major slowdown in the development of natural gas resources and made the regional markets more competitive to each other than five years ago. In fact, many of the proposed upstream projects that were described as costly, difficult, or problematic have been put in hold because companies no longer have the capital resources or motivation to develop deposits in challenging environments[53]. The recent low oil and gas price environment has decelerated the development and exploration of new discoveries, also pushing the region of South-Eastern Mediterranean to find new markets for its natural gas exports: markets, like Asia, which would pay a higher bid than that of Europe's for its natural gas giving the opportunity for the region to arbitrage. Egypt for example, which has ever been the largest producer of the region, its production rates dropped to 45.6 Bcm in 2015 from the high 62.7 Bcm in 2009 (17.76% decline). The main reasons behind the production decrease are: the decreasing offshore resources, political unrest and domestic policies. Finally, according to LNG World News (2016)[98] the country is targeting to reach between 5.5 and 6 Bcf/day by the end of 2019.

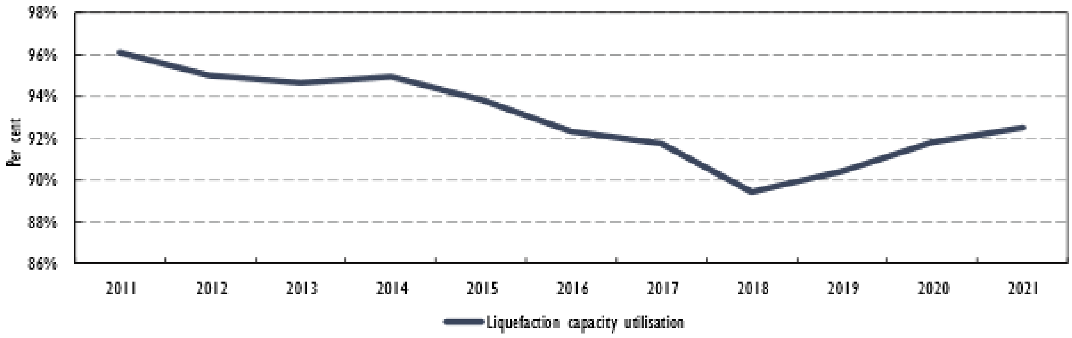
However, one would ask "How could the U.S., a net importing region, manage to turn into a major exporter, despite the low oil and gas price environment?" The answer lies in the cost-competitiveness of its liquefaction plants. In terms of cost, to turn a regasification plant into a liquefaction plant requires huge capital investments. However, the U.S. managed to exploit the already existing infrastructure and network of processing plants, pipelines, storage and loading facilities instead of started building new ones. According to (E.I.A, 2012) these existing facilities reduced greatly the costs relative to those that would be incurred by a "Greenfield" LNG facility. Regarding cost competition, many of the currently proposed liquefaction plants globally are integrated standalone projects that would produce, liquefy, and export stranded natural gas. Therefore, these projects would require much more new developments, entailing not only the construction of the liquefaction plant from the ground up, but also storage, loading and production facilities, as well as pipeline and natural gas processing facilities. While the additional developments for integrated standalone projects adds highly to their cost, they can be sited at locations where they can make use of inexpensive or stranded natural gas resources that would have minimal value independent of the project. Furthermore, while these projects may require processing facilities to remove impurities and liquids from the gas, the value of the separated liquids can improve the overall project's economics. On the contrary, liquefaction plants proposed for the lower-48 U.S. are going to use pipeline gas drawn from the largest and most liquid market in the world. Natural gas in the U.S. pipeline system has a much greater inherent value than stranded natural gas, and most of the valuable natural gas liquids have already been removed.

According to trade theory, in the long-term, as market players locate and seize arbitrage opportunities, prices will adjust to the point that there will be no additional trade (Medlock, et al., 2012). Thus, we must consider the possibility that not all export proposals that seek certification approval will get the green light. For example, Eni's "Coral FLNG", which has originally expected to take FID in 2015, has been delayed.

[53] The prices are so low that cannot replace the production and exploration costs of these projects.

Furthermore, it is possible that at least some export capacity will remain underutilized. Because of oversupply, the demand growth will not be fast enough to absorb new supply quantities coming on stream by these major liquefaction projects the next two years. So, there is going to be underutilization of LNG export plants. **Figure 18** represents the utilization rate of liquefaction terminals from 2011 to 2021.

Figure 18 Liquefaction utilization rate



<u>Source:</u> IEA, Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021

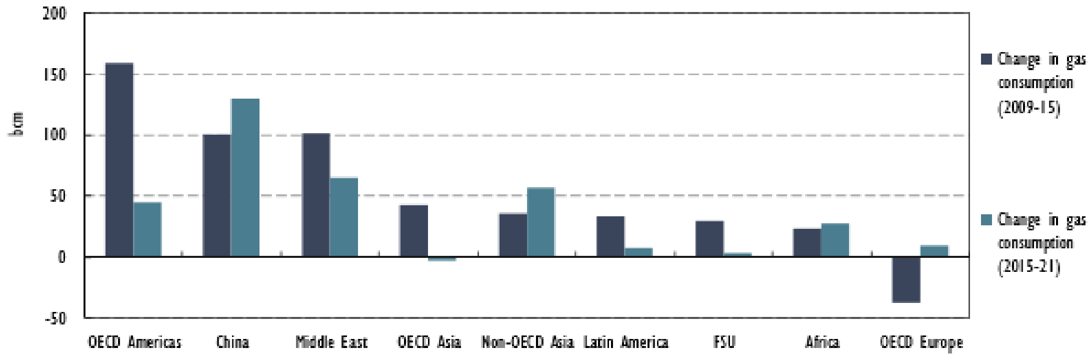
From the above figure, we can assume that the oversupply will keep up until 2018, when the new regasification projects will come on line and start absorbing the excess supply, pushing slowly the average plant utilization rate up. Meanwhile, the sharp cutback of investments in upstream activities could create feed-gas problems in producing countries. That means, returns on investments will be low and the market will get tightened (I.E.A., 2015).

2.1 Demand

Figure 19 shows the change of natural gas consumption growth in the various regions of the world. Over the prior six years, has been observed an increasing growth rate of global natural gas demand by 2.5%. Most of the increased demand growth was driven by North America (160 Bcm), Middle East (100 Bcm) and China (100 Bcm). On the other hand, growth in global gas demand is projected to decelerate to 1.5% (340Bcm) for the next five years (I.E.A., 2016). The current state of demand shows a slower primary energy demand growth and the decline in the energy intensity of the global economy are slowing demand growth for natural gas; the energy transformation in China and subdued economic growth in Europe are putting up against energy demand growth; in Middle East, lower oil prices, and therefore slowed economic activity, impact negatively the trajectory for gas demand in both the power generation and industrial sector. That means the share of natural gas in the world's energy mix is going to increase marginally, despite slower global gas demand growth.

Additionally, one of the most influential factors for slower gas demand growth is the oil price. Due to the oil-linkage on the majority of global natural gas trade, natural gas is highly dependent on the trajectory of oil prices. However, because of the long-term contractual nature of natural gas its price has a time-lag until it starts following oil price's trajectory. The result of that time-lag is a loss of competitiveness for gas and a broad-based substitution towards oil products, especially in the industrial sector. Finally, with oil prices bottom out and domestic gas prices closing the gap to international benchmarks, industrial gas demand will probably recover (I.E.A., 2016).

Figure 19 Change in natural gas consumption by region

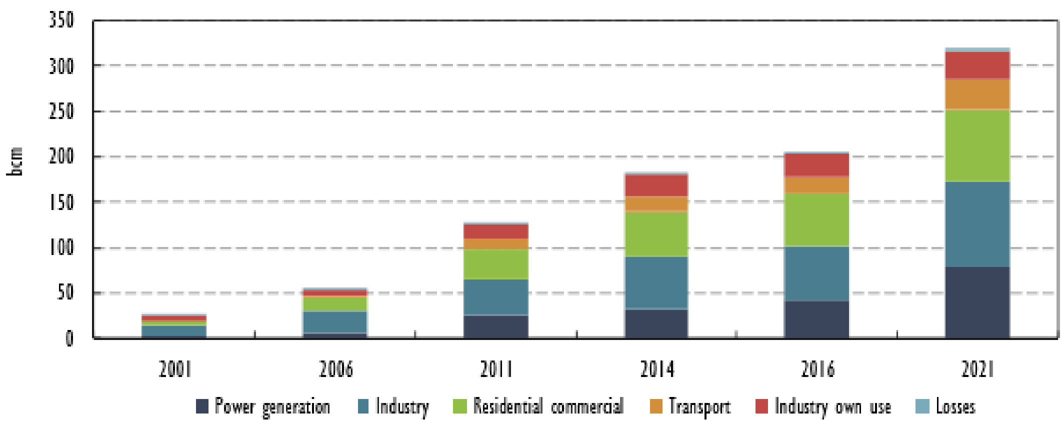


Source: I.E.A., Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021

It is well known that Japan is the largest consumer of LNG in the Asian markets due to the change its energy mix and the shutdown of nuclear plants after the Fukushima accident. The increased demand for imported LNG from Japan created a sharp increase in the spot LNG price in Asian markets. On the other hand, the emergence of U.S. LNG exports projects with prices linked to Henry-Hub has provided the Asian market with the alternative option to buy LNG in a different, yet more attractive, price formation mechanism than that of the expensive J.C.C. But, imports from the U.S. will not be the best solution for Asia in the long-term; it only safeguards its current requirements in a better price. In the long-term the most preferable option for the Asian gas market is the creation of a liquid regional hub, which would reflect the fundamentals of the market from the demand side and the global availability of spot/flexible LNG on the supply side (Stern & Rogers, 2014). However, Asia does not have an internal sufficient network of liquid hubs based on pipeline trading like those of North America's and E.U.'s, and its market is far from liberalization. Therefore, a hub could be created in the basis of LNG trade. It is worth mentioning that from 2015 onwards, the arrival of additional LNG supplies from Australia, and possibly from 2018 onwards significant volumes from the U.S., Russia, Canada, and East Africa should bring enough liquidity to Asia's LNG markets, thus, assisting in the development of a LNG trading hub, and the creation of a stronger linkage to European natural gas trading hubs in terms of price (Fattouh, et al., 2015).

China is going to play a very important role in absorbing a huge quantity of oversupply in the next five years. Besides, if Chinese gas consumption fails to pick up, global gas markets will remain oversupplied for much longer than it is expected. Finally, the International Energy Agency (I.E.A., 2016) expects that "lower gas prices, environmental regulation and large LNG contractual obligations on the part of China's state-owned companies to underpin consumption, despite a weakening economic outlook". China is also expected to emerge as the key destination in Asian markets for LNG trade and it is also the key global natural gas growth market. Its future import requirement is going to be large, but uncertain at the same time: there are many new LNG import projects coming online for the next five years, but the lack of information transparency makes future demand requirements difficult to judge (Stern, 2014). The LNG component of supply meeting these demand requirements is subject to additional uncertainties about the Chinese domestic gas production, and pipeline import volumes from Myanmar, Turkmenistan and Central Asia, and from East Siberia, following the recent signing of an agreement with Gazprom for 38 Bcm/year of pipeline gas beginning in 2018 (Fattouh, et al., 2015). According to **Figure 20**, China's gas demand is projected to increase 9% annually from 190Bcm to 320Bcm in the period 2015-2021. The main three factors that contribute in the increase are: the relative prices of oil and gas, the large LNG contractual position of both CNOOC and SINOPEC, and the diversification of the country's energy mix towards a more efficient and environmental friendly use of energy.

Figure 20 Gas demand in China by sector, 2001-2021



Source: I.E.A., Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021.

Figure 19 represents the changes of natural gas demand in China's sectors from 2001 to 2021. A major change in natural gas demand growth rates from western to eastern markets (i.e. China) for the next five years. Global demand is forecast to increase by around 340 Bcm/year and is mainly driven by China, which accounts for more than the one third of the global consumption (I.E.A., 2016). Per forecasts from C.N.P.C. (China National Petroleum Corporation) based on China's 12th F.Y.P., the projected Chinese natural gas consumption will reach 400 Bcm/year by 2030[54]. While industrial activity is slowing, Chinese gas demand benefits from ongoing efforts to diversify its energy mix away from coal and address local air quality: China is one of the leading countries in the list of "coal dependency". Coal prices may be lower than these of natural gas, but coal's side effect on the climate is clearly harmful when its consumption for power generation reaches the level of 70%. Faced with extreme pollution challenges and public health issues, China decided an urgent reform of its energy policy and turned to consumption of natural gas for power generation, which is obviously less pollutant and more environmental friendly in terms of greenhouse gas emissions. Additionally, these changes in its energy mix will definitely lead to the creation of new gas markets for power generation and residential sectors: ample supply capacity should facilitate coal-to-gas substitution. Additionally, gas-fired generation expands robustly despite the stagnant growth in electricity generation, reflecting the government's efforts to increases gas's share in the country's energy mix[55]. Overall, the prospect for China to absorb a huge amount of the excess supply is definite and along with a variety of "emerging" suppliers will safeguard its concerns of energy security.

2.2 Supply

2.1.1 "Traditional" suppliers of natural gas

Russia

Russia is one of the world's most resource-rich countries. In 2012, the value of the country's natural resources was at $75.7 trillion, of which natural gas reserves (1,680 Tcf) were at $19 trillion[56] presenting 26% of its total natural resources value. According to (B.P., 2016), total proven reserves of natural gas in the end of 2015 were at 1,139.6

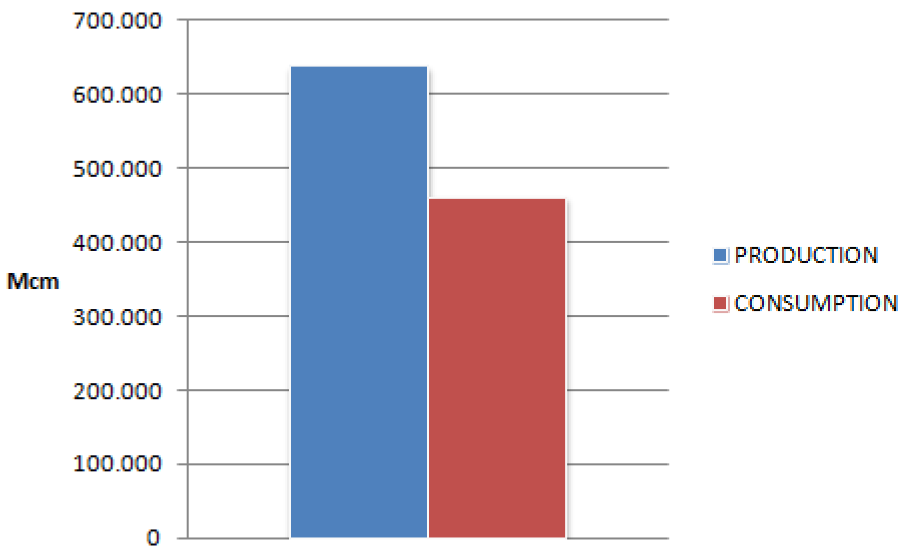
[54] D. Zhaofang (2010), "China's Market Outlook", *Research Institute of Economics and Technology*, Beijing, China, available from: http://eneken.ieej.or.jp/data/3561.pdf.

[55] According to the 12th F.Y.P. to 2015, the 18% of the Chinese population will have access to a domestic gas supply.

[56] M. B. Sauter, C. B. Stockdale, P. Ausick (2012), "The World's Most Resource-Rich Countries", *24/7 Wall St.,* available from: http://247wallst.com/special-report/2012/04/18/the-worlds-most-resource-rich-countries/.

Tcf. Russia is the second largest producer of natural gas worldwide and its natural gas rents as a percentage of GDP reach 0.52%, which is quite low than that of 2012 (2%) and backwards, whereas oil rents were at 12.7% of GDP; 2% lower than that of 2012 (14.86%)[57]. That means Russia is trying to diversify its economy dependence on natural resources, because its economy is highly dependent on oil and gas revenues. In fact, oil and gas revenues accounted for 43% of its total federal budget revenues in 2015. Additionally, Russia's revenues from natural gas exports accounted for about 13% of its total export revenues[58]. Russia's production in 2015 was at 637,875 Mcm, while its consumption reached 461,487 Mcm. **Figure21** shows the comparison between Russia's natural gas production and consumption in 2015. According to I.E.A. (2016), Russia's natural gas consumption decreased by 1.5% year-on-year due to falls in the power generation's gas consumption by 10 Bcm, and economic contractions.

Figure21 Russia's production & consumption in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

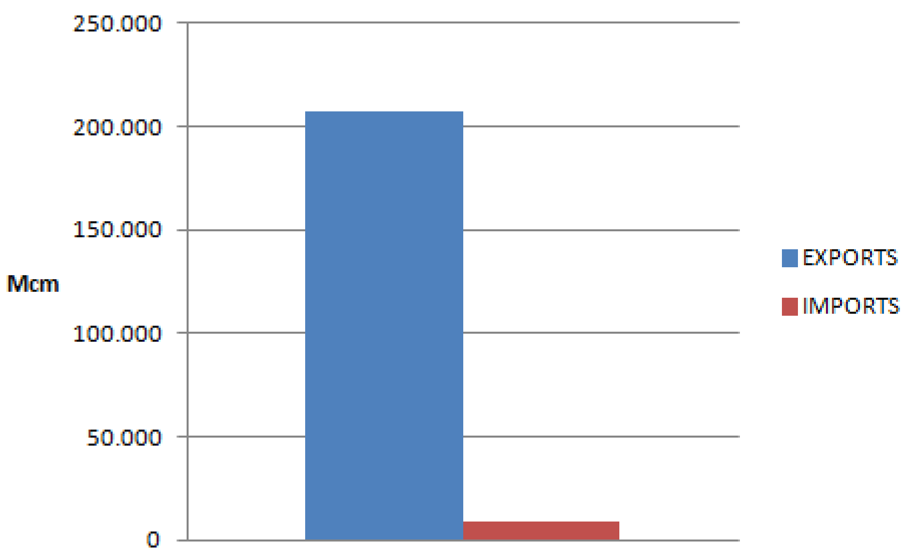
While Russia depends exclusively on oil and gas exports to Europe as a market, the "emerging" U.S. LNG exports may cut off share form Russian natural gas exports to Europe. In 2015, more than 75%[58] of Russia's natural gas exports went to Europe. Russia's total exports in 2015 amounted to 207,000 Mcm, of which the 6.76% (14,000 Mcm) was in the form of LNG, while its imports were at 8,799 Mcm. **Figure22** represents the comparison between Russia's total exports and imports in 2015. In addition, LNG exports from Australia and the Gulf States will robustly increase global supply, leaving Russia completely exposed to competition. However, Russia was opting for a more competitive strategy to continue being a major supplier of energy

[57] http://data.worldbank.org/indicator/NY.GDP.NGAS.RT.ZS?locations=RU.
[58] http://www.eia.gov/beta/international/analysis.cfm?iso=RUS.

resources to Europe during the last decade. In fact, Gazprom has expanded its market to more countries in the western regions by investing in pipeline and storage facilities. It also preserves a (quasi-)monopoly in most central eastern markets, remaining as a leading exporter to the EU. However, EU-Russia energy relations remain purely transactional, conducted by companies (Fernandez & Palazuelos, 2014). Furthermore, while Russia itself has a big interest in maintaining its energy export in Europe, it signs long-term gas deals with China to differentiate its export dependency on European demand. In a more interconnected and globalized natural gas market, where there is enough flexible LNG for arbitrage to link European gas trading hubs and Asian LNG spot prices, the response of Russia is of pivotal role. With Asia continuing to attract flexible LNG away from Europe, Russia's market power rises as its pipeline exports to Europe increase; thus, Russia can achieve a higher level for European hub prices by supply management (Fattouh, et al., 2015). In summary, two are the main parameters of Russian impact, which will affect global and especially European market fundamentals:

- Russia's ability to "balance the system" at a physical level, through managing export levels, and thus providing a "buffer" to the global LNG system.
- Its consequent ability to influence the level of European hub prices.

Figure22 Russia's total imports & exports in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

According to Gazprom's management report in 2008[59], the company plans to upgrade production and transmission systems in Eastern Siberia in order to start

[59] Gazprom (2008), "Management Report OAO Gazprom", available from: http://www.gazprom.com/f/posts/71/879403/2gmr.pdf.

exporting to China. Russia has planned to build to build pipelines to China and South Korea from producing wells in East Siberia and to Japan and South Korea from the Shakalin Islands. According to (Troner, 2000), preliminary estimates indicate that proven and probable gas reserves in Shakalin islands could be as high as 50-65Tcf, making them quite competitive against other substantial regional natural gas suppliers like Indonesia, 35 Tcf for Yakutia and 50-150 for East Siberia. These projects can easily contribute to the diversification of imports in Japan, China and South Korea away from the Gulf States with the possibility of rigid alterations in Asian LNG pricing schemes. It is obvious that after the Ukrainian gas crisis, Russia is going to diversify its exports and targets to strengthen its geopolitical role in the growing Asian gas markets. Russia sees that Asian demand offers a major growth opportunity for its export capacity in comparison with a more stable and slow paced growth in European markets in which U.S. LNG imports will be extremely competitive. Russia's RPR indicates that in the end of 2015, along with its production rates at that time have proved reserves to support more than 50 years of total global demand. It is worth mentioning that U.S.G.S. (United States Geologic Survey) in 2012[60] reported a mean estimate of undiscovered, technically recoverable natural gas resources of 1,623 Tcf and a mean estimate of 31,786 million barrels of natural gas liquids. It is sure that Russia is going to use its geographical advantages to ensure dominant positions in the Asian markets in terms of natural gas prices. Additionally, the growing demand needs of Asia are likely to cause additional exports from Russia considering the vast spare capacity of its reserves.

Regarding prices, one must consider the high risk at stake: can these future investment decisions be successful (in terms of returns of investment) in a low-price environment? In 2014, crude oil prices decreased from 115 $/barrel to below 70 $/barrel, due to higher production output and weak demand[61]. Natural gas prices are indexed by oil prices in the most of Russia's long-term supply contracts, meaning that they will also decrease. In addition, as I mentioned before, oil and gas account for 43% of its federal budget. It is also evident that Russian economy is reeling from the impact of lower oil prices and economic sanctions[62]. In November 2015, the total impact of

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[60] USGS (2012), "An Estimate of Undiscovered Conventional Oil and Gas Resources of the World 2012", *World Petroleum Resources Project,* available from: https://pubs.usgs.gov/fs/2012/3042/fs2012-3042.pdf.

[61] The Economist (2014), "Why the Oil Price is Falling?" available from: http://www.economist.com/blogs/economist-explains/2014/12/economist-explains-4.

[62] The first economic sanctions against Russia were introduced in March 2014 after its annexation of the Crimea and were gradually stepped up over the year. Participants include the EU and EFTA countries, the U.S., Canada, Australia, New Zealand and Japan. Restrictive measures include:

- Freezing assets of persons and companies close to the Russian leadership
- Severely limiting access by the main Russian banks and companies in the energy and defense sectors to EU and US financial markets
- Banning exports of technology and equipment useful to the defense and energy sectors.

lower oil prices and economic sanctions was estimated by Finance Minister Anton Siluanov at $130-140 billion a year (around 7% of GDP): $90-100 billion from reduced oil revenue (based on oil prices of 80$/Barrel) and $40 billion from sanctions[63]. It is quite clear then, that the falling oil and gas prices will affect Russia's energy investments and will have tremendous consequences to its economy. All in all, countries with dependency on high oil pricing to cover expenditures bring high risks of economic failure when the pricing environment is unstable: having fallen below 50 $/barrel at one point, in February 2015 crude oil was at 55 $/barrel and in October 2016 fluctuated at 50 $/barrel[64]; with global oil stocks still rising, volatility is likely to continue in the short-term. In the other hand, Russia should address its structural problems in order to achieve stable growth, because oil-driven growth is limited by the fact that production capacity cannot be expanded indefinitely, especially in the view of the current lack of investment due to low oil prices (Russel, 2015).

Qatar

Since the 70s, natural gas has become quite attractive in the Gulf's domestic economies as a main fuel for power generation and water desalination sectors, and as an increasingly popular feedstock for the petrochemical sector. Additionally, natural gas plays an important role in the region's diversification policies, which are based on energy-intensive industries. Robust population growth in combination with large-scale urbanization and low regulated prices for power generation, have contributed to the expansion of domestic gas consumption (Fattouh & Stern, 2011). Qatar has ever been a "traditional" and a globally dominant supplier of LNG since 2006[65]. Qatar is the fourth-largest natural gas producer and the largest LNG exporter currently (I.E.A., 2016). **Figure 23** depicts Qatar's GDP rates of each economic activity in 2012. Natural gas and crude oil accounted for 57.8% of GDP in 2012. In that direction helped the development of the major "North Field", which has been discovered by "Shell" in the 1971 and is the largest non-associated gas field[66] internationally. The developments of its natural gas reserves along with its major petrochemical industry have boosted the production of condensates and NGLs to 900,000 barrels per day in 2012, exceeding its crude oil production. Qatar started exporting LNG in 1996 and has ever been one of the leading exporters globally. In 2013, global gas imported capacity was at 236.9

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[63] J. Bush, A. Winning (2014), "Russia Puts Up Losses from Sanctions, Cheaper Oil at Up to $140 Billion per year", *Reuters*, available from: http://www.reuters.com/article/us-russia-siluanov-idUSKCN0J80GC20141124.

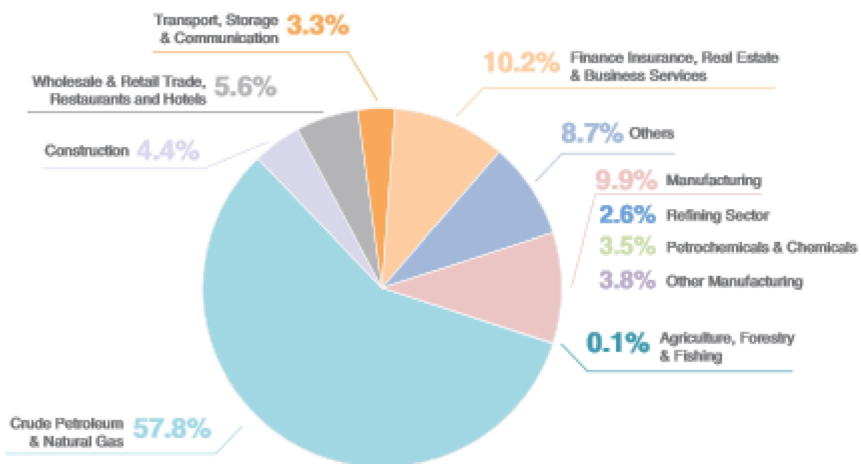
[64] B. Sharples, "Oil Trade Near 3-Week Low as U.S., Gulf, East Coast Supply Rises", *Bloomberg,* available from: http://www.bloomberg.com/news/articles/2016-10-26/oil-near-three-week-low-after-inconsistent-u-s-supply-decline.

[65] QNB (2013), "Qatar Economic Insight", available from: http://www.gulfbase.com/ScheduleReports/01827aac_Qatar-EconomicInsight2013.pdf.

[66] The gas from the "North Field" is a "wet" gas field, which means it contains significant amounts of natural gas liquids and condensates such as ethane, propane, butane, and higher alkanes.

MT, of which Qatar represented the 33% (78.17 MT) of global gas supplies, followed by Malaysia 11% (26.05 MT), and Australia 10% (23.69 MT)[67]. However, it is probable that Qatar will face fierce competition from developments of conventional and unconventional natural gas resources around the globe, as well as from new liquefaction projects in North America, particularly the U.S., Australia, East Africa, and Russia. As I stated in previous units, this new competition of supply is going to put pressure on LNG prices, especially spot LNG, and on long-term pricing formation mechanisms. These trends will impact Qatar's dominant position as a "swing supplier" between European and Asian markets, alter its current arbitrage conditions, and have an impact in its fiscal revenues due to its dependency on energy resources exports. Yet, its fiscal buffers along with its vast resource base will facilitate the adjustments to the new market conditions (Fattouh, et al., 2015). According to (I.E.A., 2016), the government declared radical reforms to its subsidy and tax system, to cope with the impact of low oil and gas prices. Qatar has been able to balance its LNG market share between the Atlantic and Pacific basins by selling volumes to Europe when Asian prices are low, and to Asia when European prices are low but still continues placing LNG loads in Europe to support Asian prices acting like a "discriminatory monopolist" (Allsopp & Stern, 2012): it has the option to distribute its supply between Asian markets of high gas price but with low price elasticity and European markets of low gas price but with high price elasticity. Additionally, according to (Fattouh, et al., 2015), "Its optimal solution is to restrict supply to the high price market (Asia) to secure higher margins. Diversion of a greater quantity from the low-price market (Europe) would significantly reduce the premium market price (Asia) with little compensating increase in the European market price".

Figure 23 GDP (current prices) by main economic activities (2012)



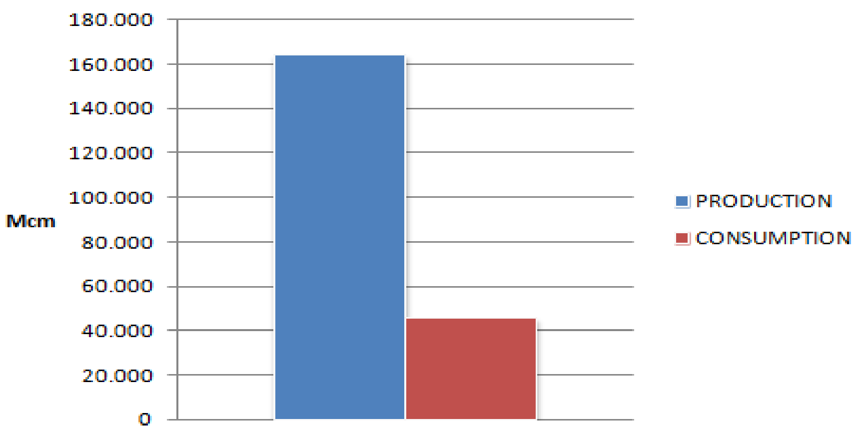
Source: National Statistic Authorities, GPCA Analysis, 2013

[67] GIIGNL (2013), "The LNG Industry in 2015", Paris, available from: http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_the_lng_industry_fv.pdf.

Qatar's strategic geographical position between Europe and Asia the major consuming regions of natural gas globally, along with the ability to export LNG, Qatar has ever had great opportunities for arbitrage between these two regions. For example, Qatar has the ability sell LNG to Europe when prices in Asia are low and to sell in Asia when its prices are high. On the other hand, U.S. and other emerging exporters like Australia are going to challenge Qatar's ability to price discriminate by turning it into a "price taker". Qatar may develop a more liquid and responsive arbitrage dynamic between European and Asian markets for spot cargoes based in the changing global environment: in 2015, 32% of global LNG volumes were still supplied by Qatar and remained the main supplier of short-term and spot quantities at 20.3 MT (2 MT increase from 2014), followed by Nigeria at 12.7 MT and Australia at 6 MT[68].

Qatar's production of natural gas in 2015 was at 163,994 Mcm, while its consumption amounted at 45,580 Mcm. **Figure 24** shows the comparison of Qatar's natural gas production and consumption in 2015. Even in a low-price environment, in 2015, Qatar has witnessed positive trends for its production and its consumption by 4.2% and 13.8% respectively from 2014. Qatar's robust rising consumption benefits from economic development, supply availability, rising living standards, diversification into energy intensive industries, and low domestic prices. The main sectors responsible for most of the increase in gas consumption are: power generation and water desalination sectors, GTL (Gas-to-Liquids) sector[69], and the petrochemical sector. Regarding power generation and water desalination sectors, they constitute a major part of the country's gas consumption and heavily rely on natural gas supplied by "QP".

Figure 24 Qatar's production & consumption comparison in 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

[68] GIIGNL (2016), "The LNG Industry in 2015", Paris, available from: http://www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2016_annual_report.pdf.
[69] Qatar is a major producer of Gas-to-Liquid products, accounting for nearly three-quarters of global GTL capacity due to the vast wet gas "North Field".

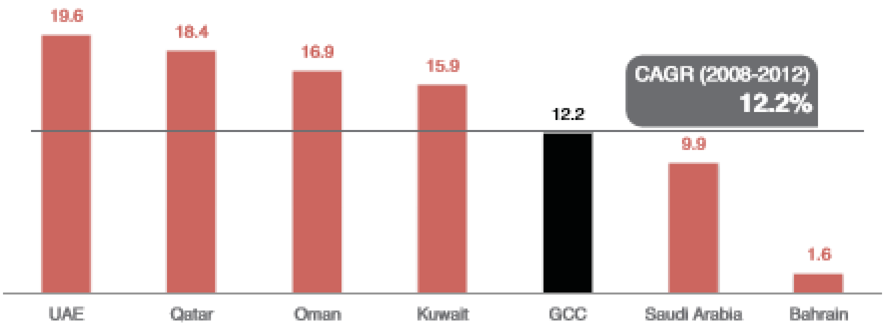
Qatar has the highest per capita water consumption in the world, with total consumption recorded at 216 m^3 per person in 2012[70]. Furthermore, because of the country's high GDP growth rates and population boost, power consumption has increased by a compound annual growth rate of 9.3% between 2001 and 2011, and its installed power generation capacity doubled in two years from 2009, thereby increasing total domestic demand for gas[71]. A trend continued until today due to its economic development, and increased infrastructure investments: to satisfy its robust growth in power generation sector, the country continues to invest in additional power generation capacity. In 2014, Q.E.W.S. (Qatar Electricity and Water Company) planned to expand its production capacity by building a plant with an installed capacity of 2,400 MW of power and 130 million gallons of desalinated water[72]. Regarding its reserves of natural gas, BP (2016) estimated that in the end of 2015 Qatar held the amount 866.2 Tcf that represents the 13.1% of global proved reserves, the third behind Iran (18.2%) and Russia (17.3%). According to production conditions and proved reserves in 2015, Qatar's RPR shows that its reserves may well hold for at least the next 150 years.

Qatar's petrochemical sector is one of the largest globally due to the size and nature of its gas reserves, and in combination with its low-cost energy structure, and its stable regulatory and business environment, the country managed to create a strong competitive advantage over that of its neighboring countries as well as against global competitors. According to "Gulf Petrochemicals & Chemicals Association" (2012)[73], from 2008 to 2012 Qatar was the second largest producer of basic petrochemicals[74] in the G.C.C. (Gulf Cooperation Council)[75] after Saudi Arabia. In fact, in 2008 Qatar produced 2.2 Mt and in 2012 4.2 Mt: the establishment of new producers and capacity expansions by the already existing producers has led to an average increase in capacity by 17.5% annually. Furthermore, Qatar has increased its share in the total G.C.C. petrochemical capacity expansion from 12.3% in 2008 to 15.3% in 2012, and its petrochemical capacity grew by 18.4% well above the GCC's C.A.G.R. (Compound Annual Growth Rate) of 12.2%. **Figure 25** represents the compound annual growth rate of the petrochemical production in the Gulf Cooperation Council from 2008 to 2012. The growth rate in that period was impressive and the driving factor for that increase has been the country's competitive gas

[70] A. Lane (2013), "Qatar Water Consumption 'Highest in the world'", available from: http://www.utilities-me.com/article-2309-qatar-water-consumption-highest-in-the-world/1/print/.
[71] Gulf Times (2013), "Qatar's Installed Power Capacity Doubles in 2 Years as Demand Rises", available from: http://www.gulf-times.com/story/347661/Qatar-s-installed-power-capacity-doubles-in-2-year.
[72] QNB (August 2014), "Qatar Monthly Monitor", available from: http://qnb.co.id/img-file/148421document(51).pdf.
[73] GPCA (2012), "GCC Petrochemicals & Chemicals Industry: Facts & Figures 2012", available from: http://www.gpca.org.ae/adminpanel/pdf/ff12e.pdf.
[74] Ethylene, propylene, methane, benzene, toluene, xylene. Butadiene, butylenes.
[75] The Member-States of the GCC are: U.A.E., Qatar, Oman, Kuwait, Saudi Arabia, and Bahrain.

feedstock low-cost of \$0.75-\$1.00 per MMBtu. In terms of GDP, Qatar is the world's fastest growing economy with real GDP growth of 12% between 2008 and 2012. As for its petrochemical sector, it represented 9.9% **(Figure 23)** of the country's nominal GDP in 2012 and was estimated at the value of \$6.7 billion. It is worth mentioning that, according to Qatar's national development strategy to 2016, its petrochemical industry is of major significance for its "diversification policy", which is considered to be a driving factor for a sustainable and stable economic growth, job creation, and for the protection of the country's economy from the extreme volatility of commodity prices: "Qatar will leverage its cheap domestic feedstock and energy to the expansion of its productive base and long-run diversification"[76].

Figure 25 CAGR of GCC petrochemical production capacities (2008-2012).



Source: Gulf Petrochemicals & Chemicals Association (GPCA), 2013

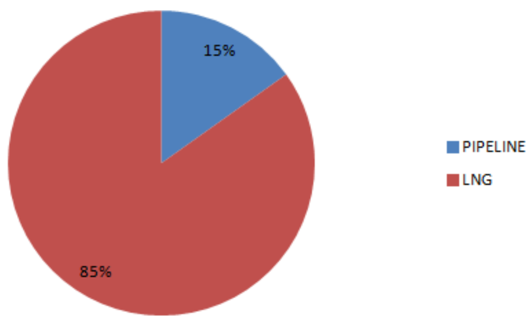
From **Figure 26** we observe that Qatar's main export activities are in the form of LNG. In fact, LNG share of exports were at 84.85% of total exports (106,400 Mcm), whereas pipeline share at 15.15% of total exports (19,000 Mcm). Qatar has a highly developed system of liquefaction infrastructure that underpinned the high exporting volumes of LNG. The country's large N.O.C. (National Oil Company) "Qatar Petroleum", which is responsible for the development of its oil and gas sector, has two sector subsidiaries companies "Qatargas" and "RasGas". These two companies developed five LNG trains from 1996 to 2000, and up until 2010 had had fourteen LNG export trains that brought total liquefaction capacity in Qatar at around 105 Bcm. Additionally, these trains have taken FIDs in a past time when the unit costs for LNG plants were lower, and also their average costs were quite lower with other LNG projects at the same period. In fact, in December 2010 "Bank Audi" estimated the break-even prices at \$12.8 per Bbl of oil and at \$1.6 per MMBtu of gas that were going to shield "RasGas" revenues from potentially severe downturns in global commodity

[76] Qatar's National Development Strategy 2011-2016, available from : http://www.mdps.gov.qa/en/knowledge/HomePagePublications/Qatar_NDS_reprint_complete_lowres_16May.pdf.

markets[77]. Additionally, in December 2015 "Fitch" [78] stated that Qatar's LNG projects can withstand oil prices of $30 per Bbl or below due to their high financial flexibility, and estimated a break-even oil price in 2016 to 2018 of $27 per Bbl, which is equivalent to a LNG price of $2.7 per MMBtu[79]. From what was stated before, we see that Qatar has ever been and remains one of the lowest-cost producers even in a low oil and gas price environment, in comparison to other competitors such as Australia. Regarding regional gas exports by pipeline, they remain limited despite its huge production levels and its key role in satisfying the growing demand of its neighboring countries. With much higher profits from global LNG trade instead, Qatar finds it unattractive to sell low-price pipeline natural gas to rapidly growing domestic and regional gas markets. Furthermore, political unrest between Qatar and its neighbors keeps the development of a wide G.C.C. natural gas grid at bay. According to (Fattouh, et al., 2015), "The most realistic option is to use the additional gas for developing future LNG projects" instead of selling it as excess capacity to its regional neighbors in order to satisfy their constantly growing demand. Moreover, because of "economies of scale" in the LNG industry, and due to the high cost escalation of liquefaction projects, the development of additional LNG infrastructures is going to depend on the following driving factors:

- The current project cost of new upstream units and facilities for wet gas production from the "North Field".
- The current cost of new liquefaction trains.
- The extent in which the coproduction of NGLs and condensate aid these investments.
- The attraction of the de-bottlenecking project of the already existing trains.

Figure 26 Share of pipeline & LNG in Qatar's exports in 2015



Source: I.E.A. (2016), Natural Gas Information 2016

[77] Bank Audi (2010), "Ras Laffan Liquefied Natural Gas Co.", available from: http://www.bankaudigroup.com/GroupWebsite/openAudiFile.aspx?id=831.

[78] Fitch Ratings (2015), "Fitch: Middle Eastern Oil & Gas Projects to Withstand Low Oil Prices", available from: https://www.fitchratings.com/site/pr/996545.

[79] These price levels represent a conservative estimate of break-even resiliency, reflecting conservative assumptions for LNG prices and stresses to operating costs, output levels, and stable tax and royalty calculations.

Overall, Qatar's strategy of LNG sales has been quite successful providing a high comparative advantage in the global LNG markets. That success can be seen because of the following significant reasons (Fattouh, et al., 2015):

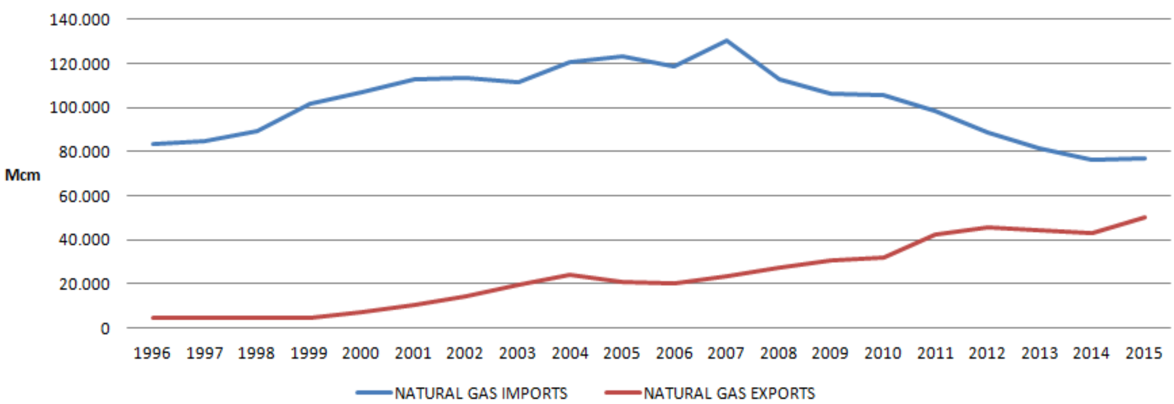
- The majority of Qatar's volumes have been sold under long-term contracts to Asian buyers at prices linked to crude oil (JCC).
- Significant volumes are under contract with buyers in Southern Europe at prices linked to the prices of oil and/or oil products.
- Qatar has been able to redirect spot[80] volumes away from Europe[81], towards spot sales in Asia, the Middle-East, and South America, where spot prices have been above even Asia's long-term contracts.
- The ability to optimize cargo deliveries between Europe and "premium" markets has helped to maintain high LNG spot prices in Asia, South America, and the Middle-East, which is consistent with Qatar's ability to exercise market power.

2.1.2 "Emerging" suppliers of natural gas

U.S.A.

One of the "key players" in global natural gas trade is the U.S., which has been exclusively a net importer of natural gas from the early 2000s (115.99Bcm), where there was the first robust upswing in imports, until 2007 (158.10Bcm), where it was the peak of import capacity till today. Form 2007 onwards, it became a huge exporter (I.E.A., 2016). **Figure 27** represents the development of the U.S. natural gas imports and exports from 1196 to 2015.

Figure 27 U.S. Imports & exports time series from 1996-2015 (Mcm)

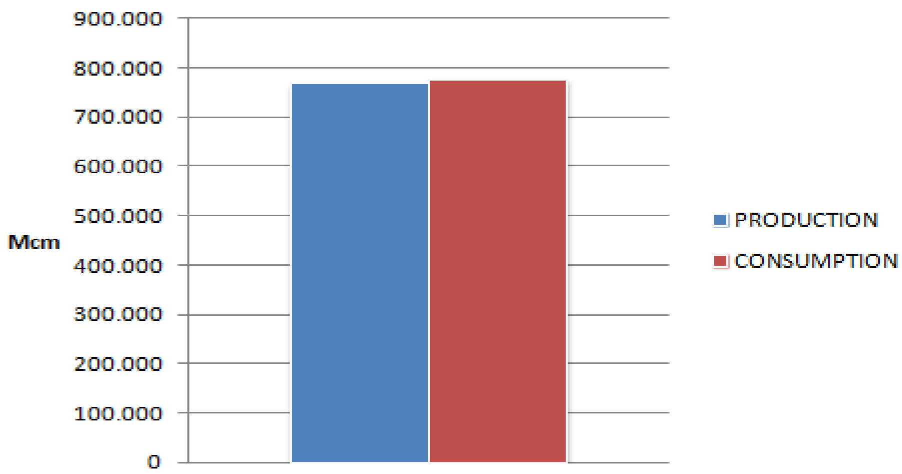


Source: I.E.A. (2016), Natural Gas Information 2016

[80] Uncontracted and contracted but with some flexibility.
[81] Where, hub prices since 2008 have been lower than oil or oil products-linked LNG prices.

The most important factor that contributed in making the U.S. energy sufficient and a huge exporter of natural gas was the development of domestic shale gas plays. In 2015, close to 50% of U.S.A. gas production and 100% of growth, originated from shale plays. Additionally, the U.S. total production in 2015 was at 768,975 Mcm, while its consumption totaled at 777, 970 Mcm. **Figure 28** shows the comparison between U.S.'s production and consumption of natural gas in 2015**.** Its production growth rate in 2015 has been increased by 5.5% from 2014, which was more modest than that of 2014 (+6.29% from 2013 to 2014) due to the falling oil and gas prices. Its consumption growth rate has been increased by 3.1% from 2014, because of the higher use of gas in the power generation sector. The consumption growth in 2014 was increased by 2.07% from 2013, and it was a more modest increase in comparison to the current growth. Also, in 2014, the use of gas for power generation was at 206.35 Mtoe. In 2015, the U.S. imports totaled at 76,966 Mcm, of which 74,375 Mcm (96.63%) was by pipeline and the rest 2,591 (3.37%) in the form of LNG (I.E.A., 2016). In general, O.E.C.D. Americas increased their imports by 7 Bcm, mainly because of the decline in Mexican production and its resulting need to import from the U.S.

Figure 28 U.S.'s production & consumption in 2015 (Mcm)



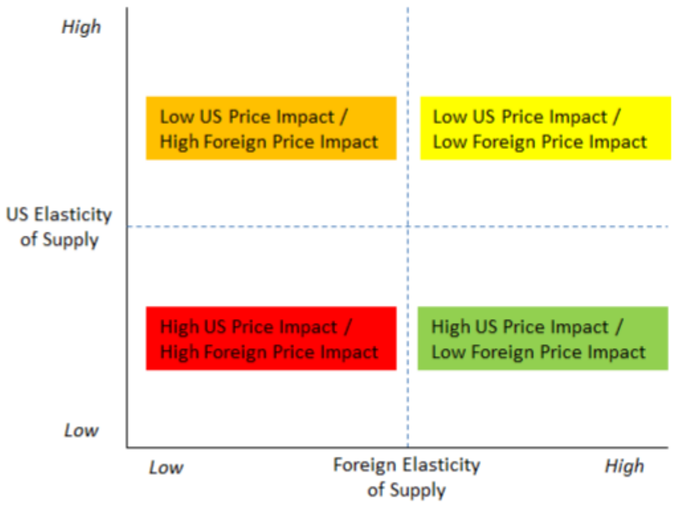
Source: I.E.A. (2016), Natural Gas Information 2016

United States have quite abundant resources of shale gas (E.I.A, 2011) and with the help of advanced technological breakthroughs such as hydraulic fracturing (vast unconventional resources unlocked), horizontal drilling (increased amount of gas from a single pad) and improvements in seismic imaging (better information on drill locations), shale gas production has increased fivefold from 2006 to 2010[82]. Additionally, rising shale gas production has resulted in lower domestic natural gas prices for U.S.A. The evolution of shale gas created the ideal conditions for U.S.'s

[82] E.I.A. (2012), "U.S. Natural Gas Exports", available from: http://www.eia.gov/dnav/ng/hist/n9130us2a.htm.

domestic natural gas producers to begin exporting worldwide, because the anticipated domestic production far exceeded the domestic consumption requirements: shale gas production in the U.S. is projected to reach 12 Tcf per year by 2030, accounting to the 46% of the total U.S. natural gas production (E.I.A, 2011). The U.S.'s total reserves at the end of 2015 was at 368.7 Tcf, representing 5.6% of the total global reserves. Additionally, its RPR, according to the production rates of 2015, is at 14 years (B.P., 2016). Exactly that emergence of shale gas, the increasing oil prices during the past decade, and the globally rising demand for natural gas have turned the U.S. from a net natural gas importer to a net natural gas exporter, thus, creating opportunities of arbitrage due to the price differentials between large importers of natural gas (i.e. Europe, Asia, and Asia-Pacific). Henry Hub prices continue to remain lower than other regions. According to **Figure 31**, we see that from the mid of 2007 till 2015 the price on Henry Hub is in a constant lower level than Asian and European prices. Therefore, the U.S. will be in an advantage point to compete against leading LNG exporting countries such as Qatar. United-States may well-become a "swing supplier" between European and Asian markets, as U.S. LNG exports will be extremely flexible with the exclusion of destination-clauses. However, the impact of the U.S. LNG exports on prices needs to be considered in both the short and long term, especially in a sector where the investment process is relatively long and therefore, where the short-term elasticity of supply can be low even if the long-term elasticity is high (E.I.A, 2012). This impact can be seen in **Figure 29**, which show us the different scenarios for the U.S. domestic and foreign markets depending on the relative supply elasticity of the markets. In a situation where elasticity is high in both markets, then the price impact of any shift in supply or demand will be relatively low in both (top right quadrant), whereas if the price elasticity is low in both markets then the price impact will be high in both (bottom Left quadrant) (Henderson, 2012).

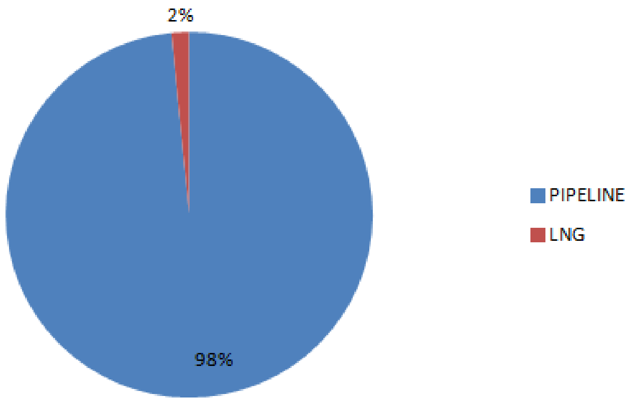
Figure 29 the potential impact of the relative elasticity of supply on prices in domestic and foreign markets



Source: J. Henderson (2012), "The Potential Impact of North American LNG Exports"

In addition to the flexibility, the huge loads of LNG that U.S. is going to export will lead to a more robust development of the spot LNG market around the globe. Taking into account, that Asian buyers seek more diversified pricing structures for their importing volumes, "traditional" LNG exporters, such as Qatar, will face pressure to offer more flexible price indexation than that of the U.S.'s Henry-Hub index basis as time develops. In 2015, exports reached the total volume of 50,415 Mcm, of which the 98% (49,633 Mcm) was by pipeline mainly to Mexico due to its declined production, and the rest 2% (782 Mcm) was in the form of LNG. **Figure 30** represents the share of pipeline and LNG exports in the U.S. in 2015.

Figure 30 Share of pipeline & LNG exports in the U.S. 2015



Source: I.E.A. (2016), Natural Gas Information 2016

Initially, it was not the factor of technology that caused this major shift from production of conventional to shale gas: technology is the mean through you can achieve that goal. The initial goal of U.S. was to reduce the highly carbon-intensive coal use in their energy mix. So, they decided to move to a higher proportion of consumption of domestic natural gas, mitigating the increase in greenhouse gases that would augment from rising U.S. energy use (Medlock, et al., 2008). Besides, environmental and energy policies are playing a huge role in determining demand and supply trends of an energy commodity. For example, the "Clean Air Act" amendments[83] in 1990 required the substitution of renewable fuels such as ethanol for gasoline. This substitution in the fuel mix served the Congress's environmental goal to reduce the emissions that contributed to photochemical smog[84]. In fact, the rules impose a fixed volume of renewable fuel use: thirty-six billion gallons or 2.35 million

[83] http://environmentallaw.uslegal.com/federal-laws/clean-air-act/.
[84] C. A. Moore, "The 1990 Clean Air Act Amendments: Silk Purse or Sow's Ear?", *Environmental Law and Policy Forum,* Duke's Law Scholarship, available from: http://scholarship.law.duke.edu/cgi/viewcontent.cgi?article=1207&context=delpf.

barrels per day by 2022[85]. The use of gasoline is also going to be reduced by the penetration of natural gas in the energy mix discussed above, increasing the natural gas supply. Another important factor that contributed in the U.S. supply rise, at least domestically, is the gas futures markets: by selling gas forward, upstream companies could increase their funding of exploration programs and eventually boost supply. Natural gas markets are mainly composed of large producers who want to sell production forward and large consumers who seek to fix their raw material cost. When gas markets in 1990 were deregulated along with the deregulation of electricity generation that began with the "Energy Policy Act" of 1992, gas futures underwent a great bloom. Independent firms that generated and sold electricity to traditional electric utilities used gas futures to cover the cost of their output when bidding to sell electricity at a fixed price: the firms could contract with a natural gas supplier to buy futures to convert the uncertain market price in the future to a specific level and bid.

Overall, the increase of gas supply can be attributed to four factors: The application of new technologies to E&P activities, shale gas reserves, energy and environmental policies and development of gas futures markets. However, what is the competitive advantage of the U.S. against "traditional" large exporting countries like Russia and Qatar that will make its exports so exceptional? The "secret" is in its gas price formation mechanism. While "traditional" exporters demand that buyers in Europe and China pay natural gas prices linked to crude oil, U.S. offers a more desirable price based on G.O.G. (Gas on Gas Competition). The pricing system in the U.S. is by 99% G.O.G. and the price is exclusively determined by the conditions of the market. The remaining small amount of 1% NP (No Price) is accounted on Mexican PEMEX, which uses the gas in refinery process and for enhanced oil recovery. In Europe, the G.O.G. price formation mechanism accounts for 64%, whereas the remaining 30% and 4% belong to O.P.E. (Oil Price Escalation) and regulated prices respectively. In Asia and Asia-Pacific regions O.P.E. stands for 59% and G.O.G. for 15.5%, while the remaining is composed mainly of regulated mechanisms (I.G.U., 2016). That remaining percent of oil indexed and regulated price mechanisms is why natural gas prices are higher in Asian and European markets than North American. Henry Hub linked price is appearing to be a game-changer for the Asia-Pacific LNG importers because consumers can negotiate prices with an exporter in different terms than the J.C.C. mechanism and that is the start of global price competition[86]. In addition, as Russia and Qatar try to keep oil prices high, U.S. position in the global gas market strengthens. There are some significant factors that are going to keep price

[85] U.S. Senate Committee (2004), "The Clean Air Act as Amended through P.L. 108-201", Feb 24, available from: http://www.epw.senate.gov/envlaws/cleanair.pdf?.

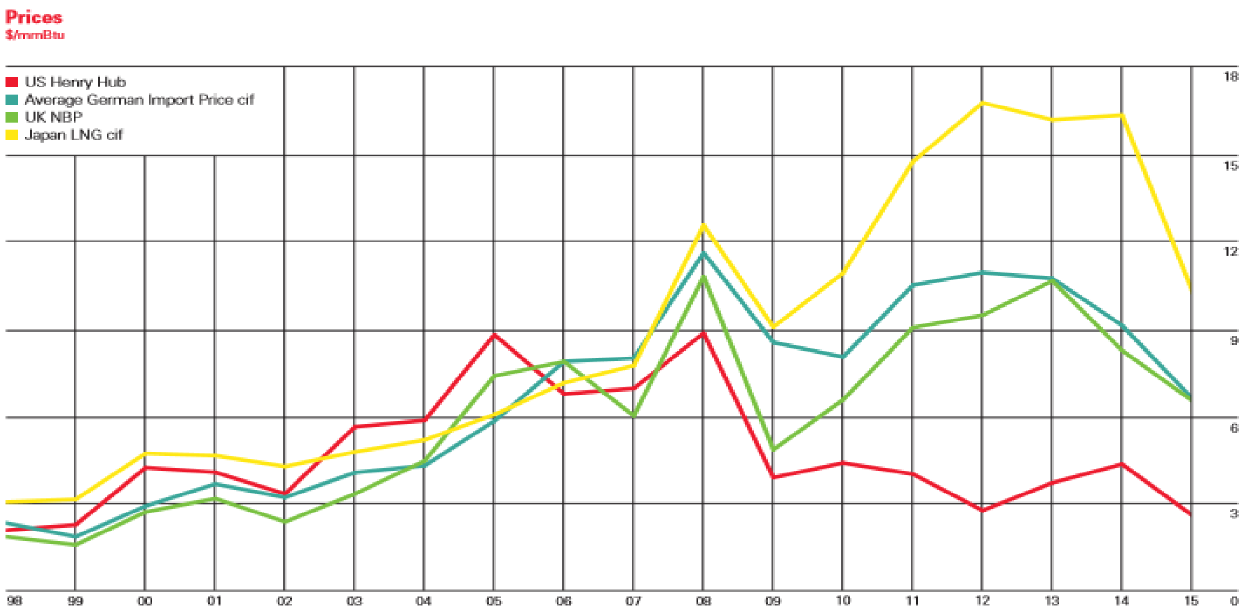
[86] The shale gas boom in North America and the competition of hub-based pricing in Europe, led to a situation where Asia-Pacific LNG importers were paying extremely higher prices of natural gas (15-17$/MMBtu in 2013) in comparison to other regions. That placed Japan in grave competitive disadvantage.

competition between Qatar and the U.S. in heightened levels from 2018 onwards, when the U.S. starts exporting LNG in Asian markets. These factors are (Fattouh, et al., 2015):

- The resistance of Asian LNG buyers to sign new contracts on a J.C.C. basis.
- The likely resistance of Asian LNG buyers to extent the already existing long-term contracts on a J.C.C. pricing basis, when their terms expire.
- Potential legal challenges to change the pricing basis of existing contracts currently in force[87].
- The reliance on Russia to support European hub prices through volume management of its exports of pipeline gas into the European market.

On the other hand, investment in new capacity and expanding output could provide Qatar with better strategic choices in view of the possible upcoming decline in oil-linked LNG sales in Asia, and safeguard its netback revenues from possible negative movements of oil prices below $100 per Bbl. Finally, Qatar can also take comfort from the fact that it is likely to remain the lowest-cost supplier of LNG from a discovered resource, with a track record of impressive project delivery (Fattouh, et al., 2015). In **Figure 31** we see the various price differentials between the U.S. Henry Hub, the U.K. NBP, Japan LNG and German import price from 2000 to 2015.

Figure 31 Natural gas price differentials in from early 2000s to 2015 ($/MMBtu)

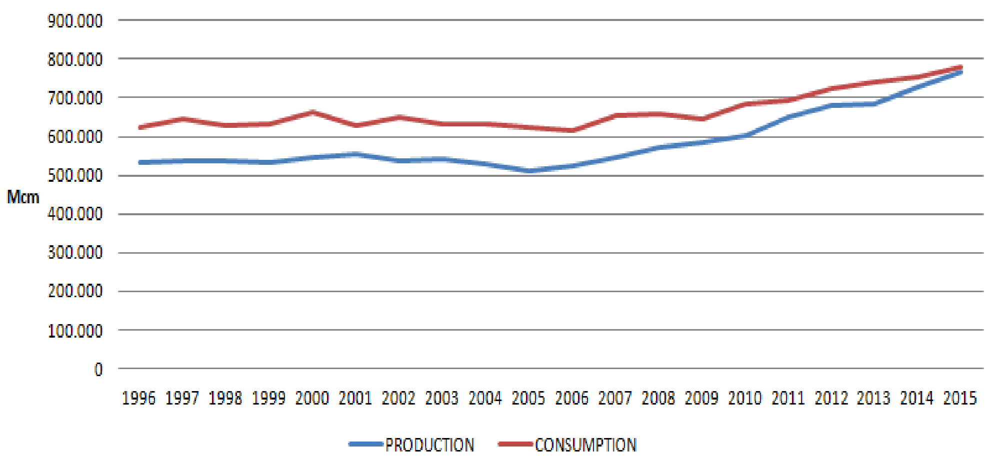


Source: B.P. (2016), B.P. Statistical Review of World Energy 2016

87 In contrast to the continuous renegotiation and arbitration proceedings relating to the oil-indexed pipeline gas contracts in Europe, this is arguably less likely, especially at oil prices below $100 per Bbl (Fattouh, et al., 2015) .

Another strong incentive for North American producers to start exporting LNG globally was the rising demand for environmental reasons. Japan became one of the largest LNG importers after the Fukushima accident, China according to its 12th F.Y.P. (Five Year Plan) aimed to increase the share of natural gas in its primary energy mix by 8.3% in 2015 (I.E.A., 2011), and finally Europe's environmental policies regarding the 20/20/20 package consider natural gas one of the most valuable primary source of energy for renewable source generation such as solar and wind (natural gas combined cycle turbines). It is important to mention that an increased Asian dependence on U.S. energy supply, could promote cooperation on a wider range of international issues (i.e. promotion of human rights in under-developed and developing countries of the East). However, over the last few years we see a high downturn in oil and gas prices globally. That reduction of prices has many negative effects for producers and especially for drilling and E&P activities. In fact, the decrease of oil and gas prices caused slower investment activity globally, making future production growth decelerate in contrast to the previous five years. Per I.E.A.'s "medium-term report 2016" global gas production is forecast to increase by 1.5% on average for the next five years. Despite low oil and gas prices, U.S. gas production has flattened but did not decline meaningfully in 2015 **(Figure 32)**. The turning point in the production trajectory reflects the sharp drop in the drilling activity because of low investments in the E&P sector. New completed wells peaked between the second and the fourth quarter of 2014 across all major shale plays. Since then the rate of completions has declined sharply, and so has the growth rate of production. The consequences of a low-price environment lead producers to cut costs and save their budget in upstream activities and thus reducing production growth short-term.[88]

Figure 32 U.S. production & consumption of natural gas from 1996 to 2015 (Mcm)



Source: I.E.A. (2016), Natural Gas Information 2016

[88] Energy Information Administration (2016), "Drilling Productivity Report", Washington, DC, available from: http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf.

2.1.3 South-Eastern Mediterranean as a potential supplier of natural gas

Except from the "traditional" and "emerging" suppliers of natural gas to Europe, there is a region close enough that can easily become a potential supplier in the near future (2019). That region is the South-Eastern Mediterranean, which accounts for many recent huge discoveries and if its exports truly come online in 2019, South-Easter's Europe liquidity will increase. We are going to see that the recent discovery of Zohr in Egypt gave light to new prospects for its regional gas markets, but also creates challenges and opportunities globally. Israel is now working to overcome its regulatory problems and evaluate new partnerships for the development and monetization of Leviathan. Generally, the South-Eastern Mediterranean is evolving as a new area for energy investors with major gas discoveries, but the trade patterns are affected by geopolitics and gas prices that will surely come under pressure due to new discoveries competing with gas from Russia, Azerbaijan and LNG imports. Finally, it is a well-known fact that security and diversity of energy sources are of great importance to South-Eastern Europe and will require substantial investment that needs to be supported from the cooperation of the region's governments.

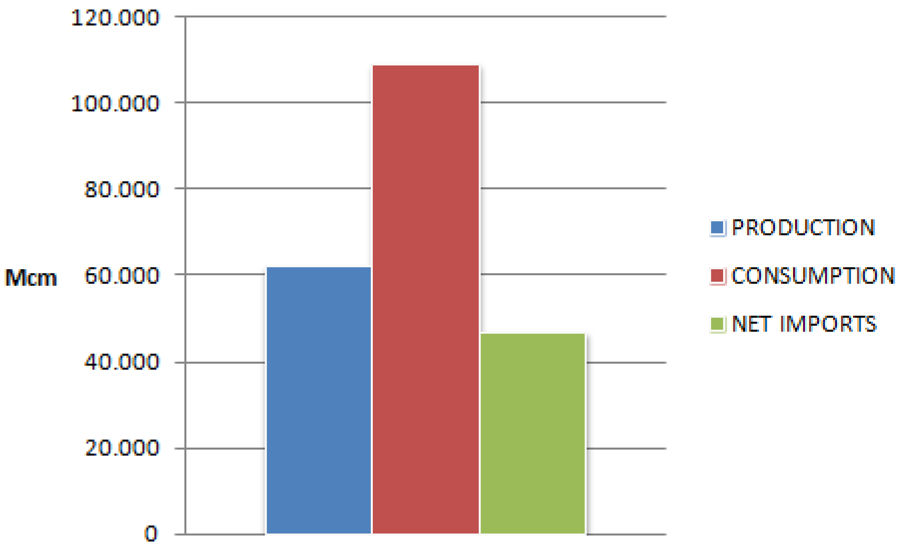
South-Eastern Mediterranean is one of the key regions in European natural gas supply and is described as a potential supplier, which will probably start exporting natural gas regionally by the late 2019. In **Figure 33**, we observe that in 2014 the region was clearly a consuming region despite Egypt's large production. The region's production totaled at 62,216 Mcm, its consumption at 109,255 Mcm, and its net imports at 47,011 Mcm. There is a shortage in the net imports quantity of 28 Mcm, which belongs to Israel's net imports[89], due to continuous terrorists' attacks in the "Arab Gas Pipeline" that halted Egyptian supply along the year[90]. In **Figure 34,** we see that the production output of each country is quite balanced to their consumption needs, in 2014, except from Turkey and Jordan that only import natural gas and their production is minimal in comparison with Egypt's, Israel's and Syria's. In the section that follows, I am going to briefly describe the three key players of the region, which would probably help in the differentiation of European natural gas imports, and thus to its energy security after 2019: Egypt, Israel and Cyprus. Besides, South-Eastern Mediterranean has been a major player in the global chart of natural gas producers since 2009, because of the recent discoveries in the Levant Basin: the "Tamar" (2009) and "Leviathan" (2011) fields in Israel, the "Aphrodite" field in Cyprus in late 2011 and the "Zohr" field in Egypt in August 2015. Furthermore, in 2010 the U.S.G.S. estimated that the volumes of undiscovered technically recoverable resources of natural gas in

[89] Net imports come from the differential consumption minus production. Israel's net imports in 2014 were at 85 Mcm, while its consumption and production quantities were at 8,015 Mcm and 7,901 Mcm respectively. So, the net imports should probably be at 113 Mcm and not at 85 Mcm, thus, implying a shortage of 28 Mcm.

[90] https://en.wikipedia.org/wiki/Arab_Gas_Pipeline.

the Levant Basin could be up to 122,378 Bcf[91]. All these large-scale[92] developments have changed the market dynamics of natural gas in the region, especially in the power generation sector, where there is a shift from oil-fired to gas-fired generators. In fact, according to I.E.A.[93] natural gas accounted for the 78.7% (135,177 GWh) of Egypt's electricity generation and for the 48.43% (29,457 GWh) of Israel's in 2014. Furthermore, **Figure 35** shows that in 2014 Egypt has the largest reserves in the region by far, which amount at 2,168,236 Mcm. Then follows Syria at 286,032 Mcm, and then Israel at 217,016 Mcm. Jordan and Turkey have extremely low reserves at 6,004 Mcm and 6,400 Mcm respectively, which I believe that they have no significant meaning in putting them in. Finally, RPR depicts that the region holds reserves for at least 170 years more, according to reserves and production rates at the end of 2014. **Figure 36** represents South-Eastern Mediterranean's RPR according production output conditions of 2015.

Figure 33 South-Eastern Mediterranean's production, consumption & net import quantities in 2014 (Mcm)



[91] C. J. Schenk et al (2010), "Assessment of Undiscovered Oil and Gas Resources of the Levant Basin Province, Eastern Mediterranean", *USGS*, available from: https://pubs.usgs.gov/fs/2010/3014/pdf/FS10-3014.pdf.

[92] Although these discoveries are quite large for the particular region, they represent only a small fraction of global reserves (less than 1.5%).

[93] https://www.iea.org/statistics/statisticssearch/report/?country=EGYPT&product=electricityandheat&year=2014.

Figure 34 South-Eastern Mediterranean production & consumption comparison in 2014

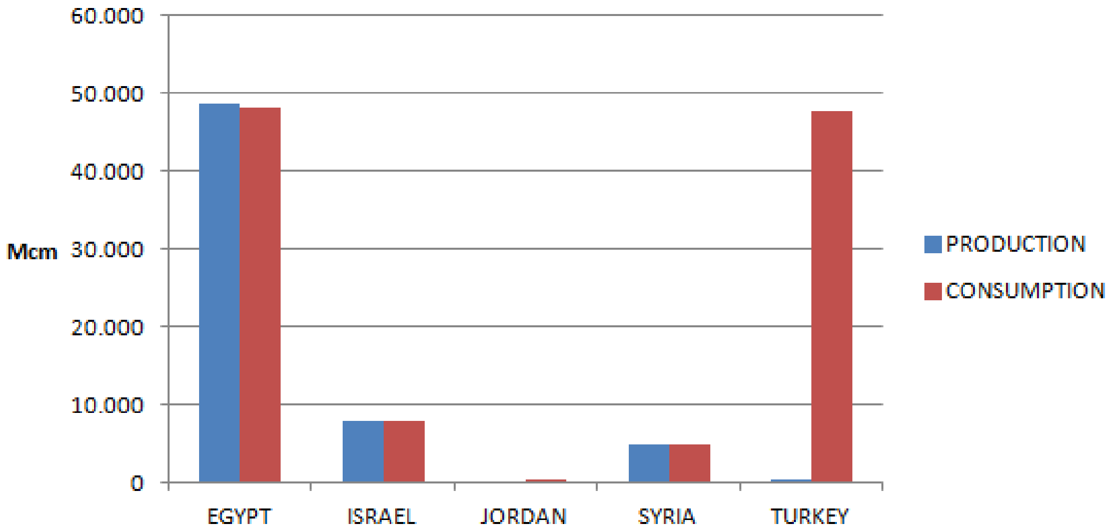


Figure 35 the three largest reserve countries in South-Eastern Mediterranean in 2014

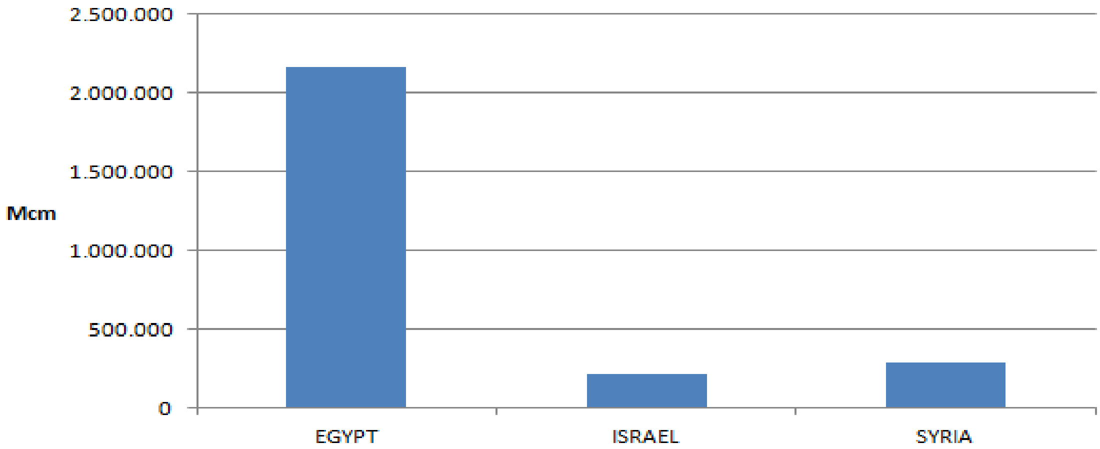
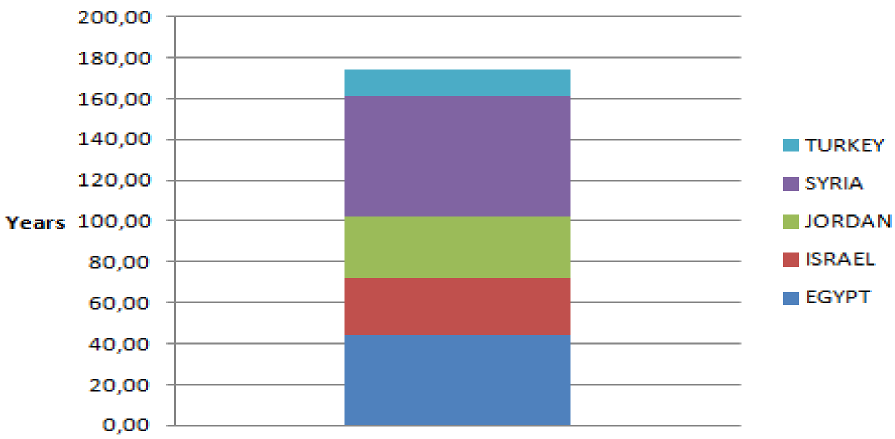


Figure 36 South-Eastern Mediterranean's RPR



<u>Source:</u> B.P. (2016), Statistical Review of World Energy 2016

According to **Figure 34,** we see that Egypt's production in 2014 was at 48,795 Mcm, which is quite close to its total consumption quantity (48,087 Mcm). That means most of Egypt's production output is intended to satisfy its own domestic demand without leaving further implications for regional exports. However, according to the recent discovery of the mega-field "Zohr" from the Italian company "ENI", in August 2015, is going to alter the whole scene of Egypt's' domestic markets as well as the regional and neighboring markets of Israel and Cyprus. In fact, its reserves hold up to 30 Tcf[94] and are valued at over $100 Billion. Those characteristics made it the largest gas field in the South-Eastern Mediterranean until today and one of the largest recent discoveries in the globe. Egypt, whose domestic primary energy consumption relies heavily on natural gas (49.8% in 2015, 43 Mtoe)[95], after the discovery of "Zohr" is going to meet its own gas demand in 2017 when the first quantities from the field reach its domestic markets. It will eventually have an option to export up to 29% of the extracted gas, while reserving the rest for its domestic needs[96]. It also has a potential to play a vital role in the development of the energy sector in the South-Eastern Mediterranean in late 2019, also helping in the problems of energy security and liquidity of South-Eastern Europe. Yet, by doing so, it is going to face strong competition from Europe's "traditional" suppliers (i.e. Russia, Norway, Qatar), as well as from "emerging" LNG exporters (i.e. U.S.A.), which started in early 2016. According to OGJ estimates as of January 1st, 2015, Egypt's proved natural gas reserves are the largest among the region of South-East Mediterranean and the fourth largest in Africa whole Africa, reaching the total of 77 Tcf[97]. In fact, with that size of reserves Egypt can potentially be the driving force of import diversification of South-Eastern Europe and Turkey, which imports are quite as high as Egypt's but with minimum production and it depends mainly in Azerbaijan for imports through "TANAP".

Including the Zohr field, Egypt is developing twelve natural gas projects with a total investment of $33 billion[98]. Yet, developments in infrastructure should be made and geopolitical obstacles to overcome. Although Egypt is a large producer and formerly a net exporter[99] of natural gas, it became a net importer in 2015, because of its government policies that subsidized the cost of fuel consumption, thus, creating additional demand and therefore a natural gas shortage in the country. Additional domestic policies, which forced natural gas producers to sell a percentage of their production domestically at prices well below the global benchmark underpinned the shortage and emerged constraints in new resource developments, therefore

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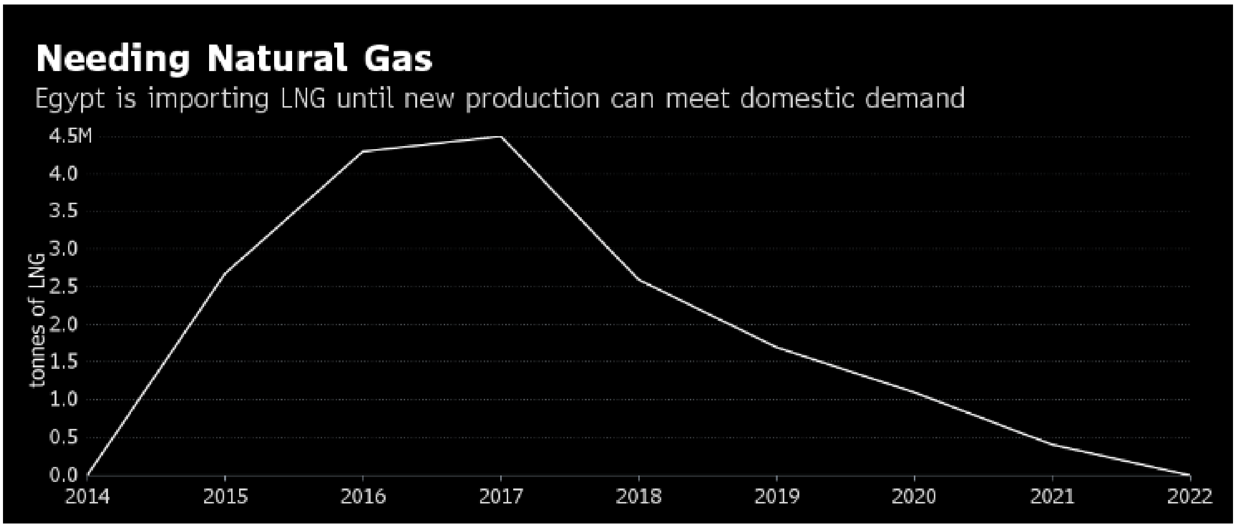
[94] https://www.eni.com/docs/en_IT/enicom/media/press-release/2015/08/PR_EniEgypt_eng.pdf.
[95] BP (2016), "BP Statistical Review of World Energy 2016".
[96] N. Kubikova, A. Figueras (2016), "The New Age of Zohr", *Egypt Oil & Gas Newspaper,* available from: http://www.egyptoil-gas.com/.
[97] E.I.A. (2015), "Egypt-International Energy Data and Analysis".
[98] LNG World News (2016), "Egypt to Up Gas Production by 2019", available from: http://www.lngworldnews.com/egypt-to-up-gas-production-by-2019/.
[99] Egypt used to export gas to Israel, Jordan and Syria in early 2000s.

decreasing total production of natural gas. The resulting shortage caused disruptions to industrial production and electricity power outages. Furthermore, let us not forget that political turmoil in the country has ever been a major parameter that defines trends in market fundamentals: the political uprising against the President Hosni Mubarak decreased investment in discovering new resources of gas[100]. According to **Figure 37** we see that as time develops, Egypt's LNG imports will sky-rock in 2017 (4.5 Mt) and then start falling until 2022, in which Egypt is estimated to become self-sufficient again. With the addition of Zohr in 2017, Egypt's gas production may surpass its consumption by 2020, leaving a surplus for export[101]. Overall, while global market factors and domestic needs negate Egypt's ability to immediately turn Zohr field into huge export potential, it provides the necessary resources for Egypt to become once again energy self-sufficient, in turn positively affecting its economic climate: its domestic industrial base could find that it can confidently resume manufacturing capacity expansions, and foreign investors may grow to look more favorably at industrial investment in Egypt[102].

Figure 37 Egypt's natural gas imports from 2014 to 2022



<u>Source</u>: Bloomberg New Energy Finance (2016), available from: http://www.bloomberg.com/news/articles/2016-06-17/egypt-exports-rare-lng-cargo-in-midst-of-newfound-buying-binge.

[100] A. Shiryaevskaya, T. Inajima, D. Murtaugh, "Egypt's Sends Rare LNG Cargo in Midst of Newfound Buying Binge", *Bloomberg Energy,* available from: http://www.bloomberg.com/news/articles/2016-06-17/egypt-exports-rare-lng-cargo-in-midst-of-newfound-buying-binge.
[101] The Economist (2015), "The Italian Energy Giant's Strategy Seems to be Paying off", available from: http://www.economist.com/news/business/21663249-italian-energy-giants-strategy-seems-be-paying-euregas.
[102] J. F. Seznec, S. Mosis (2015), "The Zohr Gas Field: A Boon for Egypt", *Middle East Institute,* available from: http://www.mei.edu/content/at/zohr-gas-field-boon-egypt.

Another important and potential exporter of natural in the South-Eastern Mediterranean is Israel. After the major discoveries of Leviathan and Tamar fields, Israel can become one a potential exporter regionally and globally, after satisfying its own needs (29.68% primary natural gas consumption in 2015, 7.6 Mtoe)[95]. Israel has already approved the construction of pipelines to supply Jordan: due to the attacks on the "Arab Gas Pipeline", Jordan supply has weakened. There are also discussions for construction of a pipeline between Israel and Turkey that could allow Israel to penetrate indirectly the European supply market. Furthermore, Israel has already begun to include natural gas in its energy mix, accounting for almost 30% of its 2015 primary fuel needs. According to Reuters (2016), Israel is expected to begin exports from its Leviathan field of natural gas by late 2019 if regulatory and government approvals are granted as hoped[103].

The third country of the South-Eastern Mediterranean with potential to export natural gas by 2019 is Cyprus. The reserves of Aphrodite field are estimated between 5-8 Tcf and Cyprus's intends to start exporting will be realized after the end of 2019. At the moment, there is no inland infrastructure in order to exploit the field neither domestically through a pipeline system. That problem makes difficult the development of the field for domestic needs. However, it is proposed to build a LNG export terminal to send gas to Europe form Aphrodite or to build a pipeline from Aphrodite to LNG terminals from surrounding regions like Egypt and then export it regionally.

2.3 Global LNG Infrastructure & Trade Analysis

The dynamics of the global LNG industry are experiencing fundamental changes, and as new reserves and demand sources multiply, so does new supply capacity increases pressing prices to be more competitive and, thus, narrowing the extreme price differential among exporters. In fact, global LNG trade hit the record of 244.8 MTPA in 2015, which was a plus of 4.7 MT from 2014 and surpassed the previous high of 241.5 in 2011 (I.G.U., 2016). Furthermore, the recent period of high spot LNG prices in Asia is going to be challenged over the next decade, considering that the only strong constraint for production growth is transportation cost of pipelines and liquefaction plants, the already existing plans will add a significant capacity in the global market: many of the costs associated with the movement of LNG to distant markets have fallen, creating new opportunities for LNG to compete in global natural gas markets. That can be seen by the various new capacities that are coming online until 2020 (Fattouh, et al., 2015):

[103] Reuters (2016), "Gas from Israel's Leviathan Could Reach Markets by 2019", available from: http://www.reuters.com/article/us-israel-natgas-idUSKCN0V90D4.

- LNG volumes from Australia, which will both displace spot volume imports in Japan and provide additional supply that is not contracted under long-term contracts.
- Volumes from the U.S. contracted by aggregators and portfolio players, much of which may be sold on the spot market
- Volumes from Russia, Canada, and East Africa, which, although are mainly conducted under long-term contracts, might significantly increase the volume of spot LNG and the liquidity of LNG spot markets.

In the previous unit about Qatar's analysis we saw that it is a leading exporter of LNG globally. However, the recent shale boom in the U.S. can easily compete against its dominant position in the LNG global market: the huge loads that will be allowed to reach FID (Final Investment Decision) for exports by the U.S. administration are going to play a pivotal role in Qatar's future strategies. Additionally, Australia's LNG projects that are already under construction will have an immediate impact in Qatar's dominant position in Asian LNG markets after 2018 when they come online. Meanwhile, a threat to Australia's exports in Asian markets is the competition of new Canadian LNG exports from the U.S. Gulf Coast through the expanded "Panama Canal". In addition to the previous projects, if Qatar decides to invest in new LNG liquefaction capacity, that would put pressure on prices, as this would intensify the extent of the oversupply. Finally, plans for future LNG expansions from East Africa and Russia, which will lead to LNG exports, verify the possibilities of further continuous LNG oversupply in the upcoming five years.

As I am going to explain in the next paragraphs, global LNG capacity expansions will increase robustly during the next period, 90% of which will be concentrated in U.S.A. and Australia. Factors contributing in this high concentration are:

- Cost-competitiveness of liquefaction projects in the U.S. relative to those at other locations.
- The current large disparity in natural gas prices between U.S. and other major regions of the world (i.e. Russia, Qatar, and Australia).
- Lower regulatory and other risks in comparison to other countries' proposed liquefaction projects (i.e. Iran, Venezuela, and Nigeria).
- Greater diversity of energy supply that North American liquefaction projects provide, particularly in Europe.
- Increasing import capacity in China.
- China's demand needs will keep growing rapidly over the next years.
- There is stabilization of demand and diversification of imports in Europe.
- There are abundant resources of low-cost shale gas in U.S.A. and creates the opportunities for arbitrage in foreign markets.

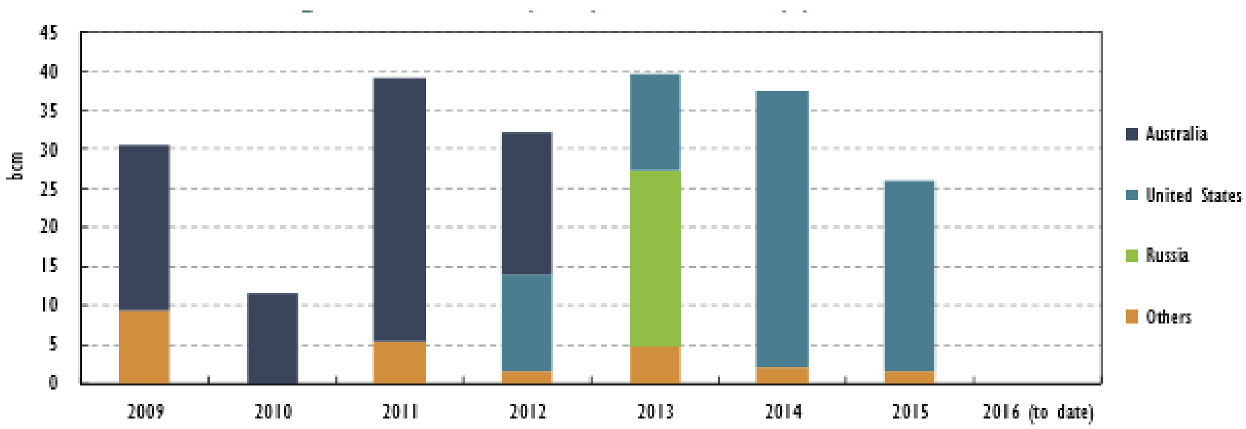
- Australia is the closest exporting region to China's coasts, so the transportation tariffs will be lower.

However, these two regions have great differences in pricing LNG. Australian LNG until now is drawn from costly deep-water fields, while North American from low-cost shale gas reserves. These price differentials may play an important role in the share of future Australian exports, due to more competitive pipeline and LNG exporters by 2020s. Yet, Australia has the potential for lower-cost unconventional gas in the future (Aling, 2014). On the other hand, U.S. faces the disadvantage of relatively higher shipping costs than that of Australia, which is closer to Asian key markets. One of the reasons for expanding LNG export infrastructure is because of the rising demand in Chinese and European markets. Already in 2015, 72% of global LNG demand was in China and surely it will keep rising for the next five years as we see in **Figure 19.** While demand growth rates are rising in China and Europe, new LNG import projects are coming online and others keep developing in these two highly consuming regions the next two years.

2.3.1 Liquefaction Infrastructures

Global nominal liquefaction capacity in January 2016 was at 301.5 MTPA and the proposed new liquefaction capacity reached 890 MTPA (I.G.U., 2016). Due to the expected high demand of Asian Markets for the next five years and the increased production of unconventional gas in the U.S.A, we have plenty of new projects coming online in 2017 and 2018, and 6 already in operation from 2015 and 2016. Many of these that will come online are stationed in the Asia-Pacific, which was accounted for the 41% of global LNG supply last year, and North America regions.

Figure 38 Total Capacity of FID taken by year from 2009 to 2016



Source: IEA, Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021

Figure 38 illustrates the capacity of LNG that will be supplied in the future according to future investment decisions. However, to create the ideal conditions (i.e. regulations, FIDs, contracts) for exporting LNG infrastructure, first you need to locate the opportunities of arbitrage/profit margin in the consuming markets, and these opportunities are driven by long-term demand needs: liquefaction projects typically take five or more years to permit and build, and are planned to work for at least twenty years. So, expectations of future competitive conditions over the project's lifetime have a significant role in investment decisions. The upcoming U.S. liquefaction projects that are likely to take FID are based on the U.S. Gulf, and the LNG volumes from these projects will not be destination-restricted and reselling from the initial buyers will be permitted. This is going to turn the U.S. into a "swing supplier" between Asia and Europe/South America. According to (Fattouh, et al., 2015), the flexibility of the U.S. LNG exports is of more importance than the absolute volume of these LNG export agreements, and is going to give the option to buyers to cooperate together and optimize the availability of LNG.

It is obvious from **Figure 38** that because of the falling prices in gas and oil markets last year, there was a reduction by 10 Bcm in FIDs. The United-States has shown great financial resilience, despite the devastating low price environment. Also with the help of advanced technology, the two-year period of 2014 and 2015 is dominated by U.S. FIDs. In fact, 2015 was the starting point for the first two trains of "Corpus Christi LNG": A Greenfield project operated by "Cheniere Energy" with a total capacity of 12.2Bcm/year. In addition, "Cheniere" got the green light for the fifth train of "Sabine Pass LNG" adding 6.1Bcm/year. Finally, there was the third train of "Freeport LNG" with 6Bcm/year. It is worth mentioning, that a major driver of U.S. producers' incentive to increase liquefaction projects is the current large price differentials between major world regions. However, as natural gas markets become more globalized and integrated, these differentials may well decrease and the interest in exports will not be of the current magnitude in the long run.

In **Table 9** we see that during the period 2015 and 2016 we had an additional LNG supply capacity of 80.2 Bcm/year coming online. Seven LNG projects are located in Asia-Pacific with total capacity of 61.5 Bcm/year and the first two trains of "Sabine Pass LNG" in the U.S.A at 12.2Bcm/year total. Furthermore, there will be twelve new LNG projects that are under construction and will contribute to an increase of LNG supply to an international total of 122.1Bcm/year from 2017 onwards: four in Australia at 36.2Bcm/year, six in U.S.A at 74Bcm/year, one floating LNG in Cameroon at 1.6Bcm/year and one in Russia the first three trains of "Yamal LNG" at 22.4Bcm/year total. So, we observe that the most of the additional supply capacity comes from the U.S. (86.2Bcm/year) and Asia-Pacific (85Bcm/year) regions. Hopefully, a significant amount of capital has already been allocated for these projects, many of which are at an advanced stage of development and backed by long-term contracts. Therefore, today's low prices will have minimal impact on their execution, making them more profitable and competitive than other projects. In the end, LNG projects in the U.S. will compete against other natural gas supply projects aimed at similar markets, such as pipeline projects from Russian natural gas sources into Asia and/or projects to develop shale gas in Asia and Europe.

Table 9 Rest of the world LNG liquefaction projects 2015-2018

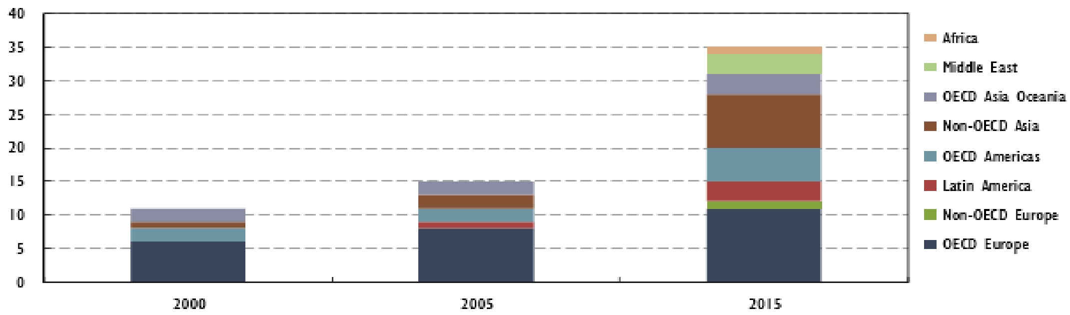
COUNTRY	PROJECT NAME	CAPACITY (Bcm/year)	FIRST CARGO
AUSTRALIA	GLNG	10,6	2015
	APLNG	12,2	2016
	Gorgon LNG (T1-T2)	14,1	2016
	Gorgon (T2)	7,1	2016
	Wheatstone LNG	12,1	2017
	Gorgon (T3)	7,1	2017
	Prelude FLNG	4,9	2018
	Icthys LNG (T1-T2)	12,1	2018
INDONESIA	Donggi Senoro LNG	2,7	2015
	Sengkang LNG	2,7	2016
MALAYSIA	MLNG T9	4,9	2016
	Petronas FLNG	1,6	2016
UNITED-STATES	SABINE PASS LNG (T1-T2)	12,2	2016
	Cove Point LNG	7,1	2017
	Sabine Pass LNG (T2-T3)	12,2	2017
	Freeport LNG (T1-T3)	18	2018
	Corpus Christi LNG (T1-T2)	12,2	2018
	Sabine Pass (T5)	6,1	2018
	Cameron LNG (T1-T3)	18,4	2018
CAMEROON	Cameroon FLNG	1,6	2017
RUSSIA	Yamal LNG (T1-T3)	22,4	2017

Source: IEA (2016)

2.3.2 Regasification Infrastructures

Global nominal regasification capacity reached 757 MPTA in January 2016, from which the 10% (77 MTPA) accounts for FLNG (I.G.U., 2016). Over the last decade, we see an overwhelmingly increase in LNG importing countries. To absorb the new capacity, new building of pipeline infrastructure and LNG terminal developments had to be made (Jensen, 2003). In fact, there are twenty new import countries totaling to thirty-five from 2005 **(Figure 39)**. As it can be seen from the figure Europe and Asia are the main drivers of this increase because of the positive demand growth rate. Amongst them is Poland, which contributes to the source diversification of Europe and next increases security of energy supply.

Figure 39 Number of LNG Importing Countries

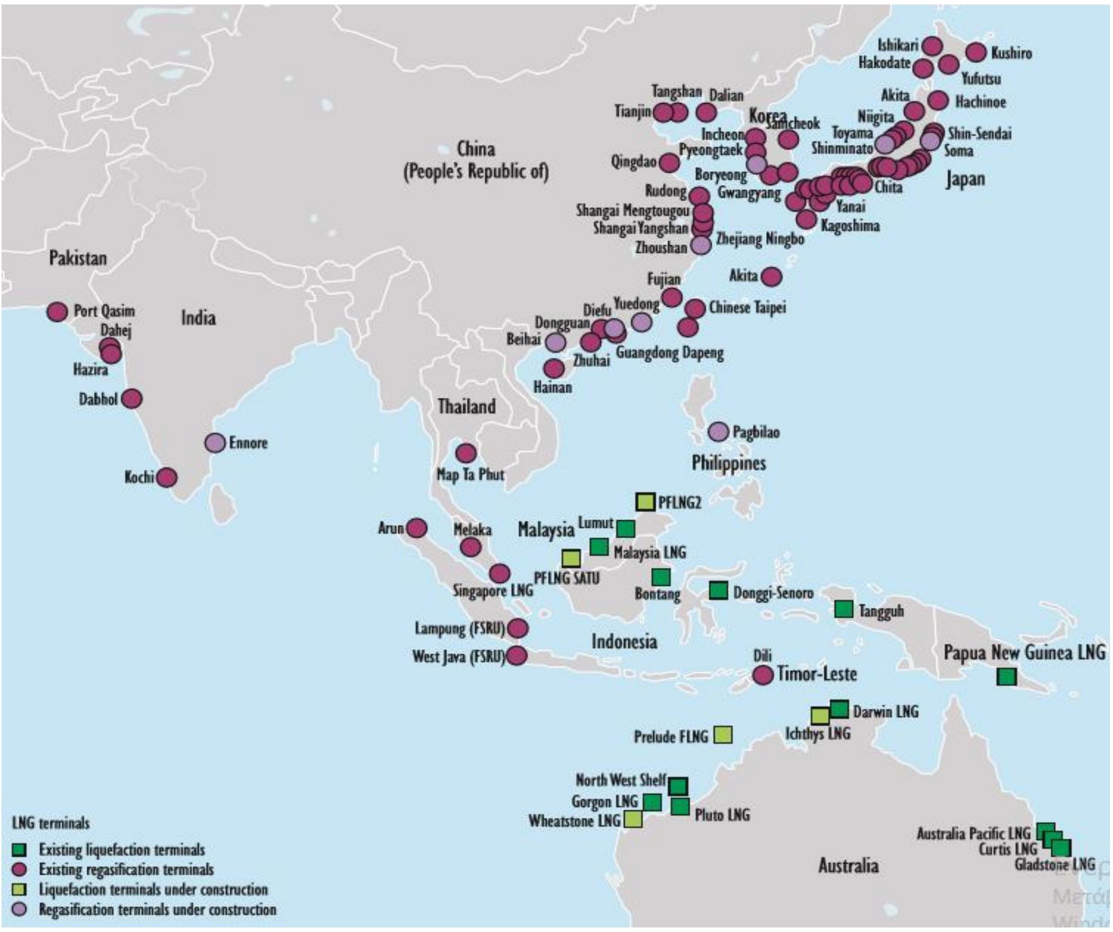


Source: IEA (2016), Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021

Map 6 shows the already existing and under construction LNG regasification and liquefaction terminals in the Asia-Pacific region. While by the end of 2015 China had already thirteen LNG terminals with a total of 56 Bcm/year, now there are eleven new projects under development that will be coming online soon with a total capacity of 38.5 Bcm/year, which represent around 28.64% of the global regasification capacity from 2015 to 2018 (134.4 Bcm/year). In fact, eight of them will come online during 2016 with a total of 26.3 Bcm/year, the “Tianjin North” in 2017 at 4.1 Bcm/year operating by “Sinopec” and in 2018 the expansion of the “Fujian LNG” and the new “Zhoushang LNG” adding up a total of 8.1 Bcm/year. **Table 10** shows the LNG regasification projects from countries around the world, except Europe. It is clear, that China’s import capacity is going to increase drastically over the next few years helping in balancing the oversupply. There are major LNG projects that will increase China’s imports by more than 110 Bcm and more than the half of it can be absorbed by the already existing LNG regasification infrastructure. It is worth mentioning, that the potential of these import facilities is not only to satisfy the short-term demand needs, there is also long-term environmental targets per its F.Y.P. While increasing the LNG import capacity by 1 Bcm, displaces 2 Mt of coal, thus, helping China achieve the targets of its 12th F.Y.P. of reducing by 40% to 45% the CO_2 emissions below 2005 levels by 2020. In addition to that environmental directives, C.N.P.C. planned to promote the use of LNG in 200,000 vehicles until the end of 2015 by creating additional capacity in LNG import terminals and thus encouraging the government decisions of cleaner energy use[104]. So, these infrastructure expansions are the key drivers of China’s energy policies towards the reduction of energy and carbon intensity.

[104] Thomson Reuters (2012), “China CNPC to Expand LNG Sales, Spur Cleaner Fuel Use”, available from: http://af.reuters.com/article/idAFL3E8HC22320120612

Map 6 Asia-Pacific LNG regasification & liquefaction infrastructure



Source: IEA (2016), Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021

Additionally, in Asia-Pacific region we observe that the second country with the most developments in regasification from 2015 to 2018 is Japan, with total regasification capacity at 16.1 Bcm/year. Japan and Korea, which both account for around 50% of global LNG imports, will face great changes in their demand dynamics. They have also accounted for 45% of total global LNG regasification capacity growth during the last six years. However, their imports are estimated to stagnate for the next five years, an estimate that depends heavily on the rate of the nuclear plants comeback in Japan (I.E.A., 2016). **Table 10** shows that from the thirty-six new regasification projects, there are six FSRU projects and one small-scale LNG project. FSRU technology is quite popular of late, especially in developing countries such as Jordan and Pakistan, where lower up-front capital costs and shorter deployments times tend to be more attractive. Furthermore, it is probable for more small LNG import markets to rise after 2018. Overall, in an environment of low gas prices, and along with the factors of oversupply and slower demand growth from "traditional" importers, suppliers will start searching for "smaller" buyers to sell their cargoes. It is worth mentioning that, with FSRU and small-scale LNG terminals becoming more popular, LNG imports for new, “small” importers will be an easy and profitable process in the long run. In the end, these “small” markets will help towards global market rebalancing and in the mitigation of oversupply (I.E.A., 2016).

Table 10 Rest of the world LNG regasification projects from 2015-2018

COUNTRY	PROJECT NAME	CAPACITY (Bcm/year)	START UP YEAR
EGYPT	Ain Sokhana 1 (FSRU)	5,7	2015
	Ain Sokhana 2 (FSRU)	7,7	2015
CHILE	Quintero Expansion	1,7	2015
INDONESIA	Arun LNG Conversion	4,1	2015
	Bali LNG (small scale)	0,5	2016
JORDAN	Aqaba (FSRU)	7,5	2015
PAKISTAN	Port Qasim (FSRU)	7,1	2015
JAPAN	Hachinohe	1	2015
	Kushiro	0,7	2015
	Shin-Sendai	2,9	2015
	Hitachi	1,4	2015
	Toyama Shinminato	1,4	2018
	Soma	1,6	2018
UAE	Dubai Jebel Ali LNG expansion	3,2	2015
COLOMBIA	Cartagena	4,1	2016
HAITI	Titanyen	0,4	2016
GHANA	Ghana LNG (FSRU)	7,5	2016
PHILIPINES	Pagbilao LNG	4,1	2016
CHINA	Dapeng/Guandong expansion	3,1	2016
	Diefu LNG	5,4	2016
	Jieyang LNG	2,7	2016
	Shenzhen	4,1	2016
	Qingdao expansion	4,8	2016
	Jiangsu Qidong	0,8	2016
	Jiangsu Rudong LNG expansion	4,1	2016
	Hainan LNG expansion	1,3	2016
	Tianjin North	4,1	2017
	Fujian LNG expansion	4	2018
	Zhoushan LNG	4,1	2018
KOREA	Samcheok expansion	0,8	2017
	Boryeong	4,1	2017
THAILAND	Map Ta Phut expansion	6,7	2017
URUGUAY	GNL Del Plata (FSRU)	5,5	2017
CHINESE TAIPEI	Taichung expansion	2,7	2018
SINGAPORE	Jurong expansion	6,7	2018
INDIA	Ennore	6,8	2018

Source: I.E.A. (2016), Gas Medium-Term Market Report 2016: Market Analysis and Forecasts to 2021

CHAPTER 3: THE EUROPEAN NATURAL GAS TRADE MODEL

In this chapter I am going to present the various natural gas trade models that describe the market and trade of natural gas internationally, and having considered the analysis of both the European and rest of the world markets in the previous two chapters, I am going to introduce the "ENGTM" model along with its characteristics, its formulation, and its results. Although "ENGTM" is a global natural gas trade model, it is not easy to analyze the determinants of global natural gas trade because of existing difficulties: limited access to information on the supply side, and continuous changes in the complex regulations that have governed both domestic prices and global natural gas trade. In general, policy modeling requires trial and error (Beltramo, et al., 1986).

3.1 Literature Review

In this unit, I am going to present and analyze in some extent the four models that have been designed to describe the market of natural gas, to make projections for supply/demand balances and give results for future policy making based on geopolitical and economic assumptions. However, there are many more models such as these that I could describe, but I intend only to give a glimpse into the global natural gas market aspects and to provide insights to the importance of natural gas as a globally traded energy commodity.

A North American Gas Trade Model (GTM)

GTM (Beltramo, et al., 1986) is a model that provides insights into North American natural gas trade issues. It is a partial equilibrium model, designed to allow interdependence between prices and quantities traded at a particular point in time between interrelated natural gas markets and also assumes that both GNP growth and the international price of oil to be exogenously determined. Furthermore, the model computes for both 1990 and 2000 market-clearing prices and a possible trade pattern of flows between eleven supply regions (one in Mexico, three in Canada, and seven in the U.S.) and fourteen demand regions (one in Mexico, three in Canada and ten in the

U.S.)[105]. It is intended to provide a background for realistic bargaining over international prices and risk sharing in a period where the U.S. market becomes deregulated, but Canada and Mexico maintain export controls and lower domestic prices than those in the U.S.

Overall, the model aims to maximize the **sum** of consumers' benefits less the costs of production and transportation[106], subject to constraints[107] on the prices and quantities traded. As the authors explain, producers' costs of supply region $\boldsymbol{i}$ are described as the integral of the supply (marginal cost) function $\boldsymbol{f_i(x_i)}$. Consumers' benefits of the demand region $\boldsymbol{j}$ in the sector $\boldsymbol{k}$ are described as the area below the inverse demand (willingness-to-pay) function$\boldsymbol{g_{jk}(z_{j,k})}$[108]**.** So, the overall maximand can be written as follows:

$$\sum_{j,k}\int_{v}^{z_k^j} \boldsymbol{g_{jk}(u)dt} - \sum_{i}\int_{v=0}^{y_i} \boldsymbol{f_i(u)dt} - \sum_{i,j} \boldsymbol{c_{i,j}x_{i,j}}$$

Where $\boldsymbol{u}$ denotes the variable of integration and $\boldsymbol{v}$ a lower bound on gas consumption in region $\boldsymbol{j}$ by sector $\boldsymbol{k}$, $\boldsymbol{c_{i,j}}$ is the cost coefficient, $\boldsymbol{x_{i,j}}$ depicts the quantity transported from supply region $\boldsymbol{i}$ to demand region $\boldsymbol{j}$ and $\boldsymbol{y_i}$ is the total quantity supplied by region $\boldsymbol{i}$. However, GTM computes a static market equilibrium in which denoted natural gas prices are the only variables that affect demand and because of that it cannot be used directly to assess the optimal timing of resource extraction. According to the authors, GTM focuses on long-term market equilibrium, rather than on short-term institutional and regulatory issues.

International Natural Gas Model (INGM)

The INGM (Justine, et al., 2009) is used to address the impact of different oil prices on natural gas markets. By using natural gas and NGL resources in each node, processing and transport capacities, and demand of natural gas and other fuels, the

[105] These particular regions were selected to reflect the major options in potential sources and destinations for natural gas traded internationally in North America.
[106] This maximand also may be described as the sums producers' and consumers' surpluses.
[107] Policy or technical constraints such as: pipeline capacity limits, take-or-pay contracts, reproducibility constraints, controlled prices and/or fuel-use allocation rules, export controls.
[108] $z_{j,k}$ is the total quantity demanded by region j, sector k.

model simulates the natural gas and LNG markets from production to end-user markets for sixty nodes and accounts all the activities in midstream such as processing and transportation of gas. INGM uses a linear program (Hogan, 2002) to simulate gas markets and the objective function maximizes the cumulative discounted sum of producer and consumer surplus, thus finding market-clearing prices and flows in developing the market equilibrium, capacity investment decisions and capacity utilization in three seasons (i.e. winter, summer, and spring or fall). Additionally, the model allows for inter-fuel competition using the following equation:

$$\boldsymbol{S_{r,f,t}} = \frac{\left(\boldsymbol{P_{r,f,t}} + \boldsymbol{PA_{r,f}}\right)^{\boldsymbol{a}}}{\sum_f \left(\boldsymbol{P_{r,f,t}} + \boldsymbol{PA_{r,f}}\right)^{\boldsymbol{a}}}$$

Where $\boldsymbol{S_{r,f,t}}$ is the share (fraction) of demand served by the fuel $\boldsymbol{f}$ in region $\boldsymbol{r}$ in year $\boldsymbol{t}$, $\boldsymbol{P_{r,f,t}}$ is the price of the fuel, $\boldsymbol{PA_{r,f}}$ is a calibration variable for the region and fuel reflecting both the ability to use the fuel for the sector and the regional access to the fuel and $\boldsymbol{\alpha}$ is the price elasticity. However, the model does not include contractual flows or prices. It assumes that LNG contracts will have short-term impact on the market and in the long-term LNG will flow based on marginal prices.

The model has contributed in showing that regardless of constraints on GTL (gas-to-liquids) capacity additions, higher oil prices generally lead to higher production and consumption of natural gas. On the other hand, when GTL capacity is allowed to expand, higher oil prices generally lead to higher natural gas prices and to less gas consumption in the power generation and industrial sectors as they switch to cheaper fuels and more natural gas is diverted to the production of GTLs. Finally, it is worth mentioning that the model is destined to be used for world natural gas supply projections for the International Energy Outlook and to support LNG supply projections for the Annual Energy Outlook, both published annually by the E.I.A.[109]

The Rice World Gas Trade Model (RWGTM)[110]

[109] E.I.A. (2008), “International Energy Outlook”, *Office of Integrated Analysis and Forecasting,* U.S. DOE, Washington DC, available from: http://www.tulane.edu/~bfleury/envirobio/readings/International%20Energy%20Outlook%2008.pdf.
[110] P. R. Hartley, K. B. Medlock (2009), “Potential Futures for Russian Natural Gas Exports”, *The Energy Journal,* special issue 2009, International Association for Energy Economics, pp. 73-95.

The RWGTM (Hartley & Medlock, 2005) is a dynamic spatial equilibrium model and as its name describes, it was developed at Rice University's Baker Institute and it encompasses the world natural gas market based in geologic data and economic theory. Dynamic spatial general equilibrium is linked through time by optimal scheduling (Hotelling-type) of resource extraction. The model has been developed to examine the effects of critical economic and political influences on the global natural gas market and provides an equilibrium in which the sources of supply, the demand sinks, and the transportation links connecting them, are developed over time to maximize the NPV of producer rents within a competitive framework. Simultaneously, accounts for the impact of new developments on current and future prices. RWGTM is an **agent-based** model and each agent participating in it seeks to maximize its profit by minimizing its costs. However, the solution is not required to be economically efficient and it also requires that all opportunities for either spatial or temporal arbitrage have been eliminated. It is worth mentioning, that while the model is non-stochastic, it allows analysis of many different scenarios[111].

The supply data is combined with economic models of the demand for natural gas and the demand functions were estimated using longitudinal state level data. For the U.S. is estimated directly and for the rest of the world indirectly considering both the energy intensity of the country and the natural gas share in its energy mix. In fact, energy intensity is estimated as a function of per capita income and price**:**

$$\ln\left(\frac{E}{Y}\right)_{i,t} = a_i - 0.086 \ln y_{i,t} - 0.012 \ln p_{i,t} + 0.834 \ln\left(\frac{E}{Y}\right)_{i,t-1}$$

Additionally, the natural gas share is estimated as a function of GDP per capita, own price, oil price, installed thermal capacity, and the extent to which the country imports energy as follows:

$$\begin{aligned}\ln(\ln \theta_{ng,i,t}) = {} & a_i \\ & + 0.068 \ln\left(\frac{E}{Y}\right)_{i,t} \\ & + 0.043 \ln p_{ng,i,t} \\ & - 0.028 \ln p_{oil,i,t} \\ & - 0.041 \ln thermcap_t + 0.098 \ln entrade_{i,t} + 0.767 \ln(\ln \theta_{ng,i,t})\end{aligned}$$

[111] Geopolitical influences can alter otherwise economic outcomes.

Furthermore, the particular cost of an LNG route from the liquefaction node $\boldsymbol{i}$ to the regasification terminal $\boldsymbol{j}$ is depicted as follows:

$$\boldsymbol{C_{i,j} = \beta_i^L + \sum_{h=1}^{H} \beta_h D_h^{i,j} + \beta_j^R}$$

Where, $\boldsymbol{H}$ is the total number inter-hub routes, $\boldsymbol{\beta_i^L}$ and $\boldsymbol{\beta_j^R}$ are the liquefaction and regasification shipping cost respectively, and $\boldsymbol{D_h^{i,j}}$ is a "dummy" variable. Finally, the model has made a great contribution in showing that in a continuously globalizing natural gas market; events in one region of the world will influence all other regions: wholesale prices convergence, Russia is going to play a pivotal role in price arbitrage and natural gas is a "transition" fuel.

The World Gas Model (WGM)[112]

WGM (Egging, et al., 2008) is developed at the "University of Maryland" along with the cooperation of "DIW Berlin". It is a large-scale **agent-based** model of the global gas markets where agents include producers, traders, storage operators, an integrated pipeline and system operator, and marketers. It also allows to model capacity investments endogenously. Collecting all the Karush-Kuhn-Taker (KKT) conditions for all market agent optimization problems along with market-clearing conditions connecting among the players, leads to a MCP (Mixed Complementarity Problem). The mathematical formulation of investment decisions from the agents are implied in the model as follows:

$$\max_{SALES_y, \Delta_y} \sum_{y \epsilon Y} \gamma_y \{ \pi_y SALES_y - c_y(SALES_y) - b_y \Delta_y \}$$

$$s.t.\ \ SALES \leq \overline{CAP} + \sum_{y\prime < y} \Delta_{y\prime}\ \ \forall y\ (a_y)$$

$$\Delta_y \leq \bar{\Delta}_y\ \ \ \forall y\ (\rho_y)$$

[112] R. Egging, et al (2009), "Representing GASPEC with the World Gas Model", *The Energy Journal,* 2009 special issue, International Association for Energy Economics, pp. 97-117.

Assuming that an agent has perfect foresight and must decide on his $\boldsymbol{SALES_y}$ and capacity expansions Δ_y in each year $\boldsymbol{y}$. Furthermore, the selling price is $\boldsymbol{\pi_y}$ and his costs are given by a convex function $\boldsymbol{c_y(SALES_y)}$. The initial cost is $\overline{\boldsymbol{CAP}}$; the costs for capacity expansion are $\boldsymbol{b_y}$; there is an upper bound on the maximum expansion in each year as $\overline{\Delta}_y$; and the discount factor for future cash flows is $\boldsymbol{\gamma_y}$. Overall, the dynamic version of the WGM has interestingly contributed in assessing the potential impact of a closer cooperation by the G.E.C.F. (Gas Exporting Countries Forum). In the end, the main conclusion by the authors was that "an intensified collusion between groups of gas exporting countries would reduce production, thus raising prices".

3.2 Introducing the "ENGTM"

3.2.1 Model inspiration

The ENGTM is focused on the European natural gas trade, which is not fully deregulated and/or integrated yet. The driving factor that made the initialization of the model is the dynamic character of natural gas trade in all its forms (i.e. pipeline, and LNG). As I have stated in the analysis of the two previous chapters, E.U. is in the midst of continuous LNG oversupply because of new various suppliers, such as the U.S., which are going to affect the Russian and Qatari share of natural gas exports into Europe and/or the pricing terms of their contractual volumes. Thereby, benefiting highly dependent on Russian gas regions (i.e. Baltic States, and South-Eastern Europe), not only by safeguarding their energy security issues, but also by achieving lower pricing deals. That will help them integrate with the rest of the European system, which is more developed. The initial purpose of the model is to describe the current trade flows between the regions to provide optimal solutions for E.U. gas imports, in terms of price and volume equilibrium between "traditional" and "emerging" suppliers. The first "reference case" scenario, in which the model computes market-clearing prices and quantities to find the optimal solution by minimizing upstream costs. The second scenario describes the E.U. gas market in the case, where Norway is fully liberalized and its production costs are a lot lower than the reference case. The second scenario is called "Norway's complete liberalization". The third "energy security" scenario, which resolves potential problems of energy supply security, by inducing the "energy security index" that does not allow any supplier to surpass the threshold of 35% of the total demand capacity in each region.

Overall, the inspiration for the creation of the "ENGTM" was the adaptation of E.U.'s trade patterns in the changing global natural gas market, along with implications of energy policies to resolve current energy security problems, and to optimize the sources and routes from which the E.U. is supplied natural gas. The model processes the data and then produces results, which show what are the optimal trade volumes and trade prices, in respect to production and transportation costs of the suppliers. In other words, its purpose is to select the cheapest sources and routes of natural gas trade between the E.U. and given suppliers, by minimizing the costs of production and transportation.

3.2.2 Description and mathematical formulation of the model

ENGTM has been modeled in GAMS (General Algebraic Modeling System) and it is a simple market equilibrium model, which allows interdependence between gas prices and quantities traded between producing and consuming regions in a single point in time: it computes market-clearing prices in 2015. The model simulates the international trade of natural gas between fifteen supply regions (i.e. North America, Russia, Qatar, Algeria, Azerbaijan, Libya, Nigeria, Norway, Denmark, Germany, the Netherlands, Italy, Poland, Romania, and the U.K.) and the twenty-seven Member-States of the E.U. (excluding Norway). The producing regions have been chosen with criteria such as proximity to the consuming market, and existing and potential trade flows per already existing and/or potential infrastructure developments. Furthermore, the supply/demand regions have been selected to reflect the major options in potential sources and routes for natural gas that is traded globally, as well as internally in E.U. These two separate groups of regions are entered in the model as "sets", and they are declared with the symbols $\boldsymbol{i}$ and $\boldsymbol{j}$ defining "supply countries" and "demand countries" respectively. Overall, the ENGTM is a partial equilibrium model, which operates to minimize the sums of production and transportation costs, which lead to maximization of consumers' surpluses. Key inputs to the model, declared as parameters, are the following:

- Production output limit which is proportional to the 80% of the total proven reserves.
- Minimum production cost as entry barrier for each supplying country.
- Transportation costs per unit from market $\boldsymbol{i}$ to $\boldsymbol{j}$.
- Maximum pipeline technical physical capacities in cross-border interconnection points within the E.U. internal pipeline gas network, as well as in interconnection points between E.U. and external suppliers.
- Maximum technical capacities in pipelines from LNG entry points connected to the rest of the E.U. pipeline and storage system.

ENGTM is an exceedingly simple transportation model, in which the variables of supply enter nonlinearly into the objective function. However, the demand variables are fixed and represent the total consumption quantity of each demand region $\boldsymbol{j}$ in 2015. The primal variables are nonnegative and are defined as follows:

- $\boldsymbol{X_{i,j}}$ = quantity transported from supply region $\boldsymbol{i}$ to demand region $\boldsymbol{j}$.
- $\boldsymbol{S_i}$ = total quantity supplied by region $\boldsymbol{i}$.
- $\boldsymbol{D_j}$ = total quantity demanded by region $\boldsymbol{j}$.

Technical constraints may affect one or more of these variables by setting lower and/or upper bounds on an individual variable. For example, there are pipeline capacity limits that impose upper bounds on the transportation variable $\boldsymbol{x_{i,j}}$. First, there are the economic constraints that are imposed to the objective function in order to obtain a feasible solution, and an optimal equilibrium between supply and demand regions. In other words, these constraints are the first conditions of the objective function that must be satisfied, for the model to give an optimal result and to be economically feasible. These two constraint equations are described as supply and demand constraints for all regions $\boldsymbol{i}$ and $\boldsymbol{j}$:

- $\sum_j \boldsymbol{X_{i,j}} \leq \boldsymbol{S_i}$ (supply constraint)
- $\sum_i \boldsymbol{X_{i,j}} \geq \boldsymbol{D_j}$ (demand constraint)

The above equations depict the symbolic algebraic relationships, which are going to be used to generate the constraints in the model. The first equation is the supply constraint for the supply regions $\boldsymbol{i}$ and it observes the supply limit of these regions, while the second represents the demand constraint for every demand region $\boldsymbol{j}$ to satisfy the demand at every market $\boldsymbol{j}$. Generally, the meaning of these two equations is based in the following two arguments: "the sum of the quantity that is going to be transported from every supply region $\boldsymbol{i}$ to any demand region $\boldsymbol{j}$, must be smaller or equal than the total available supply quantity that every supply region can offer", and that "the sum of the quantity that is going to be transported from every supply region $\boldsymbol{i}$ to any demand region $\boldsymbol{j}$, must be greater or equal than the total demanded quantity that every demand region $\boldsymbol{j}$ needs". It is obvious that these two arguments are clearly logical and they need to be stated in the construction of the model, for the trade relationships between the regions to initialize. Furthermore, to model in GAMS, every equation, along with the objective function, must be declared before it can be used to generate results. In the end, some of the constraints that are imposed as upper and/or lower bounds on an individual variable in the model are also determined by policy regulations such as the following four:

- The volume of take-or-pay clauses as lower bounds on the transportation variable $\boldsymbol{X_{i,j}}$.
- Reproducibility constraints on the production variable $\boldsymbol{S_i}$.
- Controlled prices and/or fuel-use allocation rules that determine demand volumes $\boldsymbol{D_j}$.

- Export controls that determine supply volumes $\boldsymbol{S_i}$.

Regarding the objective function of the model, it can be described as the sum of production costs plus the costs of transportation, subject to constraints on the prices and quantities traded. Specifically, producers' costs are described as the product of the supply function $\boldsymbol{F_i(S_i)}$ with the respective supply quantity $\boldsymbol{S_i}$ of each country $\boldsymbol{i}$. According to (Beltramo, et al., 1986), if the supply variable $\boldsymbol{D_i}$ is unconstrained, the equilibrium dual variable corresponding to the supply constraint will be identical to the marginal supply cost $\boldsymbol{f_i(y_i)}$ in every region $\boldsymbol{i}$. Similarly, if the demand variable is unconstrained, the equilibrium shadow price corresponding to the demand constraint will be identical to the marginal willingness-to-pay $\boldsymbol{g_j(z_j)}$. So, constraints in these primal variables lead to wedges that may be interpreted in terms of taxes or subsidies on individual variables. While the supply and demand variables are separate and nonlinear terms, the transportation costs between the markets are linear terms and they are described as the sum of linear cost coefficients $\boldsymbol{C_{i,j}}$ related to the transportation variables $\boldsymbol{X_{i,j}}$. Therefore, market equilibrium is computed by determining the values of demand and supply variables to minimize the objective function subject to supply and demand constraints, discussed above, and/or subject to upper and lower bounds on individual variable. The objective function of the model has the following form:

$$\sum_{i} \boldsymbol{F(S_i) \cdot Q_i^S} + \sum_{i,j} \boldsymbol{C_{i,j} \cdot X_{i,j}}$$

Demand calibration

Consumers' surpluses are described as the integral of the inverse demand function $\boldsymbol{g_j(D_j)}$, which is the area below the demand function. The function describing consumers' benefits is a demand function of the following form, always subject to demand constraints:

$$\boldsymbol{g_j(D_j) = a \cdot D_j^{-b}} \textbf{ while } \sum_{i,j} \boldsymbol{X_{i,j} \geq D_j}$$

Where $\boldsymbol{D_j}$ is, the total quantity demanded form region $\boldsymbol{j}$, the negative exponent $\boldsymbol{-b}$ is the reciprocal of the price elasticity of demand, which is constant along the function, and the constant $\boldsymbol{a}$ can be determined from a single point across the demand function of each region. That function represents the "willingness-to-pay" of the consumers and the demand variable $\boldsymbol{D_j}$ is affected only by the price of natural gas in each region $\boldsymbol{j}$. As we see, the form of the function is that of an isoelastic. That means, the price elasticity is constant across the length of the curve of the function, with respect to market price. Generally, when a demand function has the above form, then its elasticity is constant and equal to $\boldsymbol{e = -b}$ or to $|\boldsymbol{e}| = \boldsymbol{b}$, along its demand function (Palaiologos, 2009). If we assume that the demand function for natural gas in the region $\boldsymbol{j}$ has the following form:

$$\boldsymbol{Q_j^D = a \cdot P_j^{-b} \quad \forall\, j \in (1, 2, \dots, 28)}$$

Then by applying the well-known form of price elasticity, we gain the following result which proves the equality:

$$\boldsymbol{e = \frac{dQ}{dP} \cdot \frac{P}{Q} = -baP^{(-b-1)} \cdot \frac{P}{aP^{-b}} = -b}$$

Or

$$\boldsymbol{e_{j,P_j} = \frac{\partial \log Q_j}{\partial \log P_j} = -b}$$

Because of regulated prices in the most part of the E.U., the demands in many regions are entered exogenously in the model as fixed demand quantities. Regulated and/or contractual prices are inelastic due to upper or lower bounds on domestic pricing, and because of the long-term character of the contracts, also bound in rigid clauses. The demand functions $\boldsymbol{g_j(D_j)}$ are to be viewed as log-linear approximations to a more complex model of consumers' behavior. The validity of these approximations depends on the choice of reference prices, quantities, and demand price elasticities (Beltramo, et al., 1986). Furthermore, because of the dependency of many countries on imports from "traditional" suppliers such as Russia and Algeria, whose pricing terms are oil-indexed, the final price they offer is affected mainly by the price of oil and other fossil fuels, and so does the demand price elasticities patterns are different. By empirical estimates, I assume that the driving factors, which affect demand price elasticities, are the following[113]:

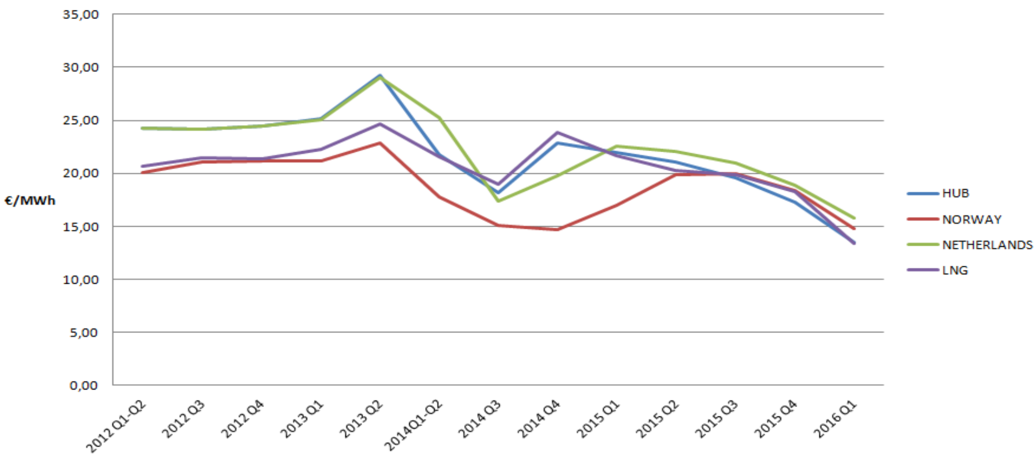
- The share of oil-indexation in the contractual volumes, as well as the duration of the contracts, which define import prices and therefore, the marginal willingness-to-pay levels.
- The prices of competing fuels, which define the cross-price elasticities of natural gas.
- The dependence of each country on Russian or Algerian gas imports.

[113] The empirical assumptions are based on the 1st Chapter about the European natural gas market analysis.

- The volume of each country's own production, which defines the level and the source of its import needs.
- Infrastructure developments on LNG terminals, pipelines, and underground or LNG storage facilities, which define the maximum technical capacity that a region could import in the lowest price available.

The above five factors affect the pricing levels of the demand quantity and thus, the demand price elasticities. Reference prices are taken from European Commission's quarterly reports on European gas markets, representing average wholesale prices between various estimated prices at the border of each importing country[114] during the year 2015[115]. Maximum demand capacities represent the total technical capacity that a region can import from pipeline and/or LNG facilities[116]. For example, in **Figure 40** we see the different estimated gas prices at the U.K. border when importing from Norway and Netherlands, as well as landed LNG and hub prices.

Figure 40 U.K.'s wholesale estimated border gas price time series from 2012-2016Q1



Source: European Commission quarterly reports on gas markets, (2012-2016Q1).

Supply calibration

The function describing the production costs is a supply function of the following form, always subject to supply upper bounds:

$$\boldsymbol{F_i(S_i) = a + b \cdot S_i \; while \sum_j X_{i,j} \leq S_i}$$

[114] Domestic prices are not taken into account.
[115] https://ec.europa.eu/energy/en/data-analysis/market-analysis.
[116] The technical capacities for pipeline, LNG and storage systems are available in: http://www.gie.eu/index.php/maps-data.

Where the variable $\boldsymbol{S_i}$ is the total production quantity available for supply in each region $\boldsymbol{i}$, and the upper bound is the production limit (80% of total proved reserves) of each region $\boldsymbol{i}$. The supply constant $\boldsymbol{a}$ and the marginal cost coefficient $\boldsymbol{b}$ (supply function's slope) have the following form respectively:

$$\boldsymbol{a = P^S_{i,min}} \ \forall \ \boldsymbol{P^S_{i,min} \neq 0}$$

$$\boldsymbol{b = \frac{P^S_{i,max} - P^S_{i,min}}{S_{i,max} - S_{i,min}} \equiv b = \frac{P^S_{i,max} - a}{S_{i,max}}} \ \forall \ \boldsymbol{S_{i,min} = 0 \, , S_{i,max} > 0}$$

Where the variables $\boldsymbol{P^S_{i,min}}$ and $\boldsymbol{P^S_{i,max}}$ represent the supply prices and therefore the production costs at quantity levels $\boldsymbol{S_{i,min}}$ and $\boldsymbol{S_{i,max}}$ respectively. Specifically, the above cost and quantity variables represent the marginally increasing production cost from $\boldsymbol{P^S_{i,min}}$ to $\boldsymbol{P^S_{i,max}}$ of each region $\boldsymbol{i}$, when the quantity of supply moves from $\boldsymbol{S_{i,min}}$ to $\boldsymbol{S_{i,max}}$ respectively. Besides, it is well-known from the economic theory that the supply function is a linear function, connecting supply quantifies and prices in a given point of time with a positive slope. The positive slope of the supply curve is based on the "law of the diminishing returns". That means the trajectory of quantity movements' results in a proportional same trajectory movement in price. In other words, when the supply quantity increases, so does the supply price (cost of production) increases and the opposite. The proportional movement of the quantity in respect to the price movement is expressed through supply elasticity. Moreover, the elasticity of supply may be high at low production levels $\boldsymbol{S_{i,min}}$, but approaches zero as $\boldsymbol{S_i}$ approaches the production limit $\boldsymbol{S_{i,max}}$. If the slope of the supply curve in a region is steep (if elasticity of supply is low), then the impact of any change in supply will be high. On the other hand, if the gradient is shallow (if elasticity is high), then the impact will be low.

According to economic theory, the linear supply curve can be derived from the increasing part of the $\boldsymbol{MC}$ (Marginal Cost) curve, which starts from the point where the MC curve intersects the $\boldsymbol{AC}$ (Average Cost) curve or equivalently when $\boldsymbol{MC = AC}$. Generally, it is valid that the section from that point onwards, and along the $\boldsymbol{MC}$ curve, represents the supply curve $\boldsymbol{F_i(S_i)}$. That also means, $\boldsymbol{P = MC = AC.}$ Furthermore, producer's benefit comes when $\boldsymbol{P^S_i > MC_i}$. Thus, a linear supply function can be also written as:

$$\boldsymbol{F_i(S_i) = P^S_i = a + b \cdot S_i \equiv F_i\left(P^S_i\right) = S_i = a + b \cdot P^S_i}$$

According to previous arguments, in order to compute parameters $\boldsymbol{a}$ and $\boldsymbol{b}$ we must enter the values of reference prices and quantities, as well as the maximum limit in production capacities $S_{i,max}$ in each region i. However, due to lack of information and unreliable sources about production costs in the various supply regions, I initially had to make assumptions to calculate the parameters. So, I decided to construct production cost curves by using the above supply function.

Firstly, I needed to set the minimum cost of entry as an "entry barrier", which a producer must undertake to start producing. The energy industry is widely defined by economies of scale, due to huge capital investments in technology and infrastructure. So, it would be paradoxical for a marginal cost of supply curve to begin from where the vertical and horizontal axes are intersected. In other words, I couldn't set the minimum cost at 0 \$/MMBtu. The above arguments led me to the assumption that the minimum cost of entry for a producer, in a supply region, could well be around the half of the wholesale gas price in that region. The wholesale gas price is the price in which the producer sells gas to the provider, who could be a NOC and/or a government. Furthermore, by setting the minimum cost at the half of the wholesale price, it gives suppliers motive to start producing, along with the opportunity to sell their product in higher prices than their initial marginal costs and thus, making their operation profitable. If the minimum cost of entry was at the same level with the wholesale price, then the producer would have had no returns to operate, and in the long-term it would be undoubtedly clear that the depreciation of its capital investment would cause terrible losses, and therefore raising more entry barriers. But what happens next, after each producer entries the production market? As I stated before, when production output increases, production costs increase too, giving rise to higher marginal supply costs. There is also a maximum production cap $S_{i,max}$, a limit in quantity, where it would be unprofitable for any producer to operate because of extremely high marginal costs and/or because of reserve depletion. Secondly, by acquiring the above given data on supply quantities from (I.E.A., 2016) and the reference prices from (I.G.U., 2016), I could apply the minimum entry and maximum production costs, from each producing region, to its supply function. Thereby, making it easier to compute the production cost coefficient (slope) b and the constant a, which depicts the starting point of the supply curve from the y axis and is given as the minimum entry-cost $P^S_{i,min} \neq 0$.

After calculating these two parameters, I was capable to define the production costs at different production quantity levels. In fact, production costs P^S_i at given supply quantities S_i were calculated in the following formation, derived from the original supply function:

$$P^S_i = \frac{S_i - a}{b}$$

After I had computed these two parameters I could calculate the initial marginal cost coefficient b. In **Table 11** I present the supply data I used to calculate the production costs at given quantities. Furthermore, we know that in North-Western Europe, where liberalization is more developed, wholesale gas prices are formed by G.O.G. mechanisms urging them to be lower than the rest of Europe, but still somewhat higher than that of North America, where prices are even lower than those of Algeria, and Nigeria. That means the minimum production costs of North America was lower than many countries of the chosen sample. Moreover, gas wholesale prices in Russia have fallen well below other countries because of the large rubble depreciation, causing production output and costs to decrease too in comparison to past years. In the end, wholesale gas prices in countries like Algeria and Libya are subject to some form of regulation causing them to be lower than production and transportation costs. So, in that cases minimum production costs won't be around the half of the wholesale price, but somewhat higher. Information about wholesale gas price levels and formation mechanisms is taken from I.G.U. (2016). Supply quantities S_i represent the production of each region in Mcm/day and data is taken from I.E.A. (2016). The variable $S_{i,max}$ represents the output limit of each region and is proportional to the sum of measured and inferred reserves as estimated by B.P. (2016) at the end of 2015.

Table 11 Supply data 2015

Countries	P-Entry (thousand$/Mcm)	Q (Mcm/day)	Max Supply Price (thousand$/Mcm)
North America	40.83	35,068.49	81.67
Russia	32.67	70,794.52	65.34
Qatar	29.04	53,733.70	58.08
Norway	58.08	4,210.41	116.15
Algeria	49.00	9,865.21	98.00
Azerbaijan	47.19	2,410.96	94.37
Libya	59.89	3,296.44	119.78
Nigeria	52.63	11,195.62	105.26
Denmark	143.38	68.28	286.75
Germany	130.67	86.90	261.34
Italy	129.76	99.31	259.53
Netherlands	116.15	1,477.30	232.30
Poland	145.19	204.84	290.38
Romania	101.63	242.08	203.27
United Kingdom	125.23	453.12	250.45

Transportation calibration

In order to make inputs in the model about per unit transportation costs, I have consulted the great work of Golombek, Gjelsvink, and Rosenthal (1995) on modeling the effects of liberalizing the natural gas markets in Western Europe. In their work, they had pointed out that there are differences between international and national pipeline transportation of natural gas. In fact, international pipeline transportation is the transportation of gas from the well-head market to the border of the import country, whereas national pipeline transportation is the transportation of gas from the border to a point where all LDCs/large gas users are assumed to be situated, and the values are only average estimates. Due to lack of reliable data on transportation costs between national and international pipeline players, I used the estimate found in their work of 2.49 $/toe, which corresponds to 0.063 $/MMBtu[117], for international trade within the borders of E.U. Moreover, international pipeline transportation costs between Algeria and the E.U., and/or Russia and the E.U. are lower by 50% and 25% respectively, than that between E.U. Member-States because of lower landed costs. Furthermore, it is well-known that transport tariffs by offshore pipelines are much higher than that of onshore because of higher landed costs too. So, the assumption is that offshore pipeline transport costs are double than that of onshore. (Golombek, et al., 1995). In **Table 12** we see the various direct transportation costs of LNG per location. It is worth mentioning, that these are "direct" transportation costs between interrelated natural gas markets. But what is the transportation tariff when natural gas passes through an E.U. transit country? I had to endogenously set "indirect" transportation cost formulas to calculate the final transportation costs between the initial supply markets $\boldsymbol{i}$, transit countries $\boldsymbol{t}$, and the final demand markets $\boldsymbol{j}$. For example, let us investigate the case of Russia supplying Greece. In that case, natural gas must go through two E.U. transit countries (i.e. Romania and Bulgaria). The transportation cost from Russia to the next country (i.e. Romania) is 0.016 $/MMBtu, from Romania to Bulgaria is at 0.063 $/MMBtu, and from Bulgaria to Greece is also 0.063 $/MMBtu. So, the final transportation cost for Russia, as well as for any other supplier is of the following form:

$$\boldsymbol{F_i(tc_i) = tc_i + \delta \cdot t \ \ \forall\, t \in [0,1,2,3,4,5], \delta = 0.063\ \frac{\$}{MMBtu}}$$

Where, $\boldsymbol{tc_i}$ is the initial transportation cost of each supplier to the next country, $\boldsymbol{\delta}$ is a constant representing the international transportation tariff between E.U. Member-States, and $\boldsymbol{t}$ is the number of the transit countries. Thereby, Russia's final transportation cost to Greece is:

$$\boldsymbol{F_i(tc_i) = 0.016 + 0.063 \cdot 2 = 0.142\ \frac{\$}{MMBtu}}$$

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[117] https://www.iea.org/statistics/resources/unitconverter/.

According to **Map 1**, offshore pipelines exist between Algeria-Spain (i.e. MEDGAZ and MEG), Algeria-Italy (i.e. TRANSMED), Libya-Italy (i.e. GREENSTREAM), Russia-Germany (i.e. NORDSTREAM), Denmark-Sweden, Norway-Netherlands (i.e. NORPIPE and EUROPIPE), Norway-Germany (i.e. EUROPIPE 2), Norway-U.K. (i.e. LANGELED SOUTH and FLAGS NLGP), Norway-Belgium (i.e. ZEEPIPE), Norway-France (i.e. FRANPIPE), Netherlands-U.K. (i.e. BBL), Belgium-U.K. (i.e. INTERCONNECTOR). We see that the most offshore pipelines are placed in the North Sea, where the market is exceptionally liquid due to high proximity with Norway, and liberalized due to numerous natural gas trade hubs. Regarding the national transportation cost of a country, it is computed by multiplying the national transport cost of France (0.38 $/MMBtu) with the size of each country's internal total pipeline length in Km, relative to the size of France. The data that is used for each country's total pipeline length is taken from (Eurogas, 2015). Finally, LNG transportation costs are taken from ICIS (2015)[118].

Table 12 Direct LNG shipping cost between E.U. countries and rest of the world's regions ($/MMBtu) 2015

COUNTRIES/REGIONS	MIDDLE EAST	NORTH AFRICA	WEST AFRICA	NORTH EUROPE
GREECE	0.710	0.221	0.583	0.505
ITALY	0.782	0.241	0.603	0.525
SPAIN	0.860	0.133	0.432	0.347
PORTUGAL	0.872	0.145	0.430	0.330
NETHERLANDS	0.988	0.257	0.541	0.227
BELGIUM	0.981	0.251	0.534	0.231
FRANCE	0.946	0.216	0.500	0.277
UNITED KINGDOM	0.980	0.249	0.533	0.232

Source: ICIS (2015), *Heren Global LNG Markets*

3.3 Model results

3.3.1 "Reference case" scenario

The "reference case" scenario represents the optimal European natural gas trade that should have be done according to data (i.e. prices, quantities, entry-costs, reserves, and production) from the year 2015. In **Table 13** I present the calculated values for the supply constant $\boldsymbol{a}$ and the supply price coefficient $\boldsymbol{b}$. By observing the calculated results of the supply function's slope in respect to total proven reserves, we see that the supply prices $\boldsymbol{P_i^S}$ from external producers are not sensitive to changes in supply quantities $\boldsymbol{S_i}$. Something that is caused by the vastness of their reserves. However, the supply prices of the E.U. countries, except that of the Netherlands, are more sensitive to changes in production outputs, exactly because their reserves are

[118] ICIS (2015), "HEREN Global LNG Markets", *ICIS,* available from: www.icis.com/energy.

few. For example, a change in Russian or Qatari production by 1 Mcm/day will have no impact in their supply price according to b values, while an increase of 1 Mcm/day in Danish, German, and Italian production output will have an increase of 2.1%, 1.5%, and 1.31% in their supply price. The Netherlands constitute an exception because of their higher reserves. So, we can conclude that the supply price from the external suppliers is highly inelastic in respect to their supply quantities, which means E.U. can ask for more supply quantity without affecting the initial supply price, especially in the cases of North America Russia, Qatar, Algeria, Norway and Nigeria. That is particularly true when it comes to reserve quantities: all their reserves combined can reach infinite capacities overpassing E.U.'s demands for many years. The externals suppliers have also much lower production costs than that of the E.U. countries, making their initial price offers quite cheap. In the end, lower entry-costs in combination with vast supplies available, are the driving factors of inelastic supply curves in respect to supply prices. We see that Denmark has the largest impact in supply price, when its production quantity changes and its true because it has the lowest reserves **(Table 11)**.

Table 13 Supply function's parameters in respect to total proven reserves.

COUNTRIES	a	b
North America	40.83	0.00
Russia	32.67	0.00
Qatar	29.04	0.00
Norway	58.08	0.01
Algeria	49.00	0.00
Azerbaijan	47.19	0.02
Libya	59.89	0.02
Nigeria	52.63	0.00
Denmark	143.38	2.10
Germany	130.67	1.50
Italy	129.76	1.31
Netherlands	116.15	0.08
Poland	145.19	0.71
Romania	101.63	0.42
United-Kingdom	125.23	0.28

The optimal supply and demand prices for every producer and consumer country are presented in the following **Figure 41** and **Figure 42** respectively:

Figure 41 Optimal supply prices in reference case scenario ($/MMBtu)

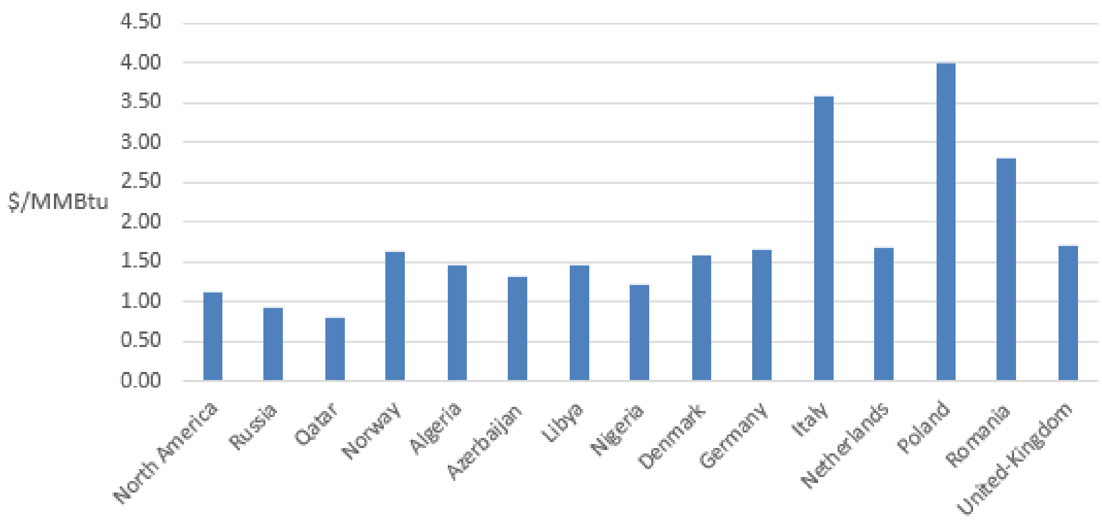
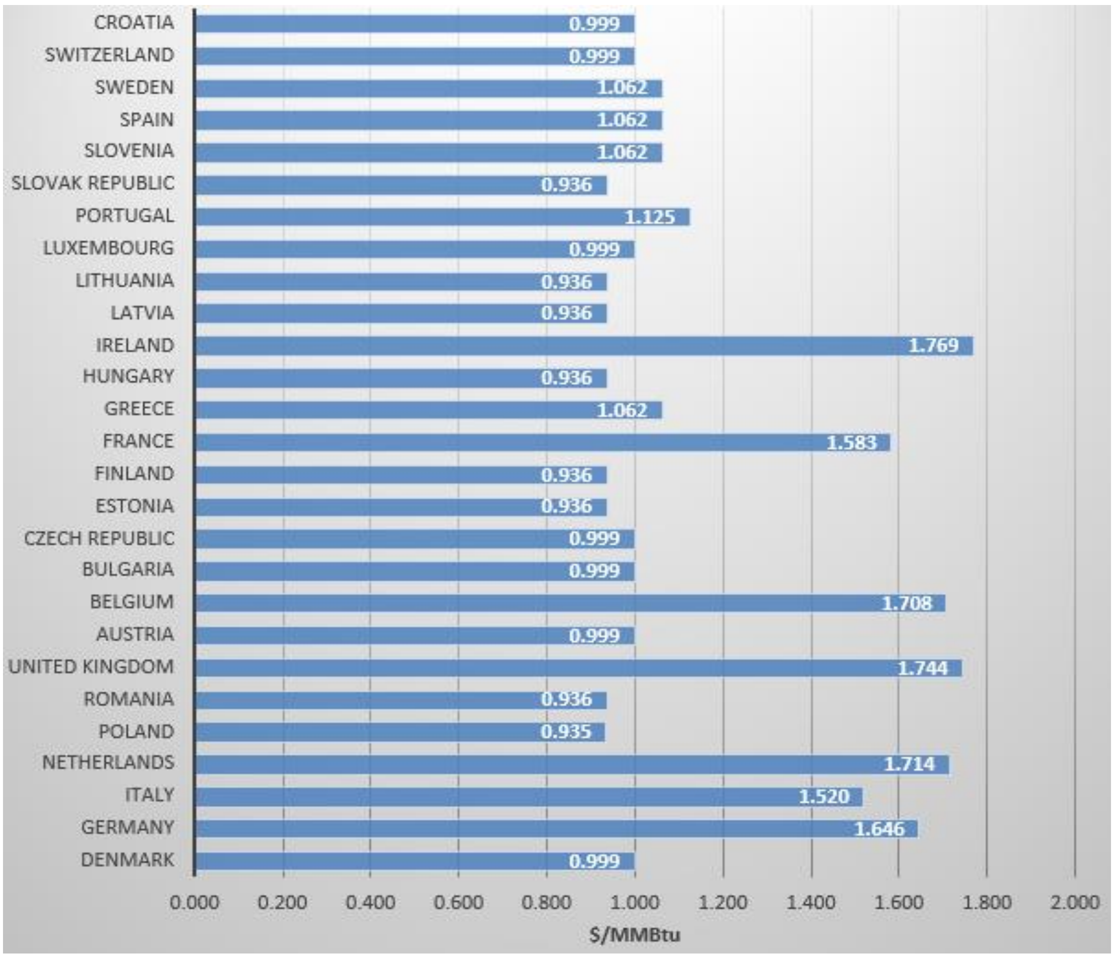


Figure 42 Optimal demand prices in reference case scenario ($/MMBtu)



In **Table 14** we see the results of the demand price elasticities in the "reference case" scenario, where the model has computed the optimal demand prices in thousand$/Mcm.

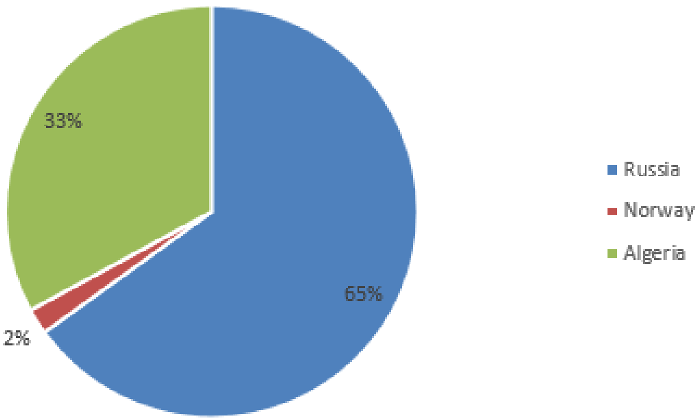
Table 14 Demand price elasticities in the "Reference case" scenario.

COUNTRIES	PRICE (thousand$/Mcm)	QUANTITY (Mcm/day)	MAXIMUM DEMAND CAPACITY (Mcm/day)	ELASTICITY
AUSTRIA	36.25	22.93	164.30	-1.22
BELGIUM	62.00	46.59	399.00	-1.47
BULGARIA	36.25	7.89	67.19	-1.19
CZECH-REPUBLIC	36.25	21.56	134.35	-1.21
DENMARK	36.25	8.69	46.74	-1.23
ESTONIA	33.96	1.29	4.54	-1.16
FINLAND	33.96	7.45	23.41	-1.19
FRANCE	57.46	107.09	404.41	-1.41
GERMANY	59.75	222.93	669.72	-1.44
GREECE	38.54	8.60	86.76	-1.20
HUNGARY	33.96	13.83	38.07	-1.18
IRELAND	64.22	12.04	40.58	-1.21
ITALY	55.17	184.99	338.66	-1.34
LATVIA	33.96	3.85	18.80	-1.17
LITHUANIA	33.96	6.27	96.34	-1.14
LUXEMBOURG	36.25	2.41	3.64	-1.11
NETHERLANDS	62.22	110.40	455.81	-1.48
POLAND	33.94	50.19	191.85	-1.20
PORTUGAL	40.83	12.99	129.86	-1.12
ROMANIA	33.96	30.83	67.25	-1.16
SLOVAK-REPUBLIC	33.96	12.71	215.08	-1.19
SLOVENIA	38.54	2.24	2.66	-1.20
SPAIN	38.54	76.32	1,010.58	-1.23
SWEDEN	38.54	2.22	21.42	-1.21
SWITZERLAND	36.25	9.61	113.50	-1.18
UNITED-KINGDOM	63.31	196.63	895.27	-1.49
CROATIA	36.25	7.15	7.21	-1.23

According to cost and benefit analysis calculated from the model, the only suppliers from which the E.U. maximizes its benefit in the "reference case" scenario are Russia, Algeria, and Norway. In fact, the optimal result for the supply and transportation variables are the following **Figure 43**:

- Russia supplies 65.05% of total demand quantity, which means 773.97 Mcm/day.
- Algeria supplies 32.93% of total demand quantity, which means 391.71 Mcm/day.
- Norway supplies 2.02% of total demand quantity, which means 24.02 Mcm/day
- The price of natural gas is benchmarked is at 1.42 $/MMBtu

Figure 43 Share of optimal supply into E.U. in the "reference case" scenario



The results of this scenario are close to reality and point out the need of the Union to further diversify its natural gas imports, something that will examine in the third "energy security" scenario. The reason why Russia supplies 65% of total E.U. demand is that its production costs are the second cheapest after Qatar, and its transportation costs are the lowest amongst the producers. In fact, Russia produces at a cost of 0.92 \$/MMBtu, whereas Algeria and Norway at 1.46 \$/MMBtu and 1.62 \$/MMBtu respectively. Furthermore, the relative transportation costs of the same producers are at 0.016 \$/MMBtu for Russia, and 0.063 \$/MMBtu for both Algeria and Norway[119]. It is clear, that the reason why Qatar does not have the biggest share of supply is because its transportation costs are the highest amongst the suppliers in the level of 0.710 \$/MMBtu to 0.980 \$/MMBtu depending on location. Qatar may be the cheapest producer at 0.8 \$/MMBtu entry cost, but its costs of transportation are restrictively high. Moreover, although North America is the third cheapest producer at 1.12 \$/MMBtu in the "reference case", it does not provide E.U. with gas because of high transportation costs at 0.622 \$/MMBtu. Generally, it is always a lot cheaper to transfer gas by pipeline in comparison to LNG and that's why Russia and Algeria are selected instead of North America or Qatar. However, Qatar and North America may be expensive transporters, but they can provide alternative solutions to energy security issues, that we are going to examine in the third scenario. Overall, we can see that the transportation costs are of huge importance when modelling natural gas trade. **Figure 44** represents the quantities traded between markets $\boldsymbol{i}$ and $\boldsymbol{j}$. We see that the only buyer of Norwegian gas is the U.K. with 24.02 Mcm/day. In **Figure 45**, **Figure 46**, and **Figure 47** we see the indicative supply curve graphs of Russia, Algeria, and Norway respectively.

[119] These are transportation cost for onshore pipeline trade. In case of offshore pipeline trade the costs are doubled: 0.032 \$/MMBtu for Russia, and 0.126 \$/MMBtu for Norway and Algeria.

Figure 44 Shipment of natural gas between markets i and j in the “Reference case” scenario (Mcm/day)

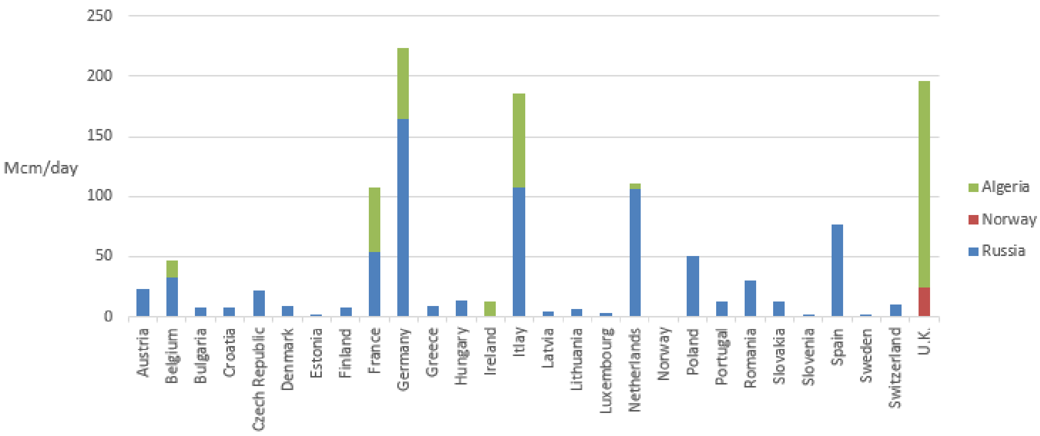


Figure 45 Russia’s indicative supply cost curve in reference case scenario

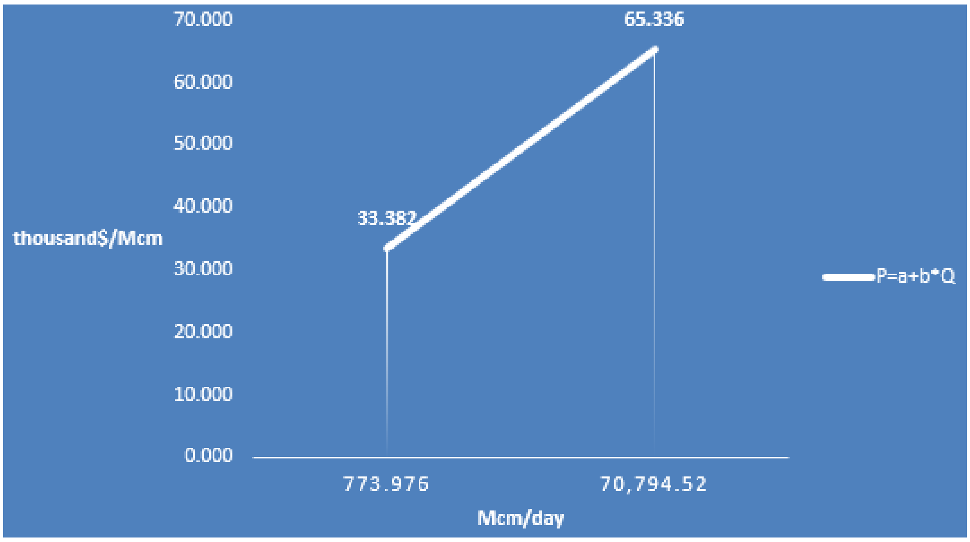


Figure 46 Algeria’s indicative supply cost curve in reference case scenario

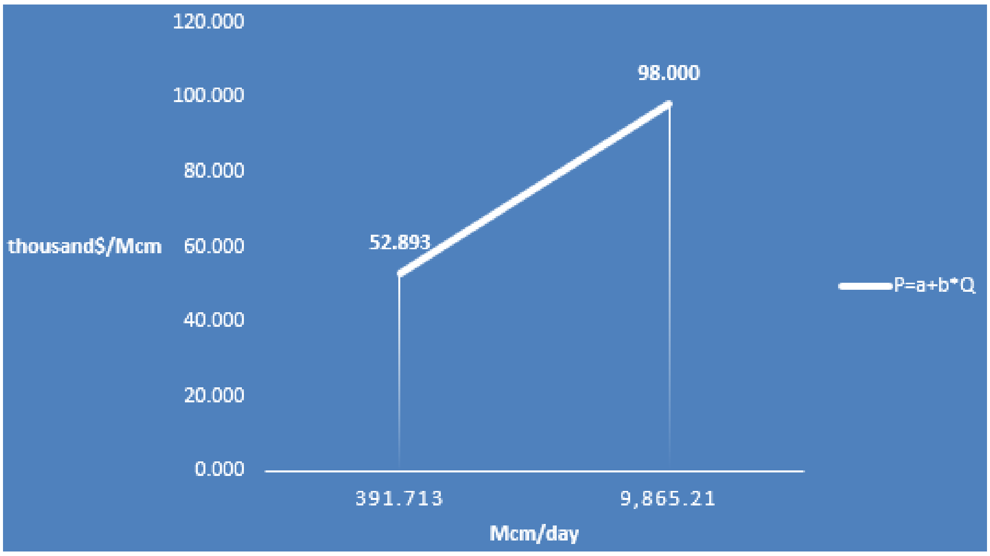
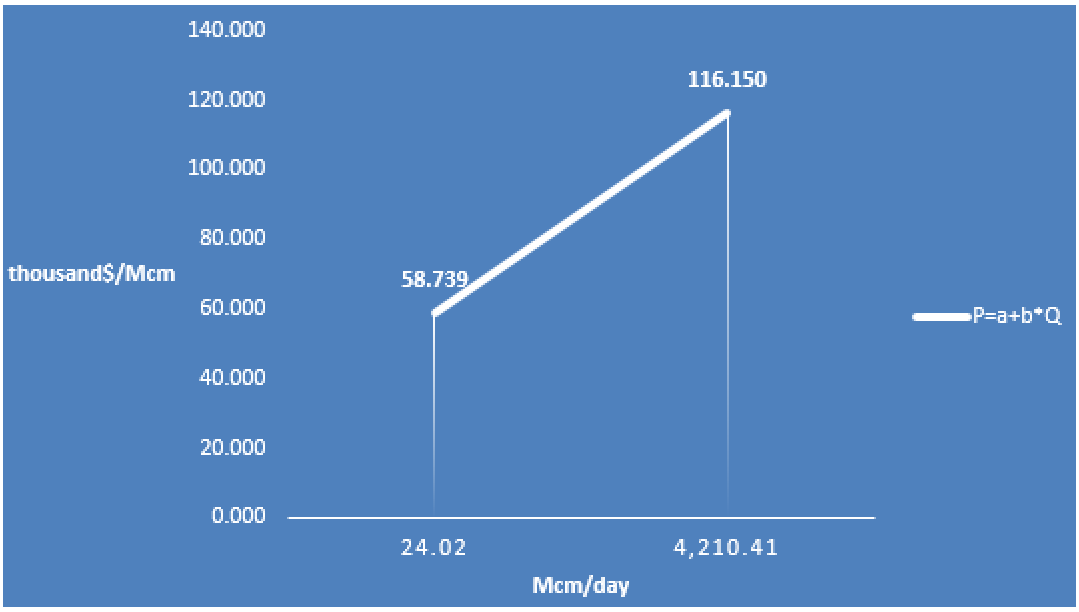


Figure 47 Norway's indicative supply cost curve in reference case scenario



3.3.2 "Norway's complete liberalization" scenario

However, the model is static and can only compute market clearing prices in a single point in time in respect to production and transportation costs, without making projections into the future. So, the second scenario that I am going to issue in this unit is called "Norway's complete liberalization", in which I assume that Norway is fully liberalized and its production cost is totally linked to the NBP price. Furthermore, the NBP price at that time is definitely going to be at lower levels than it is today (6.442 $/MMBtu)[120] because of increased competition from new external suppliers. So, the initial assumption is that NBP price will be decreased at 1.71 $/MMBtu and thus, it is going to be equal to Norway's maximum supply price. Thereby, Norway's entry barrier will also decrease to 0.86 $/MMBtu. The results of that scenario are as follows:

- Russia continues supplying 65.05% of total demand.
- Norway supplies 23.75% of total demand, which means 282.62 Mcm/day.
- Algeria supplies 11.18% of total demand, which means 1133.1 Mcm/day.
- The price of natural is benchmarked at 1.25 $/MMBtu.

In the following **Figure 48** we see the total supply share changes of each country in comparison to the "reference case" scenario. We observe that Russia still remains the first recommended supplier, although Norway's production cost was decreased 5% lower than Russia's due to liberalization and NBP linkage. However, Norway's supply share has been increased by 22% and Algeria's has been decreased by 22%. There is still evidence that Russia's lowest transportation costs operate in its favor

[120] I.C.E. (2016), Natural Gas Futures (€/MWh), available from: https://www.theice.com/products/20755783/UK-Natural-Gas-EUR-MWh-Future/data.

keeping it to the top of the "preferred" suppliers list. In **Figure 49** we see the supply quantities comparison results between the two first scenarios. Norway's total supply quantity has been increased by about 240 Mcm/day, and Algeria's has been decreased by 280 Mcm/day. Overall, to compete and surpass Russia's supply share, Norway needs to further decrease its production costs by 30% lower than that of Russia's at 1.26 $/MMBtu. In that case, Russia's share decreases to 44.63%, Norway's share increases to 48.73% and Algeria's share decreases substantially to 6.63%. Finally, if Norway's complete liberalization is about to happen, then the benchmark price for natural gas will decrease to 1.25 $/MMBtu from 1.42 $/MMBtu. That means Norway's liberalization can benefit E.U. and give an advantage point in trade negotiations between suppliers, especially between Algeria whose share has been partly eliminated. Most of suppliers decrease their prices to compete against Norway and thus E.U. can import natural gas in lower prices by around 0.17 $/MMBtu than in the reference case.

Figure 48 Share of optimal supply in the "Norway's complete liberalization" scenario.

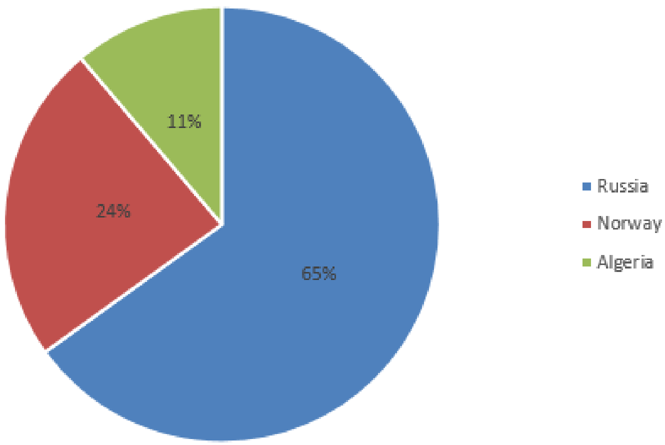
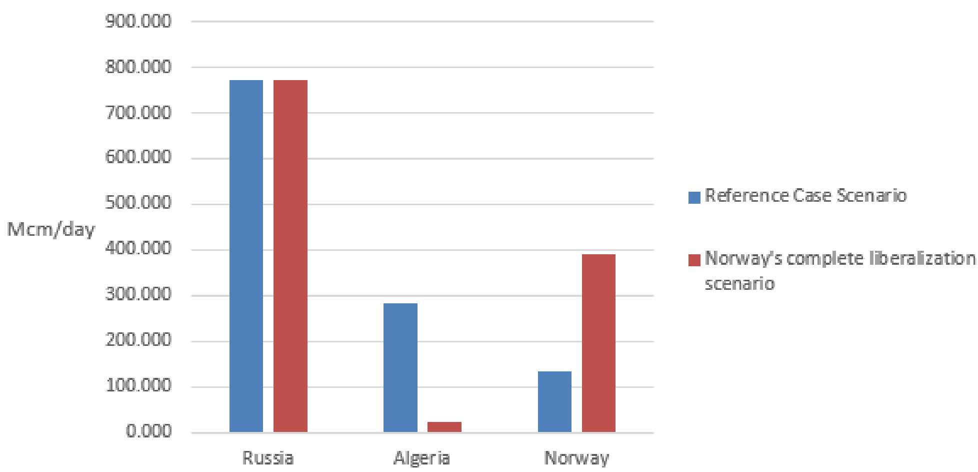


Figure 49 Supply quantities comparison between the first two scenarios (Mcm/day).



The following **Figure 50** and **Figure 51** compare the optimal supply and demand prices, respectively between the first two scenarios. By looking in **Figure 51**, we see that demand prices in Ireland, France, Belgium, U.K., the Netherlands, and Germany have been decreased in comparison to the "reference case" scenario. In respect to **Figure 52,** one can conclude that the sudden decrease in demand prices of these countries has been obviously caused by the decrease in the Norwegian production cost. Norway has cut a huge share from Algeria's exports. By lowering its supply price Norway has become a preferable supplier to five new countries (i.e. Belgium, France, Germany, Ireland, and the Netherlands), whereas in the first scenario it supplied only the U.K. As for Italy, its demand price is also decreased because Algeria decreased its supply price to compete against Norway's lower production costs. We see that Algeria lowered its supply price to maintain its position as pipeline supplier to Italy and as LNG supplier to the U.K., accepting the lower natural gas price that Italy and the U.K. are both willing-to-pay. **Table 15** represents the demand price elasticities in the "Norway's complete liberalization" scenario, after the model has computed the optimal demand prices for that scenario.

Table 15 Demand price elasticities in the "Norway's complete liberalization" scenario.

COUNTRIES	PRICE (thousand$/Mcm)	QUANTITY (Mcm/day)	MAXIMUM DEMAND CAPACITY (Mcm/day)	ELASTICITY
AUSTRIA	36.25	22.93	164.30	-1.22
BELGIUM	39.77	46.59	399.00	-1.26
BULGARIA	36.25	7.89	67.19	-1.19
CZECH-REPUBLIC	36.25	21.56	134.35	-1.21
DENMARK	36.25	8.69	46.74	-1.23
ESTONIA	33.96	1.29	4.54	-1.16
FINLAND	33.96	7.45	23.41	-1.19
FRANCE	39.77	107.09	404.41	-1.25
GERMANY	39.77	222.93	669.72	-1.25
GREECE	38.54	8.60	86.76	-1.20
HUNGARY	33.96	13.83	38.07	-1.18
IRELAND	44.35	12.04	40.58	-1.14
ITALY	52.60	184.99	338.66	-1.32
LATVIA	33.96	3.85	18.80	-1.17
LITHUANIA	33.96	6.27	96.34	-1.14
LUXEMBOURG	36.25	2.41	3.64	-1.11
NETHERLANDS	39.77	110.40	455.81	-1.26
POLAND	33.96	50.19	191.85	-1.20
PORTUGAL	40.83	12.99	129.86	-1.12
ROMANIA	33.96	30.83	67.25	-1.16
SLOVAK-REPUBLIC	33.96	12.71	215.08	-1.19
SLOVENIA	38.54	2.24	2.66	-1.20
SPAIN	38.54	76.32	1,010.58	-1.23
SWEDEN	38.54	2.22	21.42	-1.21
SWITZERLAND	36.25	9.61	113.50	-1.18
UNITED-KINGDOM	59.36	196.63	895.27	-1.44
CROATIA	36.25	7.15	7.21	-1.23

Figure 50 Optimal supply prices comparison between the first two scenarios ($/MMBtu)

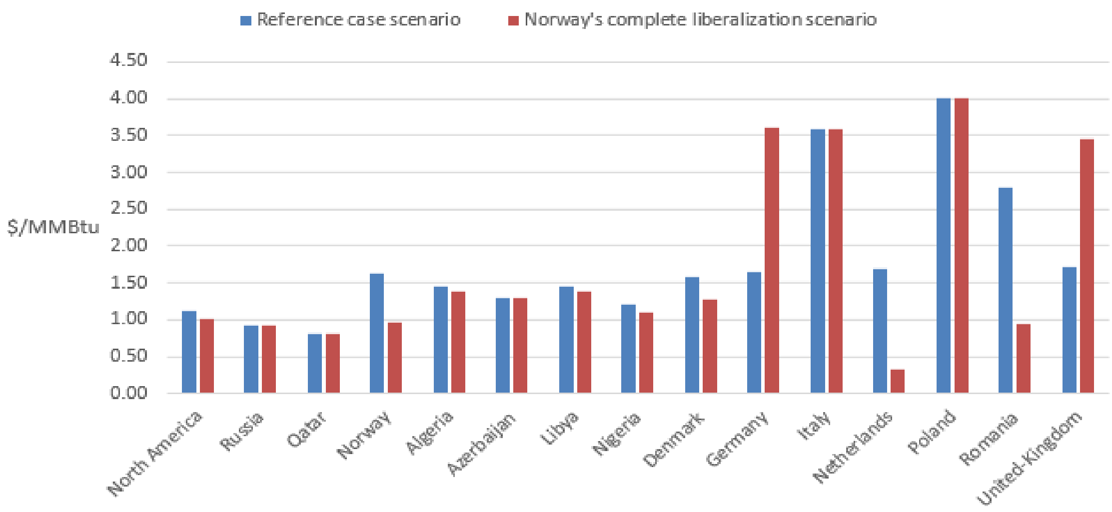


Figure 51 Optimal demand prices comparison between the first two scenarios ($/MMBtu)

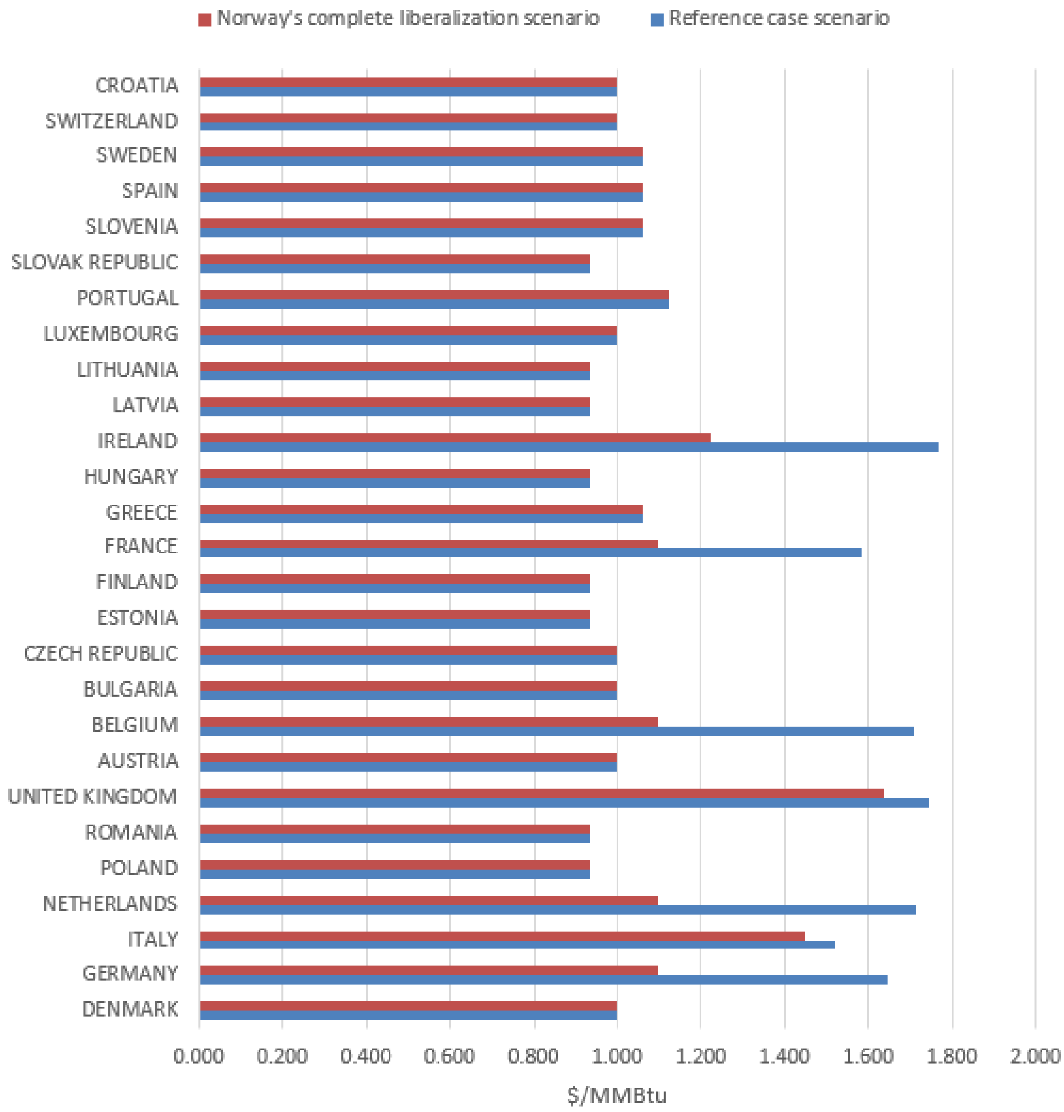
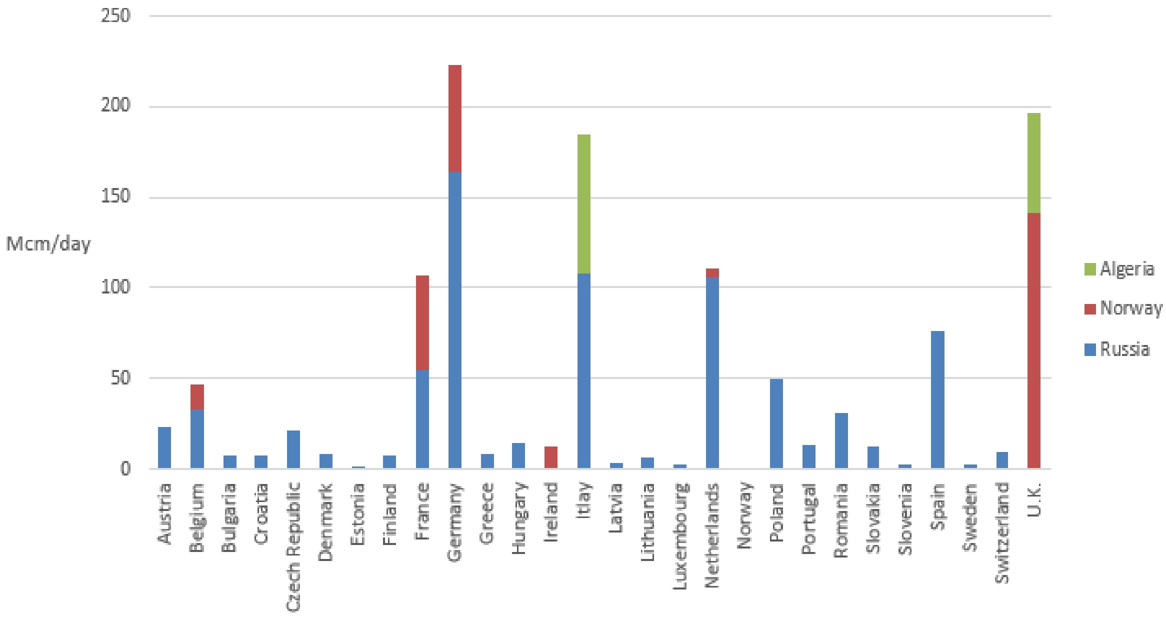


Figure 52 Shipment of natural gas between markets i and j in the "Norway's complete liberalization" scenario (Mcm/day)



Bellow, **Figure 53** and **Figure 54** represent the indicative supply curves for Norway and Algeria in the "Norway's complete liberalization" scenario. Russia's supply curve remains the same as in the previous scenario: its supply price and quantity is the same, because Norway competes only with Algeria. Norway's supply price has been decreased by 24 thousand$/Mcm due to market liberalization and its quantity increased by 260 Mcm/day. On the other hand, the competition for Algeria becomes too hard and is forced to lower its own price by 8 thousand$/Mcm. Norway's lower prices however, manage to cut Algeria's exports by about 250 Mcm/day in comparison to the "reference case scenario

Figure 53 Norway's indicative supply cost curve in the "Norway's complete liberalization" scenario

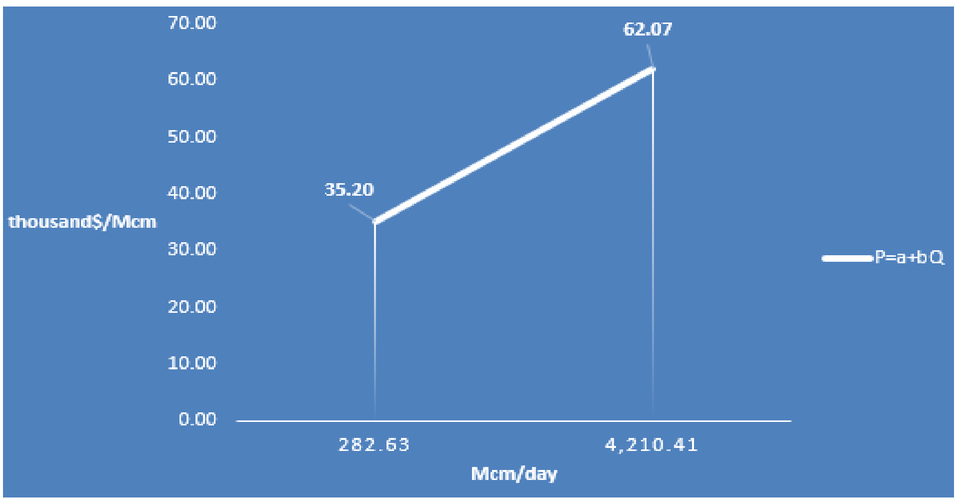
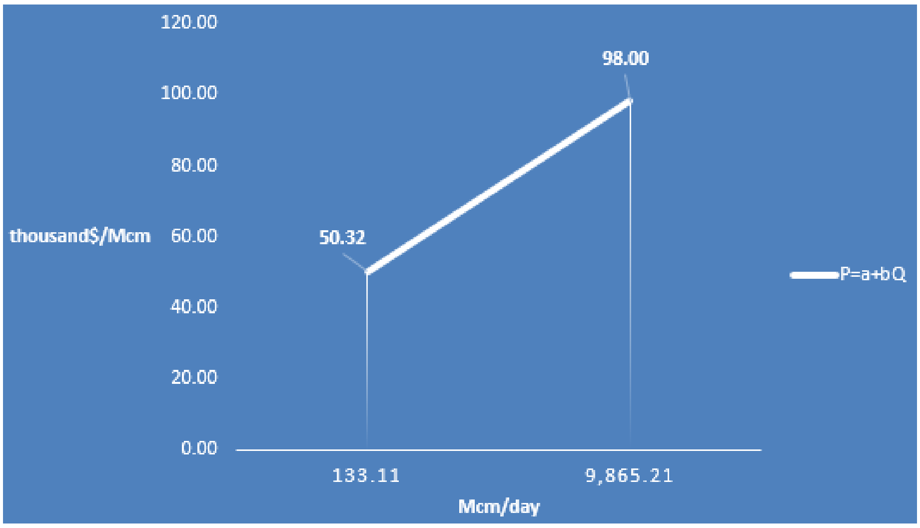


Figure 54 Algeria's Indicative supply cost curve in the "Norway's complete liberalization" scenario.

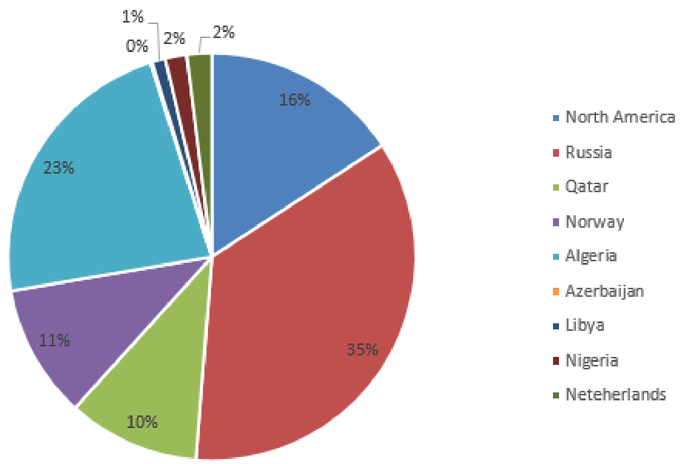


3.3.3 "Energy security" scenario

From the results of the previous scenarios we conclude that the E.U. is highly dependant on Russian natural gas imports, which is also confirmed by the previous analysis that has been done on chapters one and two of my current research. Russia is the cheapest producer and transporter of natural gas, turning it into a favorable supplier for many nations in terms of cost-benefit analysis: E.U. maximizes its benefit by reducing the cost of natural gas import to minimum. From a cost analysis point of view, it would be a rational choice to let Russia supply the most of natural gas. However, one must always take into account energy security issues when analyzing natural gas trade between countries. E.U. has to manage its sources and routes of natural gas trade and not to rely on a single producer, which supplies 65% of it total demand needs. Russia's past malpractices against Ukraine transmission pipes are prime examples of energy security problems. If these issues happen to take place again soon, E.U.'s South and Eastern Member-States would be in an exceptionally difficult position to maintain their energy systems/markets operational. In order to accommodate issues of energy security into the model I have applied an energy security index, which operates as an upper bound to the transport variable $\boldsymbol{X_{i,j}}$. The value of the index is at 0.35, meaning that each supplying country cannot transport more than 35% of the total maximum pipeline capacity connecting each market $\boldsymbol{i}$ and $\boldsymbol{j}$. By applying this index, E.U. Member-States differentiate their imports away from Russia. I am going to apply the "energy security" index in both "reference case" and "Norway's complete liberalization" scenarios and present the results bellow.

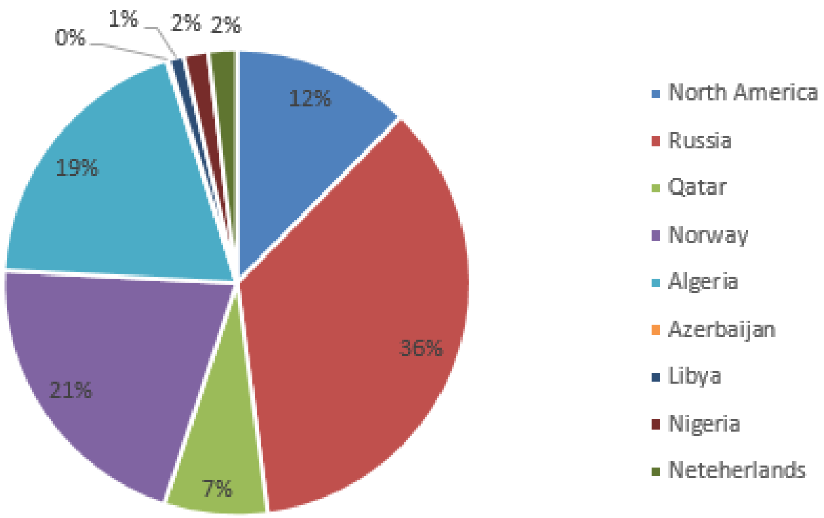
In **Figure 55** we see the share of each supplier in total demand after the "energy security" indexation. Russia and Algeria together constitute 58% of total demand, because of closer proximity to the E.U. markets mitigating transportation costs, and because Russia is the cheapest producer. Furthermore, we see many other suppliers such as, North America, Qatar, Libya, Nigeria, Azerbaijan, and the Netherlands, start participating in the trade, and thus, increasing competition against Russia. In fact, North America and Qatar together account for 26% of total supply, posing a huge threat on Russian exports. As we know, North America is the third cheapest producer (1.13 $/MMBtu) after Qatar and Russia, and its transportation costs to E.U. from the Sabine Pass are exceedingly cheaper than that of Qatar. Nigeria, Libya, and the Netherlands account for 5% of total supply. Azerbaijan accounts for 0.13% of total supply by supplying Greece only through the TAP pipeline with 1.6 Mcm/day. **Figure 57** and **Figure 58** represent the optimal trade quantities between markets $\boldsymbol{i}$ and $\boldsymbol{j}$, after the “energy security” indexation in both “reference case” and “Norway’s complete liberalization” scenarios respectively. Looking at these two figures and comparing them to the initial scenarios, one can simply understand the magnitude of Russian import dependency. As it seems, Russia is the strongest player in the game due to low cost strategy.

Figure 55 Supply shares in the “reference case” scenario after “energy security” indexation



Generally, after the application of the “energy security” index, we see the number of suppliers increase to nine in comparison to the initial scenario, where there were only three. **Figure 56** represents the share of each supplier in the total supply, after applying the “energy security” index to the “Norway’s complete liberalization” scenario. In that case, we see that Norway competes hard with North America, Qatar, and Algeria and becomes the second preferable supplier after Russia, increasing its share by 10%. Algeria and North America lose both 4% of their share, and Qatar loses 3%. Russia still holds the first position amongst suppliers and supplies 35.47% of total demand. However, after the indexation, Russia’s share was decreased by 30% in comparison to the initial scenarios without the index. Finally, that demand constraint can help to overcome issues of energy security, as well as to avoid discriminatory pricing from Russia, and to reduce its market power by 30%.

Figure 56 Supply shares in the “Norway’s complete liberalization” scenario after “energy security” indexation



The “energy security” index is applied exogenously in the model as an upper bound to the transport variable $\boldsymbol{X_{i,j}}$ which depends linearly on the maximum technical capacities of the interconnection points. So, the form of the index is as follows:

$$\boldsymbol{X_{i,j} = 0.35 \cdot MTC_{i,j}}$$

Where, $\boldsymbol{MTC_{i,j}}$ is the maximum technical capacities of the interconnection points between the markets $\boldsymbol{i}$ and $\boldsymbol{j}$**,** and $\boldsymbol{Q_j^D}$ is the demand variable. The index or the upper bound cannot be applied in the demand variable $\boldsymbol{Q_j^D}$ because Bulgaria, Romania, and Finland depend solely on Russia to satisfy their demands. So, if I had applied the index on $\boldsymbol{Q_j^D}$, these three countries would have acquired only 35% of their total demand needs from Russia and none else supplier. That means their demand balances would have deficits, something that comes out to be infeasible and not optimal. On the other hand, by applying the index on $\boldsymbol{X_{i,j}}$ all the countries acquire their total demand quantities and wherever is possible, countries with excess pipeline technical capacities have the choice to import natural gas from the next cheaper supplier, instead of Russia, without having deficits in their demand balances. The most interesting result that comes out from that scenario, is that E.U. still lacks natural gas infrastructure that connects isolated Member-States, which are heavily dependent on a single supplier. That is the case of countries such as Bulgaria, Romania, and Finland. These three countries depend solely on Russia for their imports on each scenario that I have made, because their demand needs are quite small in comparison to the maximum capacities that they can take. Furthermore, in these countries there are interconnection points only between Russia, except Bulgaria that connects also with Romania. But, Romania's natural gas is too expensive for Bulgaria to bare. So, Russia's massive and cheap output is enough to cover their demand needs, whatever feasible upper bound you impose on $\boldsymbol{X_{i,j}}$. The broad conclusion that comes out from that scenario is, by building more interconnection points in these three countries, it could integrate them with the rest of the E.U. system and thus, stop depending solely on Russia. Because in that case, the "energy security" index could be applied on $\boldsymbol{Q_j^D}$, even for these three countries, without generating infeasibilities, and similarly promote optimal solutions for every State in the basis of energy security issues. Then, the "energy security" index would be as follows:

$$\boldsymbol{X_{i,j} = 0.35 \cdot Q_j^D}$$

The benchmark price of natural gas after the "energy security" indexation in the reference case holds at 1.76 \$/MMBtu, it is higher by 0.34 \$/MMBtu without the index. If we apply the index in the "Norway's complete liberalization" scenario, then the benchmark price is reduced to 1.59 \$/MMBtu, but is still higher by 0.34 \$/MMBtu without applying the index. The increase in the price of natural gas for both scenarios, after applying the index, is justified by the increase in the number of suppliers. In fact, after the indexation, from three suppliers initially in both scenarios, they have become nine with the addition of North America, Qatar, Azerbaijan, Libya, Nigeria, and the Netherlands. All these five new suppliers are adding levels to the final import price, because their initial production and transportation costs are higher. It is clear, that in the case you want to have numerous providers of natural gas, the price that you are willing-to-pay would be somewhat higher, even accepting their higher costs. A most interesting conclusion that comes out in the current scenario analysis is that, if E.U. wants to safeguard its energy security, it is going to have an additional cost of 0.34 \$/MMBtu to its final import price. In other words, E.U.'s opportunity cost, to achieve energy security within its borders, is an additional cost of 0.34 \$/MMBtu. Opportunity cost refers to the additional cost of an activity, which someone is willing-to-pay to increase his marginal utility, if otherwise would not have the chance to do. The opportunity cost is always measured relatively to the initial cost of the activity. In that case E.U.'s opportunity cost, is the additional cost of 0.34 \$/MMBtu that it is willing-to-pay to be benefited from energy security, instead of being supplied by 65.5% from Russia. In the reference case, the opportunity cost would be at 19.31% of the final price, whereas in the second scenario it would be at 21.38%. The opportunity cost share is higher in the second scenario than the first, because the initial import price in the first scenario is lower and the opportunity cost is constant in both scenarios.

Figure 57 Shipment of natural gas between markets *i* and *j* in the “reference case” scenario after the application of the “energy security” index (Mcm/day)

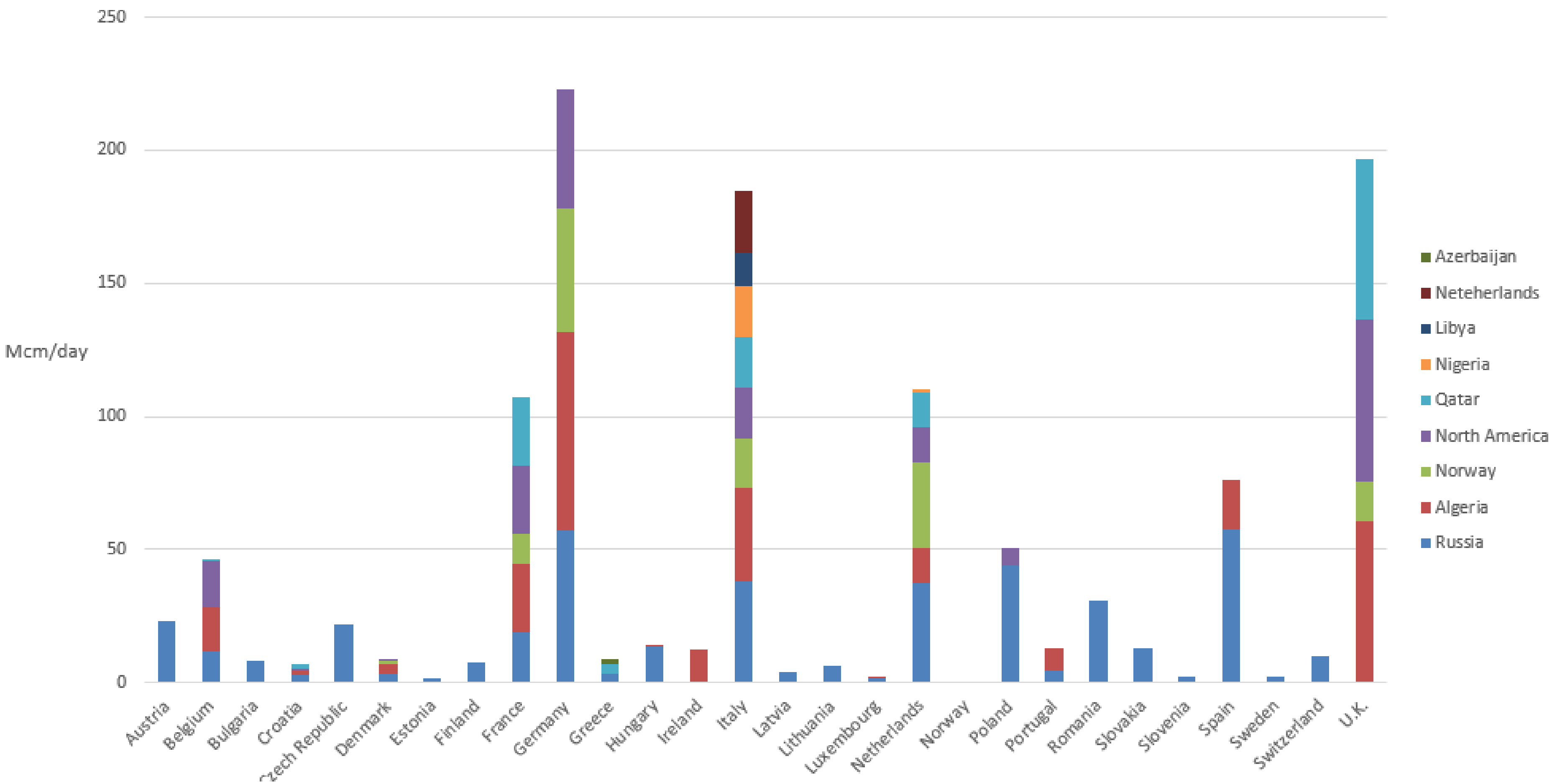
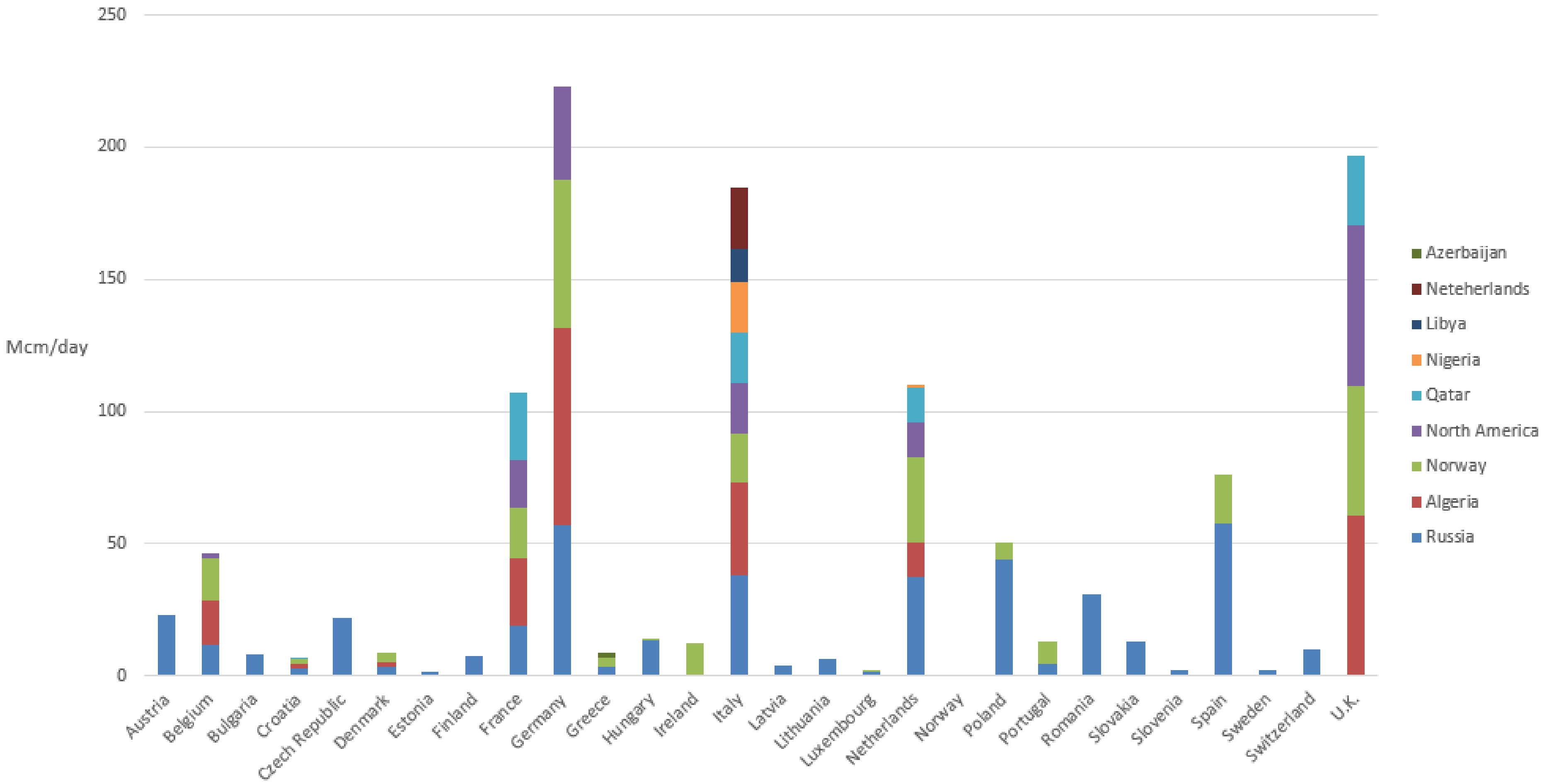


Figure 58 Shipment of natural gas between markets i and j in the "Norway's complete liberalization" scenario after the application of the "energy security" index (Mcm/day)



CHAPTER 4: CONCLUSIONS & ENERGY POLICY IMPLICATIONS

In this final chapter I am going to highlight the main topics that has been investigated in the previous three chapters. By doing so, I am going to draw the key conclusions of my dissertation, impose energy policy implications for future energy policy-making on the sector of natural gas, and finally stress out the weaknesses of the current study/model and make proposals for further research on the topic.

Natural gas has ever been one of the cleanest energy sources, even though it is placed among other fossil fuels and its price is mostly linked to oil. Increased consumption of natural gas can displace environmentally harmful coal-fired generators. Through technology innovations, natural gas can be used in the power generation sector, instead of coal, helping moderate the growth of harmful air emissions. Natural gas is also more energy efficient for many end-use applications than electricity. However, the current low oil and gas price environment does not give the incentive to invest in new natural gas plants. Instead, the current lower coal prices make more favorable to investors the already existing coal plants and prevent coal-to-gas fuel-switching. A preferable policy that could make natural gas a competitive fuel again, even in the current low price environment, is the imposition of a “floor price” in coal. That regulation exists in the U.K. and helps natural gas to be occasionally competitive. Even though natural gas prices are in the lowest levels, none can disagree that natural gas can be used as a political and geostrategic tool of leverage that defines international relations between countries, especially for those countries that their economic activities and their fiscal revenues rely on natural gas exports and/or imports. For example, U.S.’s exports could eliminate opaque and politically entangled natural gas markets such as E.U.’s, potentially reducing revenues to Russia and Qatar. Qatar’s discriminatory pricing towards E.U. will eventually end, due to increased competition from the U.S. Furthermore, U.S. natural gas exports will globally link the markets and help mitigate the existing wide price volatilities and provide a buffer against U.S. domestic shocks. However, this linkage between U.S. domestic and world natural gas markets could increase U.S.’s exposure to external natural gas price shocks. The broad conclusion that arises from “Chapter 1” is that most of E.U.’s natural gas imports depend on Russian pipelines. In fact, Europe as a continent relies on Russia for about one-third of its natural gas supply. It is clear, that E.U. does not have the means to be energy independent just like North America. It will always be in need of energy imports from external energy sources. The most optimal and feasible solution is to diversify its sources and/or routes to manage energy security problems. Furthermore, from the early 80s to the early 2000s, European gas demand expanded robustly due to the continuous increase in oil prices, and high economic and environmental cost of coal plants, replacing oil for space heating and power generation. Another conclusion that comes out from “Chapter 1” analysis, is that the E.U. is partly liberalized and not completely integrated. The North-Western part is a more developed and liquid market than the South-Eastern (see **Hubs**). However, the “European Gas Target Model” describes the ambitious, yet unfulfilling steps the E.U. towards a completely integrated and liberalized “Energy Union”, who’s every Member-State is going to enjoy a safe, interconnected, and sustainable energy market in competitive prices. I conclude that the most important step to integrate the E.U. natural gas market is through technology advancements and new infrastructure developments. E.U.’s plans about building new interconnection points, LNG and storage facilities are listed as PCIs and their analysis can be seen in **1.5**.

An interesting conclusion that arose from “Chapter 2” is that new emerging export countries, such as the U.S., will turn the tight global natural gas market into a more flexible one with new more elastic capacities spreading throughout the globe. In other words, oversupply of LNG is as a fact and will continue to be so for at least until 2020. Oversupply is the mean through E.U. can achieve diversification between suppliers and that can also be seen in the analysis of the third scenario in “Chapter 3”. In general, one of the greatest advantages that oversupply has to offer Europe is increased competition between **“**emerging” and “traditional” suppliers of natural gas. Specifically, oversupply of LNG has led to increased competition activities among “traditional” pipeline producers (i.e. Russia) and new LNG exporters (i.e. U.S.A.): more flexible U.S. and Qatari LNG volumes are cutting off share of the Russian pipeline imports into Europe. There will also going to be many new regasification projects, especially in China, which will absorb the current excess capacities. In fact, China represents around 28.64% of the global regasification capacity from 2015 to 2018 (134.4 Bcm/year). The number of importing countries in 2015 has been thirty-five, whereas in 2005 there were only fifteen importing countries. Technology advancement and innovation have played the most significant role in these changes. Technological advancements in North America helped the U.S. become energy sufficient with the ability to export natural gas globally too. Horizontal fracking managed to put the abundant U.S.’s Shale gas deposits into the fore by extremely raising the region’s gas production output. On the other hand, increased shale gas production can create negative environmental consequences, such as water contamination and local pollution. E.U.’s environmental regulation prevents its Member-States from exploring and extracting shale gas. But, in times, when energy security problems should arise, one must consider the possibility of further energy policies that would allow shale gas extraction in the E.U. vicinity. Overall, the main drivers for the increased supply capacity is North America and Australia, whereas demand growth is mainly driven by China.

The broad conclusion that arises from the first scenario, is that Russia covers 65% of total E.U. demand because of its low production and transportation costs. In fact, Russia is the second cheapest producer at 0.9 $/MMBtu and the cheapest transporter at 0.58 $/MMBtu. The model is designed to compute market-clearing prices and quantities based on production and transportation costs of each supplier. The objective function minimizes these costs and then computes the most feasible solution per given data of production and transportation costs, maximum supply quantities proportional to total proved reserves of each supplier, maximum pipeline technical capacities on the interconnection points between trade regions, and finally demand quantities. So, Russia's first place in E.U.'s trade operations is justified by its low costs. In the alternative second scenario, we saw that Norway's liberalization process caused lower supply price and decreased production costs, even lower than that of Russia's. In fact, Norway's production cost decreased to 0.86 $/MMBtu from 1.62 $/MMBtu. The main conclusion from the second scenario is that Norway still cannot compete with Russia, instead Norway cuts most of Algeria's share. In fact, Algeria's share was reduced to 11.18% from 32.92%, whereas Norway's increased to 23.75% from 2.01%. On the other hand, Russia remains still to 65.5%. For Norway to compete against Russia, it must reduce its production cost further by 30% to the level of 1.26 $/MMBtu. In that case, Norway covers 48.73% of E.U.'s total demand, Russia's share decrease to 44.63%, and Algeria's share is at 6.63%. To cutback costs, Norway needs new large capital investments in technology and/or in production and exploration activities to find new economically profitable reserves. The benchmark price of natural gas in the first scenario is at 1.42 $/MMBtu, whereas in the second at 1.25 $/MMBtu. Another conclusion that comes out, is that Norway's complete liberalization can produce lower natural gas prices than the reference case. Most of suppliers decrease their prices to compete against Norway and thus E.U. can import natural gas in lower prices by around 0.17 $/MMBtu than in the reference case. Furthermore, the willingness-to-pay of consumers such as Ireland, France, Belgium, the U.K., the Netherlands, Italy, and Germany is decreased due to lower supply price from Norway. Finally, that means Norway's liberalization can benefit E.U. and give an advantage point in trade negotiations between suppliers, especially between Algeria whose share has been partly eliminated. We see that Algeria lowered its supply price in the second scenario to maintain its position as pipeline supplier to Italy and as LNG supplier to the U.K., accepting the lower natural gas price that Italy and the U.K. are both willing-to-pay.

When comparing the first two scenarios, another conclusion that emerges is that the price elasticity of E.U.'s demand for natural gas imports will remain high even when Norway's production costs decrease. That means E.U.'s demand for natural gas imports is price-elastic. However, that conclusion is quite general and does not prevail to all regions. Because of the lack of pipeline interconnections between the States of Eastern and Baltic Europe with the rest of the E.U. system, these States are heavily dependent on pipeline imports from Russia only. So, it is highly probable that Russia will be able to exercise discriminatory pricing in these regions, and continue having greater market power. Moreover, we saw that Russia supplies continue to cover most of the demand in the first two scenarios (65%), even though Norway decreased its supply price. E.U. can mitigate that dependency by imposing control measures on import quantities. An energy policy proposal is that E.U. should enforce its Member-States to accept upper bounds on their demand quantities. For example, in the third scenario of my thesis I assume that E. U.'s Member-States cannot accept quantities more than 35% of their maximum pipeline technical capacities from each supplier. These demand constraints can help to overcome issues of energy security, as well as to avoid discriminatory pricing from Russia, and to reduce its market power by 30%. However, those constraints entail an additional cost called "opportunity cost". That means, E.U. cannot safeguard its energy security without paying a somewhat higher final import price. From the analysis of the third scenario, the conclusion that arises is that the opportunity cost for E.U. to achieve energy security is at 0.34 $/MMBtu. Yet, many of the Member-States will keep importing most or whole of their natural gas from Russia. Another broad conclusion that arises is that Bulgaria, Romania, and Finland must be integrated to the rest of the E.U. system by investing in and building new infrastructure. That could allow E.U. to impose constraints on every country's demand quantities and not on their maximum pipeline capacities and thus, each E.U. Member-State could reduce even more its dependency on Russian natural gas imports. Overall, natural gas trade is in a transitional state becoming more and more global and liberalized over the years. That means price changes in one market, will definitely affect all the other markets significantly.

The ENGTM is designed to study natural gas trade between interrelated and spatial regions in a time when the E.U. gas market has not been fully integrated and/or deregulated yet. In fact, the E.U. is partly liberalized with its North-Western part being more liberalized than the rest. Furthermore, the model is static and does not include projections into the future, thus it cannot be used to encompass the optimal timing of resource extraction. That could help assess opportunity costs and arbitrage values when a supplier finds a new deposit or exploits already existing reserves. That analysis also includes endogenous assessment of capital investment decisions. Another, final aspect, is the break-down and insertion of E.U.'s sectoral demands in the model, by making projections further, when E.U. is fully integrated, one can compare natural gas' prices with other fuels in each sector (i.e. power generation, transport, industrial, and residential), and then assess cross price elasticities to calculate the marginal utility (willingness-to-pay) of the consumers. It is a fact, that oil price movements impact market equilibrium in general, as well as in sectoral level. So, my proposals for further research it would be the following:

- The assessment of the model when the E.U. natural gas system is completely integrated, including plans and/or proposals for new pipeline infrastructure that could integrate the Baltic and South-Eastern regions with the rest of the system.

- An econometric model that can compute E.U.'s natural gas prices after 2020 and compare them with the upstream cost of capital in exploration, extraction and distribution activities during 2010-2020 through NPV rates.
- Projection of future natural gas prices and comparison to oil prices in order to extract long-run cross-price elasticities, and compute capital adjustment costs for fuel-switching in sectoral level.

In the end, I should state that in my opinion the model can improve the performance of natural gas trade by computing optimal and feasible solutions, and addressing market failures, such as excessive market power, externalities, and price discrimination. However, when such market failures arise, they must be addressed through corrective regulation, but without reducing critical benefits from the markets, such as consumers' welfare.

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