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Modeling the European Natural Gas Market

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TABLE OF CONTENTS

NOTE: For references and bibliography, please see the text's footnotes

1. 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 natural gas 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 current 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, 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 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 has 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. 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 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, 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

[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.

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 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

As a tool for studying the global nature of natural gas trade between E.U. and external suppliers, this paper uses the European Natural Gas Trade Model (ENGTM). This model is designed to compute market-clearing prices and quantities based on production and transportation costs of each supplier. The objective function used in this model 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. The mathematical formulation of the model is described in the third unit of this paper. The model is a simple, but a useful tool for any policy-maker, who wants to have a clear insight on the European natural gas trade patterns. Someone can also make energy policy considerations about the energy security of E.U. and measure the additional cost (opportunity cost) of any decision, in a time where oversupply is a fact.

2. Literature Review

2.1. 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.)[3]. The model 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[4], subject to constraints[5] 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 $\boldsymbol{g_{jk}(z_{j,k})}$[6]. So, the overall maximand can be written as follows:

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

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.

[3] These particular regions were selected to reflect the major options in potential sources and destinations for natural gas traded internationally in North America.
[4] This maximand also may be described as the sums producers' and consumers' surpluses.
[5] 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.
[6] $z_{j,k}$ is the total quantity demanded by region j, sector k.

2.2. 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 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:

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

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.[7]

2.3. The Rice World Gas Trade Model (RWGTM)[8]

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

[7] 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.

[8] 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.

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[9].

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:

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

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

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

Where, H is the total number inter-hub routes, β_i^L and β_j^R are the liquefaction and regasification shipping cost respectively, and $D_h^{i,j}$ 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.

[9] Geopolitical influences can alter otherwise economic outcomes.

2.4. The World Gas Model (WGM)[10]

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:

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

$$s.t. \;\; SALES \leq \overline{CAP} + \sum_{y' < y} \Delta_{y'} \;\; \forall y \; (a_y)$$

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

Assuming that an agent has perfect foresight and must decide on his $SALES_y$ and capacity expansions Δ_y in each year y. Furthermore, the selling price is π_y and his costs are given by a convex function $c_y(SALES_y)$. The initial cost is $\overline{CAP}$; the costs for capacity expansion are b_y; there is an upper bound on the maximum expansion in each year as $\bar{\Delta}_y$; and the discount factor for future cash flows is γ_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. ENGTM mathematical formulation and description

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: 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

[10] 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.

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 the 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.

The 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:

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

3.1. 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:

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

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 $\boldsymbol{e} = -\boldsymbol{b}$ 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:

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

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

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

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

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[11]:

- 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.
- 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

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

of each importing country[12] during the year 2015[13]. Maximum demand capacities represent the total technical capacity that a region can import from pipeline and/or LNG facilities[14].

3.2. Supply calibration

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

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

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:

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

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

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

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

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 $\boldsymbol{P_i^S > MC_i}$. Thus, a linear supply function can be also written as:

$$\boldsymbol{F_i(S_i) = P_i^S = a + b \cdot S_i \equiv F_i(P_i^S) = S_i = a + b \cdot P_i^S}$$

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 $\boldsymbol{S_{i,max}}$ in each region $\boldsymbol{i}$. 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 $\boldsymbol{S_{i,max}}$, 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) $\boldsymbol{b}$ and the constant $\boldsymbol{a}$, which depicts the starting point of the supply curve from the $\boldsymbol{y}$ axis and is given as the minimum entry-cost $\boldsymbol{P_{i,min}^S \neq 0}$.

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

$$\boldsymbol{P_i^S = \frac{S_i - a}{b}}$$

After I had computed these two parameters I could calculate the initial marginal cost coefficient $\boldsymbol{b}$. 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 $\boldsymbol{S_i}$ represent the production of each region in Mcm/day and data is taken from I.E.A. (2016). The variable $\boldsymbol{S_{i,max}}$ 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.

3.3. 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[15], 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). 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

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

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:

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

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)[16].

4. Conclusions

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 explicitly 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

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

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. Europe as a continent relies on Russia for about one-quarter 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. Moreover, E.U. is partly liberalized and not completely integrated: The North-Western part is a more developed and liquid market than the South-Eastern. 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.

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. 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.

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 an alternative scenario, where Norway's liberalization process caused lower supply price and decreased production costs, even lower than that of Russia's, Norway's production cost decreased to 0.86 $/MMBtu from 1.62 $/MMBtu. Norway still could not compete with Russia, instead Norway cut 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 on the reference case is at 1.42 $/MMBtu. On the other hand, if Norway should fully liberalize its market, the break-even price of natural gas could be at 1.25 $/MMBtu. Besides, 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.

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 Member-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, Russia supplies cover most of the demand in the (65%), even though when 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, a feasible solution could be 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. The opportunity cost for E.U. to achieve energy security is at 0.34 $/MMBtu. Yet, many of E.U.'s 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, it is worth mentioning that 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.