OUTLOOKG1UNIVERSIDAD PONTIFICIA COMILLAS DE MADRID
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)
(Instituto de Investigación Tecnológica)

A MODEL-BASED APPROACH FOR THE ANALYSIS OF THE EUROPEAN INTERNAL NATURAL GAS MARKET

Tesis para la obtención del grado de Doctor

Directores: Prof. Dr. Javier Reneses Guillén
Prof. Dr. Sonja Wogrin

Autor: MSc. Aurora del Valle Díez

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AUTOR: MSc. Aurora del Valle Díez

DIRECTOR: Dr. Javier Reneses Guillén

CODIRECTOR: Dra. Sonja Wogrin

TUTOR-PONENTE:

DEPARTAMENTO: Instituto de Investigación Tecnológica (IIT)

FACULTAD: Escuela Técnica Superior de Ingeniería (ICAI)

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This thesis is also yours.

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Acronyms:

ACER	European Agency for the Cooperation of Energy Regulators
APAC	Asia-Pacific
Bcm	Billion cubic meters
BPP	Bilevel Programming Problem
Btu	British thermal unit
CAM	Capacity allocation mechanism
CEER	Council of European Energy Regulators
CEF	Connecting Europe Facility funds
CEGH	Central European Gas Hub
CIS	Commonwealth of Independent States
CMP	Congestion Management Procedure
CSP	Contract sales price
DAT	Delivered At Terminal
DES	Delivery Ex Ship
DM	Decision Maker
E&P	Exploration and production
EC	European Commission
ECSC	European Coal and Steel Community
EIA	US Energy Information Administration
EPEC	Equilibrium Problems with Equilibrium Constraints
ETS	Emission Trading System
EU	European Union
FID	Final Investment Decision
FOB	Free on Board
FSRU	Floating Storage Regasification Unit
GBL	GasPool
GoG	Gas-on-Gas
GTM	Gas Target Model
HHI	Herfindahl-Hirschman-Index
IEA	International Energy Agency
ISO	Independent System Operator
ITO	Independent Transmission System Operator
JCC	Japanese Crude Cocktail
KKT	Karush-Kuhn-Tucker conditions
Latam	Latin America
LDCs	Local Distribution Company
LNG	Liquefied natural gas
MCA	Multi-Criteria Analysis
MCP	Mixed Complementarity Problem
MIBGAS	Mercado Ibérico del Gas
MIQCP	Mixed-integer quadratic problem
MOP	Multiobjective Programming
MPEC	Mathematical Program with Equilibrium Constraints
MSs	Member States
Mtpa	Million tonnes per annum
n/a	not applicable
NBP	National Balancing Point

NC	Network Code
NCG	Net Connect Germany
NG	Natural gas
OECD	Organization for Economic Cooperation and Development
OPE	Oil Price Escalation
OTC	Over-the-counter (i.e. off-exchange trading)
P2Gs	Power-to-Gas stations
PCI	Project of Common Interest
PEGs	Points d’Echange de Gaz
PSV	Punto di Scambio Virtuale
RES	Renewable energy sources
RSI	Residual Supply Index
SPA	Sales & Purchase agreement
ToP	Take-or-Pay
TPA	Third-party access
TRS	Trading Region South
TSO	Transmission System Operator
TTF	Title Transfer Facility
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage
WTI	West Texas Intermediate
ZEE	Zeebrugge

Chapter 1

Motivation and thesis objectives

The vision of a competitive European gas market defined in the European Gas Target Model (CEER 2011) comprises entry-exit zones with liquid virtual trading points, where market integration is served by appropriate levels of infrastructure, which is utilized efficiently and enables gas to move freely between market areas to the locations where it is most highly valued by gas market participants.

1.1. Introduction

In this section, we present the motivation for developing this doctoral thesis and give an outline of the objectives set to achieve it. We start by presenting the motivation and then the main objective. Then, specific objectives are stated. Finally, we present a brief review of the current state of the art on natural gas market models in order to highlight the strengths and the literature gaps covered by this thesis.

1.2. Motivation

The global natural gas sector is going through a transformation, facing several challenges during the last decade related to technological advances, geopolitical changes, and strategic policy shifts. This is due to a combination of the following factors: 1) the shale gas revolution in North America and the emergence of a greater diversity of suppliers due to the exploration of unconventional sources and an increase in global liquefaction capacity; 2) the globalization of the natural gas markets through liquefied natural gas (hereafter, LNG), taking advantage of price arbitrage opportunities among gas regions; 3) demand shocks as the one resulted by the accident at Fukushima in 2011 or People's Republic of China (hereafter, China) clean air policies in 2017; 4) the continued expansion of liquefied natural gas market opening new emerging markets; 5) changes in the way natural gas is traded, with an evolving framework from long-term contracts based on the cost of alternative fuels (oil price) and big take-or-pay commitments (hereafter, ToP) to liquid markets with transparent gas index prices (gas-on-gas pricing[1], hereafter, GoG) and an increasing spot market; and 6) the role of natural gas in the quest for a more sustainable energy system (CEER 2018)[2] (Dickel, 2018)

These circumstances were also underpinned in Europe by the liberalization process, the emergence of new gas trading hubs, the European transition towards contract renegotiations in favor of hub-linked pricing and an increase in spot gas imports.

While there is a huge uncertainty in the gas sector and its role in the future energy mix is not clear, the European Union (hereafter, EU), in order to adapt to the new challenges in the energy use to achieve the 2020, 2030 and 2050 objectives, is building its internal

[1] Gas-on-gas pricing or gas-on-gas competition refers to any natural gas trade in which the price is determined by supply and demand market fundamentals.

[2] The study discusses the potential future role of gas in a context of the COP21 decarbonization targets, the growing share of renewable energy and price trends of carbon and other fossil fuels, on a time horizon to 2040.

energy market. The EU continues with the privatization and liberalization process and the creation of a unique and competitive natural gas market, which can guarantee security of supply. To harmonize and liberalize the internal gas market, the EU adopted three consecutive legal packages between 1998 and 2009. These packages cover areas such as market access, transparency and regulation, in order to harmonize Member States' (hereafter, MSs) regulations, incentivize consumer protection, and favor the creation of a pan-European integrated natural gas market, supporting adequate levels of interconnection and supply. Together with these three energy packages, the European Gas Target Model (hereafter, GTM) (CEER, 2011) and (ACER, 2015), was developed, in which a common vision for the European gas market is defined, based on a simplified representation of the physical characteristics of the transport network with an entry-exit network access regime and the creation of virtual hubs (i.e. wholesale gas markets). Additionally, with the aim of dealing with the increasing trade between countries in the internal energy market (i.e. through cross-border interconnections), Network Codes or Guidelines have been developed, governing all cross-border gas market transactions.

These measures aim to build a more competitive, fully functioning and interconnected internal energy market. An additional effort is being done, for ensuring appropriate levels of interconnection among European countries in order to prevent bottlenecks and achieve an efficient European physical gas market, whilst providing additional sources of gas. In this context, the European Commission (hereafter, EC) is putting infrastructures at the forefront for the creation of a pan-European energy market and highlights the role of natural gas as a transitional fuel in a Climate and Energy framework. In this context, the EC has banked on more investment in infrastructure, presenting an updated list of key energy infrastructure projects every two years (i.e. electricity, gas and oil). These projects are called Projects of Common Interest (hereafter, PCIs) and are considered as critical infrastructure projects in order to help the EU achieve its energy policy and climate objectives. These PCIs may benefit from accelerated and cheaper planning and permit granting, and they also have the right to apply for public funding from the Connecting Europe Facility (hereafter, CEF).

This Thesis has been motivated, mainly, by the growing interest shown by the European Commission in the build-up of the internal European gas market. This market relies on the creation of entry-exit balancing zones with virtual natural gas hubs (i.e. trading points), where market integration and security of supply is achieved by appropriate levels of infrastructure - PCIs - by connecting the energy markets in Europe and by diversifying the energy sources and transport routes. This market definition is in line with the Council conclusion that "*No EU Member State should remain isolated from the European Gas and*

Electricity networks after 2015 or see its energy security jeopardized by lack of the appropriate connections”[3].

1.3. Literature review on gas market models

As there is a vast literature on natural gas models, we focus our literature review on optimization models which represent the natural gas market under a market perspective, optimizing commercial and operation decisions rather than focusing on technical or engineering aspects such as flows, pressures, etc. which are out of the scope of this review.

In order to help to understand the advantages and limits of each model surveyed in this section and this thesis’s contributions, the different natural gas market models are categorized attending to the following taxonomy: optimization models based on cost minimization and complementarity-based equilibrium models.

1.3.1. Cost minimization optimization versus equilibrium models

Many market models use a cost minimization optimization approach to represent natural gas markets although complementarity-based equilibrium models have been the most popular ones. Cost minimization models involve an imaginary central planner who optimizes the market operation in order to meet the demand at minimum overall cost. These types of models are much easier to solve as they are algebraically simpler than complementarity-based equilibrium models. However, cost minimization models fail when considering anticompetitive behavior, which may occur in natural gas systems, due mainly to the exercise of market power and market foreclosure.

The most relevant models using a cost minimization approach are described below. The Institute of Energy of Economics at the University of Cologne has developed a family of optimization models using a cost minimization approach. In particular, the **EUGAS** model (Bothe & Seeliger, 2005) and (Lochner & Bothe, 2009), is a long-term optimization model that manages future European natural gas supplies, in order to minimize costs and optimize overall social welfare, assuming perfect competition. Additionally, investment decisions are represented as a binary option. As a worldwide extension of the Europe-focused EUGAS model, the **MAGELAN** model (Lochner & Bothe, 2009) was developed. Finally, the **TIGER** model (Transport Infrastructure for Gas with Enhanced Resolution) (Lochner et al., 2010), (Lochner, 2011), and (Dieckhöner, 2012) defines pipelines, storage

[3] https://www.consilium.europa.eu/uedocs/cms_Data/docs/pressdata/en/ec/119141.pdf

and LNG infrastructure in detail in order to conduct security of supply analysis for evaluating new investment projects in natural gas.

Other representative cost minimization models are briefly described herein. The **GASCOOP** (Dueñas, 2013) model, which represents accurately the performance of the Iberian natural gas market, optimizing the downstream operation and infrastructure capacity contracting decisions considering long-term supply contracts and LNG carriers' movements. The **ROM** model (Devine, et al., 2014) simulates UK natural gas market under different demand scenarios (i.e. stochastic demand) in order to optimize natural gas flows and prices. The **RAMONA** model (Hellemo, et al., 2012) formulates the investment problem as mixed-integer quadratic problem, considering pressure flow relationships as well as the gas quality. Its stochastic version is presented in (Fodstad, et al., 2016). And last, the Natural Gas Transmission and Distribution Module (**NGTDM**), which is the module that represents the natural gas market of the multi-sector model National Energy Modeling System (NEMS) (Gabriel, et al., 2001) and (EIA, 2009), developed and used by the US Department of Energy.

On the other hand, complementarity based equilibrium models, consider the simultaneous decision process of each agent at the same time. Agents' maximization problems are connected through the market clearing conditions. The resulting problem is a Nash equilibrium (Nash, 1951), in which no player has anything to gain by unilaterally changing its own strategy.

In this line, most of the attempts at characterizing the global natural gas market and the European natural gas market include the use of a complementarity-based approach. Some earlier efforts, as (Mathiesen, 2001), analyze the market power in the EU gas sector concluding that it can be described as a Cournot oligopoly. (Golombek et al., 1994) and (Golombek et al., 1998), analyze the effects of liberalizing the gas market in Western Europe by distinguishing between upstream and downstream agents and allowing agents to arbitrage. As highlighted by the previous authors, Cournot competition seems to be appropriate for representing the European gas sector. However, the Cournot assumption may overestimate the actual market power (i.e., the resulting market price). For overcoming this drawback, some models such as the **GASTALE** model (Boots et al., 2003) and (Boots et al., 2004) or the **NATGAS** model (Zwart & Mulder, 2006), have included conjectural variations, for calibrating different levels of market power. The first one (i.e. the **GASTALE** model), is used to analyze the European natural gas market. It focuses mainly on the role of the downstream trading companies and their interaction with gas producers, modeling a two-level structure in which each producer is a Stackelberg leader with respect to traders, who may be Cournot oligopolists or perfect competitors. Different market scenarios are run to analyze the extent of market power by these producers. In (Egging & Gabriel, 2006) and (Lise & Hobbs, 2008) the GASTALE model is extended, considering storage operations, seasonally varying demand, transmission constraints and LNG terminal capacities removing the successive oligopoly approach. In (Bornaee, 2012) stochasticity is introduced in S-GASTALE for analyzing decision making under uncertainty in the natural gas market. The second model (i.e. the **NATGAS** model) represents the European wholesale gas market, considering producers' market as an oligopoly by considering price-taker traders in the downstream market. The model provides long-run projections, which are aggregated in 5-year periods, modeling supply, transport, storage and consumption patterns in the model region.

Since then, a plethora of the models in the literature have used this approach. **GASMOD** model, in (Holz, et al., 2008) and (Holz, 2009), represents the European gas supply as a game of two successive equilibrium between upstream market and wholesale trade. The model allows for the representation of different market scenarios and concludes also that the European gas sector behavior is well captured by a Cournot oligopoly. The **EPRG-GMM** model (Chyong & Hobbs, 2014), represents the Eurasian gas market, modeling the oligopolistic relationships among producers with a special focus on the bilateral market power between producer (Russia) and transit (Ukraine) countries.

These types of models have also been applied to the North American and the global gas natural gas market. The **World Gas Model (WGM)** (Egging & Gabriel, 2006), (Egging et al., 2009), (Egging, 2010) and its stochastic version (Egging, 2013) and the **Global Gas Model (GGM)** (Holz & Von Hirschhausen, 2013) (Holz, et al., 2013), and its stochastic version S-GGM (Egging & Holz, 2016), are multi-period complementarity models for the global natural gas market with explicit consideration of market power. Market players include producers, traders, pipeline and storage operators, LNG liquefiers and regasifiers as well as marketers, and allow for endogenous investments in pipelines and storage capacities, as well as for expansion on regasification and liquefaction capacities. Other works modeling the global gas market include the **FRISBEE** model (Aune, et al., 2009), (Rosendahl & Sagen, 2009), the Baker Institute's World Gas Trade Model (**BIWGTM**) (Hartley & Medlock, 2005) and the **COLUMBUS** model (Hecking & Panke, 2012).

The **NGMEP** model (Gabriel, Zhuang, & Kiet, 2005), (Gabriel, Zhuang, & Kiet, 2005) and (Zhuang & Gabriel, 2008) is a Nash-Cournot equilibrium model applied to the North American natural gas market. Its stochastic version, S-NGEM, introduces uncertainty by applying probabilistic distributions to the demand over the time horizon. More recent, models include the North American natural gas model (**NANGAM)** for North America (Feijoo, et al., 2016), (Fodstad, et al., 2016) and (Feijoo et al., 2018). Additionally, there are also many equilibrium models which consider not only gas markets, but also other fossil fuels and economy sectors. Some examples are: the **MultiMOD** (Huppmann & Egging, 2014) and the **GAMMES** (Abada, et al., 2013). Both models include endogenous substitution between fuels. Other examples, include the bottom-up model for the US upstream **DYNAAMO** (Crow, et al., 2018); the **GSAM** model (Gabriel, et al., 2000), which analyzes the overall impact of the Canadian Carbon stabilization programs on the North American natural gas market; or the bilevel model presented in (Zeng, et al., 2017) which focuses on the coordinated expansion planning of the integrated natural gas and electrical power systems using Gas-fired Power Generations and Power-to-Gas stations (P2Gs).

1.4. Literature gaps discussion

After reviewing the current state of the art in natural gas market models, we have detected the following modeling gaps, which are relevant for an accurate analysis of the European internal natural gas market.

First, as shown in the previous section, there is a plethora of models to represent the regional and global natural gas markets. However, we have detected an important and generalized gap regarding the accurate representation of the natural gas market commercial dynamics, over-simplifying long-term contract representation and disregarding spot markets. A complete representation of the long-term supply contracts is achieved in the GASCOOP model (Dueñas, 2013), but just from the downstream side. Additionally, (Abada, Ehrenmann, & Smeers, 2014) presents a theoretical equilibrium model that endogenously captures the contracting behavior of both the producer and the shipper who strive to hedge their profit-related risk. Both models also represent the spot market as another source of gas supply. However, in the case of (Abada et al., 2014), the secondary spot market among shippers is ignored. Furthermore, as the spot trade through hubs is gaining momentum, the gas-on-gas pricing is spreading. Therefore, to cover the detected gaps, we propose a global mid-term model (GasValem – GoG) whose strengths are an accurate representation of long-term contracts, an explicit consideration of the spot market trade and the secondary market (i.e. through hubs) and the coexistence of oil-indexed and hub pricing mechanism. Thus, in order to explore the impact of the growing GoG competition on the natural gas market, we additionally include GoG pricing for long-term contracting, which to our best knowledge has not been considered before.

Due to the complexity involved in representing the global gas market, we select a cost minimization approach for modeling the global gas market with the GasValem – GoG. This approach allows us to include a detailed representation of the infrastructure as well as the commercial dynamics. In order to include market power in the global gas sector, we assume market power in the upstream through contract negotiations, and in the spot market, through a mark-up (i.e. as an additional transaction costs). Furthermore, traders try to maximize their portfolio incomes, maximizing netbacks (i.e. arbitrage opportunities between gas basins) and seasonal arbitrages opportunities with storage (i.e. both LNG tanks and underground storage). On the other hand, in the downstream, we assume a price-demand elasticity but no competition in prices, where agents behave as perfect competitors and market power is included as an additional mark-up to the cost of gas.

However, even if the last decade has witnessed the liberalization of the gas industry in Europe with the development of trading hubs, the efficiency of the gas market remains as a hot topic, as Europe is still on the middle of its transition. As natural gas hubs have emerged, different market structures appeared, and players made their strategic moves in order to adapt to the new market conditions, as the still oligopolistic market structure may give room for strategic behavior. However, none of the previous models allow to represent the different hub stages during the liberalization process. Thus, as our focus is on clearly describing and analyzing agents' behavior at the different stages of hub maturity, we develop a series of four academic equilibrium models (del Valle, et al., 2017), for this purpose. This exercise allows us to first, better understand the evolution of the trading hubs; second, to fulfill the gaps regarding the downstream market structure; and third, to complement and enrich the results shown by the aforementioned global gas model.

Finally, the integration of the European gas market has been a central concern in European policy reform efforts and investment in new infrastructure appears as a key element in order to allow gas to flow among European Countries while enhancing security of supply. With this in mind, we now focus on the capacity expansion planning, looking at a long-term framework. The aim of this work is to provide a tool for assisting the investment decision making process, analyzing the different investment options.

Many of the existing models allow for capacity expansion. However, those under a cost minimization approach, such as the ones from the TIGER family, disregard market power, which might be key in the capacity expansion problem. Market equilibrium models overcome this issue, representing the interaction between market power, capacity hoarding, infrastructure bottlenecks, and their impact on optimal capacity expansion. Examples of these models are: GASTALE, NATGAS, GASMOD, WGM or GGM. However, this type of models oversimplifies the dynamic nature of the operation and investment problem, as expansion and operation decisions are assumed to be taken simultaneously while, expansion and operation decisions are taken sequentially in reality. We consider the innate sequential structure of the capacity expansion planning, where first, capacity decisions are taken, and second, operation decisions are made in the market. All approaches that model this type of two-level structure of the capacity expansion problem are referred to as bilevel (or closed loop) approach. Bilevel models - which have been widely used in the electricity sector, are still scarce in the natural gas arena and almost nonexistent in the natural gas infrastructure expansion planning. Two examples of bilevel modeling in the natural gas sector are described now. First, in WGM-MPEC (Siddiqui & Gabriel, 2013), a new method for solving mathematical programs with equilibrium constraints is presented. The method is applied to the WGM (Egging & Gabriel, 2006) restricted to North America, to represent an example of a shale gas producer in the US natural gas market acting as a dominant player. Second, the mentioned bilevel model presented in (Zeng, et al., 2017), which focuses on the coordinated expansion planning of the integrated natural gas and electrical power systems using Gas-fired Power Generations (GPGs) and Power-to-Gas stations (P2Gs).

Additionally, the capacity expansion planning problem entails several criteria that need to be borne in mind at the same time. Most of the models with endogenous capacity investment (i.e., GASTALE, NATGAS, GASMOD, WGM and GGM) contemplate the economic impact of the new infrastructure by considering its effect on the total social welfare. We have gone a step further and have incorporated multiple criteria (i.e. market integration, security of supply and competition), into the capacity expansion optimization process. Hence, by making this a multi-objective model, we obtain a portfolio of optimal investment solutions under the different criteria.

Therefore, we propose our last model whose objective is to represent a realistic decision-making process for analyzing the optimal infrastructure investments (in natural gas pipelines and regasification terminals) within the EU framework under a market perspective. Thus, in order to represent that expansion and operation decisions are taken sequentially, the different interest of market participants and the multiple criteria that need to be achieved simultaneously (i.e. market integration, security of supply, competition), we propose a multi-objective bilevel optimization model for representing the investment decision process in the European natural gas market (GASMOPEC).

¡Error! No se encuentra el origen de la referencia. graphically compares the most representative natural gas market models in the literature with respect to the criteria emphasized in this thesis. White circle points out that the criteria is not addressed at all and a black circle indicates that the criteria is fully addressed.

	Infrast. operation	Long-term contracts	Spot trade/hubs	Gas-on-gas pricing	Capacity expansion
TIGER (Lochner, 2011)	◐	◔	○	○	◐
GASTALE (Lise & Hobbs, 2008)	◐	◔	○	○	◐
WGM (Egging, 2013)	◐	◐	○	○	◐
GGM (Egging & Holz, 2016)	◐	◐	○	○	◐
GASCOOP (Dueñas, 2013)	◕	●	◐	○	n/a
RAMONA (Hellemo, et al., 2012)	●	◐	○	○	◕
GAMMES (Abada, et al., 2013)	◐	●	◐	◔	n/a
WGM-MPEC (Siddiqui & Gabriel, 2013)	◐	◐	◔	○	n/a
Hub equilibria[4] (Article II)	◔	◐	●	○	n/a
GasValem – GoG (Article III)	◐	●	●	●	n/a
GASMOPEC (Article IV)	◐	◐	○	○	●

Table 1-1 –Comparison of the most representative natural gas market models in the literature

1.5. Thesis objectives

The general objective of this Thesis is to advance research in global gas markets modeling by developing different optimization models, in order to carry out relevant studies for the assessment of the EU internal gas market while contributing to the research field of global gas markets. The developed models will be a valuable tool to assist regulators and industry players, in order to: 1) better understand the global natural gas dynamics, 2) conduct detailed analyses of the new competitive internal gas market within the European regulatory framework (i.e., subject to entry-exit access systems), and 3) take infrastructure expansion decisions efficiently in order to allocate their resources in a highly competitive

[4] "Hub equilibria" represents the four academic equilibrium models developed in order to study agents' behavior at the different stages of hub maturity.

global setting. The main objective can be broken down into the following specific objectives:

- The **first specific objective** is to represent the behavior of the different shippers (i.e., companies that are responsible for conveying the gas from producers to consumers) during the implementation and development of virtual natural gas hubs, with the aim of accurately capturing agents' decision-making process at the different stages of hub maturity. For this purpose, we present a new approach that represents the development of a hub in four stages, under a market equilibrium perspective, and study its impact on agents' behavior. The decision-making process of the different shippers is simulated under the proposed different market structures, representing four stages of the market liberalization process.
- Along the lines of the previous specific objective, hubs turn out to be an alternative to long-term contracts (hereafter, LTC) and become another source for gas procurement. Therefore, even if gas trade in Europe still relies on long-term contracts, traditional oil indexed contracts are being replaced by increasing volumes traded at hubs. This, in turn, is leading to increasing spot trade and a move towards hub-linked pricing. The topic is particularly debated within the European natural gas market, where Europe is currently in the middle of its transition. For this reason, our **second specific objective** is to develop a model able to capture accurately the performance of the new gas market dynamics, so it can provide us with reliable outcomes. For this aim, we propose a model (GasValem – GoG) which captures these new commercial trends providing insights of the mid-term natural gas market. Therefore, in addition to the different market agents and key infrastructure, the model accounts for the different supply options (i.e. long-term contracts or spot market), modeling the coexistence of oil-indexed and hub pricing mechanism, allowing to explore the impact of the growing GoG competition on the resulting prices. Moreover, this model does not only fulfill academic purposes, but can also be used by any stakeholder, such as market participant, regulatory authority or facility operator.

- Finally, infrastructures are put in the forefront in order to achieve an efficient internal gas market. Thus, in the context of the PCIs, our **third specific objective** is to provide a tool for assisting the investment decision making process to determine EC support, analyzing the different investment options. Therefore, we propose a model (GASMOPEC) whose objective is to represent a realistic decision-making process for analyzing the optimal infrastructure investments (in natural gas pipelines and regasification terminals) within the EU framework under a market perspective. Thus, in order to represent that expansion and operation decisions are taken sequentially, and to represent the different interests of market participants and the multiple criteria that need to be achieved simultaneously (i.e. market integration, security of supply, competition), we propose a multi-objective bilevel optimization model for representing the investment decision process in the European natural gas market.

This thesis' structure and its specific objectives are shown in Figure 1-1.

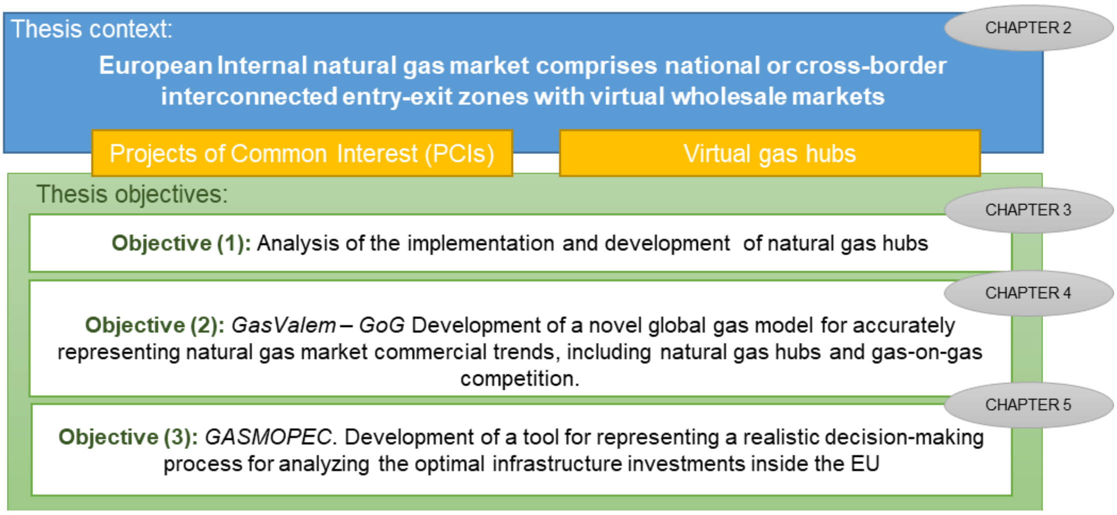

Figure 1-1 – Relationship among context, thesis objectives and structure

In addition, each specific objective is supported by one scientific contribution. This thesis is based on the work of four articles, which are labelled as Article I–IV and listed as follows.

Journal Articles

Article I del Valle, A., Reneses, J., Wogrin, S., 2018. "La creación de un mercado único de gas natural en Europa." Anales.

Article II. del Valle, A., Dueñas, P., Wogrin, S., & Reneses, J., 2017. "*A fundamental analysis on the implementation and development of virtual natural gas hubs*," Energy Economics, Elsevier, vol. 67(C), pages 520-532.

Article III del Valle, A., Reneses, J., Wogrin, S., April 2019. "*A global gas market model to deal with the new commercial trends in the natural gas market*." (currently under review in Energy - The International Journal).

Article IV del Valle, A., Reneses, J., Wogrin, S., 2018. "*Multi-objective bi-level optimization model for the investment in gas infrastructures*". Working Paper IIT-18-008A (currently under review in Energy Strategy Reviews July 2018).

We associate the papers with the different objectives as shown in Figure 1-2.

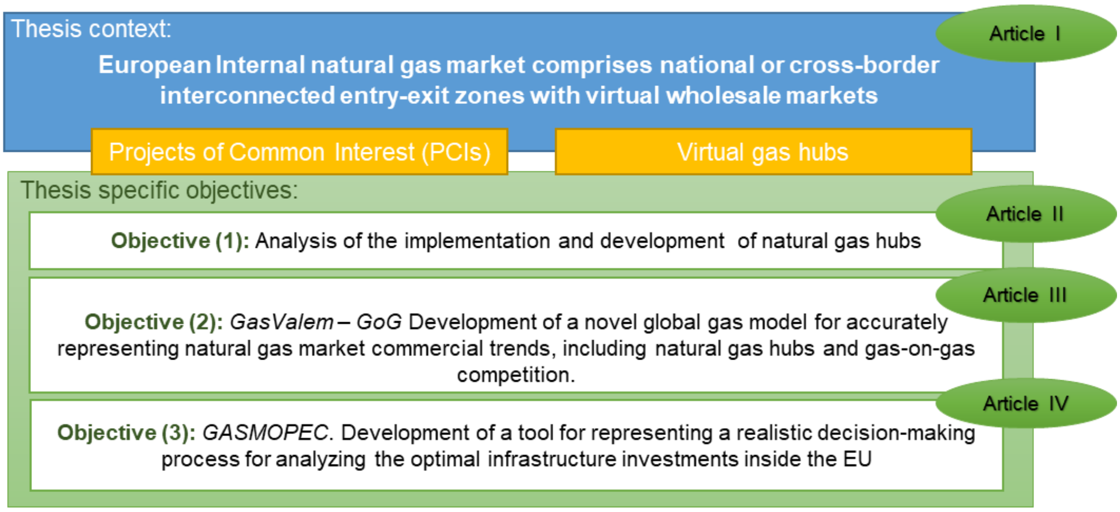

Figure 1-2 – Relationship between specific objectives and articles

1.6. How to read the remainder of the document

In this thesis, we develop different optimization models in order to carry out relevant studies for the assessment of the EU internal gas market while contributing to the research field of global gas markets modeling.

In particular, in **Chapter 2** we first provide a worldwide outlook of the natural gas sector and then we focus on the natural gas European market and in its liberalization process. This introductory part is followed by a more detailed part, diving into the Gas Target Model, and EU efforts towards the achievement of an internal European gas market, in order to better understand the context of this thesis. Chapter 2 also initiates the reader with basic concepts such as long-term contracts clauses, natural gas hubs, or entry-exit access systems, terms that will be used throughout this thesis; hence, it constitutes a basic chapter, particularly, for a reader who is not familiar with the topic.

In **Chapter 3** we study agents' behavior during the implementation and development of a virtual natural gas hub. We provide an answer to this question by carrying out a theoretical analysis developing four different equilibrium models, representing the different levels of hub maturity.

Once we have analyzed the impact of implementing virtual hubs in entry-exit systems, we focus on its impact on the new commercial dynamics. As the spot trade is gaining importance, hubs support increasing levels of trading volumes and liquidity and they appear as a natural reference for GoG pricing. To study this topic more in detail, in **Chapter 4** we develop a mid-term global gas market model (GasValem – GoG). In particular, we represent in detail the natural gas world trade, from the wellhead to the consumer, including all the different sources of gas supply (i.e. long-term market, spot trade and secondary market) and the coexistence of oil indexed and GoG pricing. The model is applied to a worldwide real case study for 2020.

In **Chapter 5**, we focus again on the European gas market, and incorporate an essential element that was initially omitted on purpose in both models but that has been highlighted as key for the achievement of the Internal European gas market: infrastructure capacity expansion. Therefore, in this chapter we present the GASMOPEC model, which allows for the assessment of the European PCIs, analyzing the different expansion plans under different criteria and obtaining a Pareto front of optimal plans. The proposed model is used for the assessment of the expansion capacity in natural gas infrastructure in Western Europe.

Finally, **Chapter 6** presents the conclusions, the thesis contributions and future research.

The document is organized as self-contained chapters. Each chapter starts with a brief introductory section with the purpose of putting the reader into context. After a conceptual and motivational introduction of the topic, its main analytical objective is clearly stated. These introductory sections are followed by the formulation of the model, and a realistic case study that illustrates the analysis and allows us to draw conclusions.

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Chapter 2

An overview of the natural gas market

The exploration of unconventional gas sources, the globalization of natural gas market due to the liquefied natural gas and in the supply side a growing demand and its role as a transition fuel to a low carbon economy, have shaped the evolution of the natural gas market during the last decade.

An overview of the Internal European natural gas market was published in **Article I** *(Del Valle, Reneses, & Wogrin, 2018).*

2.1. Introduction

In this chapter we first give an outlook of the natural gas sector (sections 2.1 and 2.2) and in section 2.3 we focus in the European natural gas market linking with the European internal gas market in section 2.4.

2.1.1. The role of gas in the shift to a low-carbon economy

In the quest for a more sustainable energy system in line with the Paris Agreement, natural gas is generally regarded as the best transition energy resource half-way between high-carbon fossil energy (i.e. coal and oil) and renewable energy, because of its lower emissions and the abundant and cheap global reserves.

However, its future consumption may be jeopardized by more restrictive carbon budget (i.e. emission targets), reducing the accumulated amount of carbon that can be released into the atmosphere. This will automatically imply a move to cleaner sources of energy, in which natural gas has potential on both, the upside (i.e. versus coal and oil) and the downside (i.e. versus renewables).

In this context, even if the future role of natural gas in the global energy mix seems increasingly uncertain, natural gas is in the middle of its growth phase, being the fastest growing energy source other than renewable power, growing at a pace of +2.8% compound annual growth rate (hereafter CAGR) 2009-2017 (BP, 2018). This growth has been favored by the North American shale boom, the rapid growth of the liquefied natural gas business, and the development of new gas markets in Asia.

Continuing with this trend, industry widely forecasts the growth of gas to continue over the coming decades (both in the mid- and in the long-run) (IEA, 2018a),(IEA, 2018c). The latest World Energy Outlook (IEA, 2018c), in all its scenarios, forecasts that natural gas will grow globally much faster than either oil or coal to 2040. For its base scenario (i.e. new policies scenario (NPS)) they expect a growth of +1.6% CAGR 2017-2040. Still, natural gas would have to face several market challenges in the future (IGU, 2018b), based on: 1) its cost competitiveness relative to other fuel sources; 2) its key role enhancing security of supply and the accessibility to reliable sources of gas; and 3) its role in a low carbon economy, as back-up for renewables integration (i.e. intermittent renewables) and as an instrument to reduce CO_2 emissions (i.e. coal/oil to gas switching) and urban air pollution. Moreover, the macroeconomic trends and the political stability will be key on both, the supply and the demand side.

Finally, future gas growth would not be homogenous among regions and sectors, and it would depend on primary energy demand growth, the gas penetration in the energy mix, and Government policies (as has occurred for example in China with the clean air program favoring coal to gas switching (Miyamoto & Ishiguro, 2018) or with the Carbon Price Floor (CPF) in the UK (Hirst & Keep, 2018)). On the one hand, Europe's ambitious targets of a net zero-carbon economy by 2050 together with a flattening energy demand, implies a change in the role of gas (both in the mid and long term). While on the other hand, for emerging economies, with growing energy requirements, natural gas is a readily available, clean (i.e. compare to the rest of fossil fuels) and cost competitive fuel. Non-OECD Asia, Middle East; and Africa are expected to be the leading regions for potential gas growth (IEA, 2018a),(IEA, 2018c).

By sector, natural gas demand will be mainly driven by increasing levels of industrialization in the emerging economies and power sector demand (i.e. coal to gas switching trend and back-up for renewables). Additionally, the transport sector (i.e. road and sea) also offers growth opportunities for natural gas, where it has potential economic and environmental benefits compared to diesel and fuel oil. Moreover, LNG as a marine fuel is expanding globally, in order to comply with the International Maritime Organization (IMO) 2020 regulations.

Natural gas will play an increasingly important role in the future energy mix during the transition to a low carbon economy, being the fossil energy source with fastest growth rates. However, natural gas appears more as a bridge fuel towards decarbonization than as a long-term solution.

2.2. World natural gas outlook

Traditionally, world natural gas markets have operated as three major self-contained regions (i.e. with supply and demand balance closely self-balanced) as interconnectivity through LNG trade was limited. This isolation resulted in different gas pricing models and supply/demand dynamics in each region. These three major regions were distributed as follows: the first regional market comprises the Americas; the second regional market comprises Europe, Africa and the Commonwealth of Independent States (hereafter, CIS)[5] countries; and the last market gathers Middle East countries, Asia and Oceania.

[5] The CIS countries include Azerbaijan, Armenia, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan, Uzbekistan, and Ukraine.

However, even if the three gas regions persist currently and they might remain for some time to come, during the last decade important developments in the world gas market has transformed the status quo and favor the globalization of natural gas markets. The shale gas revolution in the United States, new investment in infrastructures, and new developments in upstream-midstream technology, have shaped the supply side. While on the demand side, changes in regional demand patterns and the emergence of new consuming markets, environmental affairs connected with reducing CO_2 emissions, growing security of supply concerns plus the liberalization process in Europe, have refurbished the demand side. The combined impact of these developments has increased markets connectivity favoring price convergence among regions and have boosted the shift from oil-indexed prices towards gas-on-gas[6] competition.

2.2.1. Supply

The **natural gas reserves** are the amount of gas that can be economically recoverable, and depend not only on the technology, but also on the market price. According to the BP Statistical Review of World Energy (BP, 2018), the top five countries in the classification of proved reserves (probability of recovery above 90%) in 2017 were: Russia (18.1% of global proved reserves), Iran (17.2%), Qatar (12.9%), Turkmenistan (10.1%) and the United States (4.5%).

By region in 2017, Middle East[7] accounts for the (40.9%) of the global proved reserves followed by CIS (30.6%), Asian Pacific[8] (hereafter, APAC) (10.0%), Africa (7.1%), North America[9] (5.6%), Latin America (hereafter, Latam)[10] (4.2%) and Europe[11] (1.5%) (BP, 2018). The reserves to production ratio in 2017 was 52.6 years, which means that the proved reserves can cover the current production for 52.6 years. However, even if natural gas reserves are plentiful around the world, the challenge lies in financing the necessary investment for developing those reserves and solving potential infrastructure constraints.

[6] The price is determined by supply and demand fundamentals

[7] The Middle East region encompasses the Arabian Peninsula, Iran, Iraq, Israel, Jordan, Lebanon, Syria.

[8] Asian Pacific includes Brunei, Cambodia, China, China Hong Kong SAR, China Macau SAR, Indonesia, Japan, Laos, Malaysia, Mongolia, North Korea, Philippines, Singapore, South Asia (Afghanistan, Bangladesh, India, Myanmar, Nepal, Pakistan and Sri Lanka), South Korea, Taiwan, Thailand, Vietnam, Australia, New Zealand, Papua New Guinea and Oceania.

[9] North America includes the United States, Canada and Mexico.

[10] Latin America includes South America and Central America

[11] Europe region encompasses the European members of the OECD plus Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, the former Yugoslav Republic of Macedonia, Georgia, Gibraltar, Latvia, Lithuania, Malta, Montenegro, Romania and Serbia.

Natural gas production has been increasing every year since the economic crisis of 2009, with a compound annual growth rate of 2.8% (BP, 2018), hitting production records every year, with a total production of 3768 Billion cubic meters (hereafter, Bcm) in 2017 (BP, 2018) (See Figure 2-1). Much of this growth in natural gas production comes from North America (mostly from the United States (hereafter, US) supported by the shale gas boom, becoming the first producing region with 20.0% of the total annual production in 2017. This shale gas revolution refers to a phenomenon that emerged in terms of domestic gas supply (unconventional[12] sources of natural gas) in the US. More specific, shale gas is natural gas that is found trapped within shale formations. Its development was possible due to the application of new technologies such as the hydraulic fracturing technology (i.e. fracking) and horizontal drilling, by injecting water, sand and chemicals into the horizontal borehole of the well at very high pressure to fracture the shale rocks and release the gas. This technology allowed shale gas to rise from less than 1% in 2000 to over 20% of domestic gas production in the US in a decade. In 2012, the US surpassed Russia as the largest natural gas producer for the first time since 1982 thanks to the shale gas revolution. For further information regarding the shale gas revolution in the US, the reader is referenced to (Stevens, 2012).

The second major producing region is CIS with a 22.2% of the total production in 2017. Among CIS, Russia accounts for the largest production (17.3% of global production). The region's natural gas output has surged strongly during the last years (i.e. +2.2% CAGR 2009-2017). However, it remains heavily oversupplied with a large amount of spare capacity of production. In order to monetize this unused capacity and allow for increasing exports, new supply projects are being developed. Some examples are Nord-Stream II pipeline from Russia to Germany, Power of Siberia pipeline from Russia to the China, and the Yamal LNG liquefaction terminal.

Middle East ranks in the third place, with 17.9% of total annual production in 2017 followed by and Asia Pacific (16.5%). Iran, production has grown since 2006 with a compound annual growth rate of +8.1% per year and represents 33.9% of total Middle East production, followed by Qatar (26.6%) and Saudi Arabia (16.9%). Qatar has the highest LNG liquefaction capacity globally with 77.5 million tonnes per annum (hereafter, Mtpa) and in 2018 has also announced new plans in order to expand its current LNG liquefaction capacity.

In the APAC region, China is the main producer, with 24.6% of Asia's production. China has accelerated its production since 2010 in +6.4% CAGR, with a huge increase during

[12] Unconventional gas consists of coalbed methane, tight gas, shale gas and hydrates.

the last two years, in order to reduce its dependence on natural gas imports (both natural gas and LNG). Australia is the second largest producer. Australia's production has more than tripled since 2004 in order to support its increasing LNG exports.

Production inside the European Union is in an accelerated decrease, mainly due to the caps established by the Dutch Government to the Groningen field production, and a relatively flat production in the UK for the past years. On the other hand, Norway's production continues to increase at +7.9% CAGR 2007- 2017, reaching a new all-time high in 2017.

In Latam, natural gas reserves accounted for 8.2 Trillion cubic meters (hereafter, Tcm) in 2017. From these reserves, Venezuela holds a 77.5%. Although the growth in unconventional gas production, the reserves in Argentina, Brazil, Trinidad & Tobago, Peru and Bolivia account in each of these countries for less than 6%. Natural gas production is much more distributed, between the major Latam countries. Venezuela accounts for a 20.9% of total Latam production, followed by Argentina (20.8%), Trinidad & Tobago (18.9%), Brazil (15.4%), Bolivia (9.5%), Peru (7.3%) and Colombia (5.7%).

Finally, Africa's proven gas reserves represent 7.1% of the world's proven reserves (13.1 Tcm in 2017). The gas upstream sector is being boosted by new investment. This includes investment in new pipelines, liquefied natural gas terminals and gas field projects. Although there have been several gas discoveries during the last years (i.e. Mozambique, Kenya, Tanzania and South Africa), 96.5% of gas production in 2017 continues to come from Algeria, Nigeria, Egypt and Libya.

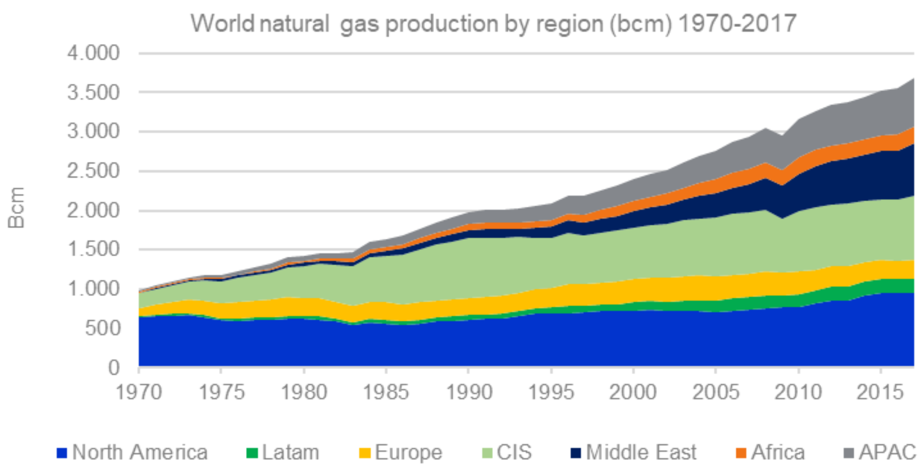

Figure 2-1 – World natural gas production by region (Bcm) 1970-2017. Source: Own elaboration based on data from (BP, 2018).

By organization, the share of non-OECD producing countries versus OECD in the global production has increased since 1990. While in 1990 production was approximately proportionately split between OECD and non-OECD countries, in 2017, non-OECD countries account for 64.3% of the total production.

By individual countries, the United States is the world's larger producer, and accounts for almost 45% of the growth in global production in 2016-2017. Russia remains as the second producing country, followed by far by Iran, Canada and Qatar. These five countries together represented more than half (52.9%) of the world's production. In 2017, China has consolidated as the 6th largest gas producer globally, followed by Norway, and Australia due to its increasing LNG exports. (see Figure 2-2)

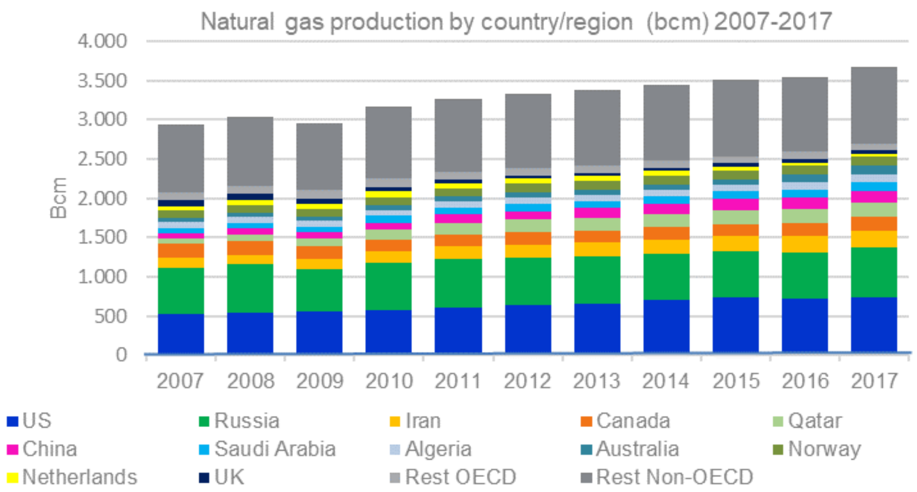

Figure 2-2 – Natural gas production by country/region (bcm) 1970-2017. Source: Own elaboration based on data from (BP, 2018).

2.2.2. Global Natural Gas Demand

Since the global financial crisis, global gas consumption has growth steadily at 2.8% CAGR 2009-2017 (see Figure 2-3), triggered by the accident at Fukushima in 2011, China clean air policies in 2017 and the continued expansion of liquefied natural gas market opening new emerging markets. These three points were supported by a recovery of the world's economic growth. In 2017, the global demand for natural gas rose up to 3757 Bcm (BP, 2018).The devastating earthquake and tsunami in Japan in 2011, which caused the accident at Fukushima Daiichi nuclear power station, shifted Japan's energy fuel mix in order to replace the resulted drop from nuclear power (i.e. prior to the earthquake nuclear power generation in Japan represented about 27% of the power generation). Given Japan's almost total lack of natural resources, its increased demand for new sources of energy (i.e. oil, natural gas, and coal) tightens global energy markets. In the natural gas market, Japan increased its natural gas demand in 23 Bcm during 2010-2012 becoming the world's largest liquefied natural gas importer.

In 2017, China's quest for blue skies shaped global natural gas market demand. Under the country's "Blue Skies" policy, the Government intensified policy action in order to fulfill its 2013 Action Plan on Prevention and Control of Air Pollution objectives. In the move towards a cleaner energy mix, natural gas consumption gained momentum mainly by coal-to-gas switching due to restrictions in the use of small coal boilers for industrial and residential use. This led to an astonishing demand growth of 15% in China and the highest increase in global natural gas demand since 2010 (+3% YoY in 2017 doubling the average growth rate of +1.5% over the prior five years). China accounted for nearly a third of the global increase (IEA, 2018b). As China's natural gas production couldn't match the demand growth, LNG imports in China surged, placing China as the world's second largest LNG importer after Japan. However, the demand growth was so strong that China grappled with a severe gas shortage and high import gas prices (IGU, 2018b).

The last factor supporting the strength of global natural gas demand are emerging markets. Natural gas growth has been driven by non-OECD countries (+2.5% CAGR 2012-2017) in the last years. This growth has been led by Asian non-OECD countries, with China and India leading the way, driven by a strong policy support to curb air pollution and a continuous economic growth. Other emerging Asian economies such as Pakistan and Bangladesh have substantially increased their natural gas demand during the last five years.

By regions, North America is the region with highest natural gas demand (942.8 Bcm in 2017) largely due to the US, accounting for 25.7% of global natural gas consumption in 2017 and for over one quarter of the total consumption growth of the last five years (2017-2012).

Asia Pacific occupied the second place in the rank of natural gas consuming regions, with a 21.0% of the global natural gas demand in 2017 (769.6 Bcm). It accounts for almost one third of total consumption growth during the last five years, led by China and other Asian emerging economies such as India, Taiwan, Bangladesh and Pakistan, largely due to the use of natural gas for the industrial sector. By contrast, natural gas consumption in the OECD-Asia has followed a different trend during the same period. Natural gas demand in Japan and South Korea has decreased over the period 2017- 2012 (-0.9% CAGR and -1.2% CAGR respectively) due to the restart of nuclear power generation and the deployment of renewables. Australia, which has increased its domestic production to meet exports, has kept almost flat its inner demand during the last three years.

CIS region is the third consuming region with 574.6 Bcm in 2017. Russia accounted for nearly 74% of this consumption.

Middle East is the region with highest demand growth (+5.1% CAGR 2012-2017) and its production accounts for 14.6% of the total natural gas demand, being the fourth world consuming region in 2017. This growth has been mainly supported by Iran's strong economic growth after the Iran Nuclear Deal in 2015. However, the re-imposition of US sanctions in 2018 has thrown uncertainty over its future evolution. Other leading countries in the region included Iraq, which has almost doubled its consumption in the last five years (5.6 Bcm growth), Qatar with 13.7 Bcm (7.0% CAGR 2012-2017) and Saudi Arabia with 17.1 Bcm (3.4% CAGR 2012-2017). Another important factor in the region is the diplomatic crisis between the United Arab Emirates (hereafter, UAE) and Qatar, started in 2017 and which has slightly reduced UAE's LNG imports from Qatar.

Europe's natural gas consumption keeps a sustained growth since 2014 driven by a stronger economic growth and coal-to-gas switching for power generation. However, consumption in 2017 (531.7 Bcm) was still below levels before the economic crisis. Within the EU, the highest absolute gas consumer is Germany (90.2 Bcm) followed by UK (78.8 Bcm), Italy (72.0) and Turkey (51.7).

Latam natural gas consumption represents just 4.7% of world's consumption. Argentina, Brazil and Venezuela gather up a 71.8% of the region's total demand.

In Africa, gas discoveries are stimulating gas consumption as an alternative to oil, mainly in power generation system. However, natural gas consumption in this region is still marginal and it represents a 3.9% of world's total demand.

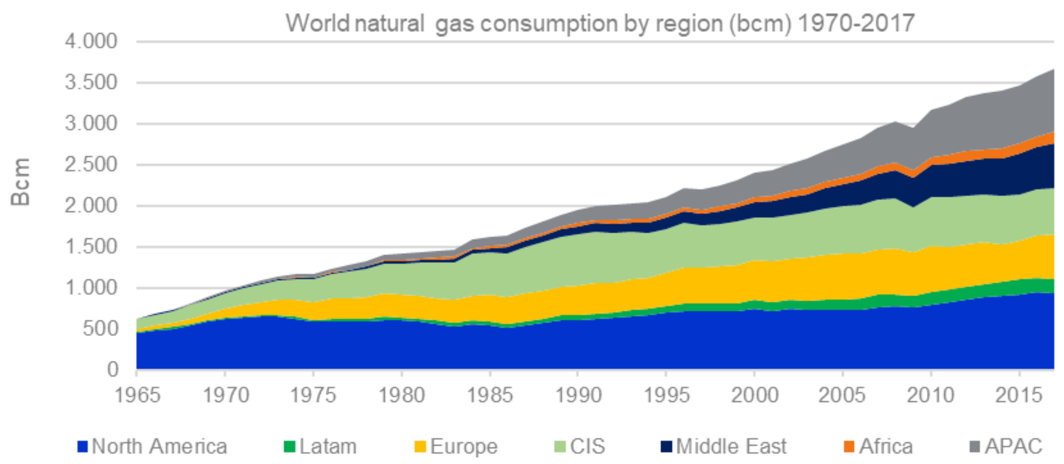

Figure 2-3 – World natural gas consumption by region. Source: Own elaboration based on data from (BP, 2018).

By organization, OECD natural gas demand grew at an annual compound growth rate of 1.4% during the last five years while non-OECD countries grew at 2.5% CAGR 2017-2012.

This has shifted the growth of natural gas demand to non-OECD countries. In absolute values, non-OECD countries accounted for 54.3% of total demand in 2017.

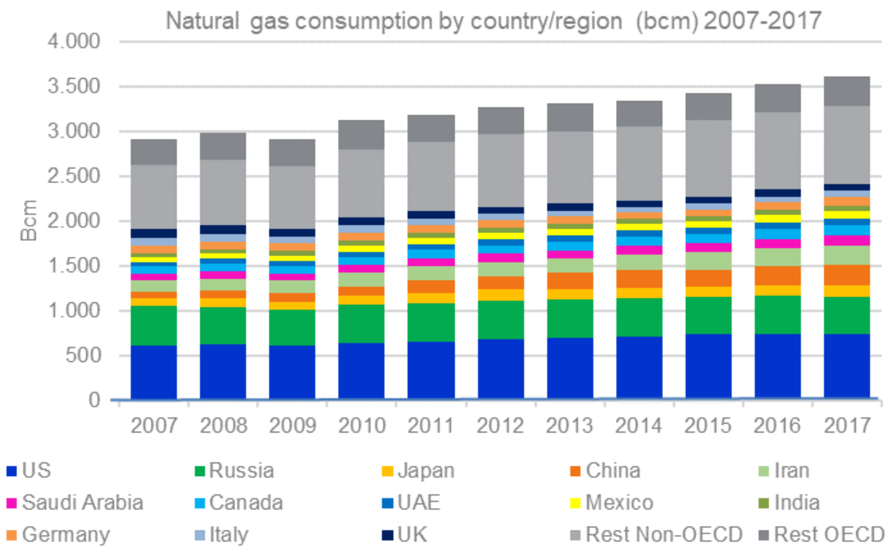

Figure 2-4 – World natural gas consumption evolution by major country and region (bcm) 2007-2017. Source: Own elaboration based on data from (BP, 2018).

The two largest producing countries are also the largest consuming countries. The United States is the world's larger consumer with 20.0% of the global consumption in 2017, followed by Russia that accounts for 12.0%. The rest of countries in the top five rank of largest consumers in 2017 are: China (6.6%), Iran (5.8%) and Japan (3.2%) (See Figure 2-4).

2.2.3. Liquefied Natural Gas (LNG)

Liquefied natural gas (or LNG) has been commercialized for more than 50 years. Natural gas is liquefied at approximately -161C° and it can be transported by ship, enhancing the globalization of the worldwide natural gas market, connecting markets and favoring the entrance of new ones. In the last decade, the growth in its use has been accelerated and it now represents 11% of the total natural gas consumption and accounts for about a third of the global trade of natural gas (IGU, 2018a). Worldwide LNG trade in 2017 amounted to 290 Mtpa, the third highest year for LNG on record and the highest annual growth since 2010.

Additionally, as LNG can be shipped to different parts of the world, it has allowed traders and marketers to take advantage of arbitrage opportunities among the regional gas markets, based on leveraging differences in gas prices. These arbitrage opportunities have evolved as LNG production increased and new imports facilities came online

(Ledesma, Young, & Holmes, 2013). The shale gas revolution in the mid-2000s in the US shifted LNG that was expected to be delivered in the US to Europe first, and later to Asia and South America as the demand in these markets increased. Additionally, the US unconventional gas production has created a persistent split between regional gas prices that has been maintained during the last decade. In 2011, after the Fukushima disaster, Japan's nuclear power plants were shut down and substantial volumes of LNG were sent to Asia. This situation provoked a huge increase on Asian LNG prices leading to almost 18 $/MMbtu (million British thermal units), increasing the price gap among basins. The switch in differentials led to a change in global gas export patterns, with a significant increase in flows to Asia. With Asian LNG prices reaching highs, European traders and marketers took advantage of arbitrage opportunities doing reloads for Asian markets. With the gradual restart of the nuclear reactors, imports were decreased and price difference between basins shrunk. In 2017, with the rapid increase of the Chinese demand, global LNG prices rebound as consequence of the international supply/demand balance. This shock in LNG demand in China skyrocketed LNG prices in Asia to 11.5$/MMbtu in the last months of 2017 and winter 2018 (See Figure 2-5).

In 2018, North America's natural gas prices continued to be moderated by US shale gas through technology and efficiency improvements. Asia's LNG demand kept on growing, but at a lower pace while Asian spot LNG prices fell. This trend was mainly supported by China as the key market driver in the Pacific Basin LNG demand growth. Moreover, prices were also influenced by the sharp decline in oil prices (October 2018), applying downward pressure, resulting in lower oil-indexed contract prices. In Europe, natural gas prices were highly impacted by the international demand/supply balance and largely depend on Asian demand. Additionally, the European market was also highly influenced by coal-to-gas switching in the power sector, with high coal and CO_2 prices, which provided a soft floor for gas. This has reduced the regional price differential between the Pacific and the European basin. In 2018, the price at the US Henry Hub averaged 3.11 $/MMBtu while the price at the UK's NBP averaged 7.88 $/MMBtu and the Asian LNG was 9.74 $/MMBtu. (See Figure 2-5). With this EU-East Asia price arbitrage, most of the cargoes went to Asia rather than to Europe. However, during the second half of 2018 due to the weak price differentials and high shipping costs, US LNG flipped from Asia to Europe and Russian LNG from the Yamal export project stayed in Europe. Nevertheless, Asia is still the preferred spot market for Middle East LNG exporters. In spite of the greater availability of global LNG production expected for the near future, the price dynamics of LNG in the EU will continue to be affected by market dynamics in Asia.

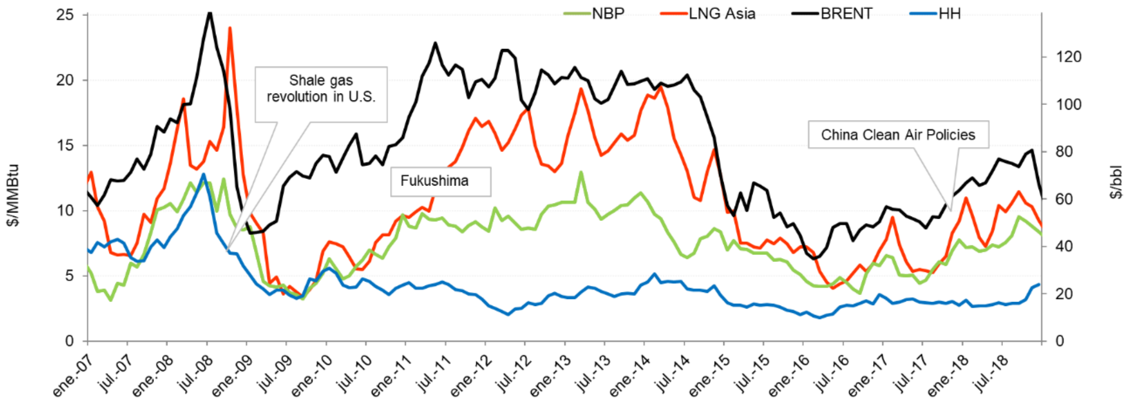

Figure 2-5 – Natural gas prices evolution. Source Own elaboration based on data from Reuters

Since the 1990s, investment in LNG infrastructure has grown rapidly worldwide as global natural gas demand increased. Exporting and importing terminals have been built around the world from North America and Europe to APAC, the Middle East and South America. As these infrastructures are capital intensive, their construction is normally supported by long-term contracts (i.e. Sales and Purchase Agreements (SPA)) (Neumann, Ruster, & von Hirschhausen, 2015) (Ruester, 2015).

Global liquefaction capacity was of 389.6 Mtpa in 2018 and is distributed among 19 countries[13]. Currently, Asia Pacific ranks in the first place as the region with more regasification capacity (38.4% of total regasification capacity). Australia accounts for 19.7% of the global LNG liquefaction capacity in 2018 and will add capacity of 10 Mtpa from one under construction (i.e. Ichthys LNG) and two planned terminals during 2018-2025.

Middle East region accounts for 25.9% of world's second LNG exporting capacity, leading by Qatar, who accounts for 20.1% of the total global LNG liquefaction capacity and they have revised its LNG capacity expansion target boosting it from 100 Mtpa to 110 Mtpa.

Africa accounts for the 17.5% of LNG exporting with six countries (i.e. Algeria, Angola, Egypt, Nigeria, Equatorial Guinea and Cameroon) having export capabilities.

In CIS region, the first train of Yamal LNG achieved commercial operations in March 2018 adding 17.4 Mtpa of liquefaction capacity.

In North America several terminals will come online in the coming years from the extended phase of build-out that began in 2016, driven largely by the US. Moreover, after an impasse

[13] Algeria, Angola, Australia, Brunei, Egypt, Equatorial Guinea, Indonesia, Malaysia, Nigeria, Norway, Oman, Papua New Guinea, Peru, Qatar, Russia, Trinidad & Tobago, United Arab Emirates, United States and Yemen

in LNG supply investment for more than two years, following 2016 and 2017 (Wolter, 2016), the second part of 2018, have represented a breakthrough. Recent large-scale final investment decisions (hereafter, FID) at LNG Canada and Golden Pass in US, indicate that the investment standstill has come to its end. Moreover, these two projects have reached FID without securing long-term offtake agreements with third parties, but by entering in the equity of the projects, introducing a new strategy in the market. In Figure 2-6, existing and under construction global liquefaction capacity is illustrated.

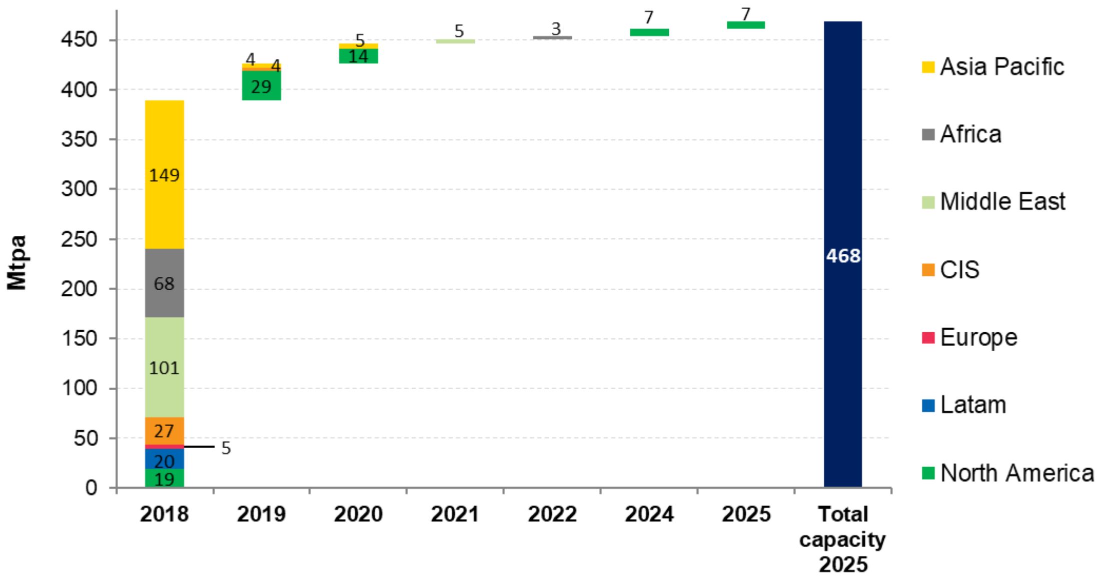

Figure 2-6 – World natural gas liquefaction capacity (Mtpa). Existing in 2018 and under construction. Source: Own elaboration with data from (IGU, 2018a), (GIIGNL, 2018)

By exports, in 2009 Middle East surpassed non-OECD Asia and Africa becoming the first LNG exporter, remaining as the main LNG exporter in 2017, with 31.7% of the global LNG exports (i.e. mainly from Qatar, Oman and UAE) (see Figure 2-7). However, its market share has been reduced during the last years from 40.8% in 2014 to 31.7% in 2017 in favor of new exporting markets such as Australia and the US. Asian non-OECD exports have slightly reduced its market share in the last four years, but it continues to be the second largest region in LNG exports with 20.9%.

The increase in LNG demand during the last two years has been supported by an increase in LNG supply from OECD Asia (i.e. Australia) and North America (i.e. United States), driven by record productions of unconventional gas and a strong increase in new liquefaction capacity.

The order of the top five exporters by share in 2017 were Qatar (26.7%), Australia (19.2%), Malaysia (9.3%), Nigeria (7.0%) and Indonesia (6.5%). Although non-OECD Asia has grown in importance as an LNG-exporting region in the last seven years, Qatar is still the largest LNG-exporting country by a large margin. Australia remains the second-largest exporter and has gained significant ground due to the entry of new liquefaction terminals in operation. The United States occupied the seventh position after Argelia in the rank of 2017 and has been responsible for nearly 3/4 of global LNG export growth during the same year.

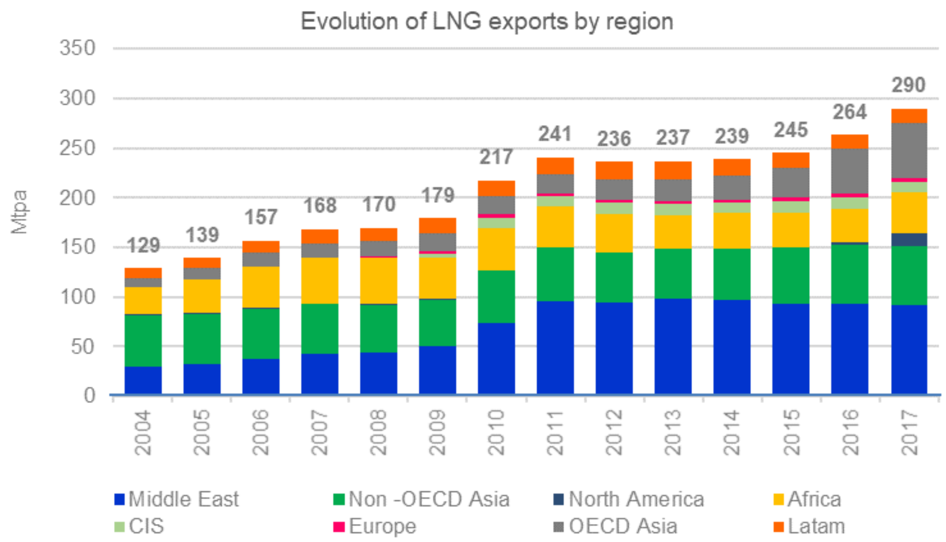

Figure 2-7 – Evolution of LNG exports by region. Source: Own elaboration based on data from IGU and GIIGNL

On the other hand, LNG has opened new consuming markets increasing the number of importing countries during the last decade, from 17 in 2007 to 42 in 2017, favored by the new technologies, such as Floating Storage Regasification Unit (hereafter, FSRU), and market flexibilities. The total regasification capacity in 2017 accounts for 795 Mtpa. From this regasification capacity, 57.8% is placed in Asia (39.5% in OECD Asia and 18.3% in non-OECD Asia). Europe is the second region in regasification capacity with 21.2% of global LNG import capacity, followed by North America (10.2%), Latam (6.0%), Middle East (2.8%) and Africa (2.0%) (IGU, 2018a), (GIIGNL, 2018).

By country, Japan is in the lead with 22.1% of world regasification capacity, followed by South Korea (17.4%), United States (9.2%), China (7.3%), Spain (6.2%), UK (4.5%), India (3.4%) and France (3.1%) (IGU, 2018a), (GIIGNL, 2018).

LNG demand is focused on Asia and Europe, which together accounted for 87% of the total LNG demand in 2017 (see Figure 2-8). LNG demand during this decade, has been boosted by Asia (both OECD and non-OECD Asia) led by Japan and Korea in the OECD side and by China and India in the non-OECD side. In 2017, Asia stands as the largest importing region, consuming over half of global LNG supply (50.3%). Europe remained as the second largest LNG importing region in 2017, after Asia, owing mainly to LNG demand in Spain, France, United Kingdom, Italy and Turkey. The rest of the markets (Latam, Africa, Middle East and North America), nowadays play a residual role in the global LNG demand. In these regions LNG is mainly used to supplement domestic production or to open new natural gas emerging markets.

The rank of LNG importers is 2017 was: Japan with 28.8% of total LNG demand imports, China (13.5%), South Korea (13.1%), India (6.6%), Taiwan (5.7%), Spain (4.2%), France (2.5%) and Turkey (2.5%) (IGU, 2018a), (GIIGNL, 2018).

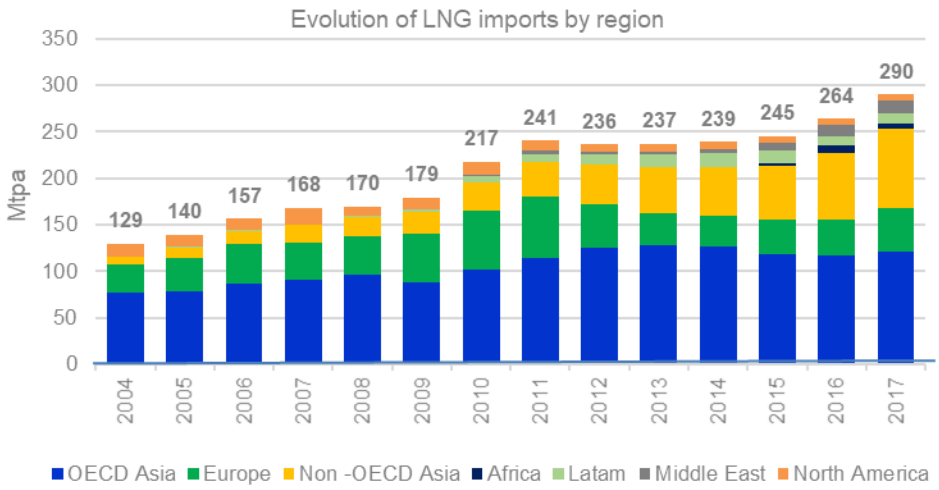

Figure 2-8 – Evolution of LNG imports by region. Source: Own elaboration based on data from IGU and GIIGNL

2.2.4. Commercial trends

Gas markets have traditionally relied on long-term bilateral contracts for supplying gas demand (Zajdler, 2012), (Neuhoff & Hirschhausen, 2005) and (Neumann et al., 2015). Still nowadays, about half of the traded gas is contracted in advance. Long-term supply contracts have played a key role for the development of gas supply infrastructures guaranteeing the recovery of investments. In summary, these long-term supply contracts are usually characterized by:

- Take-or-Pay (hereafter, ToP) clauses that imply that the buyer is obligated to make payments regardless of whether they have taken the gas or not (i.e. either takes the gas from the supplier or pays the supplier a penalty). Therefore, buyers are committed to purchase pre-fixed volumes of gas over a long time period and provide regular revenues to the seller. ToP contracts is often a percentage (e.g. 85% or 90%) of the annual contract volume, which is complemented with additional monthly maximum and minimum delivered volumes. As a result, the delivered gas volumes may not closely match buyer's customers' demand throughout the year. Thus, the buyer needs to optimize its contracts offtake in order to adapt to its demand (including seasonal patterns). To reduce buyers' exposure to the ToP commitment some contracts hold some additional flexibility over the ToP clauses such as Make Ups and Carry Forwards. The Make Up Gas allows the buyer to receive the gas it has already paid under ToP obligations in subsequent years for no further charge or at reduced prices and carry forwards allows the buyer to take more than its maximum annual contracted volume and to offset this gas against undertake gas in subsequent years.

- A price formula that has been agreed on between buyer and seller and is was usually indexed to competing sources of energy (such as fuel oil, gasoil, and coal or even wholesale electricity prices). More recently, new contracts are being priced using natural gas hub prices (i.e. typically to relevant and liquid hubs like Henry Hub or the NBP), or hybrid formulas indexed to a mixture of hub prices and alternative fuels.

- Contracts' destination flexibility will depend on the terms of the contract. Destination flexibility allows the buyer to deliver the cargo to different terminals, reducing the ToP risk (i.e. increasing offtake flexibility) by enabling the buyer to sell the gas to other markets. This allows the buyer to sell the cargo to a more rewarding destination (i.e. selling to higher priced markets), taking advantage of arbitrage opportunities. Some contracts will include a predefined delivery point, which requires the buyer to take the gas to a specific port or only sell the gas in a specified geographic area. Such restrictions have been declared illegal in certain jurisdictions as for example in the European Union, where they infringe upon the European Union antitrust rules.

- Additionally, for LNG contracts, the contract will include a provision with the shipping terms that stipulate costs and risk allocation (i.e. title, custody and risk transfer from the seller to the buyer) and are usually referenced to the Incoterms shipping rules. The most commonly used delivery terms are "Delivery ex ship"[14] (DES or DAT), and "free on board" (FOB). DES means that the seller retains title and bears all the cost and risks involved in the delivery, until the LNG is unloaded at its destination. In this case, the Sales and Purchase Agreement (hereafter, SPA) will identify a specific delivery port. By contrast, FOB means that the seller passes

[14] The DES term was eliminated from Incoterms 2010 and parties appear now to be using 'delivered at terminal' (DAT) in more recent agreements.

risk and title to the buyer, when the LNG is loaded into the ship, and the buyer bears all costs from that moment onwards.

However, the ongoing structural changes in the global gas market are having profound implications in the way natural gas is traded and priced. These changes have increased the necessity for a more flexible natural gas market. This has been reflected in the emergence of an increased spot market together with a tendency towards shorter contract (i.e. SPA) durations (typically around 10-15 years vs. the 20-25 years in the past) and increased contractual flexibility (reducing ToP commitments and destination clauses). This trend has been reinforced by the development of destination-free and gas-indexed US LNG exports, which have provided the global LNG market with additional flexibility.

Moreover, there is an ongoing move to gas-on-gas[15] (hereafter, GOG) competition. According to (IGU, 2018c), GOG competition stands at 46% of total world gas consumption. GoG dominates (almost 100%) the North American market with fully liquid trading markets in the US and Canada, and wholesale prices in Mexico referenced to US wholesale market prices. The most significant changes in price formation mechanisms, can be found in Europe, where the region is experiencing a continuous move from oil price escalation (OPE) to GOG since 2005, with GOG's share increasing from 15% in 2005 to 70% in 2017 (IGU, 2018c). This percentage is higher in northern countries and lower in southern ones. GOG price formation mechanism in Asia in 2017 accounts for 19% and have been dominated by China and India.

This GOG pricing has been supported by the emergence and consolidation of natural gas wholesale markets (i.e. hubs) in North America, Europe and Asia. Each of these regional gas markets differ on physical, competitive and regulatory arrangements. The emergence of hub pricing started in the US in the 1970s, with the Henry Hub (hereafter, HH) as the reference point for US natural gas prices. Following this evolution, the concept of hub pricing expands to Europe. The most representative trading hubs in Europe are the National Balancing Point (NBP) in the UK or the Title Transfer Facility (TTF) in the Netherlands. Finally, the APAC region has also shown its desire to develop flexible and liquid LNG market with hub-based pricing (IEA, 2013) and (Koyama, 2018). However, currently, their prices rely primarily upon long-term contracts tied to the Japanese Crude

[15] Gas-on Gas competition refers to any natural gas trade in which the price is determined by the interplay of supply and demand – gas-on-gas competition. It includes natural gas sold at natural gas hubs, long-term contracts which uses use gas price indexes in their price formula, and bilateral agreements or spot LNG cargoes, which are linked to a hub or any gas index.

Cocktail Index (JCC) (Rogers & Stern, 2014). Meanwhile, countries such as Japan, China and Singapore, have promoted initiatives to develop trading hubs.

Major transformations have shaped the evolution of global natural gas markets in the last ten years. In the supply side, an ample supply due to the exploration of unconventional gas sources has brought up new producers into the market and a surge in global liquefaction capacity. Additionally, an increase in the LNG trade has favored the globalization of the natural gas market. The demand side has kept growing triggered by demand shocks such as the accident at Fukushima in 2011 and China clean air policies in 2017, and the continued expansion of liquefied natural gas market opening new emerging markets. These changes have highlighted the necessity for a more flexible natural gas market, which has been reflected in an increased spot market together with a tendency towards more flexible SPA and new pricing mechanisms involving gas-on-gas competition.

2.3. Europe's natural gas outlook

2.3.1. A decarbonized Europe

As the European region continues to prioritize the decarbonization of its energy system, the role of gas is more unclear. Natural gas is considered as a transition energy source for the achievement of the goals of the energy policy created by the EU 20-20-20, the 2030 energy strategy and the route established for 2050 with the goal of helping the EU achieve a more competitive, secure, and sustainable energy system and to meet their long-term goals to reduce greenhouse gas emissions in 2050. Moreover, in line with the Paris Agreement objective[16], on 28 November 2018, the European Commission (EC) presented its strategic long-term vision for a climate-neutral Europe by 2050.

Europe's ambitious targets of a net zero-carbon economy by 2050 together with a flattening energy demand, implies:

[16] In Paris Agreement (COP 21 in Paris) it is established the objective of keeping a global average temperature increase below of 2 degrees Celsius (ideally, 1.5 degrees) above pre-industrial levels.

- A progressive reduction in the thermal gap (i.e. the quantity of energy necessary to cover the demand generated by conventional thermal power stations (i.e. nowadays mostly coal and natural gas), due to the gradual introduction of more renewable energy sources. However, in the near-mid-term future natural gas will play a key role in the transition to a decarbonized economy, providing back-up for renewables, reducing the carbon budget by coal-to-gas switching and as an alternative fuel to energy consumption that cannot be easily electrified (e.g. high temperature industrial processes and marine transport).
- Additionally, the electrification trend of final energy consumption, will likely increase electricity demand and could possibly increase the thermal gap, and therefore the natural gas demand for electricity generation. However, the competitiveness of gas versus coal in the power sector in Europe will depend not only on market fundamentals but also on the success of the EU Emissions Trading System (EU ETS).
- In the long run, in order reach a net zero-carbon economy by 2050, fossil natural gas demand should come to an end, in favor of renewable sources of energy which may include renewable gases (i.e. hydrogen and biogas).

Ergo, the future natural gas demand growth and the speed of the decarbonization process in Europe will be mainly driven by the evolution of the current and future energy policies, more than by market fundamentals.

In this context, in order to achieve a more competitive, secure and sustainable energy system and to meet its long-term 2050 greenhouse gas reductions target, the European Union has worked on the creation of an integrated liberalized EU energy market, for the integration of the different Member States (hereafter, MSs) through a trans-European transport network. In order to harmonize and liberalize the EU's internal energy market, common energy market rules have been adopted since 1996[17] and investment in new cross-border infrastructure has been carried out and incentivized. The key EU legislation for market liberalization and the creation of the EU internal market is illustrated in Figure 2-9

In the gas market arena, the core principles for the EU internal gas market are established in three consecutive Energy Packages, and comprises the unbundling of activities, the harmonization of the different market rules (i.e. market access, transparency and

[17] 1996 for electricity and 1998 for natural gas

regulation), the definition of entry-exit zones with the creation of liquid virtual trading points (i.e. hubs), and an appropriate level of infrastructure for ensuring market integration.

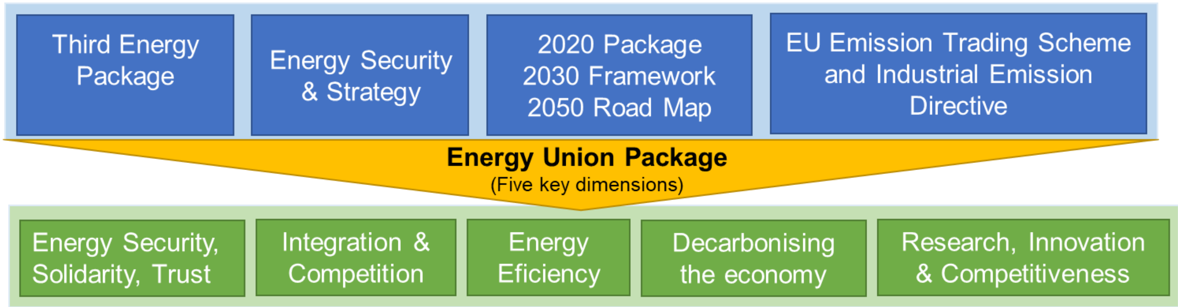

Figure 2-9 – Key EU legislation

2.3.2. Supply & demand fundamentals

Within the EU borders, natural gas production is declining due to limited reserves (UK reserves declined from 0.8 Tcm in 1997 to 0.3 Tcm in 2017, and in the Netherlands, the reserves declined from 1.7 Tcm in 1997 to 0.7 Tcm in 2017 (BP, 2018). This has turned out in around -6% average annual production decline since 2010-2017 (excluding Norway) and has led to an increase in imported gas volumes (either by pipeline or as LNG), that affects gas flows within the EU. A potential challenge for the EU is the risk of short-term supply disruptions as happened during the Russian-Ukrainian conflict (2009) or the Libya crisis in 2011 and the security of supply concerns due to the concentration of suppliers, most of them coming from countries considered as risky and Europe's dependency on these imports. Consequently, EU is trying to reduce its dependency on gas imports, by increasing their number of suppliers and reevaluating new gas routes within EU countries in terms of security of supply.

Natural gas indigenous production within EU borders accounts for 24.9% of total EU demand. Two thirds of this production are shared between UK (35.3%) and Netherland (32.4%) (See Figure 2-10). In the production side, the most remarkable decision was that taken by the Dutch Government to completely shut down production in the Groningen field by 2030, due to earthquake risks. This decision has materially limited production to nearly half in 2018 (from 21.6 bcm to 12 bcm) after a 60% reduction in 2013 (from peak of 54 bcm) and will continue to do so going forward until its closure.

Additionally, according to the Gas Infrastructure Europe (GIE) transparency platform[18], EU storage capacity is declining due both to closure and mothballing after reaching its maximum in 2016 (1,085 TWh). The most remarkable example is the permanent closure

[18] https://agsi.gie.eu

of Britain's biggest gas storage, Rough (30 TWh) (Le Fevre, 2017). This trend is expected to continue, as many of the current EU production and underground storage assets are on their way to reaching their end of operation life (Yermakov, 2019).

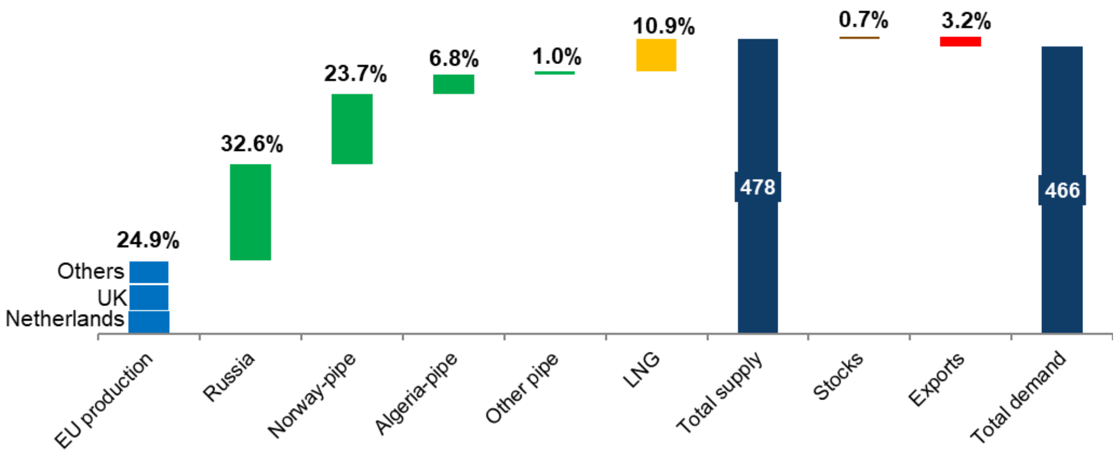

Figure 2-10 – EU gas supply balance by origin 2017. Source: Own elaboration based on data from (ACER/CEER, 2018), Eurostat, GNIIL, BP 2018.

Overall, imported gas supplied in 2017 represents a 75.1% of Europe's natural gas consumption compared with 53.6% in 2004. This gap in domestic production has being covered by an increase in Norwegian production, as well as increasing imports from Russia and LNG.

When looking specifically at the European imports, the relatively low share of LNG in total gas demand stands out. In 2017, LNG imports covered 14.5% of total EU gas imports, while imports through pipelines represents 85.5% of total imports. However, the share of LNG varies strongly among MSs. For instance, in Spain LNG share was more than half of total gas supply in 2017 and in France it was responsible for 23.5% of 2017 gas supplies, 11.3% in Italy and 9.2% in UK (See Figure 2-11). On the other hand, countries such as Germany currently lack regasification capacity. Eastern Europe, whose countries are characterized by their high dependency on Russian imports, is currently looking at LNG imports as a solution to increase supply diversification and reduce dependency on Russian gas.

If we focus on the origin of EU gas supply portfolio, Russia and Norway are the leading suppliers of natural gas to Europe, accounting for 43.5% and 31.5% respectively of imported pipeline gas. Together with Algeria (i.e. which accounts of 9.1% of total pipeline imports), these three countries sum up 84.1% of total imports.

On the other hand, LNG supplies are highly diversified and have helped to diversify EU's portfolio of suppliers, leading to more competition and lower wholesale prices. The main LNG supplier to Europe is Qatar (37.6%) followed by Algeria (22.3%). It is important to note that in 2018 imports from the United States and Russia have taken LNG market share to these two major players. This trend is expected to continue, as more liquefaction capacity will come online in the US and Russia, while the Europe-Asia spread is kept tight.

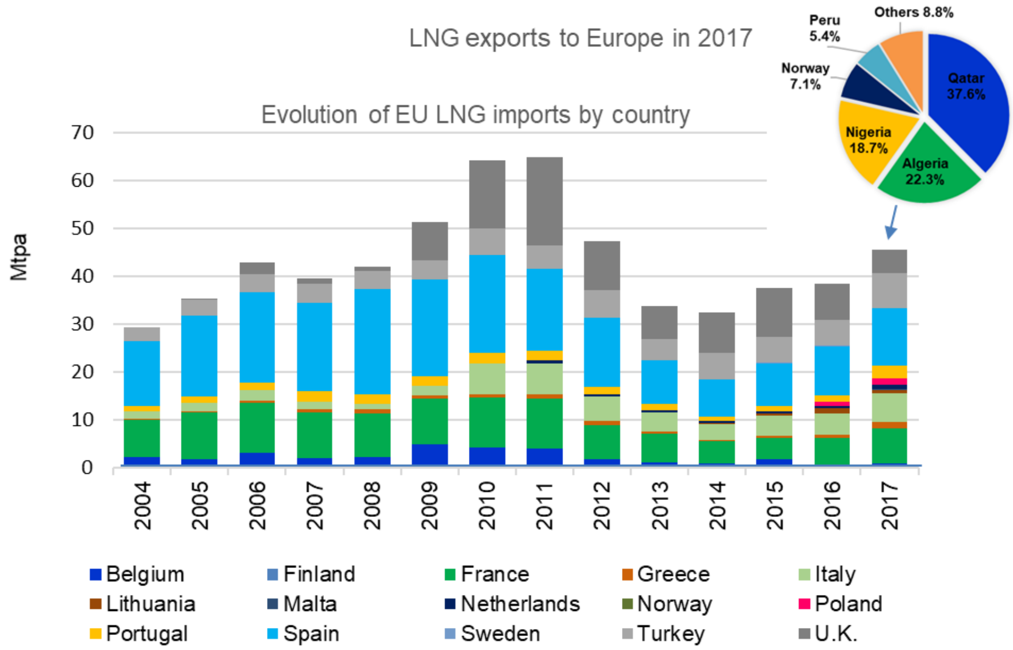

Figure 2-11 – Evolution of EU LNG imports by country and market share of LNG exporters in 2017. Source: Own elaboration based on data from GNIIL and IGU.

In 2017, Europe holds a total regasification capacity of around 173 Mtpa. By country, Spain accounts for 28.2% of total EU regasification capacity (IGU, 2018a) followed by UK (20.7%), France (14.4%), Turkey (11,4%) and Italy (6.4%). However, some EU regions are less equipped, such as Eastern Europe (only Poland and Lithuania have regasification terminals) (See Figure 2-12)

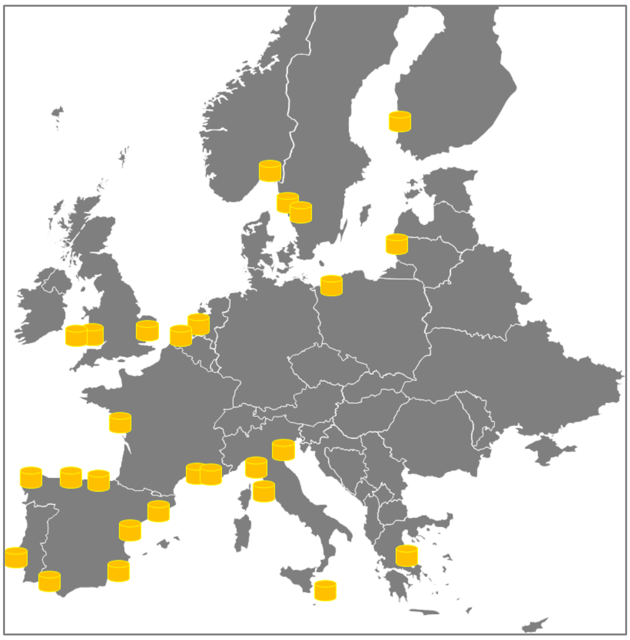

Figure 2-12 – EU regasification projects map. Own elaboration based on data from ENTSO-G and IGU

Therefore, together with UGS, LNG storage tanks can also serve to balance gas demand and supply and contribute to security of supply (ACER / CEER, 2016). However, many LNG terminals are underutilized, with an average utilization rate in the EU in 2017 less than 25% (CEER, 2017), as the significant rise of LNG supplies into Europe forecasted by the Golden Age of Gas (IEA, 2012) did not materialize.

Despite the above, traders are increasingly using LNG storage tanks in Europe as storage to further supply gas to other places taking advantage of arbitrage opportunities. For example, terminals from Northwestern Europe are being used as transfer and storage points for Russia's Arctic Yamal LNG cargoes, before shipping this gas to other regions (i.e. mainly Asia).

In 2017, natural gas demand in the EU was 466 Bcm in 2017. The six major gas consumer countries (i.e. Germany, France, Italy, Spain, Netherlands and UK) account for almost two thirds (66.3%) of total EU-28 consumption. Germany is the larger consumer with a 19.3% of the total demand in 2017, followed by the UK (17.0%), Italy (15.45), Netherlands (7.7%) and Spain (6.9%).

European natural gas consumption has grown driven by coal-to-gas switching, as a consequence of the greenhouse gas emissions trading system reform, which has ultimately resulted in higher prices on carbon, thereby driving further fuel switching away from coal. Moreover, inter-year gas consumption fluctuation in Europe is largely driven by the seasonal variability of renewable power generation, highlighting the key role of gas as a flexible resource for the backup of renewable sources.

Within the EU borders, natural gas production is declining due to limited reserves, leading to an increase in imported volumes of gas, which impacts gas flows within the EU and increases EU's energy dependence. However, as the region continues to prioritize the decarbonization of its energy system, the role of gas is more unclear and it would be mainly driven by energy policies measures, more than by market fundamentals.

2.4. The European Internal Gas Market

2.4.1. First steps towards liberalization

The privatization and liberalization process of European natural gas markets appeared in the political agenda in the 80's and 90's, being the starting point for a deep restructuring and change in the governing of the gas sector in the EU. However, this process has been extremely slow because the European Community lacked legitimacy for the development of any energy policy at a Communitarian level until the Treaty of Lisbon in 2009. In this Treaty, the European Community was given competencies in energy policy further than specific topics like coal and nuclear energy, which were summarized in previous treaties (i.e. Treaty of Paris (European Coal and Steel Community (ECSC)) and the EURATOM Treaty of the European Atomic Energy Community).

However, and despite the fact that energy policy was considered as competence of the Member States; when electricity and gas were recognized as a commodity, they became part of the competencies of the Community in the development of the Single Market. These facts, combined with the need to coordinate actions at European level regarding climate change, competitiveness for the creation of an internal energy market and a common security of supply policy, led to the development of the First (EC 1998) and Second (EC 2003) gas Directive. Both Directives lay the foundations, setting the bases and the common rules for the liberalization and creation of a European internal gas market. This includes several market reform principles such as the unbundling of activities (i.e. forcing the separation between regulated and liberalized activities), the non-discriminatory third-party access (hereafter, TPA) to the transport and distribution network, and the free choice of suppliers by consumers.

Additionally, Regulation No 1775/2005 (EC 2005), aims at setting non-discriminatory rules for access conditions to natural gas transmission systems (i.e. setting harmonized principles for tariffs design methodologies, capacity allocation, congestion management, transparency requirements and balancing rules) with the objective of ensuring the proper functioning of the internal gas market. Furthermore, the completion of the internal gas market needed a minimum common approach concerning security of gas supply. Consequently, Directive 2004/67 (EC 2004) was enacted, for establishing a high-level regulation for ensuring adequate levels of security of gas supply. Since the First Directive, the European gas market reform has attempted to integrate and harmonize gas markets while considering the specifics of national and regional markets. However, due to the discretion of the European framework regulation, MSs could choose to a large extent how to apply the different regulatory instruments, bringing about different regulatory regimes which lack of cross-border integration, and harmonization.

2.4.2. The Third Energy Package

Despite the Directives and Regulations adopted until then, the European gas market continued to be a "puzzle" of national and regional markets with highly heterogeneous regulatory regimes (Haase, 2008). There was a clear need for additional and common technical norms, for structural changes, and for new reforms for the harmonization and integration of the national and regional markets into a single European market. In July 2009, the European Commission (EC) adopted the Third Directive (2009/73/EC) (EC 2009a) and Regulation EC Nº 715/2009 (EC 2009b). These two documents alongside some other Directives and Rules are known as the Third Energy Package. The Third Energy Package was enacted with the goal of improving the functioning of the internal energy market and resolve existent structural problems to guarantee its correct development and the harmonization of the norms between the MSs. The package covers five main areas: 1) the unbundling (effective separation) of energy suppliers from network operators, removing the incentive of vertically integrated companies to discriminate against competitors; 2) strengthening the independence of regulators 3) the establishment of the Agency for the Cooperation of Energy Regulators (ACER) by CE 713/2009, with the objective to help different national regulators to cooperate and guarantee the good functioning of the internal energy market; 4) the creation of European Networks for Transmission System Operators (ENTSO-G) in order to facilitate cross-border cooperation between transmission system operators (TSOs) and 5) increased transparency in retail markets to benefit consumers.

The Package includes also the development of Network Codes (NCs), in order to harmonize networks operation frameworks across the different transmission systems.

These NCs encompass issues such as the Congestion Management Procedures (CMP), Capacity Allocation Mechanisms (CAM), Gas Balance in Transport Networks, Inoperability and data Exchange, and the transparency and harmonization of the tariff structure.

Regarding the design of network services rules (i.e. contracting and operating rules), the European Union opts for a simplified representation of the physical characteristics of the network with an entry-exit capacity access scheme from the physical network (where entry and exit capacities are assigned separately (Hunt, 2008)). Additionally, the European Union resorts to the creation of efficient wholesale national and supra-national gas markets in order to reduce entry barriers encouraging competition and transparency and guaranteeing gas supply (i.e. long-term supply security and daily gas balance operations) and risk management or speculative trading. Within a gas market, the concept of hub appeared. These hubs present a point (physical or virtual) in the gas system in which legal gas properties are transferred (i.e. including spot, prompt and forward) between different agents in the market and a third entity (in addition to the buyer and seller) that deals with management.

Depending on the actual geographical location hubs can be physical and located in a specific point of the gas grid system, such as the regasification terminal, flange, tank, compressor station, processing plant, etc. Or they can have a virtual location, which is often but not always included within the country's gas grid network. This is often referred to as entry-exit zone or balancing zone.

Additionally, depending on their purpose, we distinguish three types of gas hubs. First, transit hubs, which are transit locations, or physical points, at which market participants can choose to trade gas. Second, balancing hubs, which are normally embedded in a balancing zone and are used by market agents to balance their portfolios on daily basis. Last, trading hubs, which are used by agents for the financial risk management.

2.4.3. Natural gas hubs in Europe

For the rest of this Thesis we define virtual hubs as balancing electronic platforms that are associated with a set of delivery points for which the same specific balancing regime is applicable, including the rules that apply to TSO balancing and the procurement of balancing services. Hence, the virtual hubs are not linked to a specific gas facility or any physical junction of pipelines, but to the gas facilities embedded in the balancing zone.

Gas hubs in Europe have been slow to develop in comparison with development in the United States where the Henry Hub, created in 1988, stands out as a physical negotiation place for natural gas. In Europe, the first gas hub was the National Balancing Point (NBP), created in 1996 in the United Kingdom, and then Zeebrugge (ZEE) Belgian, created in the year 2000. This was followed by the Dutch Title Transfer Facility (TTF) established in 2010, the CG in Germany, PEG Nord in France, PSV in Italy and MIBGAS in the Iberian Peninsula. All these European hubs are virtual hubs, with the exception of Zeebrugge in Belgium.

Hub development has been quite different among the different EU countries. Northwest Europe has the most advanced hubs, followed by Central Europe, while gas hubs are still at their early stage in Southern Europe. The British market (NBP) and the Dutch one (TTF) are the most developed with high levels of transparency and number of participants and in which not only physical exchanges take place, but also financial tools for risk management are available. Both markets work as a reference for the rest of the European markets. On the other hand, there exist hubs with lower maturity levels, like Zeebruge in Belgium and the hubs in Germany which are used as balance markets, or emerging hubs (not very active or lacking liquidity) like MIBGAS in Spain and Portugal or PSV in Italy (Heather, 2012), (Heather, 2015) and (Heather & Petrovich, 2017). In addition, the share of gas hub trading (i.e. pricing based on gas-on-gas competition) varied significantly among these regions. In North West Europe[19], it accounted for 92% of natural gas consumed in 2017. In Central Europe[20], GOG pricing stood at 73% and while on the Mediterranean[21] reached a 39% in 2017. However, South East Europe[22], had only about 10% of its gas consumption based on GoG competition (IGU, 2018c).

2.4.4. The Model for the European Gas Market

With the objective of continuing the advance towards the achievement of an internal European gas market; the EU, ACER and the Council of European Energy Regulators (CEER) support the implementation of the European Gas Target Model (GTM) developing a common vision for the European gas market consistent with the implementation of the Third Energy Package, the Regional Gas Initiatives and the development of energy policies for sustainability and security of supply. The GTM creates a non-binding, high-level frame with a description of characteristics for future development of the European gas market, acting like a tool for the development of Frame Guidelines and the Network Codes under the umbrella of the Third Energy Package. The GTM was suggested by the

[19] Belgium, Denmark, France, Germany, Ireland, Netherlands, UK

[20] Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland

[21] Greece, Italy, Portugal, Spain, Turkey

[22] Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia

CEER in 2011 (CEER, 2011), backed by the Madrid Forum in 2012, and updated in 2015 (ACER, 2015).

The gas market model suggested by the GTM is based on three pillars (MECO-S. Market Enabling, Connecting and Securing model (Glachant, 2011)) and aims at the creation of a number of functioning wholesale markets within the EU, at the connection and integration of those markets in order to maximize short- and mid-term price alignment between them, and at favoring security of supply. MECO-S Model fundamentals are illustrated in Figure 2-13.

These three pillars share the need for investment in new infrastructures in order to enable the free movement of gas between the different zones of the EU.

- Pillar 1: Enable functioning wholesale markets. Structuring network access to the European gas network through the creation of functioning wholesale gas markets reducing entrance barriers.
- Pillar 2: Tightly connect markets. To encourage the integration of markets, favoring short- mid-term price convergence, facilitating cross-border trade, and market coupling.
- Pillar 3: Enable secure supply patterns. To enhance security of supply through gas markets and supply sources.

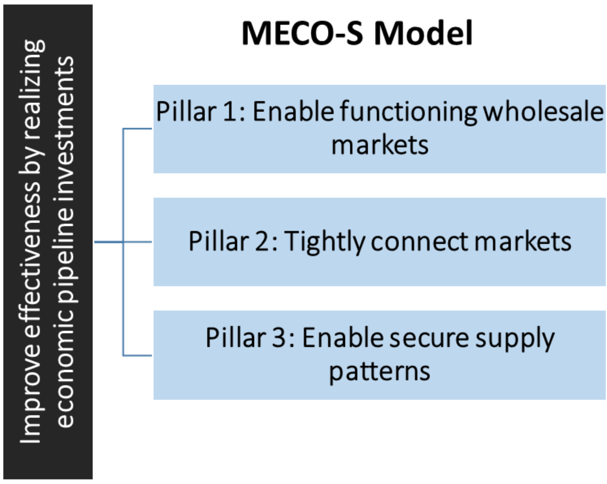

Figure 2-13 – MECO-S Model. Source: Own elaboration based on (Glachant, 2011)

2.4.5. Entry-Exit regime and Balancing zones

The liberalization process of the gas sector has ended up with the definition of two main different regulation frameworks for the network services such as contracting and operating rules and a cost recovery framework for the regulated infrastructure. On the one hand, point-to-point systems establish two prices at both pipeline extremes. The difference between both prices reflects transportation costs and scarce capacity valuation when transportation constraints appear. On the other hand, entry-exit systems fragment the market by defining balancing zones where the network is embedded and establish entry and exit tariffs. Balancing zones disregard transportation and distribution network characteristics, except at entry and exit points (Vazquez, Hallack, & Glachant, 2012).

Entry-Exit	**Point to Point**
Primary allocation of capacity for introducing and removing gas in the point defined as "Entry Points" or "Exit Points".	Capacity allocation associated with an exit point and a path or route of transport determined. You cannot hire separate input and output.
Associated to **Virtual hub**	Associated to **Physical hub**
✓ Flexibility in the allocation of capacity	✓ Efficient use of transport infrastructure
✓ Promotes liquidity	✓ Tariffs are cost reflective
✗ Imbalances need penalties	✗ High barriers to entry
✗ Cost associated with flexibility	✗ It requires a mature market
Europe	**U.S.**

Table 2-1 – Main natural gas systems regulations comparative

As mentioned before, hubs can be a physical point (i.e. where several gas products or gas reception installations converge), or a virtual point (i.e. not linked to a specific gas facility or any physical junction of pipelines, but to the gas facilities embedded in the balancing zone). The former (physical hubs) are associated with a regulatory point to point scheme, and the latter (virtual hubs) to an entry-exit scheme (Vazquez et al., 2012). Virtual hubs are assumed to reduce entry barriers to the market and enhance liquidity. However, given that they do not take the transport network into consideration, the following two questions need to be tackled. First, the rules in which transport capacity is assigned to the different agents, and second, the coordination between the technical characteristics of the network and the operation with the resulting flows in the market given that the network is transparent for the market.

In practice, this implies inefficiencies in the assignation of network capacity (Vazquez & Hallack, 2013), as the system operator calculates ex-ante the use of the network's capacity. Thus, it will offer less capacity than the actual available capacity (i.e. technical capacity) to maintain a security margin for the operation and count with a certain margin to maneuver balance operations.

Both, the Third Energy Package and the GTM defines a European Gas market made of entry-exit balancing zones interconnected with wholesale virtual gas markets (i.e. virtual hubs). These virtual balancing zones are not purely associated with the physical gas network, but they are based on market needs and can be as big as the existent infrastructure allows it (in a way that the existence of congestions within the balancing zone is not an impediment for an efficient trade), and not being bounded by countries' national frontiers. A simplified scheme of virtual hubs in balancing zones is represented in Figure 2-14.

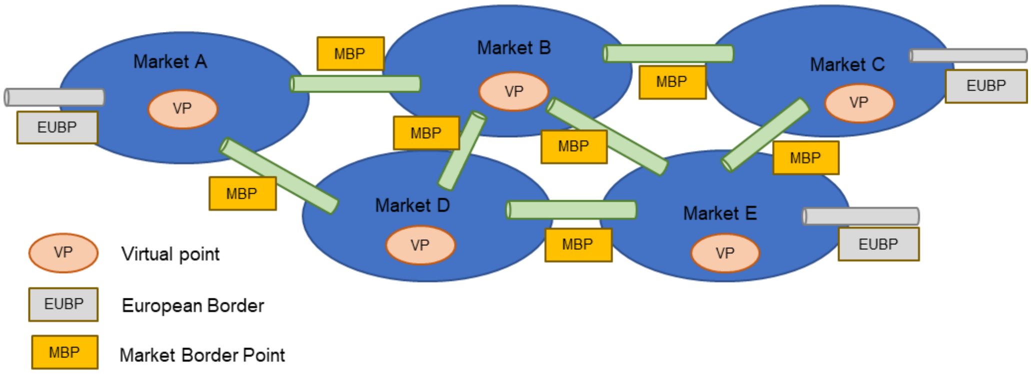

Figure 2-14 – Virtual hubs and balancing points scheme

This poses a question on the number of entry-exit balancing zones and the number of hubs, and if it is necessary that every MS implements their own balancing zone. The mere implementation of entry-exit balance zones and the creation of a gas hub are not enough conditions for the creation of an efficient gas market given that they do not ensure adequate levels of liquidity, nor necessarily facilitate cross-border exchanges or the integration of markets. The GTM deals with these aspects allowing the creation or connection of balancing zones for enabling market integration and for facilitating the creation of efficient gas hubs. Namely, efficient gas hubs are hubs with acceptable presence of agents, low concentration in the possession of gas actives, sufficient demand volumes, adequate diversity of supply and a certain ratio between the number of transactions in the hub and the total demand (Churn ratio). In (CEER, 2011) the following parameters are established as references to characterize an efficient wholesale market: a Herfindahl (HHI) index below 2000, at least three different sources of supply, a minimum demand of 20 bcm per zone, a Churn Ratio higher than three, and a concentration ratio of agents greater than 110. Of all the reference parameters, the most complex is the one referring to the 20 bcm volume of gas in the balance zone because, according to (BP, 2018), only six out of the twenty-eight MSs have an equal or superior demand (Germany, Spain, France, Italy, the Netherlands and United Kingdom). Due to this, there is a need to create supranational balance zones that englobe more than one country and are sufficiently connected without network congestions. For this goal, in (CEER, 2011), three options for the creation of balance zones were identified (see Figure 2-15).

Creation of a balancing zone at a national level - This is the appropriate option for those MSs that fulfil the established criteria for the creation of an efficient and correctly functioning market.

1. Creation of trading regions - This implies the creation of an entry-exit balance zone that is common between at least two MSs (or part of them), but maintains, at a national level, the supply to the final customer, the distribution, and balancing operations even though the frame defined in the Guidelines is still valid.
2. Creation of cross-border balancing zones - These consist of unique entry-exit balancing zones that include the transmission and distribution network and englobe at least two MSs (or part of them) under one unique virtual trading point where gas exchange transactions are negotiated (virtual hub). This model requires a compilation of unique market rules for the market area that comprises the balance zone.

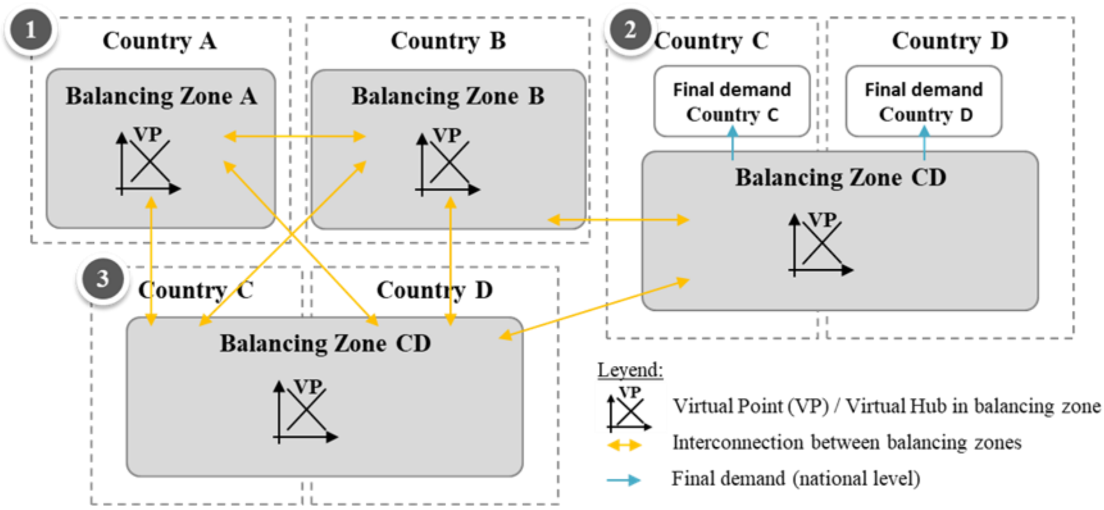

Figure 2-15 – Entry-Exit regime and Balancing zones

The Third Energy Package contemplates the option of creating balancing zones at a national level as the first step to reduce internal gas congestions in networks inside of countries, to encourage the free movement of gas inside its borders and to advance towards the creation of liquid virtual hubs. The two other options are contemplated in all those cases in which the country does not have the ability to create a wholesale market within its borders. The advantages of both second options are that, because they usually englobe a bigger balancing area, there is an increase number of participants in the market, enhancing liquidity and reducing the number of entry-exit points. Namely, the points where agents have to contract entry or exit capacity, facilitating cross-border trade. However, the system operator's work becomes more complicated, due to having to manage network congestions that will be greater, the bigger the balancing zone is. As mentioned above, in this context, the system operator will tend to offer to the market less network capacity than the available one for balance operations, resulting in a greater cost that will later affect final consumers. Due to this, and under this diagram, it is important to incentivize system operators to maximize the interconnection capacity that they offer and to avoid that the balancing actions taken by system operators underestimate said capacity. The later two options are preferable in countries with enough cross-border interconnections in which congestions are unlikely. Finally, the creation of cross-border balancing zones requires a higher level of harmonization than Trading areas, given that the former needs the existence of a set of common market rules between both transport and distribution system operators, while in Trading regions balancing and distribution operations are kept at a national level.

2.4.6. Network codes

While the European Gas Target Market (GTM) offers a view of the different stages in the evolution of the unique European gas market, and the Third Energy Package defines a legal and regulatory global frame for this market, the Network Codes (NCs) establish the bases of how this vision is going to take place. The NCs define operation norms of cross-border transport networks and are legally binding and applicable to all cross-border gas transactions. These codes have the objective of moving forward towards a better integration of the market, establishing harmonious norms for all the Union and facilitating efficient and non-discriminatory gas exchange between balancing zones.

The ENTSOG develops the NCs with the contribution of the list of annual priorities defined by the EC, under the regulatory frame and the instructions given by ACER enriched with the results of public consultations. A NC becomes mandatory for Member States after a process called comitology. Since 2013, the following NCs have been defined and approved: Network Code on Interoperability and Data Exchange Rules[23], Network Code on Gas Balancing of Transmission Networks[24], Network Code on Capacity Allocation Mechanisms (CAM) in Gas Transmission Systems[25], Network Code on the management of network congestions and conditions to access natural gas transport networks

[23] Commission Regulation establishing a Network Code on interoperability and data exchange rules (703/2015/EU)

[24] Commission Regulation establishing a Network Code on Gas Balancing of Transmission Networks (312/2014/EU)

[25] Commission Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013

"Congestion Management Procedures (CMP)"[26] and Code of Rules on the harmonization of the structures of transportation tariffs (TAR NC)[27].

2.4.7. Market integration and interconnection: Projects of Common Interest (PCI)

In both the Third Package and the GTM, investment in new infrastructures appears as the base for the achievement of objectives of the single European gas market facilitating cross-border trade, the integration of markets, and the convergence of prices while contributing to security of supply.

The Regulation EC Nº 347/2013 (EC 2013) lays down the Guidelines for a trans-European energy network (TEN-E). These guidelines provide a strategic framework for the vision of the European long-term energy infrastructure and provide support for the completion of the Union internal energy market. Within these guidelines the concept of the Project of Common Interest (PCI) is introduced. These projects are considered as key structures for the physical integration of EU markets allowing the diversification of supply sources and routes. The new directories for trans-European energy networks establish a hierarchical list of the projects that can be eligible for Union financial support, according to certain objectives and priorities.

Additionally, the ENTSOG publishes the Ten Year Network Development Plan (TYNDP) giving the vision of the European TSO's on the infrastructures of the natural gas market, creating a strategic long-term frame for the EU to guarantee the development of a pan-European transmission system.

In this context, the EC published the first list of PCI projects in October of 2013. This list is renewed every two years, having been renewed at the end of 2015 and of 2017. The priority of these infrastructure projects is based on projects' economic, social, and environmental viability. To become a PCI a project must have a significant impact in energy markets favoring the integration of the market in at least two countries in the EU, must impulse competency and help energy security of the EU diversifying sources, and must contribute to the objectives in the topics of climate and energy change in the EU enhancing the integration of renewable energies. These requirements are gathered up in Regulation (EU) 347/2013 (EC. 2013) in the following four main criteria: market integration, security

[26] CAM NC: 'Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No984/2013', OJ L 72/1

[27] REGULATION (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas

of supply, competition and sustainability. In line with these criteria, the indicators considered for the assessment of projects impact are defined in the ENTSOG CBA Methodology (ENTSOG, 2018).

The European Union aims to create a European internal natural gas market, made of entry-exit balancing zones interconnected with functioning wholesale gas markets (i.e. virtual hubs). The connection and integration of the different European markets is key in order to maximize price alignment and enhance security of supply.

2.4.8. Long-term supply contracts versus spot market in Europe

Long-term contracts have favored the development of intensive capital investment projects (both in the upstream and the downstream) such as natural gas cross border pipelines and LNG terminals (i.e. liquefaction and regasification). However, they might have slowed the liberalization process of the gas market in Europe (Ashe, et al., 2013). Nevertheless, the EU gas wholesale markets have been transformed during the last decade and have become more dynamic with market participants using long- and short-term products according to market fundamentals. These changes were underpinned by the liberalization process with the emergence of new gas trading hubs, the structural changes in the global gas market and the inability of oil indexed traditional long-term supply contracts to adjusts to supply/demand fundamentals as seen during the economic crisis in Europe (i.e. shippers where bound to traditional oil long-term contracts in a context of high oil prices and a weak demand).

Therefore, even if gas trade in Europe still relies on long-term contracting, traditional oil indexed contracts are being replaced by imports of spot gas resulting in increasing volumes of gas traded at hubs, together with a broadly continuous movement from OPE to GOG pricing since 2005, with GOG’s share increasing from 15% in 2005 to 70% in 2017 (IGU, 2018c). This, in turn, will establish natural gas hubs as the natural candidates to provide reliable price signals for natural gas. Thus, it is essential that new gas hubs developed across Europe serve at least as balancing trading points and, potentially, allow marketers to risk manage their portfolios.

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Chapter 3

A fundamental analysis on the implementation and development of virtual natural gas hubs

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The ongoing gas market liberalization in Europe has brought up a new competitive environment in which marketers must adapt their behavior to the changing conditions. The development of gas virtual hubs increases market interactions among shippers, but the oligopolistic market structure may give room for strategic behavior.

The analysis and results in this section have been published in (del Valle et al., 2017)

Notation

Hub stages models

Sub-indexes

a	Index of shippers
w	Index of wholesalers
r	Index of retailers
p	Index of periods

Parameters

$P_{ap}^{c_0}$	Intercept of shippers' cost function per period (€/MWh)
α_{ap}^{c}	Slope of shippers' cost function per period (€/MWh^2)
$P_{ap}^{i_0}$	Intercept of the conventional demand function per period (€/MWh)
α_{ap}^{i}	Slope of the conventional demand function per period (€/MWh^2)
$P_{p}^{e_0}$	Intercept of the electricity demand function per period (€/MWh)
α_{ap}^{e}	Slope of shippers' electricity demand per period (€/MWh^2)
P_{p}^{x}	Price of global LNG market per period (€/MWh)
$\overline{Q}_{ap}^{c}$	Maximum gas volume contracted per shipper per period (MWh)
$\underline{Q}_{ap}^{c}$	Minimum gas volume contracted per shipper per period (MWh)
$\overline{Q}_{a}^{c}$	Maximum gas volume contracted per shipper for all periods (MWh)
$\underline{Q}_{ap}^{c}$	Minimum gas volume contracted per shipper for all periods (MWh)
$\overline{Q}_{p}^{x}$	Maximum liquidity of global LNG markets for all shippers (MWh)

Variables:

p_{ap}^{i}	Shippers' price for conventional demand (captive demand) (€/MWh)
p_{p}^{i}	Shippers' / Retailers' price for conventional demand (€/MWh)
p_{p}^{e}	Electricity demand price (€/MWh)
q_{ap}^{i}	Gas demanded by shipper for supplying conventional demand (MWh)
d_{rp}^{i}	Gas demanded by retailers for supplying conventional demand (MWh)
q_{ap}^{e}	Gas demanded by shipper for its electricity demand (MWh)
q_{ap}^{x}	Gas demanded by shipper for the global LNG market (MWh)
q_{ap}^{c}	Gas contracted by shipper from long-term contracts (MWh)

c_{ap}	Procurement cost function (€/MWh)
Δq_{ap}	Shippers' gas purchase in the hub per period (MWh)
∇q_{ap}	Shippers' gas sales in the hub per period (MWh)
λ_p	Price in the Hub (€/MWh)
ε_{ap}^1	Dual variable of the upper bound on gas demanded by a shipper per period
ε_{ap}^2	Dual variable of the lower bound on gas demanded by a shipper per period
ε_a^3	Dual variable of the upper bound on gas demanded by a shipper for all periods
ε_a^4	Dual variable of the upper bound on gas demanded by a shipper for all periods
$\mu_{ap}^{q_i}$	Dual variable of the lower bound on gas demanded by a shipper for its captive demand
$\mu_{ap}^{q_e}$	Dual variable of the lower bound on gas demanded by a shipper for its electricity demand
$\mu_{ap}^{\Delta q}$	Dual variable of the lower bound on gas purchases by a shipper in the hub
$\mu_{ap}^{\nabla q}$	Dual variable of the lower bound on gas sales by a shipper in the hub
χ_{ap}^1	Dual variable of purchases on gas delivered to the global LNG spot market by a shipper
χ_{ap}^2	Dual variable of sales on gas delivered to the global LNG spot market by a shipper

This chapter aims at developing the first objective of this thesis and it is based on the analysis and results in ***Article II*** (del Valle et al., 2017).

3.1. Introduction

In this chapter we analyze the development of gas virtual hubs, by simulating the decision-making process of the shippers during the different stages of hub maturity. First, in section 3.1.1, we present the context and in section 3.1.2, the current development of the European natural gas hubs. In section 3.2, we describe the modeling assumptions. In section 3.3 we present the market equilibria that result from the different market structures as a consequence of the implementation and development of a virtual hub, which is illustrated in section 3.4 with a case study. In section 3.5, model outcomes are discussed, and conclusions are drawn. Finally, Appendix A contains the selected optimization approach and in Appendix B the problem formulation using the Karush-Kuhn-Tucker conditions is stated.

3.1.1. Context

The EU is leading the way towards the gas market liberalization through the implementation of virtual hubs. The 3rd EU Gas Directive (2009/73/EC) proposes the unbundling of activities (i.e., separation of networks from activities of production and supply), the implementation of entry-exit access systems and the constitution of national or supra-national virtual hubs in order to enlarge the market, reduce the entry barriers and improve the degree of competition. The "vision" for the regulatory design of the single European gas market was first set out by the Council of European Energy Regulators (CEER) in the Gas Target Model (hereafter, GTM) at the 18th Madrid Forum in 2011. The GTM was geared towards creating a framework for the establishment of a competitive European gas market, comprising entry-exit zones with liquid virtual trading points, being consistent with the implementation of the Third Energy Package.

An entry-exit system is a third-party network access system, which allows network users to book capacity rights at specific entry and exit points of the so-called balancing zones. Every day, the users nominate the amount of gas that they expect to inject to and withdraw from the entry and exit points, respectively. The nomination process determines the gas transport through the pipelines embedded within the balancing zone. Since the entry and exit nominations may not coincide with the real inflows and outflows, virtual trading points (i.e., virtual hubs) have been created where gas balancing and wholesale trading is facilitated. Therefore, the virtual hubs are balancing electronic platforms that are associated with a set of delivery points for which the same specific balancing regime is applicable, including the rules that apply to TSO balancing and the procurement of balancing services. Hence, the virtual hubs are not linked to a specific gas facility or any physical junction of pipelines, but to the gas facilities embedded in the balancing zone.

The liberalization process has changed the legal and economic framework of the gas industry, from monopolies to oligopolies, as in most of the EU countries (e.g., Spain and Portugal, Germany, or the UK). The introduction of competition in the gas market due to the ongoing liberalization in Europe increases the interaction among shippers (i.e., companies that are responsible for conveying the gas from producers to consumers) in downstream gas systems. As the entries and exits from the balancing zones may be uncertain, shippers buy and sell gas to balance their position. Shippers have usually performed OTC bilateral operations in the search of daily balancing their entries, exits and inventory variations. The creation of European gas hubs is based on the shippers' necessity to cope with their imbalances and on regulators' interests regarding transparent and public price formation. Despite the similarities between the 3rd Gas Directive and the Electricity Directive 2003/54, the organization and development of wholesales trading platforms in the electricity market and in the gas markets have been entirely different (Polo & Scarpa, 2013).

Gas markets have traditionally been based on long-term supply bilateral contracts for covering gas demand. These contracts normally entail restrictive clauses (e.g., Take-or-Pay (ToP) clauses) that reduce flexibility and slow down the market liberalization process. However, this liberalization is gaining importance as it is being reflected on gas-on-gas (GoG) competition and a general trend toward more flexible long-term supply contracts, although rigid contracts are still signed. Conversely, gas demand is expected to be even more volatile (e.g., gas-fired power plants) in the future and yet current pricing and market structures are not amenable to that outcome.

The introduction of virtual hubs is expected to reduce transactions costs, achieve additional flexibility, increase liquidity, and favor forward and future markets. Once the market gains liquidity, the hub might turn out to be an alternative to long-term contracts and become another source of procurement, allowing shippers to physically adjust their portfolio over time. These markets should not only provide a market place for the buying and selling of gas, but also should allow shippers to financially risk manage their gas portfolios and help to provide a source of security for demand. Additionally, functional gas hubs, serve as reliable price references, fostering gas-on-gas pricing. Therefore, mature gas markets should be transparent and open, attracting many participants and fostering trading and competition and, ultimately, providing the best price signal at any given time.

3.1.2. The development of virtual hubs within Europe

The first gas hub in Europe appeared in the UK in 1996 (i.e. the National Balancing Point (NBP)). Following the UK, in the 2000s, trading hubs emerge across the EU. The first continental gas hub was the physical hub Zeebrugge (ZEE), in Belgium, which was in inaugurated in 1998 with the start of operation of the Interconnector pipeline linking the Belgian and the British markets. After that, and driven by regulatory changes, numerous new gas hubs appeared all over Europe, such as the GasPool (GBL) and NetConnect Germany (NCG) in Germany, the Title Transfer Facility (TTF) in The Netherlands, the Punto di Scambio Virtuale (PSV) in Italy, the Points d'Echange de Gaz (PEGs) and the Trading Region South (TRS) in France, the Central European Gas Hub (CEGH) in Austria, and the Mercado Ibérico del Gas (MIBGAS) in Spain and Portugal.

However, the development of these hubs has not been homogeneous among EU countries, being the British market (NBP) and the Dutch one (TTF) the most developed. In (Heather, 2015) and (Heather & Petrovich, 2017), five key elements for the assessment of hub maturity are defined. These five key elements are: 1) the number of active market participants, 2) the traded products and whether they are used for risk management or for balancing purposes, 3) the traded volume, 4) the tradability index (i.e. ICIS assessment for determining liquidity) and 5) the Churn rate (i.e. the multiple of traded volume to actual physical throughput).

Additionally, the GTM (CEER, 2011) (CEER, 2015) defines its own metrics to assess whether a wholesale market is "*well-functioning*". These metrics have been grouped into two market characteristics:

- Market participants' needs - "*products and liquidity are available such that effective management of wholesale market risk is possible*"
- Market health – "*the wholesale market area is demonstrably competitive, resilient and has a high degree of Security of Supply*".

In the last update of the GTM (CEER, 2015), the following metrics are established as a reference to characterize market participants' need, considering all gas trading activities (including spot[1], prompt[2] and forward trade):

- Order book volume: as sufficient bid and offer volumes to allow shippers to deal with their imbalances and risk management.

[1] Day-ahead product

[2] The first month forward for which a futures contract is being traded.

- Bid-offer spread: as a measure of transaction cost (i.e. low bid-offer spread is equivalent to a low transaction cost)
- Bid-offer spread price: as a measure of the distance between average price and best price on each bid- and offer-side
- Number of trades per day: with sufficient trading activities, with enough liquidity for representing a reliable market price.

Furthermore, market health is measured by the calculation of the following metrics for each wholesale gas market:

- Herfindahl-Hirschmann Index (HHI)[3] with a threshold value lower or equal to 2000
- At least three sources of gas
- A Residual Supply Index[4] (hereafter, RSI) of over 110% of demand
- Market concentration for bid and offer activities of over 40% market share per company and market concentration for trading activities of over 40% market share per company.

In (ACER/CEER 2018), an assessment of the performance of gas wholesale markets in EU MSs, using the aforementioned GTM metrics is developed. The main conclusions drawn in the report regarding the assessment of European wholesale market are summarized below. First, the concentration of upstream gas suppliers is a challenge in many hubs. In the case of market health metrics, related to aspects of upstream competition, only the UK and France meet all three upstream metrics (i.e. diversity of gas supply sources, concentration of gas suppliers, and the hubs' potential to meet its gas demand without its largest upstream supplier) in 2017. In the case of the Netherlands, Belgium, Italy and Germany, their upstream market HHI is only slightly above what the target model recommends. However, there is a significant disparity in terms of supply diversification across the EU. There are markets with almost a complete dependence on one external supply source (i.e. such as Finland, and some SFR Yugoslavia countries[5]) or market, versus others which are sufficiently interconnected, and/or with less concentrated domestic production and/or access to LNG.

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[3] The Herfindahl-Hirschman Index (HHI) is a common measure of market concentration used to determine market competitiveness. It is calculated by squaring the market share of each firm competing in a market and then summing the resulting numbers. High HHI generally indicate a low competition and existence of market power, whereas a lower HHI value indicates the opposite

[4] The Residual Supply Index (RSI) measures the reliance of a market on its largest supplier. It is calculated as follows. RSI= (Total capacity - Largest Seller's Capacity) / (Total Demand)

[5] Bosnia and Herzegovina, Bulgaria, Moldova and North Macedonia.

On the other hand, concentration on the spot, prompt and forward markets is low in all (i.e. specially at TTF, GPL, NBP and NCG) but a few hubs (i.e. Polish hub and Baltic hub). The lowest levels of concentration were found at TTF, GPL, NBP, and NCG.

TTF and NBP are to be the EU's best functioning hubs. Even if NBP has been commonly used as a price reference for other EU hubs and for long-term contracts indexation, over the last two years, TTF has overtaken NBP both in traded volumes and in its role as price-setter in Europe. Regionally, North West Europe has the most advanced hubs (i.e. more resilient), followed by Central Europe. In Southern Europe, gas hubs are still at their early stage, but these MSs benefit from the flexibility that LNG provides. Central East Europe and Baltic regions are progressively diversifying their supplies away from Russian gas.

Figure 3-1 shows results of the evaluation of the different MSs in the fulfillment of the criteria defined in the GTM. Due to the previous criteria, European gas hubs are categorized in four categories according to (ACER/CEER 2018). These four categories are:

- **Established hubs:** hubs with a broad liquidity with sizeable forward markets which contribute to supply hedging. These hubs are considered as price reference for other EU hubs and for long-term contract pricing indexation.
- **Advanced hubs**: hubs with high liquidity but more reliant on spot products than on longer- term products. On the way on their supply hedging role.
- **Emerging hubs**: hubs with improving liquidity from a lower base taking advantage of enhanced interconnectivity and regulatory interventions. These markets still have high reliance on long-term contracts and bilateral deals (i.e. OTC).
- **Incipient hubs:** hubs at their early stage with very low liquidity. Core reliance on long-term contracts and bilateral deals.

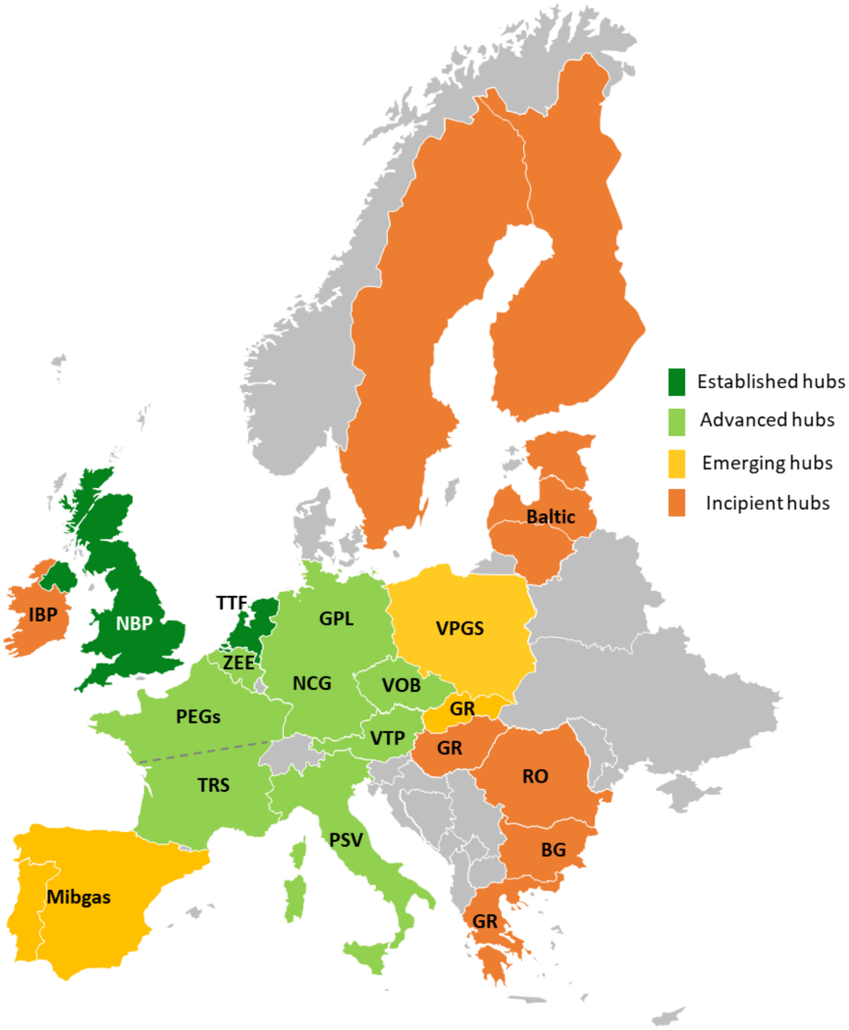

Figure 3-1 – European natural gas hubs. Own elaboration based on data from (ACER/CEER 2018) and (Heather & Petrovich, 2017).[6]

Therefore, the development of the European gas hubs, with different volumes and liquidities has brought up the two following questions: How do shippers behave at the different levels of hub maturity? And, to what extent does the implementation of virtual hubs in entry-exit systems diminish the barriers for the entrance of new market players, provide more flexibility and foster competition? In order to answer these questions, we present a novel representation of the strategic behavior of profit-maximizing shippers within the different stages of the evolution of virtual gas hubs.

[6] The 1 November 2018 was the launch of a single market for gas in France, the Trading Region France (TRF), when TRS merges with PEG Nord. This was the last step of the integration of the French gas market, which started in 2005, by reducing the three market zones to just two marketplaces: Trading Region South ("TRS") in the South and Peg Nord in central an northern region.

3.1.3. Natural gas market modeling and development of natural gas hubs. A literature review.

The gas sector liberalization process has received wide attention during the last years and several models and analyses have been developed. (Mathiesen, 2001) analyzes the market power in the EU gas sector concluding that it can be described as a Cournot oligopoly. (Golombek et al., 1994) and (Golombek et al., 1998), analyze the effects of liberalizing the gas market in Western Europe by distinguishing between upstream and downstream agents and allowing agents to arbitrage. The GASTALE model, (Boots et al., 2003) and (Boots et al., 2004), focuses mainly on the role of the downstream trading companies in the European gas market. Their interaction with producers is modeled as a two-level structure in which each producer is a Stackelberg leader while traders can be considered as Cournot oligopolies or perfect competitors. NATGAS model (Zwart and Mulder, 2006) represents the European wholesale gas market as an oligopolistic producer market by considering price-taker traders in the downstream market and providing long-run projections, which are aggregated in 5-year periods, of supply, transport, storage and consumption patterns in the model region. (Egging and Gabriel, 2006) develop a complementary equilibrium model, in which producers are represented as Cournot players while the rest of the players behave in a perfectly competitive environment and analyze different scenarios and the importance of pipeline and storage capacity. GASMOD model (Holz et al., 2008) represents the EU gas supply as two successive equilibrium between upstream market and wholesale trade (i.e., downstream market) in which infrastructure capacities are included. The model allows the representation of different market scenarios and concludes that the European gas sector behavior is well captured by a Cournot oligopoly. As highlighted by the previous authors, Cournot competition seems to be appropriate for representing the European gas sector.

Additionally, the role and implications of the implemented entry-exit regulations to European gas markets has been largely discussed and described in (CEER, 2011) and (ACER, 2015). The preferred option in the EU for enhancing market liquidity is based on virtual hubs. (Vazquez et al., 2012b) show the consequences and the challenges that the EU has to face once an entry-exit scheme has been chosen and concludes that the efficiency of the market and the operation and planning of the gas network cannot rely on purely market-based instruments. Finally, (Hunt, 2008) analyzes the adequacy of the entry-exit scheme for the EU transmission system and its implications in the development of a European wholesale market.

Regarding the different evolution and characteristics of the EU gas hubs, (Ellis et al., 2000) explores how gas companies could shape the future of the gas industry developing three scenarios for the European gas market and concluding that First EU's gas Directive was not sufficient for the introduction of competition. The Oxford Institute for Energy Studies (OIES) has published a plethora of reviews about the topic. In the first place (Heather, 2012) provides a timely review of the main hubs development by analyzing the drivers for their implementation and the challenges to be overcome and concludes that the hubs might become a reliable base for hub-based pricing. Following this study, (Stern & Roger, 2011) and (Stern & Roger, 2014) analyze the transition to hub-based pricing in continental Europe. In (Petrovich, 2013) and (Petrovich, 2014) the price convergence and the correlation of the different European natural gas markets is studied, and in (Heather, 2015) and (Heather & Petrovich, 2017) metrics in order to measure hub maturity (i.e. liquidity) are proposed and used to categorize the European gas hubs accordingly. (Miriello and Polo, 2015) studies the development of wholesale markets under an analytical framework where they propose new regulations, review those adopted by four countries in the EU, and conclude that a compulsory wholesale market encourages competition and that the unbundling of retail and wholesale activities might diminish the barriers to entry in the downstream market. (Hulshof et al., 2016) analyzes the development of spot market gas prices at the TTF hub, concluding that the day-ahead gas prices are predominantly determined by gas-market fundamentals. Last, (Xunpeng, 2016) describes the political will and regulations for the creation of the needed competition environment, and trading culture as the key factors for the successful development of hubs.

Although several studies have addressed hub development experience, they do not address the question of how shippers behave during the different stages of gas maturity. Therefore, our main objective is to analyze the evolution of prices, quantities and profits by companies during the development of virtual hubs in the downstream gas market in order to study to what extent virtual hubs encourage competition. As already noticed, the EU gas market framework plays a relevant role as the main area to have implemented virtual hubs, which are already working. However, all analyses, results, lessons and conclusions apply to any virtual hub and should be in particular of interest for stakeholders that are planning to follow the same path.

For this purpose, we model the market segments in which shippers participate (i.e., electricity market, conventional demand, and the global LNG spot market), present a new approach that represents the development of a hub in four stages, and study its impact on agents' behavior. The thorough analysis of the consequent market results of implementing a hub is a major contribution of this chapter. The four proposed stages, which are described with detail in section 2.1, are programmed as a mixed complementarity problem (hereafter, MCP), and the different behaviors are simulated and analyzed through case studies.

3.2. Modeling Assumptions

3.2.1. Methodology

We analyze the evolution of the shippers' behavior during the development of virtual hubs. Each shipper maximizes its profits by optimizing the exercise of their long-term supply contracts, facing the conventional demand and interacting with the other shippers in the hub, in the electricity market and in the global LNG spot market. The decision-making process of the different shippers will be simultaneously simulated and analyzed under the four proposed stages in the development of virtual gas hubs.

First, we consider the stage prior to the implementation of a hub, but after the liberalization has taken place and new entrants have arrived. The only source of gas procurement is through long-term supply contracts as well as a minor amount from LNG spot markets. Shippers' behavior within the electricity market has been assumed as an oligopoly, while the global LNG spot market is represented as a competitive market. The conventional segment is represented as a captive demand because consumers' switching rates among companies are habitually almost negligible right after the start of a liberalization process.

Second, we represent the early stages of the liberalization process, in which conventional consumers switching rates increase, but are still very low (i.e., the retail competition is low), and the wholesale trade through the hub emerges, mainly for shippers' balancing purposes. The hub is nevertheless an alternative to long-term contracts for gas procurement, as it provides transparency by revealing a unique zonal gas price. In short, at this stage, the shippers are assumed to be vertically integrated and participate in both the wholesale (procurement) and retail activities and act as competitive players in the virtual hub. However, the market structure does not favor the entry of new agents into the market, as the conventional demand is still captive and supplied by vertically integrated shippers, and the hub liquidity is low.

Third, as (ACER / CEER, 2018) have shown a weak, but positive correlation between switching rates and time since market liberalization, the next step is considering increasing switching rates. The conventional demand is therefore no longer captive and assumed to be mostly supplied through long-term contracts. Once the conventional demand is participating in the competitive market, and trading in the virtual hub is gaining importance, new shippers start entering the market.

Fourth, we explore the unbundling of wholesale and retail activities, as proposed in (Polo & Scarpa, 2013), as a measure to enhance retail competition going a step further into the liberalization. In the First and Second directives, the European Commission only recommends the unbundling of the infrastructure from the downstream and upstream activities. This measure entails the unbundling of downstream activities into 1) a wholesale activity, in which the wholesalers procure gas through long-term contracts with the upstream producers and convey it downstream; and 2) a retail activity, in which the retailers purchase gas from the wholesalers and cover the conventional demand. The traditional shippers are consequently divided into wholesalers and retailers.

Therefore, any kind of business relationship between the wholesaler and the retailer of the same company, or when linked by any kind of participation, is assumed to be forbidden. Accordingly, the wholesalers would have to post a non-discriminatory wholesale price and commit to provide gas upon request to any retailer, facilitating the entrance of new participants and fostering liquidity in the gas hub. A schematic picture of the downstream natural gas sector as used in this chapter is shown in Figure 3-2.

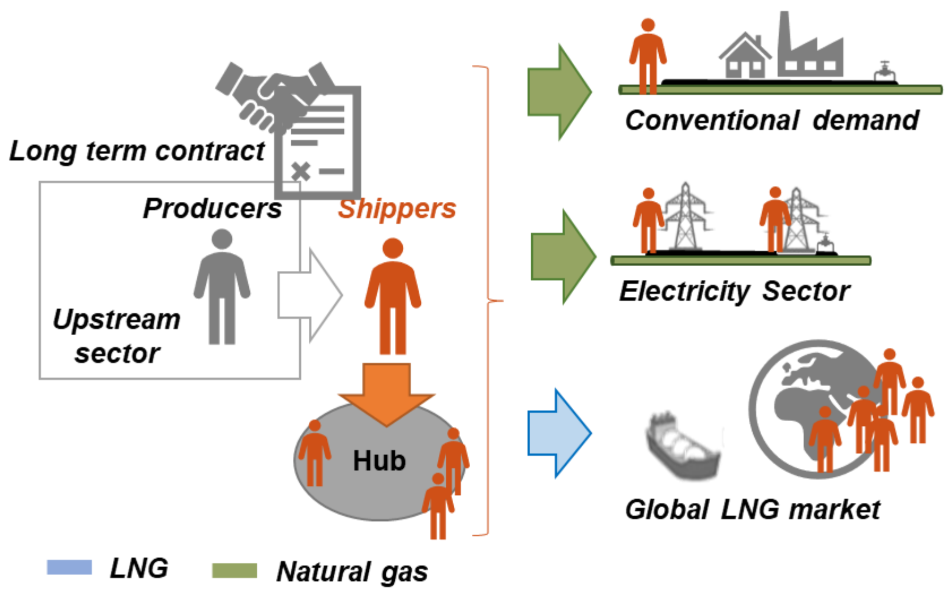

Figure 3-2 – Schematics of the downstream gas sector

Stage		Electricity sector	Global LNG market	Conventional demand	Virtual gas hub
1	Prior to the implementation of a gas hub	Oligopoly	Perfect competitive market	Captive demand	No
2	Emerging gas hub			Captive demand	Yes
3	Introduction of competition in conventional demand			Oligopoly (Entry of new shippers)	Yes
4	Unbundling of wholesale and retail activities			Oligopoly (Entry of new retailers)	Yes

Table 3-1 – Proposed stages for representing the implementation of a virtual hub and the different levels of hub maturity

3.2.2. Demand representation

The demand has been segmented into three different categories:

3.2.2.1. Electricity generation

The share of power generation gas demand over total gas consumption has been diminishing during the last years in EU countries, due to the economic crisis, the continued deployment of renewables and relatively high gas import prices when compared to coal (IEA, 2015). Yet, gas-fired power plants still play an important role in electricity markets, as gas sets the marginal price during most of the time in numerous EU power markets (Glachant, et. al., 2011). Moreover, strong environmental policies may play a role in enhancing the position of gas, which offers flexibility, low carbon emissions, and back-up for intermittent generation.

The wholesale electricity market is not represented in detail, but each shipper is instead assumed to own some gas-fired power plants with a particular gas consumption. The gas is assumed to set the marginal price and to cover the gap (i.e., the residual demand) after the rest of technologies have been matched during the market-clearing process. This residual gas demand is represented by a linear price-quantity function:

$$p_p^e = P_p^{e_0} - \left(\sum_a \alpha_{ap}^e \cdot q_{ap}^e\right) \quad \forall p \qquad (3.1)$$

The electricity sector inverse demand function (3.1) is the same for all the cases of this chapter. This approach is similar to a conjectural-variation based approach as defined in (Centeno, et al., 2007) , in which the slopes represent the explicit price-quantity influence of each shipper in the clearing market process.

3.2.2.2. Conventional consumers

The 2nd EU legislative package (Directive 2003/55/EC) allowed the entry of new competitors in gas markets, and opened the possibility for consumers to freely choose their gas supplier. Nonetheless, the downstream gas market still relies to some extent on monopolistic structures, as a large proportion of consumers does not contract an alternative supplier different from the incumbent company in most of the EU countries. For example, few countries have switching rates above 10% (ACER / CEER, 2018). However, the overall EU consumers' switching trend is increasing in gas markets

Conventional demand has therefore been represented as a captive demand of each shipper, that is, consumers cannot switch provider during the first stage of the hub implementation. The conventional demand is elastic as gas has substitute goods, like oil or electricity, and particularly businesses and industries could look for other alternatives, but due to the complexity of changing from one fuel to another in the short term, the elasticity is reduced. Each gas agent is assumed to supply its own market (i.e., to act as a monopoly). The demand has been considered as an affine function of the price. The inverse demand function is:

$$p_{ap}^{i} = P_{ap}^{i_0} - \alpha_{ap}^{i} \cdot q_{ap}^{i} \quad \forall a, p \tag{3.2}$$

(ACER / CEER, 2018) shows, in addition to the positive correlation between switching rates and time since market liberalization, that switching tends to be higher in those countries where the market has been liberalized for a longer time. Accordingly, in the later stages of the hub development, the conventional demand is considered to be supplied by all shippers under a Cournot oligopoly framework.

3.2.2.3. Deliveries to the global LNG spot market

The world is interconnected via pipelines and via LNG routes. According to (BP, 2018), almost two thirds of gas flow by pipeline while total LNG trade satisfied the remaining third (34.7%). The increase in LNG trade, thanks to LNG technology development, has accelerated the integration and globalization of gas markets creating new international arbitrage opportunities due to the divergence of prices across the globe. A representation of the global LNG spot market is hence of great interest for representing shippers' arbitrage opportunities.

On the other hand, most of the cross-border pipelines trade is nowadays linked to long-term contracts more than to arbitrage opportunities, and the markets that are reached via pipeline are limited to medium- to large-distance connected neighboring nodes and restricted to habitually local unidirectional trade. LNG is in contrast more cost-efficient in very long distances above 3,000 km (Cornot-gandolphe et al., 2003) and allows arbitraging as observed in the EU and Asia (Silverstovs et al., 2005).

Therefore, based on the previous facts, shippers arbitraging opportunities in the global gas market are represented through the LNG spot markets, while the international opportunistic trading through pipelines is omitted.

The influence of each shipper on the global LNG market price is assumed to be negligible. The market is perfectly elastic and the price remains constant. Consequently, we have represented this market as a perfectly competitive market, assuming that the shippers are price takers. As the fleet of LNG carriers is however limited, the volume of gas that can be traded (either sold or purchased) at the global LNG spot market has been limited in volume by the following transportation constraint. (From now on, the dual variables of each constraint are displayed after the colon.)

$$q_{ap}^{x} \leq \overline{Q}_{ap}^{x} \quad \forall a,p \quad : \chi_{ap}^{1} \tag{3.3}$$

$$-\overline{Q}_{ap}^{x} \leq q_{ap}^{x} \quad \forall a,p \quad : \chi_{ap}^{2} \tag{3.4}$$

Both the exogenous price and the transportation constraints (3.3), (3.4) hold for all the cases.

3.2.3. Long-term contracts

Long-term supply bilateral contracts have traditionally played a main role for satisfying gas demand. Producers sign long-term supply contracts with shippers, in which producers guarantee the recovery of their investments in capital-intensive facilities and shippers guarantee a firm supply at a price that is predefined by an oil or hub indexed formula. Long-term supply contracts are typically characterized by ToP clauses, which entail fixed payments up to an agreed-upon floor even when the contract is not exercised and the gas is not delivered. While long-term contracts may have slowed down the gas market liberalization process (Asche et al., 2000) and (Polo and Scarpa, 2013), they have favored the development of long-term, capital-intensive supply projects such as pipelines and LNG terminals. These projects would not be possible without the provided insurance by long-term contracts. Furthermore, consumers, such as industries or LDCs on behalf of households, sign long-term contracts with shippers for similar reasons. Despite this rigid structure, gas demand is gaining volatility (e.g., gas-fired power plants consumption) and yet current pricing and market structures may not be amenable to that outcome. In short, supply contracts have traditionally exhibited the following characteristics: 1) maximum and minimum ToP delivery volumes with some flexibility, such as make-up and carry-forwards clauses, which may help comply with both limits; 2) an agreed delivery price whose formula is indexed to substitute fuels to prevent consumers' switching; and 3) additional clauses, such as destination clauses to prevent shippers from reselling, although these are prohibited in some markets like the EU. For further details on long-term contracts the reader is referred to sections 2.2.4 and 2.4.8.

Even when oil-indexed long-term contracts still play a key role (Asche et al., 2000) they are becoming more flexible as hubs are changing the traditional rigid framework and increasingly promoting a market-priced environment. Gas-to-gas competition is encouraging the ongoing transition from long-term oil-indexed contracts to hub-based contracts (Luca, 2014).

Gas is considered to be only procured by agreeing long-term contracts with producers. Pricing formulas have been simplified and are represented as an increasing linear function, which captures that each shipper commonly holds a supply contract portfolio in which price formulas may differ. These differences can be related, for example, to the flexibility of the contract, to the distance between the departure and delivery ports as transportation costs are included in the price formula, and to the moment when the contracts were signed as the price formulas have evolved during the last years and been linked to diverse energy indices, mainly oil, electricity and gas. These costs are represented by the following function:

$$c_{ap}\left(q_{ap}^{c}\right) = \left(P_{ap}^{c_0} + \alpha_{ap}^{c} \cdot q_{ap}^{c}\right) \cdot q_{ap}^{c} \quad \forall a, p \tag{3.5}$$

Where $\mathrm{c_{ap}}$ is the procurement cost function, which is an equivalent of the supply contracts portfolio that is represented as an affine function with intercept $\mathrm{P_{ap}^{c_0}}$ and slope $\alpha_{\mathrm{ap}}^{\mathrm{c}}$. The exercised gas volume from the contract portfolio is represented by $\mathrm{q_{ap}^{c}}$ and constrained by (3.6) the multi-period (typically, a year) minimum ToP $\underline{\mathrm{Q}}_{\mathrm{a}}^{\mathrm{c}}$ and maximum $\overline{\mathrm{Q}}_{\mathrm{a}}^{\mathrm{c}}$ available amount of gas and (3.7) the minimum ToP $\underline{\mathrm{Q}}_{\mathrm{ap}}^{\mathrm{c}}$ and maximum available amount of gas $\overline{\mathrm{Q}}_{\mathrm{ap}}^{\mathrm{c}}$ in each period.

$$\overline{Q}_{a}^{c} \geq \sum_{p} \left(q_{ap}^{c}\right) \geq \underline{Q}_{a}^{c} \quad \forall a \quad : \varepsilon_{a}^{3}, \varepsilon_{a}^{4} \tag{3.6}$$

$$\overline{Q}_{ap}^{c} \geq q_{ap}^{c} \geq \underline{Q}_{ap}^{c} \quad \forall a, p \quad : \varepsilon_{ap}^{1}, \varepsilon_{ap}^{2} \tag{3.7}$$

3.2.4. Network access and virtual hubs

Two types of organized gas markets depending on the Third Party Access (TPA) regulatory framework (i.e., point-to-point in the US or entry-exit in the EU) can be found: physical hubs and virtual hubs. Physical hubs are linked to a specific gas facility where gas trade takes place at the location. On the other hand, virtual hubs are electronic balancing platforms. Therefore, virtual hubs are not linked to a specific gas facility, but to the gas facilities that are embedded in a balancing zone.

The US wholesale gas markets are fundamentally physical hubs, under a point-to-point regulatory framework, based on bilateral contracts among shippers and network operators (Vazquez, Hallack, & Glachant, 2012a). EU gas markets did not go so far into the network details and favor organizing gas transactions around a virtual hub, which is not a physical representation of pipelines, but instead a regulated set of entry and exit points with a very simplified representation of the actual physical characteristics of the network (Heather, 2010). The fundamental logic for virtual hubs is to increase the market liquidity that is associated with the simplification of the network.

We consider an EU-based framework and, consequently, we analyze the virtual hubs implementation and development. Once the virtual hub has been introduced, different types of competition may arise as a result of different market structures. The wholesale market is assumed to emerge as a balancing platform to cope with their daily imbalances, with high market concentration and low liquidity. A long while after the market liberalization, the hub might turn out to a competitive and liquid wholesale market as long as barriers to entry are reduced and might become an alternative to long-term supply contracts, improving the flexibility of day-to-day operation. Finally, we explore the unbundling of wholesale and retail activities.

The virtual hub is represented as a virtual trading point neglecting all the physical characteristics of the network, considering an entry-exit transport capacity scheme. As previously mentioned, the aim of the chapter is to study the features of virtual hubs under an entry-exit regime during its difference levels of hub maturity assuming absence of any entry barriers to the transport infrastructures that might limit entry. Therefore, we represent virtual hub as a virtual trading point disregarding the network characteristics and considering that TPA and transport services are offered at nondiscriminatory terms. The network access costs are the same for all participants and set equal to zero which is equivalent to consider that market decisions are independent of network utilization. This strong assumption entails the absence of network congestions and, therefore, that market decisions are independent of network utilization. Actually, congestions within current European gas markets do not exist or are disregarded when clearing the market.

3.2.5. Other assumptions

First, the upstream sector is omitted, but captured through long-term supply contracts, which are the only source of gas procurements for traders besides the hub.

Second, agents' operation decision-making occurs simultaneously. Therefore, modeling this type of market equilibrium requires the simultaneous consideration of each shippers' profit maximization problem, in which shippers choose their sales quantities simultaneously (one-stage game), by maximizing their profits given the quantities chosen by other shippers. The resulting equilibrium (if it exists) is a Nash-Cournot equilibrium, in which no player has anything to gain by changing its own strategy unilaterally. The problem will be modeled as an MCP problem.

Finally, even when one pursuit of implementing virtual hubs is achieving a transparent and public price formation, no efficiency improvement regarding information on access is considered.

3.3. Model description

This section describes how shippers make their operation decisions, in a deregulated context, and compete in quantity to maximize their profits during the different stages of development of the virtual hub. For this aim, four different equilibrium models are developed in order to represent the aforementioned market stages. The problem' s KKT conditions can be found in Appendix B.

3.3.1. Prior to the implementation of a gas hub

3.3.1.1. Equilibrium problem

In this section, we introduce the gas sector prior to the hubs creation, with vertically integrated shippers in the downstream market, where each shipper has its own gas contract portfolio, made up of long-term supply contracts, represented by the cost function (3.5). These long-term contracts entail ToP obligation clauses and maximum available gas amounts represented by (3.6) and (3.7). As there is no gas wholesale market, the only procurement source is the long-term contracts.. Each shipper can use their contracted gas

q_{ap}^{c} to supply its electricity demand (3.1), to supply its captive demand (3.2), or to ship it to the global LNG spot market (3.4). The optimization problem for every shipper is given by:

$$\Pi_a = Max \sum_p \begin{pmatrix} p_{ap}^{i}(q_{ap}^{i}) \cdot q_{ap}^{i} + p_p^{e}\left(\sum_a q_{ap}^{e}\right) \cdot q_{ap}^{e} + \\ P_p^{x} \cdot q_{ap}^{x} - c_{ap}(q_{ap}^{c}) \end{pmatrix} \quad \forall a \tag{3.8}$$

With $q_{ap}^{c} = q_{ap}^{i} + q_{ap}^{e} + q_{ap}^{x}$ and subject to (3.1) - (3.7) and:

$$q_{ap}^{i}, q_{ap}^{e} \geq 0 \quad \forall a, p \quad : \mu_{ap}^{q_i}, \mu_{ap}^{q_e} \tag{3.9}$$

Table 3-2 summarizes the main characteristics and hypotheses of the proposed market equilibrium, in which each shipper maximizes its profits (3.8) subject to the set of constraints (3.2) - (3.7) and (3.8). All the shippers' maximization problems are linked through the electricity market (3.1), whose price is endogenous to shippers' optimization problem and is represented by an affine function of the total delivered gas to the market by all shippers. On the other hand, the global LNG market is modeled as a perfectly competitive market, in which the price is exogenous to the shippers.

Stage 1	**Prior to the implementation of a gas hub**
Electricity sector	• Represented as an oligopoly • Shippers compete in the electricity sector • Price is endogenous to shippers' optimization problem
Global LNG market	• Perfect competitive market • Shippers are price takers • Price is exogenous to shippers' optimization problem
Conventional demand	• Represented as a monopoly • Captive demand of each shipper • Price is endogenous to shipper's optimization problem • Vertically integrated companies (wholesale and retail)
Virtual gas hub	No
Shippers' maximization problems are linked through the electricity market	

Table 3-2 – Stage 1: Prior to the introduction of a gas hub. Main characteristics

3.3.1.2. Equilibrium solution

The solution to this problem satisfies the first order conditions for maximizing shippers' profits with respect to the decision variables. The convexity of the problem ensures the globality of the solution. The equilibrium is solved through the KKT conditions.

When the constraints are not binding, also for the supply contracts, and some gas is sold in all markets all dual variables are equal to zero, and the system of equations yields the following relation:

$$c'\left(q_{ap}^{c}\right) = p_{ap}^{i}\left(q_{ap}^{i}\right) + \frac{\partial p_{ap}^{i}\left(q_{ap}^{i}\right)}{\partial q_{ap}^{i}} \cdot q_{ap}^{i} = p_{p}^{e}\left(\sum_{a} q_{ap}^{e}\right) + \frac{\partial p_{p}^{e}\left(\sum_{a} q_{ap}^{e}\right)}{\partial q_{ap}^{e}} \cdot q_{ap}^{e} = P_{p}^{x} \qquad (3.10)$$

The marginal costs of each shipper depend on their portfolio of long-term supply contracts, which results in a different marginal cost for each shipper. Independently of the behavior in each market, the marginal cost of each shipper is equal to the marginal income from the market. As the global LNG market price is considered constant, all marginal costs and marginal incomes will reach this value as long as the maximum capacity constraint is not binding. Therefore, the global LNG market price is transferred to the conventional demand and the electricity sector as it has happened lately in the EU due to Asian LNG price. However, the price may not be fully transferred when the global LNG market is constrained by the lack of transportation capacity (3.11). In case that the LNG fleet would be large enough, the global LNG price would equal the shippers' apparent cost and would be fully transferred (3.12).

$$c'\left(q_{ap}^{c}\right) = P_{p}^{x} - \chi_{ap}^{1} \ \ if \ \overline{Q}_{ap}^{x} = q_{ap}^{x} \rightarrow \chi_{ap}^{1} > 0 \qquad (3.11)$$

$$c'\left(q_{ap}^{c}\right) = P_{p}^{x} \ \ if \ \overline{Q}_{ap}^{x} > q_{ap}^{x} \rightarrow \chi_{ap}^{1} = 0 \qquad (3.12)$$

The previous statements do not hold for a specific shipper when any supply constraint is binding and hence any dual variable is active (i.e., $\varepsilon_{ap}^{1}, \varepsilon_{ap}^{2}, \varepsilon_{a}^{3}, \varepsilon_{a}^{4} > 0$). For the case of maximum supply constraints, upper bounds in (3.6) and (3.7), the difference between the hub price and the marginal cost, as captured by ε_{ap}^{1} and/or ε_{a}^{3}, is equal to the shippers' willingness to pay for an additional unit of gas.

The minimum supply constraints, also known as ToP clauses, lower bounds in (3.6) and (3.7), force shippers to take at least the minimum volume of their contracted gas. When these constraints are binding, the associated dual variables are positive and the real cost is decreased. Put differently, the shipper is willing to reduce the offered price to increasing the demand and, hence, complying with the ToP clause.

We denote the resulting marginal cost as the apparent cost c^{App} as done in (Reneses, et al., 2004) and defined as:

$$
\begin{aligned}
c^{App}\left(q_{ap}^{c}\right) &= c'\left(q_{ap}^{c}\right) \quad \textit{if no supply constraint is binding} \\
c^{App}\left(q_{ap}^{c}\right) &= c'^{\left(q_{ap}^{c}\right)} - \varepsilon_{ap}^{2} - \varepsilon_{a}^{4} \quad \textit{if ToP constraints are binding} \\
c^{App}\left(q_{ap}^{c}\right) &= c'^{\left(q_{ap}^{c}\right)} + \varepsilon_{ap}^{1} + \varepsilon_{a}^{3} \quad \textit{if maximun supply constraints are binding}
\end{aligned} \tag{3.13}
$$

3.3.2. Market equilibrium with an emerging gas hub

3.3.2.1. Equilibrium problem

With the introduction of a hub and without entry barriers, the shippers have another source of gas procurement for gaining flexibility. The shippers have the possibility of buying and selling gas in the hub, which is formulated as in (3.14), in which total sales $\nabla \mathrm{q}_{\mathrm{ap}}$ equal total purchases $\Delta \mathrm{q}_{\mathrm{ap}}$.

$$
\sum_{a} \Delta q_{ap} = \sum_{a} \nabla q_{ap} \quad : \lambda_p \quad \forall p \tag{3.14}
$$

The dual variable λ_{p} is the hub price.

As in the previous stage, the shippers' gas procurement from long-term contracts is represented by the cost function (3.5). Each shipper uses its contracted gas q_{ap}^{c} to supply its electricity demand (3.1) and its captive consumers (3.2), to trade in the global LNG spot market (3.4) or to sell it in the hub to other shippers (3.14).

The shippers are assumed to behave as competitive players in the hub. Then, the maximization problem for each shipper is given by:

$$
\Pi_a = Max \sum_{p} \left(\begin{array}{c} p_{ap}^{i}\left(q_{ap}^{i}\right) \cdot q_{ap}^{i} + p_{p}^{e}\left(\sum_{a} q_{ap}^{e}\right) \cdot q_{ap}^{e} + P_{p}^{x} \cdot q_{ap}^{x} \\ -c_{ap}\left(q_{ap}^{c}\right) - \lambda_p \cdot \Delta q_{ap} + \lambda_p \cdot \nabla q_{ap} \end{array} \right) \quad \forall a \tag{3.15}
$$

With $q_{ap}^{c} = q_{ap}^{i} + q_{ap}^{e} + q_{ap}^{x} - \Delta q_{ap} + \nabla q_{ap}$ and subject to (3.1) - (3.7), (3.14) and:

$$
q_{ap}^{i}, q_{ap}^{e}, \Delta q_{ap}, \nabla q_{ap} \geq 0 \quad : \mu_{ap}^{q_i}, \mu_{ap}^{q_e}, \mu_{ap}^{\Delta q_{ap}}, \mu_{ap}^{\nabla q_{ap}} \quad \forall a, p \tag{3.16}
$$

Table 3-3 summarizes the main characteristics and hypotheses of the considered market equilibrium, where each shipper maximizes its profits (3.15) subject to the set of constraints (3.2) –(3.7) and (3.16), and linked through the electricity market (3.1) and the hub (3.14).

Stage 2	**Emerging gas hub**
Electricity sector	• Represented as an oligopoly • Shippers compete in the electricity sector • Price is endogenous to shippers' optimization problem
Global LNG market	• Perfect competitive market • Shippers are price takers • Price is exogenous to shippers' optimization problem
Conventional demand	• Represented as a monopoly • Captive demand of each shipper • Price is endogenous to shipper's optimization problem • Vertically integrated companies (wholesale and retail)
Virtual gas hub	Yes. Trade among shippers
Shippers' maximization problems are linked through: Electricity market + Virtual gas hub	

Table 3-3 – Stage 2: Emerging gas hub. Main characteristics

3.3.2.2. Equilibrium solution

The equilibrium problem is solved by using the KKT conditions and the hub balance equation. In a competitive environment in the hub, when no supply constraints are active and some gas is sold in all markets, the marginal costs of all shippers reach a unique value, which in the equilibrium coincides with the gas hub price λ_p.

$$\begin{aligned}\lambda_p = c'\left(q_{ap}^c\right) &= p_{ap}^i\left(q_{ap}^i\right) + \frac{\partial p_{ap}^i\left(q_{ap}^i\right)}{\partial q_{ap}^i} \cdot q_{ap}^i \\ &= p_p^e\left(\sum_a q_{ap}^e\right) + \frac{\partial p_p^e\left(\sum_a q_{ap}^e\right)}{\partial q_{ap}^e} \cdot q_{ap}^e = P_p^x\end{aligned} \tag{3.17}$$

Even if the hub is represented as a perfectly competitive market, the shippers market power over both the conventional demand (monopoly) and the electricity market (oligopoly) in addition to their participation in the global LNG spot market, lead to raising marginal costs and hub price. Note that in this stage, we assume that the hub is not able to attract new agents and open the market to competition. As a result, the mere introduction of a hub does not ensure perfectly competitive shippers' behavior and the additional gained flexibility by the shippers might lead to a global increase in shippers' profits instead of a reduction in prices. Furthermore, as the marginal cost of all shippers reaches a unique value, some conventional demand might lose welfare if their previous supplier. i.e., shipper, had lower marginal costs than the other shippers.

As in the case above, the existence of transportation constraints, non-zero χ^1_{ap}, uncouples the hub price from the global LNG market price which is then not directly transferred to the conventional consumers and the electricity sector (3.11).

$$\begin{aligned} \lambda_p = c^{App}\left(q^c_{ap}\right) = p^i_{ap}\left(q^i_{ap}\right) + \frac{\partial p^i_{ap}\left(q^i_{ap}\right)}{\partial q^i_{ap}} \cdot q^i_{ap} \\ = p^e_p\left(\sum_a q^e_{ap}\right) + \frac{\partial p^e_p\left(\sum_a q^e_{ap}\right)}{\partial q^e_{ap}} \cdot q^e_{ap} = P^x_p - \chi^1_{ap} \end{aligned} \tag{3.18}$$

3.3.3. Market equilibrium with a mature gas hub

3.3.3.1. Equilibrium problem

In the next stage of the liberalization process, switching rates tend to be higher so that we cannot further consider the conventional demand as a captive. However, retail competition is low and the wholesalers still supply gas directly to the retailers through bilateral contracts. Accordingly, the companies are assumed to be vertically integrated and responsible for both the wholesale and retail activities. The conventional demand is more open to competition and each shipper is assumed to supply part of it and compete with the rest of the shippers. The inverse conventional demand function is represented by:

$$p^i_p = p^{i_0}_p - \alpha^i_{ap} \cdot \sum_a q^i_{ap} \quad \forall p \tag{3.19}$$

At this stage, the hub is mature and able to facilitate transactions and the entry of new players. The maximization problem for each shipper is:

$$\Pi_a = Max \sum_p \begin{pmatrix} p^i_p\left(\sum_a q^i_{ap}\right) \cdot q^i_{ap} + p^e_p\left(\sum_a q^e_{ap}\right) \cdot q^e_{ap} + P^x_p \cdot q^x_{ap} \\ -c_{ap}\left(q^c_{ap}\right) - \lambda_p \cdot \Delta q_{ap} + \lambda_p \cdot \nabla q_{ap} \end{pmatrix} \quad \forall a \tag{3.20}$$

Subject to: (3.1) – (3.7), (3.14), (3.16) and (3.19).

Table 3-4 summarizes the main characteristics and hypotheses of the proposed market equilibrium, where each shipper maximizes their profits (3.20) subject to the set of constraints (3.2) – (3.7) and (3.16) that are linked through the electricity market (3.1), the hub (3.14) and the conventional demand (3.19), in which the shippers are now assumed to be Cournot players.

Stage 3	Increased competition in conventional demand
Electricity sector	• Represented as an oligopoly • Shippers compete in the electricity sector • Price is endogenous to shippers' optimization problem
Global LNG market	• Perfect competitive market • Shippers are price takers • Price is exogenous to shippers' optimization problem
Conventional demand	• Represented as an oligopoly • Price is endogenous to shippers' optimization problem • Vertically integrated companies (wholesale and retail)
Virtual gas hub	Yes. Trade among shippers
Shippers' maximization problems are linked through the electricity market + virtual gas hub + conventional demand	

Table 3-4 – Stage 3: Increased competition in conventional demand. Main characteristics

3.3.3.2. Equilibrium solution

When the KKT optimality conditions are solved and no constraint is active, the marginal cost of all shippers reaches a unique value, which coincides with the perfectly-competitive gas hub price. As in the previous case, the hub price is influenced by shippers' behavior when supplying the conventional demand and the electricity sector. The difference lies in the conventional demand (3.17), which is no longer considered as a monopoly as they compete and act as Cournot players. Therefore, prices are the same for all the conventional demand, and they are expected to decrease on average, as more competition is introduced when the competitive pressure evolves from a monopoly to an oligopoly. Moreover, as in the previous case, some households might increase their welfare while some might reduce it, as shipper' marginal cost reaches a unique value.

$$\begin{aligned}\lambda_p = c'(q_{ap}^c) = p_p^i\left(\sum_a q_{ap}^i\right) + \frac{\partial p_p^i(\sum_a q_{ap}^i)}{\partial q_{ap}^i}\cdot q_{ap}^i \\ = p_p^e\left(\sum_a q_{ap}^e\right) + \frac{\partial p_p^e(\sum_a q_{ap}^e)}{\partial q_{ap}^e}\cdot q_{ap}^e = P_p^x\end{aligned} \tag{3.17}$$

Furthermore, the implementation of the hub diminishes entry barriers and new shippers can enter into the market. Nevertheless, the market structure may hinder the entry of new players and dilute the expected encouragement effect of the hub.

3.3.4. Market equilibrium with unbundling of wholesale and retail activities

3.3.4.1. Equilibrium problem

In this stage, we explore the unbundling of wholesale and retail activities. Accordingly, competition is enhanced in the downstream segment, and transactions between wholesalers and retailers in the hub are favored at the expense of intra-firm bilateral contracts. The traded gas between wholesalers and retailers is assumed to be done through the hub.

The conventional demand that is supplied by the retailers is defined by (3.21), where d_{rp}^{i} is the total supplied demand to the consumers.

$$p_p^i = p_p^{i_0} - \alpha_p^i \cdot \sum_r d_{rp}^i \quad \forall p \tag{3.21}$$

The conventional demand price is endogenous to the retailers' problem, and a function of the total delivered gas. The retailers are assumed to be price takers with respect to the hub price, but Cournot players when they satisfy the conventional demand. The maximization problem for the retailers is given by:

$$\Pi_r = Max \sum_p \left(p_p^i \left(\sum_r d_{rp}^i \right) \cdot d_{rp}^i - \lambda_p \cdot d_{rp}^i \right) \quad \forall r \tag{3.22}$$

Subject to $\mathrm{d}_{\mathrm{rp}}^{\mathrm{i}} \geq 0$.

All the retailers' optimization problems are linked through equation (3.21).

On the other hand, the wholesalers directly supply the electricity sector and participate in the global LNG spot market, which are represented by (3.1) and (3.4), respectively.

We assumed wholesalers to be perfectly competitive agents when participating in the hub. The wholesalers buy and sell gas in the hub to other market participants (i.e., to other wholesaler or any retailer), subject to the hub balance equation (3.23) where d_{rp}^{i} is the purchased gas in the hub by the retailers in order to supply the conventional demand. The hub price is the dual variable of the constraint.

$$\sum_a \Delta q_{ap} + \sum_r d_{rp}^i = \sum_a \nabla q_{ap} \quad : \lambda_p \quad \forall p \tag{3.23}$$

The maximization problem for each wholesaler is:

$$\Pi_a = Max \sum_p \left(\begin{array}{c} p_p^e\left(\sum_a q_{ap}^e\right) \cdot q_{ap}^e + P_p^x \cdot q_{ap}^x - c_{ap}\left(q_{ap}^c\right) \\ -\lambda_p \cdot \Delta q_{ap} + \lambda_p \cdot \nabla q_{ap} \end{array} \right) \quad \forall a \tag{3.24}$$

With $q_{ap}^c = q_{ap}^e + q_{ap}^x - \Delta q_{ap} + \nabla q_{ap}$ and subject to (3.1), (3.4) - (3.7) and (3.23). Table 3-5 lists the main characteristics and hypotheses of the considered market equilibrium.

Stage 4	**Unbundling of wholesale and retail activities**
Electricity sector	• Represented as an oligopoly • Shippers compete in the electricity sector • Price is endogenous to shippers' optimization problem
Global LNG market	• Perfect competitive market • Shippers are price takers • Price is exogenous to shippers' optimization problem
Conventional demand	• Represented as an oligopoly • Unbundling of wholesale and retail activities • Conventional demand supplied by retailers • Increase in market competition (entry of new retailers)
Virtual gas hub	• Trade among wholesalers • Retailers supplied by wholesalers
Shippers divided into wholesalers and retailers: Wholesalers supply the electricity sector and participate in the global LNG market. Retailers supply the conventional demand.	

Table 3-5 – Stage 4. Unbundling of wholesale and retail activities

3.3.4.2. Equilibrium solution

The equilibrium solution for the wholesalers is similar to the previous case for the shippers, except that the conventional demand is now supplied by the retailers. When the KKT optimality conditions are solved and no constraint is active, the marginal cost of all wholesalers again reaches a unique value, which coincides with the gas hub price.

$$\lambda_p = c'\left(q_{ap}^c\right) = p_p^e\left(\sum_a q_{ap}^e\right) + \frac{\partial p_p^e\left(\sum_a q_{ap}^e\right)}{\partial q_{ap}^e} \cdot q_{ap}^e = P_p^x \tag{3.25}$$

When any constraint is active, the previous conclusions still hold.
The equilibrium solution for the retailers leads to the following equilibrium when $d_{rp}^i \geq 0$:

$$\lambda_p = p_p^i\left(\sum_r d_{rp}^i\right) + \frac{\partial p_p^i\left(\sum_r d_{rp}^i\right)}{\partial d_{rp}^i} \cdot d_{rp}^i \tag{3.26}$$

The wholesalers and retailers problems are linked through the hub price:

$$\begin{aligned} c'\left(q_{ap}^{c}\right) &= p_{p}^{i}\left(\sum_{r} d_{rp}^{i}\right) + \frac{\partial p_{p}^{i}\left(\sum_{r} d_{rp}^{i}\right)}{\partial d_{rp}^{i}} \cdot d_{rp}^{i} = \lambda_{p} \\ &= p_{p}^{e}\left(\sum_{a} q_{ap}^{e}\right) + \frac{\partial p_{p}^{e}\left(\sum_{a} q_{ap}^{e}\right)}{\partial q_{ap}^{e}} \cdot q_{ap}^{e} = P_{p}^{x} \end{aligned} \tag{3.27}$$

The unbundling of wholesale and retail activities may facilitate the entrance of new players into the market and yield lower prices for the conventional demand. However, if this new market structure impedes the entry of new agents (wholesalers and retailers) into the market, the oligopolistic market structure may give room for wholesalers' strategic behavior in the hub and might yield a successive oligopoly, in which wholesalers and retailers may exercise market power which can yield higher consumer prices than vertically integrated companies as shown in (Tirole, 1988) and (Boots et al., 2004).

3.4. Case study

For the sake of clarity, we simulate a hypothetical gas system with three shippers who signed upstream long-term contracts to supply their demands during a two-time-period scope. The four aforementioned stages of the hub are simulated in order to illustrate the proposed market equilibria.

For modeling this type of market equilibrium, the problem is formulated as an MCP and has been implemented in the GAMS language and solved by using PATH (Rutherford, 1995). The existence and uniqueness of the solution is ensured due to the convexity of the problem.

3.4.1. Cases description

Each shipper owns a long-term contract portfolio to procure the required gas for the different markets (Table 3-6). Each shipper faces the conventional and the electricity sector demands, and can participate in the global LNG market. The parameters that define the three types of market are shown in Table 3-7. As mentioned above, the electricity market is modeled as an oligopoly, and the price is endogenous to the shippers' optimization problem. The global LNG spot market is modeled as a competitive market in which the shippers are price takers. Additionally, we assume that the shippers get better prices through the long-term agreements than in the spot market; i.e., the LNG spot market price is higher than the long-term procurement cost.

Period	Shipper	$\overline{Q}_{ap}^{c}$ MWht	$\underline{Q}_{ap}^{c}$ MWht	$\overline{Q}_{ap}^{c}$ MWht	$\underline{Q}_{a}^{c}$ MWht	$P_{ap}^{c_0}$ €/MWht	α_{ap}^{c} €/MWht^2
p1	A	500	200	650	350	17.90	0.02
	B	800	300	1050	550	17.70	0.01
	C	950	400	1300	600	17.50	0.01
p2	A	500	200	650	350	18.01	0.02
	B	800	300	1050	550	17.90	0.01
	C	950	400	1300	600	17.08	0.01

Table 3-6 – Long-term contract characteristics

Period	Shipper	$P_{ap}^{i_0}$ €/MWht	α_{ap}^{i} €/MWht^2	$P_{ap}^{e_0}$ €/MWht	α_{ap}^{e} €/MWht^2	P_{p}^{x} €/MWht
p1	A,B,C	70.00	0.08	85.00	0.02	100.00
p2	A,B,C	73.00	0.06	92.00	0.03	98.00

Table 3-7 – Demands faced by shippers

Regarding the conventional demand, different shippers' behavior and market structures are considered depending on the stage of the development of the hub.

The proposed stages of development of a virtual gas hub have been simulated. In all cases the agents participate in the hub within a perfectly competitive framework. The four presented stages are summarized in Table 3-1 and listed below. Stage 1: Prior to the introduction of the hub; Stage 2: Market equilibrium with an emerging gas hub; Stage 3: Market equilibrium with a mature gas hub. In this stage, the entry of new shippers is simulated. Stage 4: Market equilibrium with unbundling of wholesale and retail activities. The entry of new retailers in the market is analyzed.

3.4.2. Results

The obtained results from the simulations, except for the LNG spot price, which is an input, are shown in the Table 3-8 and Table 3-9. The stages are examined in terms of their impact on gas prices and demand.

Stage	Agents	Period	Hub price	Conventional demand price (€/MWh)			Electricity market price (€/MWh)	LNG spot price (€/MWh)
Stage 1		p1	-	65.78	63.62	62.68	64.79	100
		p2	-	67.33	65.44	63.71	66.49	98
Stage 2		p1	58.08		64.04		64.81	100
		p2	57.96		65.48		66.47	98
Stage 3	3 shippers	p1	60.2		62.65		66.4	100
		p2	60.53		63.64		68.39	98
	9 shippers	p1	61.15		62.03		67.11	100
		p2	61.68		62.81		69.26	98
Stage 4	3 wholesalers 3 retailers	p1	60.2		62.65		66.4	100
		p2	60.53		63.64		68.39	98
	3 wholesalers 12 retailers	p1	61.28		61.95		67.21	100
		p2	61.84		62.7		69.38	98

Table 3-8 – Market prices (i.e. conventional. electricity market and global LNG market) per period

Stage	Agents	Trade through the hub (MWh)	Household demand (MWh)	Electricity market (MWh)	LNG spot (MWh)	Shippers' total profits (€)
Stage 1		-	599	1860	540	142584
Stage 2		360	599	1860	540	142771
Stage 3	3 shippers	361	743	1716	540	144434
	9 shippers	708	807	1652	540	144859
Stage 4	3 wholesalers 3 retailers	2460	743	1716	540	144434
	3 wholesalers 12 retailers	2460	816	1643	540	144901.

Table 3-9 – Gas delivery to each market (i.e. conventional, electricity market and global LNG market) and total profit during both periods for the studied cases

When stage 1 and stage 2 are compared, we obtain that the shippers purchase and sell gas in the hub, until their marginal costs are equal. This statement does not hold when maximum supply constraints appear for a shipper, in which case the difference between the hub price and the marginal cost is equal to the shippers' willingness to pay for an additional unit. The total profit increases with the introduction of the hub, as shippers gain flexibility, even if strategic behavior is not explicitly considered in the hub. However, not all shippers increase their profits with their participation in the hub. Some shippers may observe their profits reduced for participating in the hub, as it is the case of the largest shipper, shipper C, who diminishes its profits about 3% in stage 2. This shipper has the lowest marginal cost and sells gas to the rest of the shippers in the hub until all shippers' marginal cost are equal. Therefore, it has less gas to supply to its captive demand at higher prices.

Regarding the market share, comparing stage 1 and stage 2, we obtained that the market share becomes the same for all shippers for conventional and power sector demands in stage 2. The reason behind is that with the introduction of the hub, the marginal costs of all shippers are equal and we represent three symmetric shippers with identical conventional demand elasticities and same influence in the electricity sector. Shippers B and C, which have lower marginal cost and more available gas from long-term contracts, lose market share from stage 1 (B: 37.33%, C: 46.65%) to stage 2 (B: 33.33%, C: 33.33%) in favor of shipper A (i.e. case I: 16.00%, case II: 33.33%) in the first period.

Moreover, the conventional demand price is reduced for those consumers supplied by shippers A and B. In contrast, this does not hold for consumers supplied by shipper C, for which the price is higher as shipper C can now sell gas to other shippers in the hub rather than satisfy its captive demand. However, with the introduction of the hub, with no additional measure to create competition and captive conventional demands, consumer surplus decreases in 3.84% (from stage 1 to stage 2). In stage 3, captive demand is more open to competition and the conventional demand price decreases, with respect to stage 2. The price paid by the consumers is reduced from 64.04 €/MWh in stage 2 first period to 62.65 €/MWh in stage 3, first period, even when no new entry is modeled, as now shippers compete among them to supply the demand and the market power is lowered. Hence, the consumer surplus increases (53.84%). However, due to the oligopolistic nature of the gas market and its connection with the electricity market (modeled as another oligopolistic market) the electricity market price increases and shippers' profits slightly rise. Moreover, during the different proposed stages, the conventional demand market becomes more competitive than the electricity one and, as the supply constraint (3.6) is active, the supplied gas to the electricity sector diminishes in the same proportion as conventional demand increases.

Once the hub is implemented, the conventional demand switching rate increases due to the price transparency. Consequently, the barriers to entry diminish and new shippers enter into the market. In Figure 3-3, the impact of the entry of new market players in the hub trade, conventional demand and electricity sector is represented. We assumed that the new shippers do not have access to any long-term supply contract, being the hub their only source of gas procurement, so that the gas available in the market remains constant. As shown in Figure 3-3, transactions in the hub increase considerably, from 361 MWh with 3 shippers to 709 MWh with 9 shippers (almost double).

Hub prices rise accordingly, from 60.2 €/MWh with 3 shippers to 61.5 €/MWh with 9 shippers and 61.54 €/MWh with 33 shippers. With the entry of new shippers, market power in the conventional demand sector is reduced and, as the hub is modeled as perfect competition, conventional demand prices will decrease and household and market prices will tend to converge, as shown in Figure 3-4.

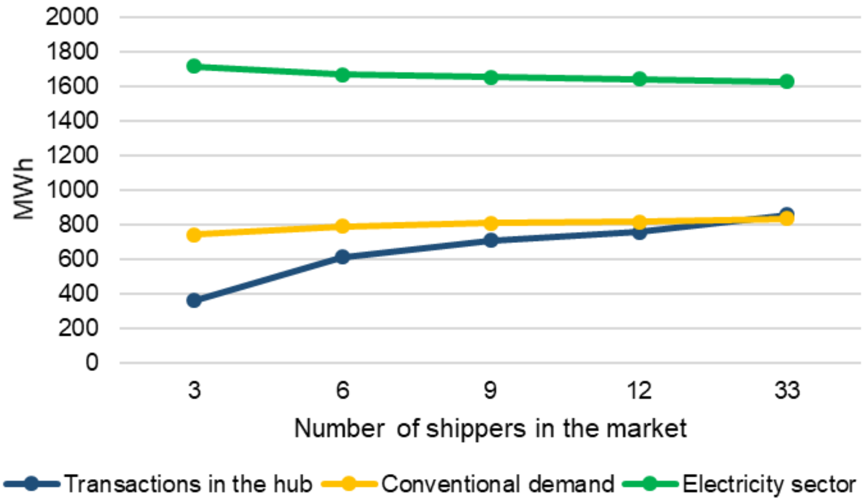

Figure 3-3 – Evolution of transactions in the hub, conventional demand and the electricity sector with the entry of new shippers in the market

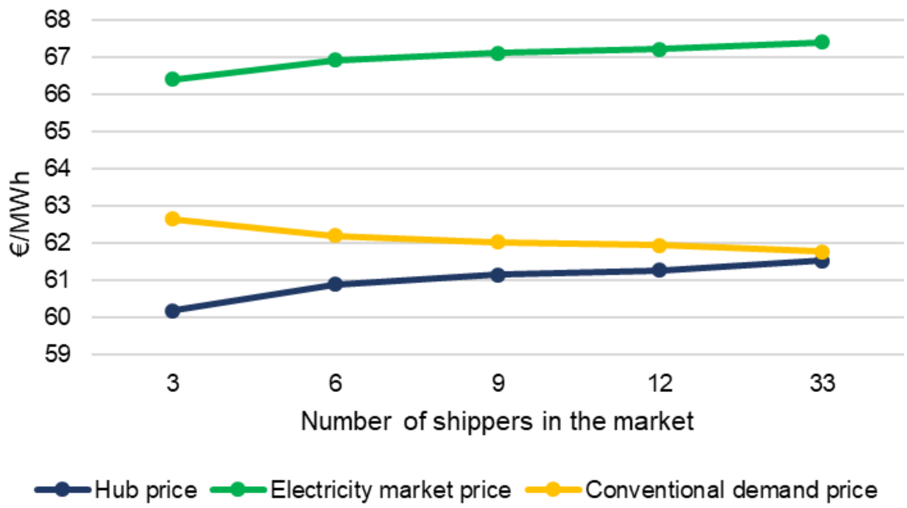

Figure 3-4 – Evolution of prices in the hub, conventional demand and the electricity sector with the entry of new shippers in the market

In stage 4, we represent the unbundling of wholesale and retail activities. We have considered that wholesalers behave as competitive agents in the hub, for avoiding double marginalization and hence higher prices with this measure. Under this market structure, we assume that the entry of retailers for supplying the conventional demand is favored, hence market power reduces, the conventional demand price decreases, and consumer surplus increases. However, the total profits increase, at the expense of raising the gas price in the electricity sector. The price link between and the oligopolistic nature of both markets (electricity and gas market), give gas market players flexibility and more room for strategic behavior.

If the unbundling of wholesale and retail activities is not able to reduce entry barriers and attract new market players it might lose its meaning, as it can end up in a successive oligopoly or even when considering wholesalers behave as perfect competitors in the hub, yield the same results as vertical integrated companies (presented in the 3rd stage).

In Table 3-10 the amount of gas in each market in percentage is presented. Because the global LNG market price is higher than the other markets price and constant (100 €/MWh in p1 and 98 €/MWh in p2), the shippers divert as much gas as possible. The transportation constraint (3.4) is in all cases active. This result is reflecting the late years LNG market situation during which LNG carriers were diverted to Asia, but prices were rather constant. Moreover, the model shows that the global LNG market price is partially transferred to the rest of the markets as it occurred in many European countries.

Stage	Conventional	Power sector	LNG global market
	%	%	%
1	19.98	62.02	18.00
2	19.99	62.01	18.00
3	24.77	57.23	18.00
4	31.64	50.36	18.00

Table 3-10 – Gas reserved for each market (i.e. households, electricity market and global LNG market) in percentage during both periods without new market participants

During the different proposed stages, the power sector price increases as we move forward in the liberalization, as less gas is delivered to this market since the conventional and the global LNG markets are more attractive. As the supply constraint (3.6) is active, the supplied gas to the electricity sector diminishes in the same proportion the supplied conventional demand increases.

3.5. Conclusions

The different stages of the implementation and development of a virtual gas hub within an entry-exit framework have been analyzed. The gas market is segmented by type of consumer. Each shipper, as a key player, maximizes its profit by supplying gas to households, businesses and industries (conventional demand), participating in the electricity market, trading gas to the global LNG market and interacting with the rest of the agents in an incipient virtual hub. A novel representation of the shippers' strategic behavior during the implementation of virtual hubs at the different levels of hub maturity in entry-exit system is presented. First, the business as usual case includes a global LNG market which is represented as a perfectly competitive market, the electricity market which is represented as an oligopoly, and the conventional demand which is captive (i.e., monopolized). Second, a hub is implemented. Third, as switching rates are expected to grow due to the gas price transparency, the conventional demand is no longer considered as captive. Fourth, we explore the unbundling of wholesale and retail activities proposed as an additional measure to enhance retail competition and increase market transactions.

From the simulation and the analysis of the different market equilibria, we draw several conclusions which apply to the implementation of any virtual hub. Therefore, it should be in particular interest for stakeholders that are planning to follow the same path pursued by the EU during the last decade.

Prior to the implementation of the hub, independently of the behavior in each market (i.e., monopoly, oligopoly or perfect competition), the marginal cost of each shipper is equal to the marginal income from the market. As the global LNG market price is held constant, all marginal costs and marginal incomes will reach this value as long as the transportation constraint is not binding. Therefore, the global LNG market price is transferred to the conventional demand and the electricity sector as it has happened lately with Asia and Europe. However, the price was not directly transferred as the global LNG market presents some transportation constraints due to the limited fleet of LNG carriers. In the case that the LNG fleet would be large enough, the price would equal the shippers' apparent cost and would be transferred to the household consumers and the electricity sector. An integrated global gas market, which is of interest for consumers as a price stabilizer, undoubtedly requires an increment of the LNG fleet.

With the introduction of a hub, the shippers have another source of gas procurement and gain flexibility as they have the possibility of buying and selling gas in the gas hub. As a result, the marginal cost of all shippers reaches a unique value, which coincides with the gas hub price as long as supply constraints are not binding. Furthermore, the aggregated profit of the shippers may increase even when anticompetitive behavior is not explicitly represented due to the gained flexibility by the agents in the hub and the oligopolistic nature of the gas and electricity markets. Therefore, the hub constitution is a necessary, but not sufficient solution to encourage competition. However, even if with the hub the shippers' total profit increases, not all the agents increase their profits with their participation in the hub. Besides, there is a clear trend of reducing market shares of large participants in favor of small ones.

Furthermore, as the marginal cost of all shippers converges to a unique value, some conventional consumers might lose wealth if their current supplier has lower marginal costs than other shippers in the market. In this case, the shipper might sell gas to other shippers in the hub rather than supply its gas to its conventional demand. Nevertheless, as the conventional demand switching rates tend to be higher as the market liberalization persists over time thank to the transparency of gas prices, during the evolution from monopolized demand to a Cournot oligopoly, the paid price by the conventional demand is reduced as now shippers compete among them to supply the demand and the market power is reduced.

Additionally, the unbundling of wholesale and retail activities is forced, in order to favor the entry of new participants and guarantee the competition. Hence, with the entry of new retailers, market power in the conventional demand segment decreases, delivery prices lower, and consumer surplus increases. However, if the market is not able to attract new agents it might end up in successive oligopoly which yields higher prices.

Appendix A: The optimization approach

We assume that the interactions among all the market agents, each one pursuing its maximum profit, is an equilibrium. For the representation of this equilibrium, complementarity structures are used, based on general equilibrium framework and on non-cooperative game setting. By simultaneously solving the optimization problems of several players within the complementarity system, this model type gives the equilibrium solution to the entire market game.

Hence, the equilibrium solution goes beyond the solution of the individual optimization problem of each player, by giving the simultaneous solution to all agents in the game. However, in many situations, the individualistic interests of each player causes that the equilibrium solution turn out not to be Pareto optimal, like the known example of the Prisoner's Dilemma.

Complementarity models are quite appropriate for modeling the coexistence of regulated/deregulated, perfect/imperfect competition that characterizes the natural gas market liberalization. We use the definition of a complementarity problem defined in (Gabriel et al., 2013): having a function F: $\mathbb{R}^n \rightarrow \mathbb{R}^n$ the pure nonlinear complementarity problem denoted is to find $x \epsilon \mathbb{R}^n$ such that for all i:

$$\begin{gathered} F_i(x) \geq 0 \\ x_i \geq 0 \\ x_i \cdot F_i(x) = 0 \end{gathered} \tag{3.28}$$

More compactly, it can be expressed as (3.29) , where $\perp$ denotes the inner product of two vectors equal to zero.

$$0 \leq F(x) \perp x \geq 0 \tag{3.29}$$

The mixed version of the complementarity problem (MCP) also allows for both equations with corresponding free variables and inequalities with associated nonnegative variables. The most common form of the MCP is stated as follows, based on (Gabriel et al., 2013). Having a function F: $\mathbb{R}^n \rightarrow \mathbb{R}^n$, $MCP(F)$ is finding a vector $x \,\epsilon\, \mathbb{R}^{n_1}, y \,\epsilon\, \mathbb{R}^{n_2}$, such that for all i:

$$F_i(x,y) \geq 0; \; x_i \geq 0; \; x_i \cdot F_i(x) = 0; \; i = 1, \ldots, n_1 \tag{3.30}$$
$$F_{j+n_1}(x,y) = 0; \; y_j \; free; \; j = 1, \ldots, n_2 \tag{3.31}$$

A general maximization problem becomes therefore,

$$\max_x f(x) \tag{3.32}$$
$$s.t. \quad g_i(x) \leq 0; (\lambda_i), \forall i \epsilon I \tag{3.33}$$

$$h_j(x) = 0; (\mu_j), \forall j \epsilon J \tag{3.34}$$

$$x \geq 0 \tag{3.35}$$

Where i and j are indexing the inequalities and equalities respectively.

The corresponding Karush-Kuhn-Tucker conditions (KKT) are the necessary and sufficient conditions for optimality of the problem if we have a convex objective function and a convex solution space feasible region.

$$\nabla f(x) + \sum_i \lambda_i \cdot \nabla g_i(x)^T + \sum_j \mu_j \cdot \nabla h_j(x)^T = 0 \tag{3.36}$$

$$g_i(x) \leq 0 \ \perp \lambda_i \geq 0 \quad \forall i \epsilon I \tag{3.37}$$

$$h_j(x) = 0 \ \perp \mu_j \ \ free \quad \forall j \epsilon J \tag{3.38}$$

Equation (3.36) makes sure the solution is stationary, (3.37) guarantees complementarity, and (3.38) feasibility. Note that the dual variable λ_i of the inequality has to be greater than or equal to zero, while the dual μ_j of the equality can take any real number (i.e. it is free).

Depending on the character of the constraints of the optimization problem, $g_i(x)$ or $h_j(x)$, different types of complementarity problems can be distinguished.

If the constraints are exogenous parameters, the linear or non-linear complementarity problem can be expressed as a Mixed Complementarity Problem (MCP)**.** Their common characteristic is the simultaneous solution to all optimization problems in the model. There can be several linked optimization problems in such a model, either in a game context (linked via reaction functions) or in any other setup where the link is done via physical balance or market clearing conditions. Market games such as Cournot games can be modeled in the MCP format. More generally, MCP models allow to represent Nash games (Nash, 1951) in pure strategies.

Appendix B: Problem formulation. Karush-Kuhn-Tucker (KKT) conditions

This section contains the Karush-Kuhn-Tucker (KKT) conditions of the problems described above.

Prior to the introduction of a gas hub

The KKT conditions of the shippers' maximization problem are the following:

$$\begin{pmatrix} -\dfrac{\partial p_{ap}^{i}\left(q_{ap}^{i}\right)}{\partial q_{ap}^{i}} \cdot q_{ap}^{i} - p_{ap}^{i}\left(q_{ap}^{i}\right) + \dfrac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}\right)}{\partial q_{ap}^{i}} \\ +\varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} + \varepsilon_{a}^{3} - \varepsilon_{a}^{4} - \mu_{ap}^{q_i} \end{pmatrix} \leq 0 \quad \perp q_{ap}^{i} \geq 0 \tag{3.39}$$

$$\begin{pmatrix} -\dfrac{\partial p_{p}^{e}\left(q_{ap}^{e}\right)}{\partial q_{ap}^{e}} \cdot q_{ap}^{e} - p_{ap}^{e}\left(q_{ap}^{e}\right) + \dfrac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}\right)}{\partial q_{ap}^{e}} \\ +\varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} + \varepsilon_{a}^{3} - \varepsilon_{a}^{4} - \mu_{ap}^{q_e} \end{pmatrix} \leq 0 \quad \perp q_{ap}^{e} \geq 0 \tag{3.40}$$

$$\begin{pmatrix} -P_{p}^{x} + \dfrac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}\right)}{\partial q_{ap}^{x}} + \\ +\varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} + \varepsilon_{a}^{3} - \varepsilon_{a}^{4} + \chi_{ap}^{1} - \chi_{ap}^{2} \end{pmatrix} \leq 0 \quad \perp q_{ap}^{x} \geq 0 \tag{3.41}$$

Complementary slackness conditions

$$\left(-\overline{Q}_{ap}^{c} + q_{ap}^{c}\right) \leq 0 \quad \perp \varepsilon_{ap}^{1} \geq 0 \quad \forall a, p \tag{3.42}$$

$$\left(\underline{Q}_{ap}^{c} - q_{ap}^{c}\right) \leq 0 \quad \perp \varepsilon_{ap}^{2} \geq 0 \quad \forall a, p \tag{3.43}$$

$$\left(-\overline{Q}_{a}^{c} + \sum_{p} q_{ap}^{c}\right) \leq 0 \quad \perp \varepsilon_{a}^{3} \geq 0 \quad \forall a \tag{3.44}$$

$$\left(\underline{Q}_{a}^{c} - \sum_{p} q_{ap}^{c}\right) \leq 0 \quad \perp \varepsilon_{a}^{4} \geq 0 \quad \forall a \tag{3.45}$$

$$\left(-\overline{Q}_{ap}^{x} + q_{ap}^{x}\right) \leq 0 \quad \perp \chi_{ap}^{1} \geq 0 \quad \forall a, p \tag{3.46}$$

$$\left(\overline{Q}_{ap}^{x} - q_{ap}^{x}\right) \leq 0 \quad \perp \chi_{ap}^{2} \geq 0 \quad \forall a, p \tag{3.47}$$

$$\left(-q_{ap}^{i}\right) \leq 0 \quad \perp \mu_{ap}^{q_i} \geq 0 \quad \forall a, p \tag{3.48}$$

$$\left(-q_{ap}^{e}\right) \leq 0 \quad \perp \mu_{ap}^{q_e} \geq 0 \quad \forall a, p \tag{3.49}$$

All the shippers' maximization problems are linked through the electricity market (3.1) and the linear inverse demand function for households is represented by (3.2).

Market equilibrium with an emerging gas hub

The KKT conditions of the shippers' maximization problem are the following:

$$\begin{pmatrix} -\frac{\partial p_{ap}^{i}\left(q_{ap}^{i}\right)}{\partial q_{ap}^{i}}\cdot q_{ap}^{i} - p_{ap}^{i}\left(q_{ap}^{i}\right) + \varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} + \varepsilon_{a}^{3} - \varepsilon_{a}^{4} \\ + \frac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial q_{ap}^{i}} - \mu_{ap}^{q_i} \end{pmatrix} \leq 0 \quad \perp q_{ap}^{i} \geq 0 \tag{3.50}$$

$$\begin{pmatrix} -\frac{\partial p_{p}^{e}\left(\sum_a q_{ap}^{e}\right)}{\partial q_{ap}^{e}}\cdot q_{ap}^{i} - p_{p}^{e}\left(\sum_{a} q_{ap}^{e}\right) + \varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} \\ +\varepsilon_{a}^{3} - \varepsilon_{a}^{4} + \frac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial q_{ap}^{e}} - \mu_{ap}^{q_e} \end{pmatrix} \leq 0 \quad \perp q_{ap}^{e} \geq 0 \tag{3.51}$$

$$\begin{pmatrix} -P_{p}^{x} + \frac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial q_{ap}^{x}} \\ +\varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} + \varepsilon_{a}^{3} - \varepsilon_{a}^{4} + \chi_{ap}^{1} - \chi_{ap}^{2} \end{pmatrix} \leq 0 \quad \perp q_{ap}^{x} \geq 0 \tag{3.52}$$

$$\begin{pmatrix} \lambda_p \quad + \frac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial \Delta q_{ap}} \\ -\varepsilon_{ap}^{1} + \varepsilon_{ap}^{2} - \varepsilon_{a}^{3} + \varepsilon_{a}^{4} - \mu_{ap}^{\Delta q} \end{pmatrix} \leq 0 \quad \perp \Delta q_{ap} \geq 0 \tag{3.53}$$

$$\begin{pmatrix} -\lambda_p \quad + \frac{\partial c_{ap}\left(q_{ap}^{i}, q_{ap}^{e}, q_{ap}^{x}, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial \nabla q_{ap}} \\ +\varepsilon_{ap}^{1} - \varepsilon_{ap}^{2} + \varepsilon_{a}^{3} - \varepsilon_{a}^{4} - \mu_{ap}^{\nabla q} \end{pmatrix} \leq 0 \quad \perp \nabla q_{ap} \geq 0 \tag{3.54}$$

Complementary slackness conditions are (3.42)- (3.49) and

$$\left(-\Delta q_{ap}\right) \leq 0 \quad \perp \mu_{ap}^{\Delta q} \geq 0 \quad \forall a, p \tag{3.55}$$

$$\left(-\nabla q_{ap}\right) \leq 0 \quad \perp \mu_{ap}^{\nabla \mathrm{q}} \geq 0 \quad \forall a, p \tag{3.56}$$

The linear inverse demand function for the electricity sector is represented in (3.1) and household demand in (3.2).

Finally, the hub market-clearing condition:

$$\sum_{a} \Delta q_{ap} = \sum_{a} \nabla q_{ap} \quad : \lambda_p \quad \forall p \tag{3.57}$$

Market equilibrium with a gas and hub and introduction of competition in household demand

The KKT conditions for maximizing shippers' profits are (3.51) - (3.54) and

$$\begin{pmatrix} -\frac{\partial p_p^i\left(\sum_a q_{ap}^i\right)}{\partial q_{ap}^i}\cdot q_{ap}^i - p_p^i\left(\sum_a q_{ap}^i\right) + \varepsilon_{ap}^1 - \varepsilon_{ap}^2 + \varepsilon_a^3 - \varepsilon_a^4 \\ + \frac{\partial c_{ap}\left(q_{ap}^i, q_{ap}^e, q_{ap}^x, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial q_{ap}^i} - \mu_{ap}^{q_i} \end{pmatrix} \leq 0 \quad \perp q_{ap}^i \geq 0 \qquad (3.58)$$

And the complementary slackness conditions are (3.42) - (3.49), (3.55) and (3.56).

Market equilibrium with unbundling of wholesale and retail activities and establishment of a compulsory wholesale market

Wholesaler

The KKT conditions of the wholesalers' maximization problem are the following:

$$\begin{pmatrix} -\frac{\partial p_p^e\left(\sum_a q_{ap}^e\right)}{\partial q_{ap}^e}\cdot q_{ap}^i - p_p^e\left(\sum_a q_{ap}^e\right) \\ + \frac{\partial c_{ap}\left(q_{ap}^e, q_{ap}^x, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial q_{ap}^e} + \varepsilon_{ap}^1 - \varepsilon_{ap}^2 + \varepsilon_a^3 - \varepsilon_a^4 - \mu_{ap}^{q_e} \end{pmatrix} \leq 0 \quad \perp q_{ap}^e \geq 0 \qquad (3.59)$$

$$\begin{pmatrix} -P_p^x + \frac{\partial c_{ap}\left(q_{ap}^e, q_{ap}^x, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial q_{ap}^x} \\ + \varepsilon_{ap}^1 - \varepsilon_{ap}^2 + \varepsilon_a^3 - \varepsilon_a^4 + \chi_{ap}^1 - \chi_{ap}^2 \end{pmatrix} \leq 0 \quad \perp q_{ap}^x \geq 0 \qquad (3.60)$$

$$\begin{pmatrix} \lambda_p \; + \frac{\partial c_{ap}\left(q_{ap}^e, q_{ap}^x, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial \Delta q_{ap}} \\ -\varepsilon_{ap}^1 + \varepsilon_{ap}^2 - \varepsilon_a^3 + \varepsilon_a^4 - \mu_{ap}^{\Delta q} \end{pmatrix} \leq 0 \quad \perp \Delta q_{ap} \geq 0 \qquad (3.61)$$

$$\begin{pmatrix} -\lambda_p \; + \frac{\partial c_{ap}\left(q_{ap}^e, q_{ap}^x, \Delta q_{ap}, \nabla q_{ap}\right)}{\partial \nabla q_{ap}} \\ +\varepsilon_{ap}^1 - \varepsilon_{ap}^2 + \varepsilon_a^3 - \varepsilon_a^4 - \mu_{ap}^{\nabla q} \end{pmatrix} \leq 0 \quad \perp \nabla q_{ap} \geq 0 \qquad (3.62)$$

And the complementary slackness conditions are (3.42) - (3.46), (3.49), (3.55),(3.56) and (3.65).

Finally, the hub market-clearing condition between wholesalers and retailers is:

$$\sum_{a} \Delta q_{ap} + \sum_{r} d_{rp}^{i} = \sum_{a} \nabla q_{ap} \quad : \lambda_p \quad \forall p \tag{3.63}$$

Retailer

The KKT conditions of the retailers' maximization problem are the following:

$$-\frac{\partial p_p^i\left(\sum_r d_{rp}^i\right)}{\partial d_{rp}^i} \cdot d_{rp}^i - p_p^i\left(\sum_r d_{rp}^i\right) + \lambda_p - \mu_{rp}^{d_i} \leq 0 \quad \perp d_{rp}^i \geq 0 \tag{3.64}$$

Complementary slackness condition

$$\left(-d_{rp}^i\right) \leq 0 \quad \perp \mu_{rp}^{d_i} \geq 0 \quad \forall r, p \tag{3.65}$$

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Chapter 4

A global gas market model to deal with the new commercial trends in the natural gas market

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The way natural gas is traded has changed over the past decade in Europe with an increasing amount of spot market transactions, the proliferation of flexible-destination contracts and Gas-On-Gas pricing.

The analysis and results in this section are based on (Del Valle, Reneses, & Wogrin, 2019).

Notation

GasValem – GoG model

Sub-indexes

o	Producers
t	Traders
k	Marketers
z, z_1	Zone
p	Period
y	Year
m	Month
d	Day
w	Well
c	Long-term contract
h	Hub
i	Commodity Index
s	Demand sector

Parameters

$\overline{Q}_{dw}^{Well}$	Daily maximum well production (MMbtu)
$c1_{w}^{Well}$	Well’s extraction quadratic cost curve ($/MMbtu)
$c2_{w}^{Well}$	Well’s extraction quadratic cost curve ($/MMbtu^2)
a_{w}^{Well}	Golombek cost function. Minimum per unit cost term
b_{w}^{Well}	Golombek cost function. Linear cost term
c_{w}^{Well}	Golombek cost function. Quadratic cost term
$\underline{Q}_{yctk}^{c}, \overline{Q}_{yctk}^{c}$	LTC minimum and maximum yearly Take-Or-Pay (ToP) commitments (MMbtu)
$\underline{Q}_{ymctk}^{c}, \overline{Q}_{ymctk}^{c}$	LTC minimum and maximum monthly Take-Or-Pay (ToP) commitments (MMbtu)
$Cost_{t}^{Tra}$	Unitary cost applied by traders ($/MMbtu) to the gas sold in the global market
$Cost_{t}^{TraRe}$	Unitary cost applied by traders ($/MMbtu) to the gas sold in their home market (i.e. as a vertically integrated company)
$Cost_{k}^{MakWholesale}$	Unitary cost applied by marketers in the wholesale market ($/MMbtu)
$Cost_{k}^{MakRetail}$	Unitary cost applied by traders in the retail market ($/MMbtu)

$\bar{Q}_{dz}^{Liq}$	Daily maximum liquefaction capacity (MMbtu/d)
$Cost_{z}^{Liq}$	Liquefaction unitary cost ($/MMbtu)
$COST_{pzz_1}^{Pipe}$	Pipelines' transport unitary cost (point to point) ($/MMbtu)
$Cost_{zz_1}^{Ship}$	LNG carriers' transport unitary cost (point to point) ($/MMbtu)
$\bar{Q}_{dz}^{Reg}$	Daily maximum liquefaction capacity (MMbtu/d)
$\bar{Q}_{pz}^{Tank}$	Maximum LNG storage capacity in the regasification terminal tanks (MMbtu)
$Cost_{z}^{Reg}$	Regasification cost ($/MMbtu)
$Cost_{z}^{Tank}$	LNG storage cost ($/MMbtu)
$\bar{Q}_{dz}^{Inj}$	Underground storage maximum injection capacity (MMbtu/d)
$\bar{Q}_{dz}^{Wit}$	Underground storage maximum withdrawal capacity (MMbtu/d)
$\bar{Q}_{z}^{Sto}$	Underground storage maximum storage capacity (/MMbtu)
$Cost_{pz}^{Inj}$	Underground storage injection cost ($/MMbtu)
$Cost_{pz}^{Wit}$	Underground storage withdrawal cost ($/MMbtu)

Variables:

q_{po}^{Prod}	Producers' natural gas per period (MMbtu)
q_{pw}^{Well}	Well natural gas production per period (MMbtu
$q_{pw}^{WellLTC}$	Wells' production assigned to LTC per period (MMbtu)
q_{pw}^{Rwell}	Well natural gas reserves (MMbtu)
q_{ptz}^{Tra}	Traders' natural gas per period and zone (MMbtu)
$q_{pzz_1ctk}^{QNG}$	Natural gas assigned to LTC (MMbtu)
$q_{pzz_1ctk}^{QLNG}$	Liquefied natural gas assigned to LTC (MMbtu)
$q_{ptkz}^{VerticallyInt}$	Direct natural gas sales between traders and marketers (MMbtu)
q_{pctk}^{c}	LTC exerted volume
$q_{ptkzz_1c}^{Flex-NotDiverted}$	Exerted volume of a flexible LTC which is not diverted (MMbtu)
$q_{pzz_1ctk}^{No\ flex}$	Exerted volume of a no flexible LTC (MMbtu)
$q_{pzz_1ctk}^{Diverted}$	Exerted volume of a flexible LTC which is diverted (MMbtu)
q_{ptz}^{LiqTra}	Liquefied natural gas by trader (MMbtu)
q_{ptz}^{RegTra}	Regasified LNG by traders (MMbtu)
$q_{ptzz_1}^{PipeTra}$	Natural gas flows through pipelines assigned to traders (MMbtu)

q_{pzk}^{Mak}	Marketers natural gas portfolio (MMbtu)
q_{pkz}^{Demand}	Total final natural gas demand by marketer (MMbtu)
q_{pkz}^{Power}	Power sector natural gas demand (MMbtu)
$q_{pz}^{Residential}$	Residential and conventional natural gas demand (MMbtu)
$q_{pz}^{Industrial}$	Industrial natural gas demand (MMbtu)
q_{pkz}^{RegMak}	Regasified LNG by marketers (MMbtu)
q_{pkz}^{WitUGS}	Natural gas withdrawal from underground storage (MMbtu)
q_{pkz}^{InjUGS}	Natural gas injected in underground storage (MMbtu)
$q_{pz_1z}^{PipeMak}$	Natural gas flows through pipelines assigned to marketers (MMbtu)
$q_{pkz}^{HubSalesMak}$	Marketers' natural gas sales at the hub (MMbtu)
$q_{pkz}^{HubPurchMak}$	Marketers' natural gas purchases at the hub (MMbtu)
$q_{pzz_1}^{Pipe}$	Natural gas flows through pipelines (MMbtu)
$q_{pzz_1k}^{ShipTra}$	LNG shipped by traders (MMbtu)
$q_{pkz}^{TankMak}$	LNG stored by marketers at the tanks of the regasification terminal (MMbtu)
CSP_{cp}	Contract Sales Price ($/MMbtu)
p_p^{Index}	Index price ($/bbl for oil products and $/MMbtu for natural gas)
γ_{pz}	Hub price ($/MMbtu). Dual variable of hub balance equation
β_{pkz}	Marketer marginal cost ($/MMbtu)
λ_{pz}	Natural gas retail price ($/MMbtu). Dual variable of marketers-demand balance equation

This chapter aims at developing the second specific objective of this thesis and it is based on the analysis and results in ***Article III*** (Del Valle, Reneses, & Wogrin, 2019) as working paper, which is under review at the time of this thesis publication.

4.1. Introduction

Section 4.1 of this chapter is an introductory section, made up of four subsections. Section 4.1.1 introduces the context and the motivation for developing this model. Next, section 4.1.2 presents the current status of the literature regarding long-term supply contracts in natural gas markets, while section 4.1.3 describes the different types of price formation mechanisms. Last, in section 4.1.4, a brief review on the state of the art of world/global natural gas market models is presented. Section 4.2 is devoted to the description of the proposed model, presenting its main characteristics and defining the interaction among the different market agents. Section 4.3 applies the model to a real case study for the year 2020 representing the global gas market. The obtained results are also analyzed in this section. Section 4.4 contains the chapter's conclusions. Last, the results for 2017 are displayed in Appendix C.

4.1.1. Context and motivation

The European natural gas market has traditionally been dominated by bilateral long-term supply contracts between producers/traders (sellers) and marketers/shippers (buyers) that fixed a minimum volume to be exchanged (Take-or-Pay clauses (ToP), with typical values between 80 and 90%) at a defined price and at a delivery point over a number of years. These arrangements were believed to have several effects. First, they guarantee producers the repay of their heavy investments in capital-intensive facilities and guarantee marketers a firm supply at prices well-known in advance. Second, they allow market risk sharing between producers and marketers. Producers must deliver the pre-agreed volume of gas (taking the price risk) and marketers must purchase this minimum off-take (taking the volume risk), irrespective of other opportunities that might arise in the market. Third, in Europe and Asia, oil price escalation (OPE) (i.e. the price is tied to a basket of heavy and light fuel oils), has been traditionally used to protect gas buyers on a long-term basis against prices above those for the main competing fuels, allowing risk hedging, since oil is considered as a trusted commodity by investors. Conversely, the North American natural gas market has been dominated by gas-on-gas competition (GoG) (i.e. hub pricing) with fully liquid trading markets.

Over the past decade, the nature of buying and selling gas in Europe has been transformed and gas market fundamentals have undergone a significant shift. The ongoing structural changes in the global gas market are having profound implications in the way natural gas is traded and priced. Among these changes, the following can be highlighted: 1) the increase in LNG trade and the subsequent globalization of the natural gas market (Neumann, 2009) and sustained price convergence among price across regions; 2) a greater diversity of suppliers and an ample supply due to the exploration of unconventional gas sources and an increase in global liquefaction capacity; 3) a tendency towards shorter contract durations (typically around 10-15 years vs. the 20-25 years in the past) and increased contractual flexibility (reducing ToP commitments and destination clauses); 4) the appearance of new LNG -consuming markets; 5) demand shocks like those that resulted from the Fukushima crisis or China's natural gas demand growth accelerated by coal to gas switching promoted by the Government clean air policies; and 6) the low level of oil prices (i.e. late 2014-2017) and the expectations/uncertainties on its future evolution. This has been triggered by other factors including the energy market globalization, macroeconomics and political choices.

These circumstances were also underpinned in Europe by the liberalization process, the emergence of new gas trading hubs and the inability to adjust oil indexed traditional long-term supply contracts to supply/demand fundamentals as seen during the economic crisis in Europe. This crisis had negative repercussions for gas demand (i.e. resulting in a fall in demand) and shippers were bound by long-term commitments to purchase expensive oil-linked gas while hub prices promptly responded to the new supply demand balance (Luca, 2014).

The aforementioned combination of factors lies behind the European transition towards contract renegotiations in favor of hub-linked pricing and an increase in spot gas imports. Therefore, even if gas trade in Europe still relies on long-term contracting, traditional oil indexed contracts are being replaced by imports of spot gas resulting in increasing volumes traded at hubs, together with a broadly continuous movement from OPE to GOG pricing since 2005, with GOG's share increasing from 15% in 2005 to 70% in 2017 (IGU, 2018b).

This, in turn, will lead to the marketers and ultimately to the traders requiring and using gas hubs in order to manage their portfolios and risk management. As more and more supply contracts are GOG priced (often referenced to NBP or TTF), it is essential that new gas hubs developed across Europe serve at least as balancing trading points and, potentially, allow shippers to risk manage their portfolios.

This growing spot market has also opened additional opportunities for traders and has brought up the figure of portfolio players, who have even created dedicated portfolios for supplying this new type of demand. The role of these portfolio players is to absorb new volumes into their portfolios and to seek for buyers later, selling at peaking prices and, thus, maximizing their portfolios incomes. This context has allowed to increase the number of players trading LNG with high levels of shorter-term trading and liquidity.

Additionally, new commercial models have appeared in the LNG trade, such as capacity tolling and modular equity investments, and projects developers are increasing projects' share devoted to spot sales, especially in North America, favoring the shift to more flexible LNG market structures and increasing available spot volumes in the market.

Simultaneously, with the strong increase of traders' volumes marketed in the spot market, traders have increased their long-term positions, committing to long-term offtake agreements, even investing in new regasification terminals or being foundational off-takers from new liquefaction projects, allowing them to access new markets and to take advantage of short-term trends.

In this context, we propose a model which captures these new dynamics in order to give insights of the mid-term global natural gas market, representing the above-mentioned commercial trends in the global natural gas trade and which allows to analyze the impact of natural gas hubs and Gas-On-Gas pricing on the resulting market prices. The model is use in this thesis, for the assessment of global optimal patterns of flows, demand and prices in order to provide a worldwide framework to the rest of the models. Moreover, the model is a valuable tool in order to perform scenario analysis and to evaluate the impact of the different natural gas dynamics.

4.1.2. Long-term contracts vs. spot market

The role of long-term contracts in natural gas markets, both from a theoretical and an empirical perspective, has been of considerable interest. (Hubbard & Weiner, 1986), (Hubbard & Weiner, 1991) and (Creti & Villeneuve, 2005) explain the existence of long-term gas contracts as an efficient hedge against risk and the exercise of market power, considering the high level of concentration of suppliers (around a 70% of the European supply is provided by Russia, Norway and Algeria and 36% by Russia alone (BP 2018)). However, this does not prevent producers from exerting their dominance at the contracting stage. (Allaz & Vila, 1993) concludes that under some market conditions, long-term contracts can increase competition in the upstream and suggests that forward trading makes markets more competitive. On the other hand, (Le Coq, 2004) shows that, with subsequent repeated interaction on the spot market, the contract market helps to sustain collusion on the spot market. (Kawai, 1983) exhibits that long-term contracts in the upstream may benefit consumers by reducing uncertainty and its implication on consumption prices and (Neuhoff & Hirschhausen, 2005), (Neumann & von Hirschhausen, 2006) and (Abada, et al., 2014) conclude that not only gas consumers but also gas producers might benefit from signing long-term contracts.

However, the rigidity of traditional long-term contracting has not been able to adapt to the new market situation, in which a more flexible and dynamic structure is needed. This market need has been satisfied by a growing shorter-term trade, under short-term contracts or on the spot market. Worldwide, this “non long-term” trade[1] accounted for nearly 30% of the LNG market in 2017 (IGU 2018a), almost doubling its share in a decade. This trend has been made possible by the increase in LNG contracts with destination flexibility (i.e. allowing for diversion) and in contracts with shorter durations and lowers ToP clauses, as well as the emergence of natural gas hubs, the increasing role of portfolio players and traders, and the growth in the number of exporters and importers. This spot market has allowed to diversify suppliers and manage demand variations. Despite the growth of spot traded LNG volumes and shorter contract lengths, the majority of the global LNG trade is still based on long-term contracts.

The topic is particularly debated within the European natural gas market, where continental Europe is currently in the middle of this transition (Luca, 2014), (Melling, 2010) and (Jonathan Stern & Rogers, 2011), with almost 30% (IGU, 2018b) of its supply still linked to long-term contracts and an important development of spot price based hubs, following the US (1980s) and the UK (1990s) (Heather, 2010). Hubs have become the dominant price-setting mechanism in the majority of markets in North West Europe and is spreading southwards and eastwards supported by the increasing levels of trading volumes and liquidity (Heather, 2015), (Heather & Petrovich, 2017). However, in Southern and South-Eastern Europe there is a considerable amount of LTCs which still are indexed to oil product prices. More fundamentally, a move to hub-based prices removes much of the logic of the existing long-term contracts (Stern, 2011), as (Hulshof, et al., 2016) and (Zhang, et al., 2018) show that hub-based pricing mechanism can better reflect gas market fundamentals. (Heather, 2015) defines five main requirements that lead to a successful trading: liquidity, volatility, anonymity, transparency and traded volumes.

[1] “Non long-term” trade refers to all volumes traded under contracts of less than 5 years duration including spot.

Nonetheless, outside of Europe and the US, liquid physical or notional trading gas hubs have yet to emerge.

For further information regarding long-term contracts and hubs the reader is referred to Chapter 2.

4.1.3. Types of price formation mechanism

We distinguish five major pricing mechanism for the international natural gas markets. A more detailed breakdown of the pricing mechanism can be found in (IGU, 2018b).

Oil price scalation (OPE): The price is linked to a basket of competing fuels, typically crude oil, gas oil and/or fuel oil. This mechanism was originated in Europe in the 1960s and has historically dominated natural gas trade in Europe and Asia. While OPE has lost share in Europe, it has risen to almost 69% in Asia in 2016 and it accounts for more than 70% in Latam.

Gas-on-gas competition (GoG): The price is determined by supply and demand fundamentals. GoG competition has gained ground both in the spot trading at natural gas hubs (i.e. physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK)) and in long-term supply contracts (i.e. bilateral agreements) and futures organized markets (e.g. NYMEX in the US or ICE in the UK). Globally, the share of GoG was 45% in 2017 (IGU, 2018b).

Netback price: A pricing formula in which the price received by the gas supplier is a function of the effective price at the specific market location, less the cost for delivering the product from the defined point to the market location (Melling, 2010). This mechanism has been widely applied specially to those regions lacking of a reference gas hub, such as Asia, Latin America, or Africa. Latam imports are mainly driven by the netback rule for linking natural gas with the North American market. The netback mechanism is also applied to the African natural gas market (Santley et. al., 2014).

Bilateral Monopoly (BIM) Under BIM, the price is determined by bilateral agreements between large entities, usually at the Government or at a state-owned company level, for a fixed period of time. This mechanism is associated with a single dominant buyer or seller on at least one side of the transaction. The BIM share is 3% of total transactions in 2017 (IGU, 2018b), and is found predominantly in Middle East, the Former Soviet Union and Africa.

Regulated: The price is set by Government (Ministry or Regulatory Authority). The price can range from being set to cover the cost of service, including the recovery of investment and a reasonable rate of return, to a subsidize price set below the average cost of supplying that gas. Regulated prices account for almost half (42%) of the domestic gas and is largely used in Former Soviet Union, Middle East, Asia and some countries in South America

Unlike other internationally traded commodities, gas price formation varies deeply between regional markets, depending on several structural factors (domestic production and share of imports, regulation, contracting mechanism, existence of a spot market, liquidity, etc.) Moreover, the degree of market opening, (that is, the time since the liberalization process), seems to be the primary determinant of pricing patterns (Davoust, 2008).

The North America[2] market is highly competitive with fully liquid trading markets in the US and Canada based on supply/demand balances to such an extent that GoG competition accounts for almost 100% (IGU, 2018b).

In Europe, GoG pricing has spread to continental Europe via the UK, and around 70% of gas sold is priced on a gas-on-gas basis. Owing to the new regulatory environment, several gas hubs have emerged serving as natural pricing mechanism such as the NBP in the UK and the TTF in the Netherlands. GoG competition accounts for 70% of natural gas traded in Europe in 2017 (IGU, 2018b). This move has been supported by increasing volumes of spot gas and increasing volumes traded at hubs, followed by the renegotiations of long-term contracts pricing, being replaced by GoG indexation in the pricing term and a reduction in the ToP levels. Hybrid pricing formulas, where oil indexation is partly maintained but within a price corridor set by hub prices or contracts indexed to both gas and oil, have also appeared. The development of GoG varies among Europe, with huge differences between the North and the South. While in North-Western Europe GoG competition is well developed (with a 92% of GOG pricing in 2017 (IGU, 2018b)) and gas prices are no longer contractually pegged to oil prices, in the Southeast Europe there is around 11% GoG competition and in the Mediterranean countries OPE still accounts for 61% (IGU, 2018b).

In Asia, LNG prices have historically been indexed to crude oil benchmarks, representing almost 69% in 2016.

[2] United States, Canada and Mexico.

4.1.4. Global gas market modeling

During the last decade the gas sector has attracted huge attention and, as a result, an increasing number of optimization models representing the natural gas market have arisen. The most relevant ones are cited below, classified in models which follow two approaches: i) a cost minimization approach considering a detailed infrastructure description assuming perfect competitive players, such as the TIGER (Lochner, 2011), (Dieckhöner, 2012). (Dieckhöner, et al., 2013) and the RAMONA model (Hellemo, et al., 2012) and (Fodstad, et al., 2016), or the model proposed in (Zhang, et al., 2016) for China; or ii) equilibrium models for the European/global natural gas market with explicit consideration of market power such as the GASTALE model, (Boots, et al., 2003), (Boots, et al., 2004), (Lise & Hobbs, 2008) and (Bornaee, 2012), NATGAS model (Zwart & Mulder, 2006), GASMOD model (Holz, 2008), the World Gas Model (WGM) (Egging & Gabriel, 2006), (Egging et al., 2010), and (Egging, 2013), the Global Gas Model (GGM) (Holz & Von Hirschhausen, 2013) (Holz, et al., 2016), and (Egging & Holz, 2016), the NANGAM model for North America (Feijoo, et al., 2016) (Sankaranarayanan, et al., 2017) and (Feijoo, et al., 2018) and the bottom-up model for US upstream DYNAAMO (Crow, et al., 2018). However, the former models ignore or over-simplify the long-term supply contract representation. In (Dueñas, 2013), the Iberian natural gas market operation is optimized, considering a detailed representation of long-term contract clauses and optimizing contract volumes. (Abada, et al., 2013) includes substitution between different types of fuels (i.e. gas, coal, oil) and takes into account long-term contracts in an endogenous way (i.e. optimizing long-term prices and quantities of contracts), considering that shippers can buy gas via long-term contracts or directly target the spot markets. (Abada, et al., 2014) presents a theoretical equilibrium model that endogenously captures the contracting behavior of both the producer and the shipper who strive to hedge their profit-related risk.

This model extends the literature by presenting a mid-term optimization model for the global natural gas sector, named Natural Gas Valorization Model with Gas-on-Gas competition, (GasValem-GoG). The main contributions of the model are:

- First, it is unique on its scope (i.e. mid-term) and granularity (monthly detailed). To our best knowledge, the rest of the existing gas market models with a global outlook have yearly (or even more spaced) granularity representing seasonality or peaking days using representative days/periods. The monthly detail allows to accurately represent the seasonal spreads. Additionally, within this time frame, we allow for the optimization of marketers' use of the underground storage and the LNG tanks for seasonal price arbitrage.

- Second, the model includes a novel variety of supply options, representing in detail the main long-term contract clauses and the new market supply flexibilities (i.e. spot trade). Therefore, players optimize their natural gas portfolio, choosing between buying or selling gas at the different hubs and the exerted volume above the long-term contract ToP clause for supplying the final natural gas demand. Moreover, different types of LNG long-term contracts are modeled, and contracted LNG cargoes under long-term arrangement can be diverted to a more rewarding destination.

- Third, it models the coexistence of oil indexed (OPE) and GoG pricing mechanisms. GoG competition is represented using an iterative process where the long-term contract price formula is linked to the resulting natural gas hubs prices.

4.2. GasValem-GoG Model description

4.2.1. Model description

GasValem-GoG is an optimization model that solves an optimal pattern of gas flows determining gas demand and prices while minimizing supply cost (i.e. maximizing netbacks). The model represents the whole chain of gas (i.e. natural gas and LNG), considering the agents and infrastructures involved in the upstream and downstream. The natural gas chain is represented in Figure 4-1.

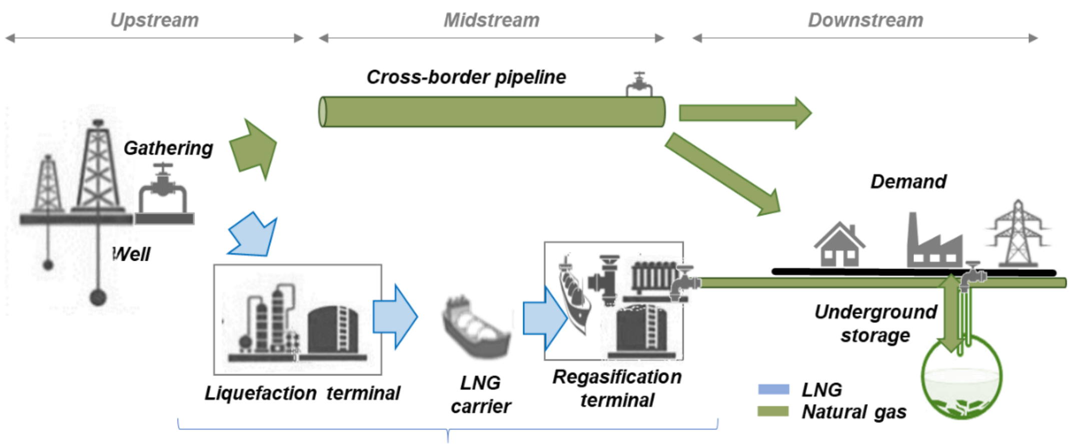

Figure 4-1 – Natural gas chain

The production wells are operated by producers. Producers interact with the rest of the system through traders, which are dedicating trading companies for each producer. Traders can sell gas domestically or use the pipeline transmission system or the liquefied natural infrastructure to export gas to other zones. Marketers signed long-term contracts with traders and can trade gas in the spot market (i.e. hubs) for supplying their natural gas demand and optimizing their gas portfolio. Spot trade can take place at physical hubs (e.g. Henry Hub) or virtual hubs (e.g. NBP in the UK) or in absence of trading hubs, spot LNG cargoes (Over the Counter - OTC), where the price of the cargoes reflects the current supply-demand situation (e.g. Asian LNG market).

Three final demand sectors are considered: residential, power generation and industrial demand. Flows of gas are defined through cross-border pipelines between zones for natural gas and through LNG carriers for liquefied natural gas. For each infrastructure, technical constraints, congestions, gas balance equations considering losses and operational cost are modeled. In the case of LNG flows, they are constrained by the defined LNG routes as well as liquefaction and regasification terminals' technical characteristics. Marketers have the possibility of storing the gas in the tanks of regasification terminals or in underground storages.

The key distinguishing characteristic of the model is that it represents different flexible supply options and it allows to analyze their role on the final gas price formation. First, the optimization of flexible volumes in long-term supply contracts (i.e optimizing any volume above the minimum take-or-pay threshold). Second, flexible LNG supply contracts are modeled, where marketers can divert contracted LNG under long-term arrangement, to more rewarding destination. Third, the spot market (i.e. uncontracted supplies) is represented through gas hubs, where traders and marketers can trade. Fourth, the seasonal arbitrage is exploited by marketers withdrawing gas from the underground storage during the cold period and injecting gas during warm period.

Finally, the model is also pioneer introducing the new gas-hub pricing mechanism in the long-term supply contracts price formation, as increasingly gas hubs should be seen as the best market price indicators which long-term contract need to reflect.

A schematic picture of the model is presented in Figure 4-2, in order to help the reader to follow the whole description.

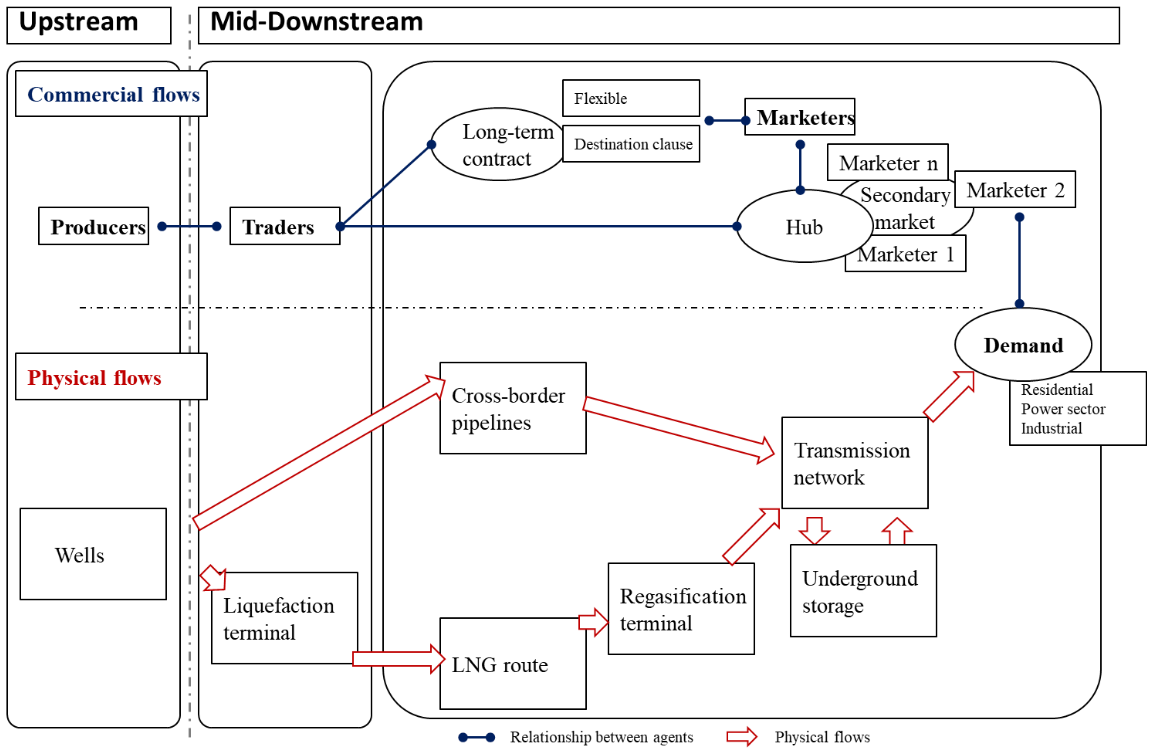

Figure 4-2 – Model structure

4.2.2. Optimization approach

The proposed optimization-based framework consists of the formulation of the natural gas market value chain from the wellhead to the consumer (i.e. supply and demand) as a mathematical programming problem, namely a quadratic problem. Therefore, the problem consists of the maximization of the utility of the demand, while minimizing the cost associated to the natural gas supply chain, under some technical constraints which represent the physical characteristics of the natural gas sector.

The basic setup can be expressed in the following form: Given a function $f: Q \to \mathbb{R}$ sought a $q^* \in Q$ such that $f(q^*) \leq f(q)$, for all $q \in Q$ (minimization), given some linear equality $h_i(q)$ and/or inequality $g_j(q)$ constraints

$$Objective\ function = f = \text{Min}\, Supply\ cost\ (q) - Utility\ of\ demand\ (q) \tag{4.1}$$

$$s.t. \quad h_i(q) \quad i = 1 \cdots n, \qquad g_j(q) \quad j = 1 \cdots m \tag{4.2}$$

The optimization technique has been widely used for modeling operational problems in the natural gas sector as they are algebraically simpler and structurally less complicated than complementarity-based equilibrium models, allowing for larger models. However, optimization models do not explicitly represent the market power. Leveraging on the advantages of optimization models, we proposed an optimization problem for representing in detail the global natural gas sector (i.e. with a large number of decision variables), solving optimal pattern of gas flows determining gas demand and prices. This approach allows us to include a detailed representation of the infrastructure as well as for representing the commercial dynamics. Therefore, the model minimizes supply cost, optimizing long-term contracts flexible volumes and spot market trade. Apart from LTCs, minimizing supply cost implies optimizing production cost and transport routes, maximizing netbacks for traders, as they will supply their gas to the most rewarding destinations, and taking advantage of seasonal arbitrages opportunities (i.e. using storage).

For not denying market power in the global gas sector, we assume market power in the upstream is exerted in contracts negotiations, and in the spot market, through a mark-up (i.e. as an additional transaction costs). In the downstream, we assume price-demand elasticity but no competition in prices, where agents behave as perfect competitors and market power is included as an additional mark-up to the cost of gas.

Finally, an iterative process is proposed in order to endogenously model GoG indexation in long-term contracts. (see section 4.2.9)

4.2.3. Producers

The upstream sector (also known as exploration and production (E&P)) involves the activities related to searching for, recovering and producing crude oil and natural gas, all of them capital intensive. Therefore, it encompasses all those activities related to wells (i.e. exploration, planning, design and construction, drilling, operation and management).

Producers operate wells (i.e. natural gas fields), for producing natural gas q_{pzo}^{Prod} (i.e. the summation of natural gas production per well q_{pw}^{Well}), and sell it to the market through traders, where q_{ptz}^{Tra} is traders' volumes of gas per period and zone.

$$q_{pzo}^{Prod} = \sum_{w \epsilon z} q_{pw}^{Well} \ \forall p, z, o \tag{4.3}$$

$$q_{ptz}^{Tra} = \sum_{o \epsilon t} q_{pzo}^{Prod} \ \forall p, t, z \tag{4.4}$$

Gas reserves q_{pw}^{Well} (i.e. the amount that can be economically recoverable), are estimated during the prospecting stage. Each well's production is subject to the daily maximum production capacity $\overline{Q}_{dw}^{Well}$, and the balance equation for the gas reserves.

$$q_{pw}^{Well} \leq \sum_{d \in p} \overline{Q}_{dw}^{Well} \quad \forall p, w \tag{4.5}$$

$$q_{pw}^{Well} = \sum_{p-1} q_{pw}^{Rwell} - \sum_{p} q_{pw}^{RWell} \, \forall p, w \tag{4.6}$$

Figure 4-3 illustrates the decision variables of the wells' optimization problem.

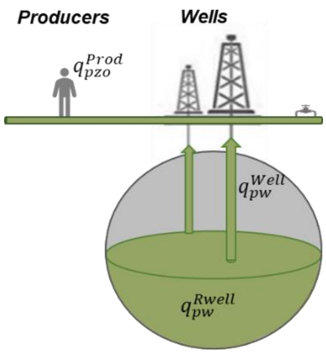

Figure 4-3 – Schematics of production well

Producers' costs are associated to the operation of the well for gas production and no additional mark-up is considered. Two different options for representing wells' production costs are defined.

The first option represents costs associated with the production at the wells as an increasing quadratic cost function, as the one defined in (4.7).

$$Production\ Cost = \sum_{p,w} \left(q_{pw}^{Well} \cdot \left(c1_w^{Well} + c2_w^{Well} \cdot q_{pw}^{Well} \right) \right) \tag{4.7}$$

The second option considers Golombek cost functions for production cost (Golombek et al, 1994). These cost functions are defined as:

$$C\left(q_{pw}^{Well}\right) = a_w^{Well} \cdot q_{pw}^{Well} + \frac{1}{2} \cdot b_w^{Well} \cdot \left(q_{pw}^{Well}\right)^2 - c_w^{Well} \cdot \left(\overline{Q}_{pw}^{Well} - q_{pw}^{Well}\right) \cdot ln\left(1 - \frac{q_{pw}^{Well}}{\overline{Q}_{pw}^{Well}}\right) - c_w^{Well} \cdot q_{pw}^{Well} \quad \forall p, w \tag{4.8}$$

$$s.t. \qquad a_w^{Well} \geq 0; b_w^{Well} \geq 0; c_w^{Well} \leq 0; \quad \forall q_{pw}^{Well}: 0 \leq q_{pw}^{Well} \leq \overline{Q}_{pw}^{Well} \tag{4.9}$$

Where a_w^{Well} is the minimum per unit cost term, the b_w^{Well} is the linearly increasing cost term and c_w^{Well} the term refer to as marginal costs at full capacity.

And $\overline{Q}_{pw}^{Well} = \sum_{d\in p} \overline{Q}_{dw}^{Well} \quad \forall p, w$. Thus, the marginal cost function is:

$$C'\left(q_{pw}^{Well}\right) = a_w^{Well} + b_w^{Well} \cdot q_i + c_w^{Well} \cdot ln\left(1 - \frac{q_{pw}^{Well}}{\overline{Q}_{pw}^{Well}}\right) \qquad \forall p, w \tag{4.10}$$

$$s.t. \qquad a_w^{Well} \geq 0; b_w^{Well} \geq 0; c_w^{Well} \leq 0; \quad \forall q_{pw}^{Well}: 0 \leq q_{pw}^{Well} \leq \overline{Q}_{pw}^{Well} \tag{4.11}$$

The resulting cost functions are increasing and convex, allowing to linearize them using piecewise linear approximations. This is done by sampling the curve at three intermediate points and constructing linear interpolations between them, which provide lower bounds for the cost function, such as the example shown in Figure 4-4. Thus, Golombek wells´ cost functions are linearized and the costs function are defined by:

$$Production\ cost = Cost_{pw}^{Well} \geq \left(\propto_{jw}^{Well} \cdot q_{pw}^{Well} + k_{pw}^{Well}\right) \ \forall p, w, j \tag{4.12}$$

Where $\propto_{jw}^{Well}$ is the slope defined for each linear curve (j), used for the piecewise linear approximation formulation.

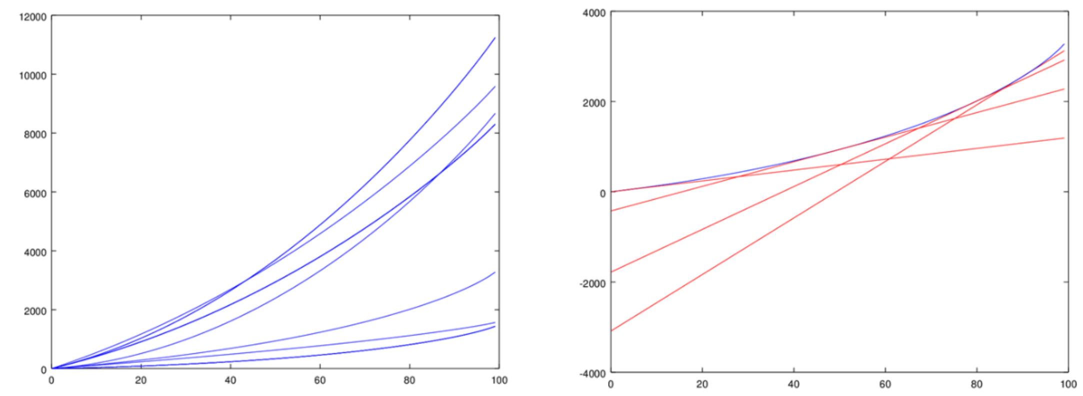

Figure 4-4 – Golombek production cost functions (left) and linearization using piecewise linear approximation (right)

The production cost of the gas contracted in advance through LTC $q_{pw}^{WellLTC}$ (i.e. $q_{pzz_1ctk}^{QNG}$ and $q_{pzz_1ctk}^{QLNG}$ for natural gas and LNG, respectively) is assumed to be produced at the cheapest price as buyers have the right to call on these supplies and this cost is already considered in the LTC price.

$$\sum_{w\in z} q_{pw}^{WellLTC} = \sum_{c,t,k,z_1} q_{pzz_1ctk}^{QNG} + \sum_{c,t,k,z_1} q_{pzz_1ctk}^{QLNG} \quad \forall p, z \tag{4.13}$$

4.2.4. Traders

Traders are modeled as dedicated trading companies for each producer, acting as interfaces between producers and marketers. Traders balance equation with producers is formulated in (4.4). Traders can sign long-term supply contracts with marketers (either natural gas ($q_{pzz_1ctk}^{QNG}$) or LNG ($q_{pzz_1ctk}^{QLNG}$)) or sell their gas in gas hubs. In order to represent those countries where the whole gas chain (i.e. from gas production to gas commercialization) is vertically integrated, direct sales between traders/marketers and final demand which are in the same producing zone ($q_{ptkz}^{VerticallyInt}$), are modeled. This gas is priced at a reduced cost resembling regulated pricing mechanism set at the cost of service.

Long-term contract volumes are characterized by its minimum Take-Or-Pay (ToP) commitments (i.e. yearly and monthly) and the optimization of its flexible volumes (i.e. any volume above the ToP), is at the buyers' discretion (i.e. buyer has the right to call on these supplies). Therefore, the delivered volume of gas by contract q_{ptkc}^{c} (i.e. either NG or LNG) is constrained by maximum-minimum yearly volume clauses:

$$\underline{Q}_{yctk}^{c} \leq \sum_{p \in y} q_{pctk}^{c} \leq \overline{Q}_{yctk}^{c} \; \forall y, c, t, k \tag{4.14}$$

And also by monthly volume clauses:

$$\underline{Q}_{ymctk}^{c} \leq \sum_{p \in (y,m)} q_{pctk}^{c} \leq \overline{Q}_{ymctk}^{c} \; \forall y, m, c, t, k \tag{4.15}$$

Additionally, some LNG contracts have flexible delivery destination, $q_{pzz_1ctk}^{Flex}$, so that the LNG carrier can be diverted to a more profitable market ($q_{pzz_1ctk}^{Diverted}$). If the contract entails destination clauses (i.e. non-flexible $q_{pzz_1ctk}^{No\,flex}$) the carrier cannot be re-routed and the destination is predefined by the contract.

Traders balance equation in the midstream (i.e. with marketers) is represented by (4.16). Additionally, traders can sell NG in the hub $q_{ptz}^{HubSalesTra}$. Note that hubs are defined per zone, but not all zones have a hub.

$$\begin{aligned} q_{ptz}^{Tra} + q_{ptz}^{RegTra} = q_{ptz}^{LiqTra} + \sum_{z_1,c,k} q_{ptkzz_1c}^{QNG} + \sum_{z} q_{ptkz}^{VerticallyInt} \\ + \sum_{z_1} \left(q_{ptzz_1}^{PipeTra} - q_{ptz_1z}^{PipeTra} \right) + q_{ptz}^{HubSalesTra} \; \forall p, t, z \end{aligned} \tag{4.16}$$

Traders charge a fixed mark-up for providing their service $Cost_t^{Tra}$. That is, they sell their gas at an effective cost which is made up of the real cost plus the mark-up (i.e. the mark-up term is associated to traders' market power). Traders' markup is already included in the LTC price. Therefore, traders' cost is:

$$Traders'cost = \sum_{p,t,z} \left(Cost_t^{TraRe} \cdot \sum_k q_{ptkz}^{VerticallyInt} \cdot + Cost_t^{Tra} \cdot q_{ptz}^{HubSalesTra} \right) \tag{4.17}$$

Traders operation and interaction with the rest of the agents is illustrated in Figure 4-5.

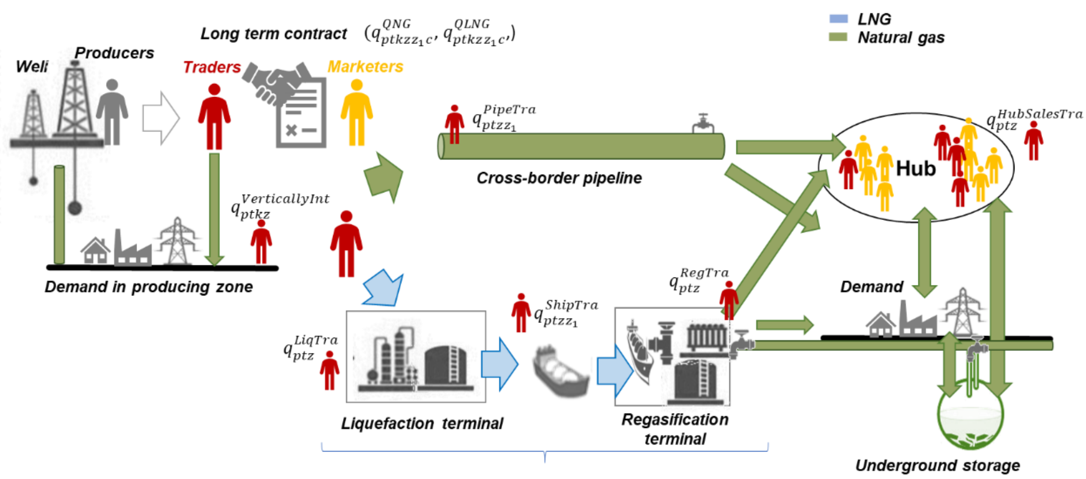

Figure 4-5 – Traders interaction with the rest of the agents

4.2.5. Marketers

Marketers sign long-term supply contracts with traders or buy gas in the hubs (i.e. from traders or from other marketers) to supply gas to their final demand or to sell it to other marketers in the hub. Marketers will seek to optimize their gas portfolio minimizing their cost and maximizing netbacks, minimizing long-term contracts off-take if hub prices are lower and vice versa. Marketers also have some seasonal flexibility as they can store natural gas in underground storages and LNG in the tanks of regasification terminals. The total volume of gas available for marketers q_{pzk}^{Mak} per period to supply their final demand (q_{pkz}^{Demand}) (i.e. $q_{pzk}^{Mak} = q_{pkz}^{Demand}$) is:

$$\begin{aligned} q_{pzk}^{Mak} = q_{pkz}^{RegMak} &+ \left(q_{pkz}^{WitUGS} - q_{pkz}^{InjUGS}\right) + \sum_{z_1}\left(q_{pz_1z}^{PipeMak} - q_{pzz_1}^{PipeMak}\right) \\ &+ \sum_t q_{ptkz}^{VerticallyInt} + \sum_{t,z_1c} q_{ptkz_1zc}^{QNG} \\ &+ \left(q_{pkz}^{HubSalesMak} - q_{pkz}^{HubPurchMak}\right) \quad \forall p,k,z \quad : \beta_{pkz} \end{aligned} \tag{4.18}$$

Where $q_{pkz}^{HubPurchMak}$ and $q_{pkz}^{HubSalesMak}$ are the purchases and sales of the marketer in the hub, respectively. The hub balance equation is stated in (4.19), and the resulting hub price is the dual variable γ_{pz}:

$$\sum_{k} q_{pkz}^{HubSalesMak} + \sum_{t} q_{ptz}^{HubSalesTra} = \sum_{k} q_{pkz}^{HubPurchMak} \quad \forall p,k,z \quad : \gamma_{pz} \tag{4.19}$$

The cost associated to marketers is:

$$Marketers'cost = \sum_{p,k,z} Cost_{k}^{MakWholesale} \cdot q_{pkz}^{HubSalesMak} + Cost_{k}^{MakRetail} \cdot q_{pkz}^{Demand} \tag{4.20}$$

Where $Cost_{k}^{MakWholesale}$ and $Cost_{k}^{MakRetail}$ represents marketers' wholesale and retail mark-up respectively, and q_{pkz}^{Demand} the demand supplied by each marketer per zone and period.

Marketers operation and their interaction with the rest of agents is shown in Figure 4-6.

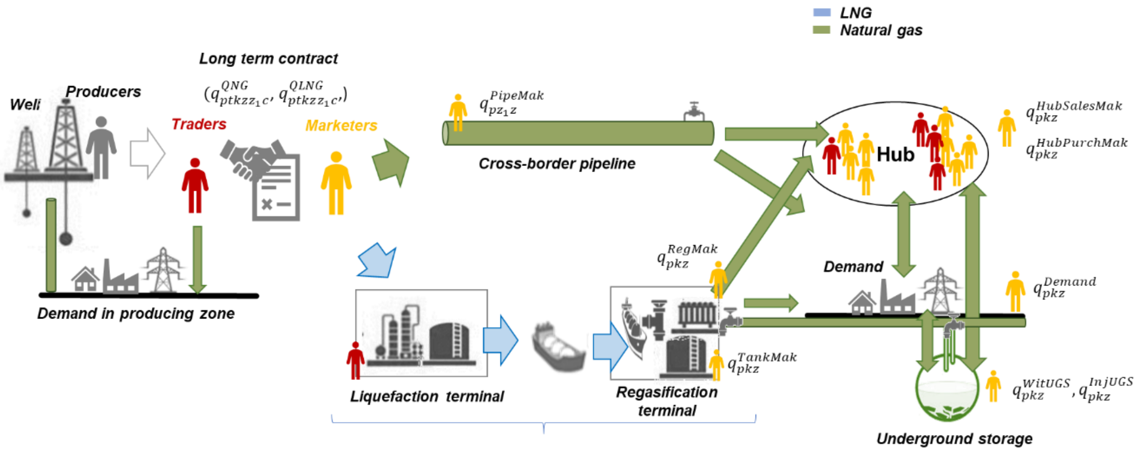

Figure 4-6 – Marketers operation and interaction with the rest of agents

4.2.6. Final demand

Each zone comprises one node and one marketer that supplies the total demand, differentiating among three final consumption sectors (s) (i.e. power sector, conventional and residential and industrial). The balance equation between marketers and final demand per period and zone is:

$$\sum_{k \in z} q_{pkz}^{Demand} = q_{pz}^{Power} + q_{pz}^{Residential} + q_{pz}^{Industrial} \quad \forall p,z \quad : \lambda_{pz} \tag{4.21}$$

The dual variable of the balance equation λ_{pz} is displayed after the colon and represents each zonal market price, resulting from the optimization.

For each zone, gas demand has been defined on a monthly basis by its inverse demand curve (i.e. affine inverted price curve). That is, we assume an affine relationship between market price and demand for each sector (s), which is given by:

$$q_{pz}^{s} = Q_{pz}^{s} - \alpha_{z}^{s} \cdot \lambda_{pz} \; \forall p, z, s \tag{4.22}$$

Where Q_{pz}^{s} represents the demand intercept, α_{z}^{s} the demand slope, and λ_{pz} is the market price, i.e. the dual variable of the marketers-demand balance equation (4.21).

Demand is represented by the utility of the demand function in the objective function, in order to solve the resulting non-linear equilibrium problem between marketers and final demand in the downstream as an optimization quadratic problem (Barquín et al. 2004).

Therefore, demands are translated into utility functions and introduced in the objective function as an income.

$$U\left(q_{pz}^{s}\right) = \int_{0}^{Q_{pz}^{s}} \lambda_{pz}\left(q_{pz}^{s}\right) \; d\left(q_{pz}^{s}\right) = \frac{1}{\alpha_{z}^{s}}\left(Q_{pz}^{s} \cdot q_{pz}^{s} - \frac{\left(q_{pz}^{s}\right)^{2}}{2}\right) \tag{4.23}$$

It is important to note that in the limit case of having an inelastic demand (i.e. α_{z}^{s}=0) the utility function is not well defined. However, for those cases, the resulting optimization problem is solved minimizing total cost (i.e. without maximizing the utility of the demand) (see (4.48) and the downstream balance equation (4.21).

This formulation would allow to introduce a conjectural-variation approach in the model by means of the α_{z}^{s} in the quadratic term of the utility of the demand in the objective function, as previously done in (Barquín et al. 2004). However, modeling and assessing different types of anticompetitive behavior is out of the scope of this thesis. Moreover, this approach is strongly value-dependent, and choosing the appropriate conjectural variation values for a world-wide problem requests a huge calibration effort. Thus, we assume a price-demand elasticity but no competition in prices, where agents behave as perfect competitors. As mentioned, market power in the downstream global gas sector is included as an additional mark-up to the cost of gas, which is internalized in marketers' marginal costs and directly increases market clearing prices. Therefore, we consider an effective cost, which is made up of a real cost plus a penalty term (mark-up).

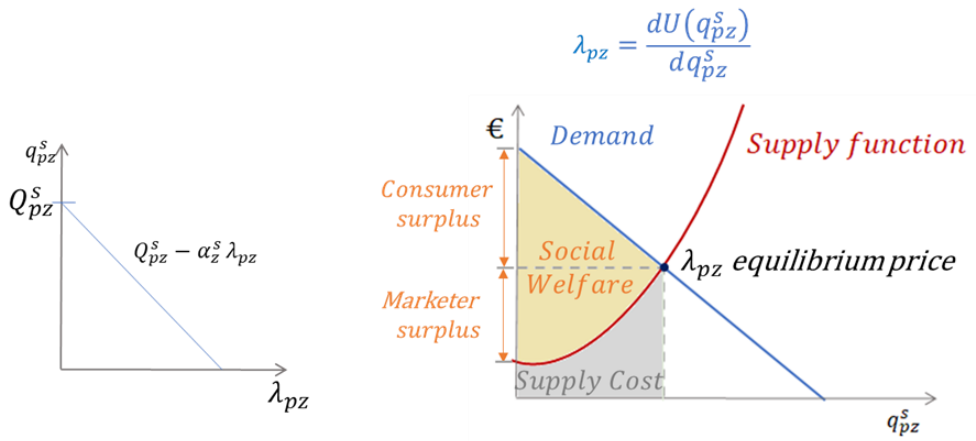

Figure 4-7 – Affine demand function (inverted price function) and market clearance solution.

4.2.7. Gas transportation: Pipelines and LNG carriers

In most cases, gas reserves are not located in the same geographic location as major consumption regions, so natural gas needs to be transported via pipelines and via LNG carrier.

4.2.7.1. Cross-border pipelines

Both, traders $q^{PipeTra}_{ptzz_1}$ and marketers $q^{PipeMak}_{pz_1z}$ can move gas through pipelines. Pipelines' minimum and maximum flows are constraint by long-term contracts volumes $q^{QNG}_{ptkzz_1c}$ and by the technical capacity of the pipeline $\overline{Q}^{Pipe}_{y,z,z_1}$ (bcm/day). Natural gas flows through pipelines are defined by:

$$q^{Pipe}_{pzz_1} = \sum_t q^{PipeTra}_{ptzz_1} + \sum_k q^{PipeMak}_{pkzz_1} \quad \forall p, z, z_1 \tag{4.24}$$

$$\sum_{z_1} q^{PipeTra}_{ptzz_1} \geq \sum_{c,t,k,z_1} q^{QNG}_{ptkzz_1c} \quad \forall p, z, t \tag{4.25}$$

$$\sum_{z} q^{PipeTra}_{ptzz_1} \geq \sum_{c,t,k,z} q^{QNG}_{ptkzz_1c} \quad \forall p, z, z_1, t \tag{4.26}$$

$$q^{Pipe}_{pzz_1} \leq \sum_{d \in p} \overline{Q}^{Pipe}_{d,z,z_1} \quad \forall p, z, z_1 \tag{4.27}$$

The transportation costs $COST^{Pipe}_{pzz_1}$ (USD/MMbtu) are represented as point-to-point capacity cost.

$$Network\ transport\ cost = \sum_{p,z,z_1} \left(COST^{Pipe}_{pzz_1} \cdot q^{Pipe}_{pzz_1}\right) \tag{4.28}$$

4.2.7.2. LNG shipping

As an alternative to pipeline transportation, gas can be shipped as LNG. The process of transporting LNG comprises three stages: 1) Natural gas is liquefied at a liquefaction terminal; 2) LNG is loaded into an LNG carrier and is shipped to its destination; and 3) LNG is unloaded at a regasification terminal and regasified. Figure 4-8 illustrates the LNG transportation chain.

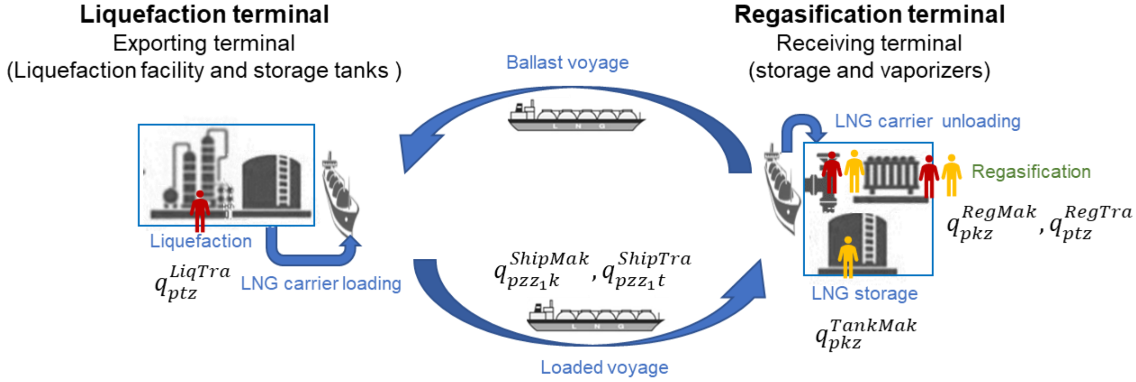

Figure 4-8 – LNG transport chain

Liquefaction terminal: The liquefaction capacity is aggregated per zone and defined by its total maximum daily liquefaction capacity $\bar{Q}_{dz}^{Liq}$ and its liquefaction cost $Cost_z^{Liq}$. The volume of liquefied gas per trader q_{ptz}^{LiqTra} is subject to the maximum daily liquefaction capacity $\bar{Q}_{dz}^{Liq}$.

$$\sum_t q_{ptz}^{LiqTra} \leq \sum_{d\epsilon p} \bar{Q}_{dz}^{Liq} \; \forall p, z \tag{4.29}$$

The balance equation of liquefaction terminals states that the total liquefied volume of gas minus liquefaction losses equal to all the gas exported by LNG carrier from long-term contracts $q_{pzz_1ctk}^{QLNG}$ and traders' shipped LNG to hubs $q_{pzz_1k}^{ShipTra}$.

$$q_{ptz}^{LiqTra} \cdot \left(1 - Losses_{pz}^{Liq}\right) = \sum_{z_1,c,k} q_{ptkzz_1c}^{QLNG} + \sum_{z_1} q_{ptzz_1}^{ShipTra} \; \forall p, t, z \tag{4.30}$$

The liquefaction cost from LTC is already included in the LTC price. Therefore, the liquefaction cost is:

$$Liquefaction\ Cost = \sum_z \left(Cost_z^{Liq} \cdot \sum_{ptz_1} q_{ptzz_1}^{ShipTra} \cdot \left(\frac{1}{1 - Losses_{pz}^{Liq}} \right) \right) \tag{4.31}$$

LNG carrier: Once the gas is liquefied, the LNG is shipped to its destination in LNG carriers. The volume of gas shipped by marketers assigned to long-term contracts $q_{pzz_1k}^{ShipMak}$ is the total volume exercised of the LNG supply contract $q_{pzz_1ctk}^{QLNG}$, which can be flexible or not. For contracts with flexible delivery clauses, $q_{ptkzz_1c}^{Flex}$, if the carrier is not re-routed, the volume of gas is $q_{ptkzz_1c}^{Flex\ NotDiverted}$ and if it is diverted, is represented by $q_{pzz_1ctk}^{Diverted}$. The ship can only be diverted to a hub where the gas owner can trade.

$$q_{pzz_1k}^{ShipMak} = q_{pzz_1ctk}^{QLNG} = \sum_{c,t} q_{pzz_1ctk}^{No\ flex} + \sum_{c,t,z_1} q_{pzz_1ctk}^{Diverted} + \sum_{c,t} q_{ptkzz_1c}^{Flex\ NotDiverted} \quad \forall p,z,z_1,t,k \quad (4.32)$$

$$q_{pzz_1ctk}^{Flex} = q_{pzz_2ctk}^{Diverted} + q_{pzz_1ctk}^{Flex\ NotDiverted} \quad \forall p,z,z_1,z_2,c,t,k \quad (4.33)$$

Additionally, traders can ship spot LNG cargoes $q_{pzz_1t}^{ShipTra}$.

Therefore, LNG shipping costs are:

$$Shipping\ Cost = \sum_{zz_1}\left(Cost_{zz_1}^{Ship}\cdot\left(\sum_{p,k} q_{pzz_1k}^{ShipMak} + \sum_{p,k} q_{pzz_1k}^{ShipTra}\right)\right) \quad (4.34)$$

Where $Cost_{zz_1}^{Ship}$ represents the freight cost from shipping LNG from one zone (z) to another (z1).

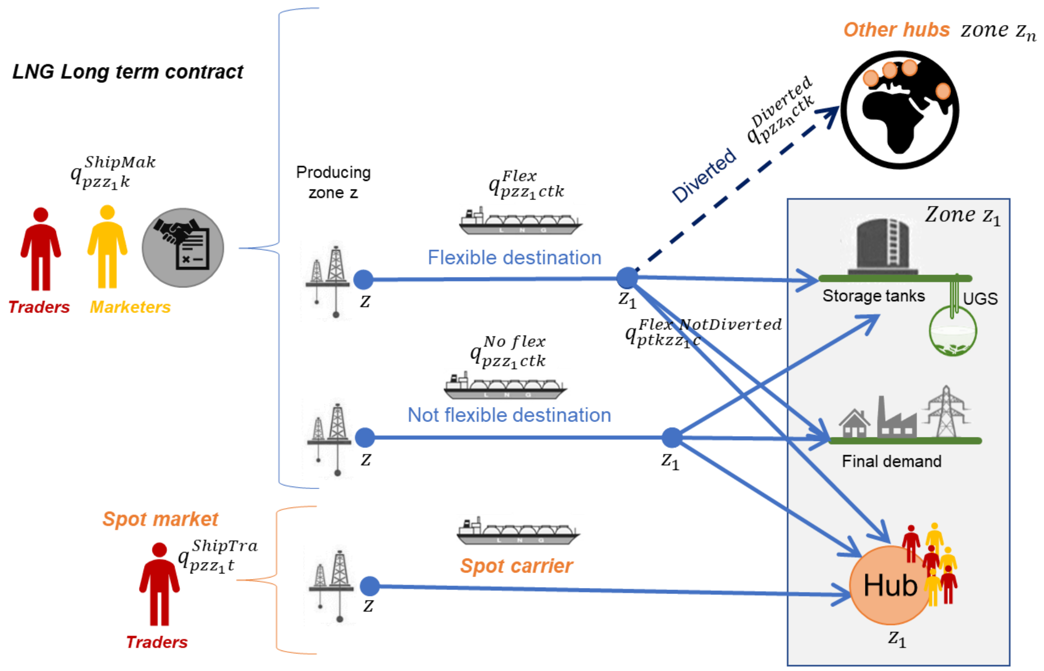

Figure 4-9 –LNG carrier voyage

Regasification terminals: An aggregated regasification capacity is represented per zone, defined by a maximum daily regasification capacity $\bar{Q}_{dz}^{Reg}$, a maximum LNG storage capacity $\bar{Q}_{pz}^{Tank}$, a regasification cost $Cost_{z}^{Reg}$, and an LNG storage cost $Cost_{z}^{Tank}$. The volumes of regasified gas per marketer q_{pkz}^{RegMak} and per trader q_{ptz}^{RegTra} are subject to the maximum regasification capacity $\bar{Q}_{yz}^{Reg}$.

$$\left(1 + Losses_{pz}^{Reg}\right) \cdot \left(\sum_{k} q_{pkz}^{RegMak} + \sum_{t} q_{ptz}^{RegTra}\right) \leq \sum_{d \epsilon p} \bar{Q}_{dz}^{Reg} \tag{4.35}$$

Only marketers have the possibility of storing gas in the tanks of regasification terminals. The volume of LNG stored per marketer $q_{pkz}^{TankMak}$ is subject to the maximum LNG storage capacity $\bar{Q}_{pz}^{Tank}$.

$$\sum_{k} q_{pkz}^{TankMak} \leq \bar{Q}_{pz}^{Tank} \ \forall p, z \tag{4.36}$$

Losses in regasification terminals are assigned to the regasification process, stating the balance among inputs (carriers unloading) and outputs (regasification plus regasification losses) per marketer as:

$$q_{pkz}^{TankMak} - q_{p-1kz}^{TankMak} = \sum_{z_1} q_{pkz_1z}^{ShipMak} - q_{pkz}^{RegMak} \cdot \left(1 + Losses_{pz}^{Reg}\right) \ \forall p, z \tag{4.37}$$

Where $q_{pkz}^{TankMak} - q_{p-1kz}^{TankMak}$ represent LNG inventory variations in the regasification terminal tanks.

Traders cannot store gas in LNG tanks and all the unloaded gas should be regasified and directly sold in the market.

$$\sum_{z_1} q_{ptz_1z}^{ShipTra} = q_{ptz}^{RegTra} \cdot \left(1 + Losses_{pz}^{Reg}\right) \ \forall p, t, z \tag{4.38}$$

The cost associated to regasification terminals includes first, a variable tariff for regasifying at the regasification terminal, and second, a tariff for storing LNG per day at the tanks of the regasification terminal:

$$Regasification\ Cost = \sum_{z} \left(\begin{array}{c} Cost_{z}^{Reg} \cdot \left(\sum_{k} q_{pkz}^{RegMak} + \sum_{t} q_{ptz}^{RegTra}\right) \\ + Cost_{z}^{Tank} \cdot \sum_{k} q_{pkz}^{TankMak} \end{array} \right) \tag{4.39}$$

4.2.8. Underground storage (UGS)

Natural gas can be stored at very competitive costs in underground gas storages (UGS). These facilities are normally depleted natural gas or oil fields, salt caverns and aquifers, which allow storing large amounts of natural gas, dealing with seasonal demand variation and therefore, serving as seasonal storage. That is, using storage for seasonal price arbitrage (i.e. injection during warm months and withdrawal during cold months).

In the model, the total underground storage capacity is aggregated and only one virtual underground storage is considered per zone, defined by its maximum daily injection capacity $\bar{Q}_{dz}^{Inj}$, its maximum daily extraction capacity $\bar{Q}_{dz}^{Wit}$, its maximum NG storage capacity $\bar{Q}_{z}^{Sto}$, its injection costs $Cost_{pz}^{Inj}$, its withdrawal costs $Cost_{pz}^{Wit}$, and the NG storage cost $Cost_{pz}^{Sto}$. The marketer that supplies the demand at that zone is the only agent allowed to store NG in the underground storage. The total volume of injected gas q_{pkz}^{InjMak} is subject to the maximum daily injection capacity $\bar{Q}_{dz}^{Inj}$:

$$\sum_{k} q_{pkz}^{InjMak} \leq \sum_{d \in p} \bar{Q}_{dz}^{Inj} \; \forall p, z \tag{4.40}$$

The volume of extracted gas q_{pkz}^{WitMak} is subject to the maximum daily extraction capacity $\bar{Q}_{dz}^{Wit}$:

$$\left(1 + Losses_{pz}^{Sto}\right) \cdot \sum_{k} q_{pkz}^{WitMak} \leq \sum_{d \in p} \bar{Q}_{dz}^{Wit} \; \forall p, z \tag{4.41}$$

The volume of stored NG q_{pkz}^{StoMak} is subject to the maximum NG storage capacity $\bar{Q}_{z}^{Sto}$:

$$\sum_{k} q_{pkz}^{StoMak} \leq \bar{Q}_{z}^{Sto} \qquad \forall p, z \tag{4.42}$$

The balance equation represents the balance among inventory variations, injections, and withdrawals:

$$q_{pkz}^{StoMak} - q_{(p-1)kz}^{StoMak} = q_{pkz}^{InyMak} - \left(1 + Losses_{pz}^{Sto}\right) \cdot q_{pkz}^{WitMak} \; \forall p, k, z \tag{4.43}$$

The costs in the underground storage are due to gas withdrawal and injection as well as the cost for contracting storage capacity. The underground storage cost is therefore:

$$UGS\ Cost = \sum_{pkz} \left(Cost_{pz}^{Sto} \cdot q_{pkz}^{StoMak} \right) + \sum_{pkz} \left(Cost_{pz}^{Inj} \cdot q_{pkz}^{InjMak} \right) + \sum_{pkz} \left(Cost_{pz}^{Wit} \cdot q_{pkz}^{WitMak} \cdot \left(1 + Losses_{pz}^{Sto}\right) \right) \tag{4.44}$$

Figure 4-10 illustrates underground storages' decision variables in the model.

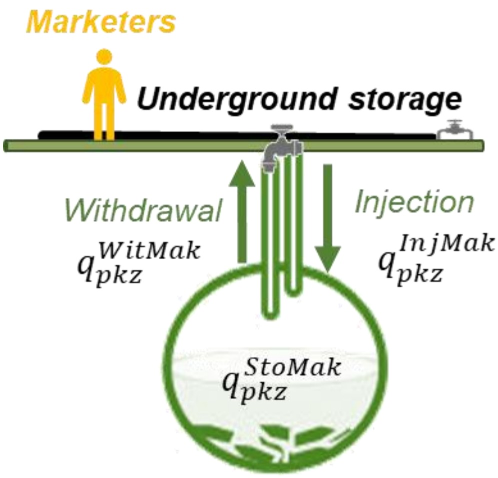

Figure 4-10 – Schematics of an underground storage

4.2.9. Price formation mechanism

One of the key distinguishing characteristics of the model is that it represents different flexible supply options and it allows to analyze their role on the final gas price formation. In the model we distinguish the following major pricing mechanism for the international natural gas market: Oil price scalation (OPE), gas-on-gas competition (GoG), hybrid pricing formulas which contemplates both OPE and GoG pricing, regulated prices, and netback pricing.

4.2.9.1. Long-term contract (LTC) pricing

LTC pricing is formula based, negotiated between buyer and seller. The contract sales price (CSP) contains a fixed base price and a variable part (floating part OPE or GoG indexed) and is represented by (4.45), allowing contracts to be indexed to more than one index price p_{ip}^{Index}.

$$CSP_{cp} = A_c + B_{ci} \cdot p_{ip}^{Index} \tag{4.45}$$

Oil priced LTC (OPE) uses different oil products as benchmark depending on the region. In Europe, oil pricing is normally linked to Brent prices (USD/bbl) (e.g. CSP=5%

Brent+1.75) while in Asia-Pacific LTCs prices are often connected to the price of oil imported into Japan, also known as the Japanese Crude Cocktail (JCC), and in America to the Texas light sweet (West Texas Intermediate (WTI)). On the other hand, for Gas on Gas (GOG) competition in Europe we assume that LTC can be either 100% GOG (with NBP and TTF as the main reference hubs) or hybrid pricing formulas (oil and gas hub indexation). In Asia, the GOG pricing trend is still weak and mainly linked to the US Henry Hub (HH). In the North American gas market (USA, Canada and Mexico) we assume all contracts to be 100% GOG using the HH as a reference, (e.g. CSP=115% HH).

For OPE, the oil index in the CSP formula is given exogenously in the model while for gas hub index (i.e. NBP, TTF, HH), the gas hub index price is calculated endogenously and iteratively as the dual variable γ_{zp} of the hub balance equation per period (4.19). Therefore, the new price for the LTC is calculated as:

$$CSP_{cp} = A_c + B_{ci} \cdot \gamma_{zp/i\epsilon z} \tag{4.46}$$

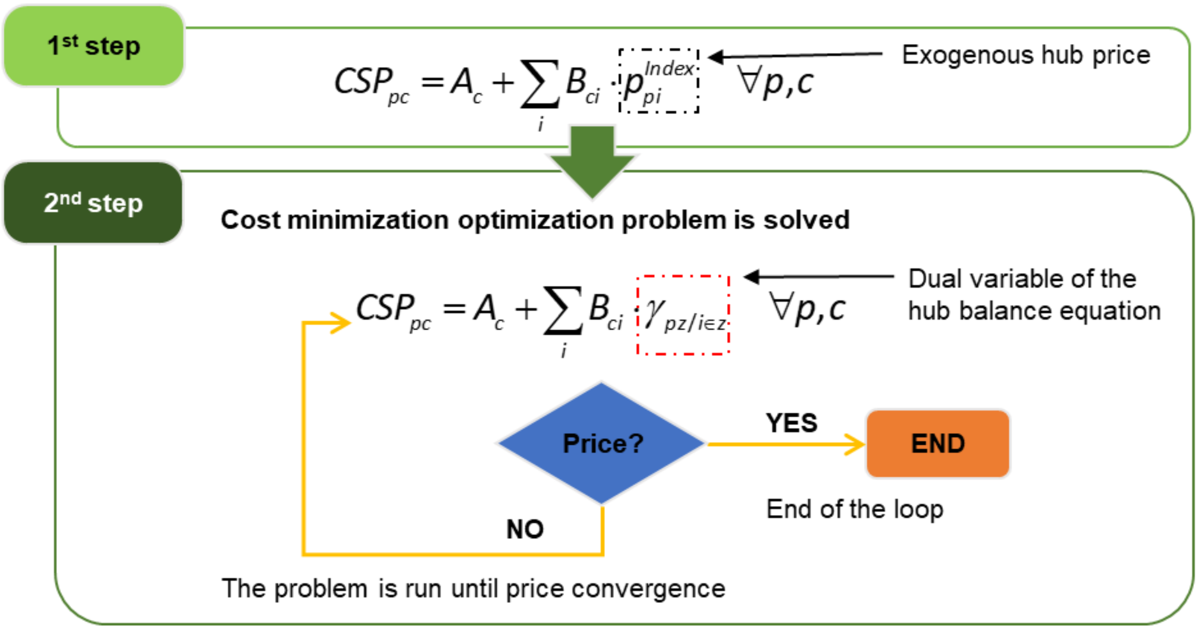

Figure 4-11 – Gas-to-gas index pricing. Iterative process

Additionally, some OPE contracts prices might be delimited by horizontal asymptotes, S-curve mechanism introducing an upper and lower ink, reducing the expected volatility of oil prices and protecting marketers in times of high oil prices and similarly to protect traders in periods when oil is cheap. Two examples of this type of contracts is represented in Figure 4-12.

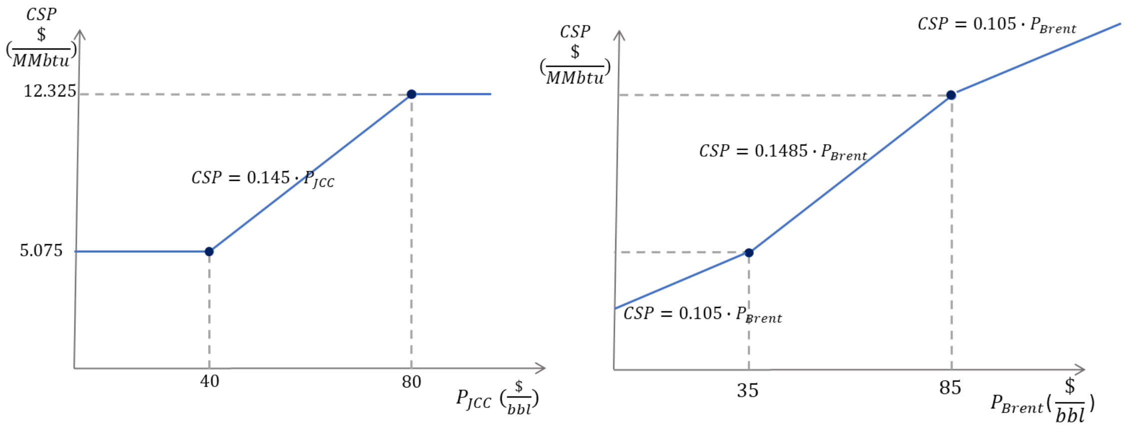

Figure 4-12 – Example of long-term contract pricing S-curve formulas.

Finally, the cost of the gas contracted in advance through LTC is:

$$LTCs'cost = \sum_{cp} CSP_{cp} \cdot \left(\sum_{zz_1ctk \in c} q^{QNG}_{pzz_1ctk} + \sum_{zz_1tk \in c} q^{QLNG}_{pzz_1ctk} \right) \tag{4.47}$$

4.2.9.2. Regulated prices

The regulated category is defined mainly for producing regions (i.e. zones) which are self-supplied (or almost) and the market is far from being liberalized, such as the Former Soviet Union, Middle East, Africa and some domestic production in Asia Pacific and Latin America. Regulated prices are set at a sufficient level to cover the cost of service, including traders' mark-up (cheaper than the one applied for selling their gas out of the zone).

4.2.9.3. Netback pricing

The netback pricing is calculated by taking the revenues from the sold natural gas, less all costs associated with getting that gas to the defined market, including transportation and production costs. This pricing mechanism has been applied to natural gas spot transactions.

4.2.10. Objective function

GasValem-GoG is a quadratic optimization model which minimizes the total cost of the gas supply chain (i.e. operational cost and long-term contract portfolio optimization) while maximizing the utility of the demand considering the relevant technical constraints of the infrastructure and the main characteristics of the gas sector. The objective function includes all the detailed costs:

$$
\begin{aligned}
&Objective\ Function \\
&= \sum_{spz} \frac{1}{\alpha_z^S}\left(Q_{pz}^s \cdot q_{pz}^s - \frac{\left(q_{pz}^s\right)^2}{2}\right) \\
&- \sum_{p,w}\left((q_{pw}^{Well} - q_{pw}^{WellLTC}) \cdot \left(c1_w^{Well} + c2_w^{Well} \cdot (q_{pw}^{Well} - q_{pw}^{WellLTC})\right)\right) \\
&- \sum_{cp} CSP_{cp} \cdot \left(\sum_{zz_1ctk\in c} q_{pzz_1ctk}^{QNG} + \sum_{zz_1tk\in c} q_{pzz_1ctk}^{QLNG}\right) \\
&- \sum_{z}\left(Cost_z^{Liq} \cdot \sum_{ptz_1} q_{ptzz_1}^{ShipTra} \cdot \left(\frac{1}{1 - Losses_{pz}^{Liq}}\right)\right) \\
&- \sum_{zz_1}\left(Cost_{zz_1}^{Ship} \cdot \left(\sum_{p,k} q_{pzz_1k}^{ShipMak} + \sum_{p,k} q_{pzz_1k}^{ShipTra}\right)\right) \\
&- \sum_{z}\left(Cost_z^{Reg} \cdot \left(\sum_{k} q_{pkz}^{RegMak} + \sum_{t} q_{ptz}^{RegTra}\right) + Cost_z^{Tank}\right. \\
&\left.\cdot \sum_{k} q_{pkz}^{TankMak}\right) - \sum_{p,z,z_1}\left(COST_{pzz_1}^{Pipe} \cdot q_{pzz_1}^{Pipe}\right) - \sum_{pkz}\left(Cost_{pz}^{Sto} \cdot q_{pkz}^{StoMak}\right) \\
&+ \sum_{pkz}\left(Cost_{pz}^{Inj} \cdot q_{pkz}^{InjMak}\right) \\
&+ \sum_{pkz}\left(Cost_{pz}^{Wit} \cdot q_{pkz}^{WitMak} \cdot \left(1 + Losses_{pz}^{Sto}\right)\right) \\
&- \sum_{p,t,z}\left(Cost_t^{TraRe} \cdot \sum_{k} q_{ptkz}^{VerticallyInt} + Cost_t^{Tra} \cdot q_{ptz}^{HubSalesTra}\right) \\
&- \sum_{p,k,z} Cost_k^{MakWholesale} \cdot q_{pkz}^{HubSalesMak} + Cost_k^{MakRetail} \cdot q_{pkz}^{Demand}
\end{aligned}
\tag{4.48}
$$

4.3. Case Study

4.3.1. Description

The proposed global gas model is used for the assessment of the global optimal pattern of gas flows determining gas demand and prices and minimizing supply cost (i.e. maximizing netbacks), considering different sources of gas supply (long-term contracts and spot trade in hubs). The case study is based on 2020 using forecasted values for demand, production, and long-term contracts in place (i.e. both for natural gas and LNG). The case study includes 25 zones (see Figure 4-13), considering greater detail in the European Continent.

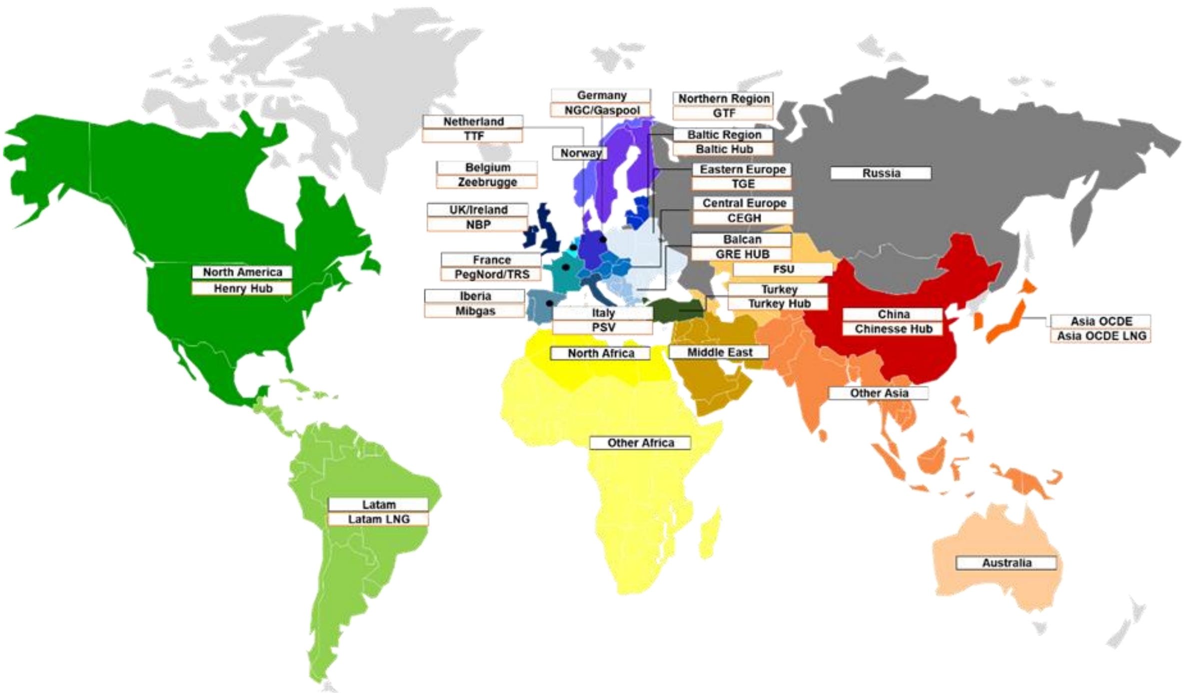

Figure 4-13 – GasValem-GoG case study zones and their corresponding gas hub

4.3.2. Data

Three different types of demand have been defined (residential & commercial, industrial and power sector). In the short term, the power sector presents a more elastic demand than the industrial and the residential sector (i.e. we assume residential elasticity is close to one). The future total demand per zone has been taken from (BP 2018) for year 2017 and a compound annual growth rate from the International Energy Agency New Policies Scenarios to 2025 (IEA 2018) has been applied for the 2020. The monthly demand profile in each zone has been obtained from Governments', Regulatory Authorities' or Energy Agencies' national statistics (e.g. US Energy Information Administration (EIA)), and public regional reports.

The same procedure has been applied for setting maximum production rates and natural gas reserves, using the data from (BP 2018) for year 2017.

For the case of infrastructures, inside EU, ENTSOG has been used as reference for the current infrastructures and outside the EU, public data from several public and private organizations, has been used, such as: IGU, GIIGNL and information from projects' website or stakeholders' website.

Regarding production costs, long-term contracts prices and characteristics and wholesale prices, they are based on private and public information. GIIGNL, in their annual report gives detailed information regarding medium- and long-term contracts in force. Gas prices for household and non-hoseholds consumers (bi-annual data) for Europe can be found in Eurostat.

All this data gathering has encompassed a deep analysis of the global natural gas market performance together with a heavy data mining task among research centers, International Institutions and public institutions, and is also a major contribution of this thesis.

The model has been calibrated for year 2017, by fitting the model to the observed data in the market in order to adjust the unknow input parameters in the model. Agents´ strategic behavior have been calibrated as a mark-up (input parameter), based on real-world data. The Results from year 2017 can be found in Appendix C.

The simulated time horizon is one year with monthly granularity. We include all the existing infrastructure, as well as all the current projects that already have taken FID[3] and are planned to be commissioned before 2020. Technical data for infrastructures in Europe (i.e. LNG liquefaction and regasification terminals and pipelines) are taken from ENTSOG 2018[4]. The rest of cross-border pipelines, outside Europe, have been taken from public sources mainly from Energy Agencies data (such as IEA and EIA), sector associations (e.g IGU and GIIGNL) and Regulation Authorities. For oil products, we have considered an average annual price of 70 USD_{2017}/bbl for Brent, 65 USD_{2017}/bbl for WTI and 68 USD_{2017}/bbl for JCC, based on historic monthly profiles for the three of them based on Reuters information.[5]

As Russia's response to the ongoing changes in the European gas market remains uncertain, for this case study we have assumed Russia's strategy is volume-based, with the key aim of maintaining or even increasing its market share in Europe.

4.3.3. Results

North America is self-sufficient and the first natural gas consumer with an inner demand of 20.1% of the total global gas demand. The second and the third gas consumers are Middle East and Russia, which consume 11.9% and 9% of the total gas demand, respectively, and China occupied the fourth place with 5.6%. Considering only regions, Asia moves up to the second place (17.3%), and Europe[6] and CIS[7] account for 11.8% and

[3] Final Investment Decision.

[4] https://www.entsog.eu/

[5] All prices are real prices 2017.

[6] Including Turkey

[7] CIS includes Russia + Former Soviet Union (FSU)

11.0% respectively. The four European larger consumers[8] hold more than half of the total European gas demand (52%). By sector, in North America the industrial sector holds almost 40% of the natural gas demand followed by the power sector which consumes well over one third. In OECD Asia power sector is the sector with major gas consumption (55%) while in non-OECD Asia the industry consumes around 60%. Europe is the region with higher penetration of natural gas for residential/commercial (even if there are differences across the regions) followed by the power sector. In Latam, the industry consumes almost 60% of the total gas demand and the power sector more than a third[9].

The three larger consumers are also the three larger producers: North America (27.0%), Russia (19.8%) and Middle East (18.4%) of the total gas production. With a decreasing domestic production (which accounts for 19.9% of the total demand, mainly from UK and Groningen (Netherlands)), Europe relies heavily on imports. Russia supplies 44.2% of total European natural gas demand by pipeline and is its first natural gas exporter, followed by Norway (13.0%) and North Africa (i.e. Algeria) (8.1%). Even if LNG, which accounts for the 10.8% of Europe's natural gas demand, has helped Europe to diversify its portfolio, the main three suppliers provide around 65% of the market.

Australia is a net exporter, exporting LNG mainly to the rest of Asia. OECD Asia is the first world LNG consumer and covers the totality of its demand with LNG. Non-OECD Asia produces 13.8% of the total production, and only China accounts for 4.2%. Latam's production is around a 5% share of the global production. This region imports LNG mainly from North America, and exports LNG to Asia and Europe.

Underground storage (UGS) and LNG tanks are used for reducing seasonal variations (i.e. as arbitrage). UGS is mainly used in Europe - 5.6% of the total demand during the withdrawal season (October-March), especially in Germany, France and Central Europe, and in North America, where it accounts for 3.2% of the total natural gas demand. However, with an increasingly competitive flexible market, especially in Europe and with the flexibility offer by the ramp-up of the shale gas production in North America, gas storage profitability diminished. Nonetheless, the role of underground storage in peaking demand days due to stream weather conditions is blurred into the monthly detailed. In Asia (OECD and no-OECD) gas in the LNG tanks is used by the Asian marketers as a marginal source of flexibility, to flatten prices in peaking periods and to optimize their contract

[8] Germany, UK+ Ireland, Italy and Turkey

[9]Latam gas consumption experienced several inter-annual fluctuations depending on the hydro-power generation.

portfolio, mostly in Japan and South Korea (0.13 bcm), as the rest of Asia has domestic production as another source of flexibility.

The natural gas balance per node is shown in Figure 4-14 and Figure 4-15 and the breakdown of gas consumption by sector is represented in Figure 4-16.

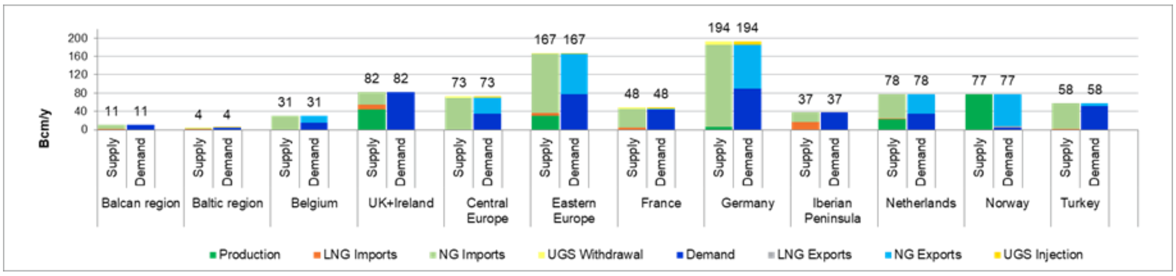

Figure 4-14 – Natural gas demand by sector

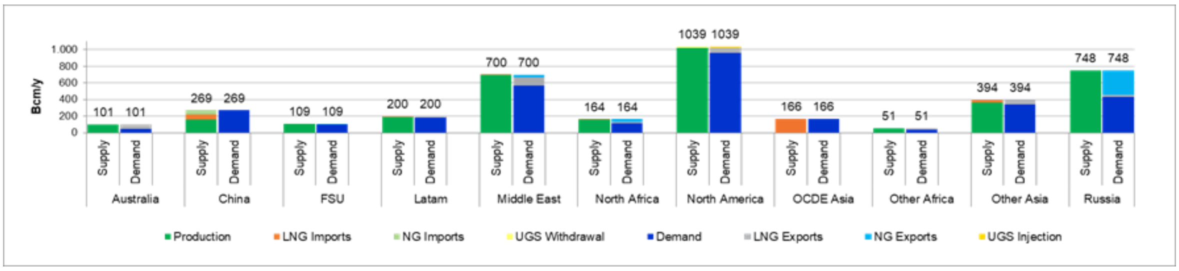

Figure 4-15 – Natural gas balance by region for 2020

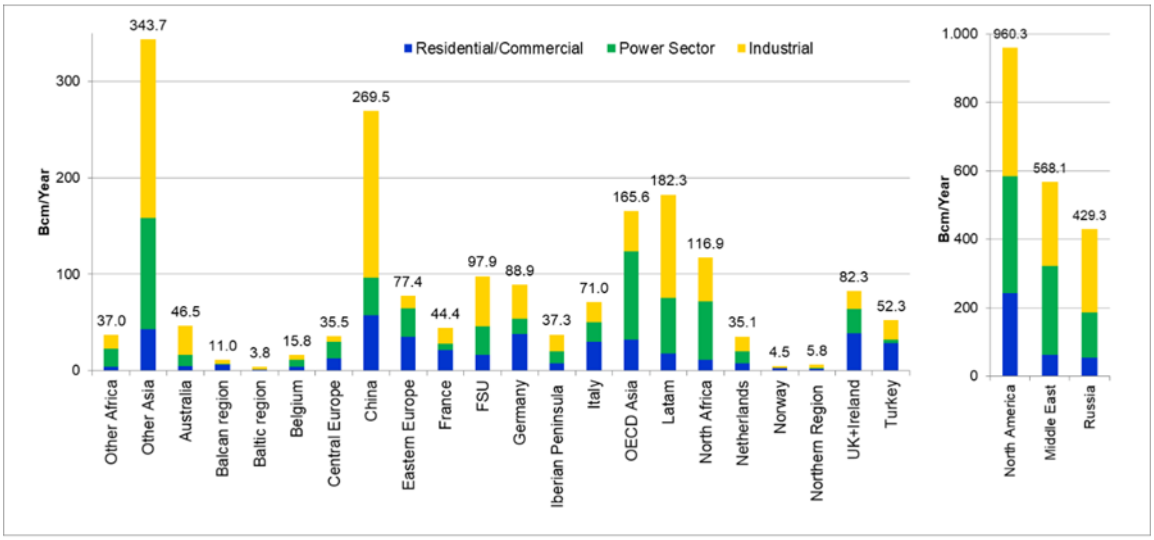

Figure 4-16 – Natural gas balance by region for 2020

Most of the global flows through pipelines are omitted as they are flows within zones in this case study, except for Europe, which is more disaggregated. Europe receives 86.6% of its total imports by pipeline, mainly from Russia, Norway and Algeria. Russia supplies

247.9 bcm/y of natural gas to Europe by pipeline through Eastern Europe[10][11] and Nord-Stream (I & II). North Africa (Algeria) exports by pipe to Iberian Peninsula and Italy are 18.6 bcm/y and 15.9 bcm/y. A well interconnected Europe allows natural gas flows among the different European nodes. Germany acts as a transit zone allowing Norwegian and Dutch gas to reach Central Europe, as well as some Russian gas. Russia targets also the Chinese market by pipeline, through the coming online of Power of Siberia with 44.9 bcm. A Sankey diagram is presented in Figure 4-17, for visualizing global natural gas flows, which are featured as directed arrows that have a width proportional to the flow quantity:

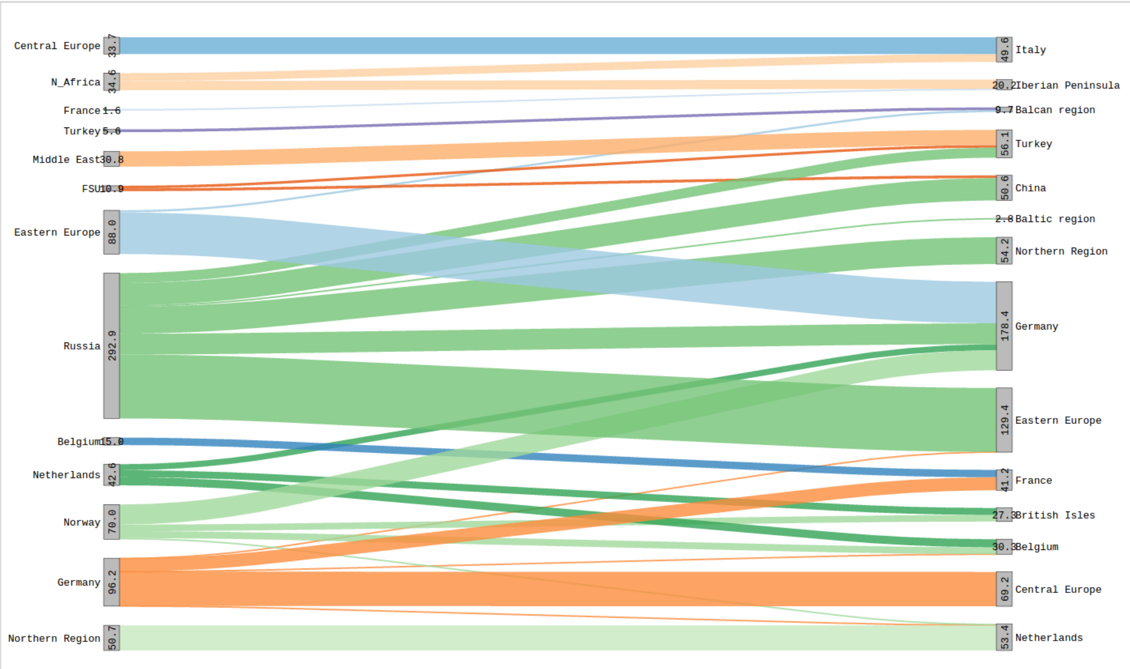

Figure 4-17 – Natural gas flows

Based on what is currently under construction, the global LNG capacity is projected to increase 23.0% (86.41 bcm) by 2020, being the United States (50.1% of the total increase) and Australia (19.6%) the largest sources of this LNG capacity growth. On the other hand, the new regasification capacity coming online will suppose 77.6 bcm of new regasification capacity, around 6% increase from current capacity. Middle East remains as the first LNG supplier exporting 29.6% of the total LNG demand, followed by North America (18.4%) and Australia (16.1%). While the Australian LNG focuses on the Asian Pacific basin, the American expands, reaching both the Asian and European markets, and it becomes the main supplier of the Latin American LNG market. Additionally, with the start-up of the

[10] Poland, Romania, Belarus, Moldova and Ukraine

[11] Further nodes disaggregation would be needed in order to account for the re-routed gas flows bypassing traditional routes through Ukraine, which is not the aim of this case study.

Yamal LNG, Russia supplies 25.4 bcm to OECD Asia which represents 7.7% of the global LNG demand.

All Asia accounts for 75.7% of the total LNG imports, with OECD Asia as the first LNG importer (48.6% of the total LNG demand), and China the second (18.1%). OECD Asia counts with a diversified portfolio of suppliers, where Other Asia supplies 24.2%, Australia 19.6%, Middle East 19.3, Russia 15.3%, North America 13.9%, and the remaining 7.7% supplied by others. In non-OECD Asia, Middle East is the main LNG importer, with a market share of 50.6% of the total LNG demand, followed by Australia (24.3%), Other Asia (10.5%) and North America (9.1%)[12].

Europe is the second largest LNG importing region, with a share of 17.7% of the global LNG demand, representing a 12.5% of the total European natural gas demand. North America is the first European LNG supplier with 34.2% of the total European LNG supplies, being Middle East the second (28.7%) and North Africa the third (18.1%).

Latam LNG imports are 11.5 bcm (6.3% of its total natural gas demand), of which 79.2% comes from North America and the rest from Africa, Middle East and Other Asia.

LNG flows among the different zones are shown in Figure 4-18 through a Sankey diagram.

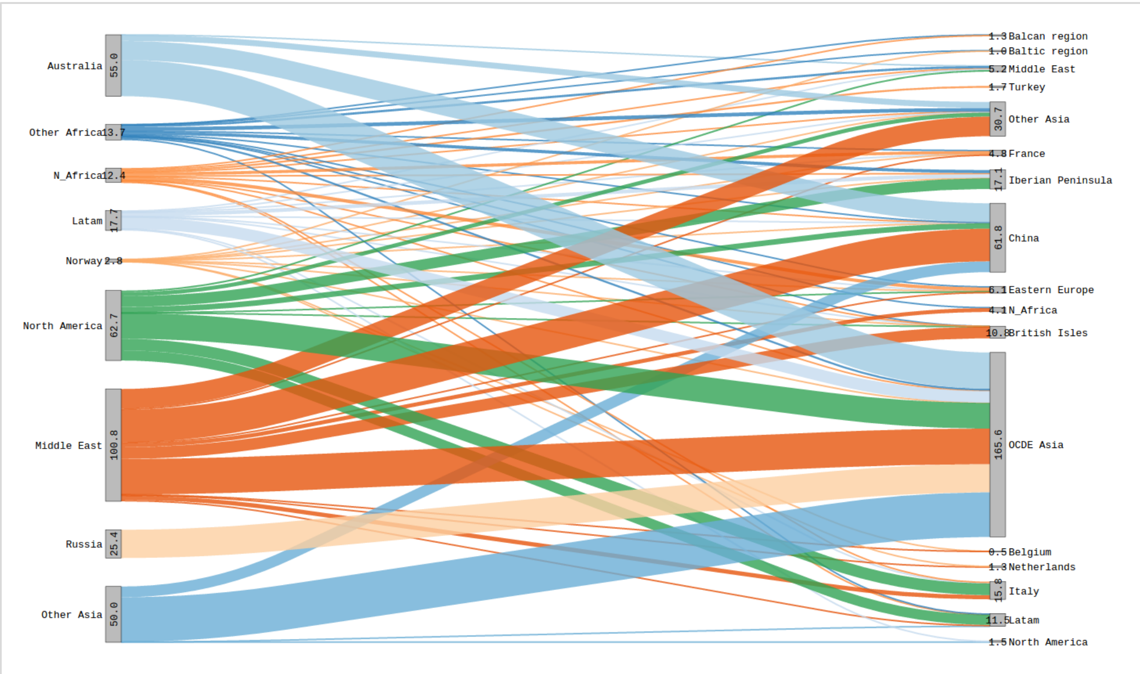

Figure 4-18 – LNG flows

[12] US-China trade war has not been considered and therefore no extra tariff has been included.

The highest prices were found in the main LNG importing regions in Asia Pacific, that is, China and OECD Asia (Japan and South Korea) (see Figure 4-19). The spread with the TTF was around 2.5 USD_{2017}/MMbtu. European marketers take advantage of the Asian LNG spread, diverting LNG cargoes as shown in Figure 4-21 (i.e. UK+Ireland, Iberian Peninsula and Italy) resulting in higher market prices for their home markets. In Northwest European countries, where GOG dominates, prices are somewhat lower than in the rest of Europe, but still a lot higher than in North America, where prices are even below those in Africa. Middle East countries, Russia and Former Soviet Union (FSU) have the lowest prices. These markets are supplied by their own domestic production and the resulting price is set to cover the “cost of service”, including lower markups for traders and marketers, which in many cases are state-owned companies. Finally, Latam prices are reduced due to cheap spot LNG cargoes from North America, reducing the netback between the Latam and the European market. Additionally, some European marketers take advantage of the spread between the two basins and divert part of their volumes from their long-term contracts signed with American traders (i.e. indexed to HH) to Latam (as is the case of Italian and Iberian marketers).

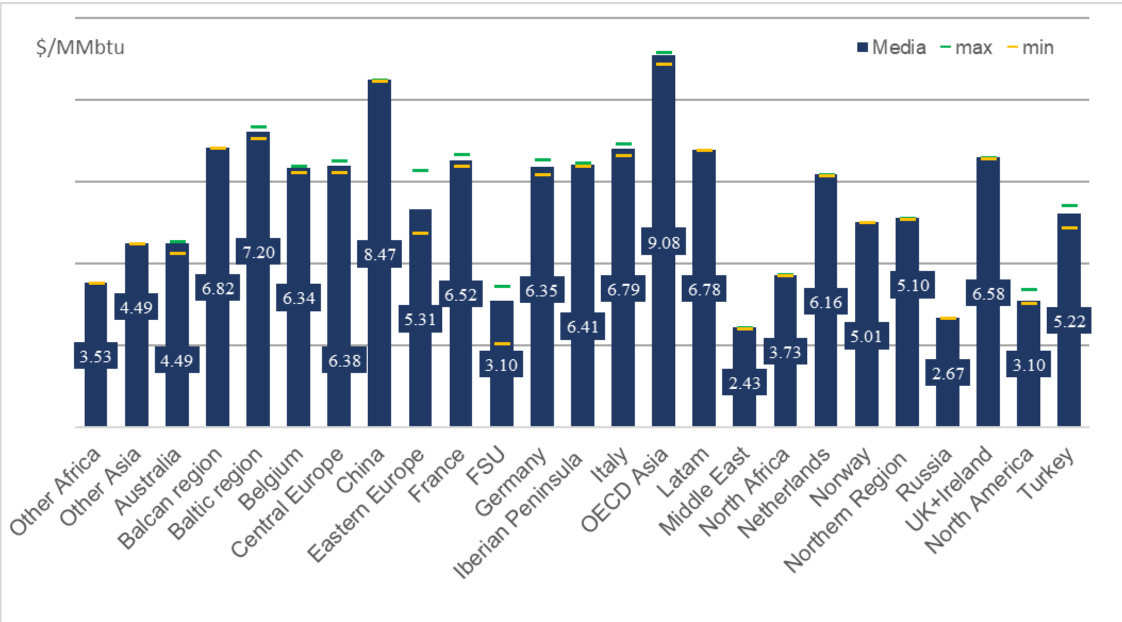

Figure 4-19 – Wholesale gas prices per region. (USD_{2017}/MMBtu)

Most of the long-term contracts are only exerted till the ToP, in favor of spot purchases in the hubs, as with an oversupplied natural gas market (new liquefaction capacity online) and tight oil prices (assumed Brent 70 USD_{2017}/bbl) the spot market appears as a better supply option (i.e. moreover for those LTC priced to oil products). There is an exception for the deliveries under long-term contract from North America, whose GoG indexation to

HH (CSP=115% HH), together with flexible supply basis have been more attractive than spot market to marketers and have been exerted reaching maximum allowed volumes.

The spot market in Europe represents 31.5% of its overall gas demand (from natural gas and LNG), favor by liquid natural gas hubs. OECD Asia buys 38.9% of its LNG demand in the spot market and China 28.2% (by pipeline and LNG), as traders and marketers (i.e. diverting cargoes) take advantage of the Asian LNG spread among the other basins. Russia is the player that contributes more to the overall spot natural gas supplies (41.6%)[13], both by pipeline and LNG cargoes to European and Chinese markets, followed by Middle East (18.4%), which exports natural gas by pipe to the Turkish spot market and LNG to China and OECD Asia (see Figure 4-20). American shale gas reaches the European hubs (i.e. mainly Iberia (Mibgas) and Italy (PSV)), representing 11.0% of the European spot volumes traded at hubs. Additionally, North America LNG represents 15.8% of spot LNG traded in Asia and the majority (98.4%) of Latam's spot market (where Latam's LNG spot market account for the 70.6% of its total LNG demand).

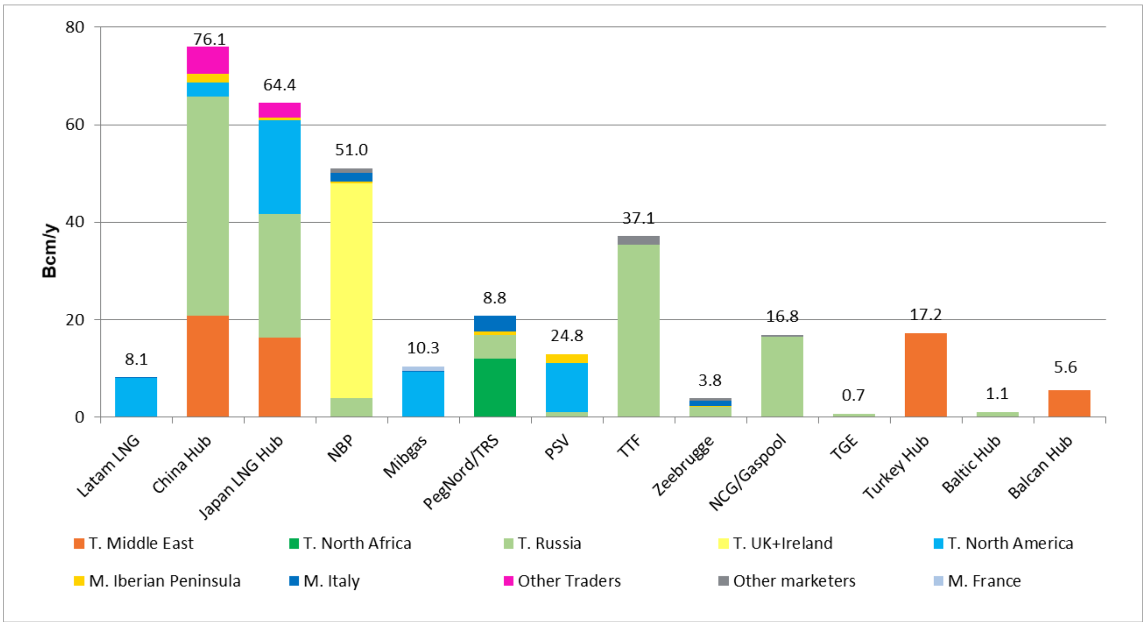

Figure 4-20 – Spot market. Sales in the different hubs or OTC markets.[14][15].

[13] Without considering the traded volumes at HH.

[14] The Henry Hub has not been included in the graph, as it has been assumed that all the North American trade is done through the hub, with a traded volume of 959 bcm, and supplied by domestic production (i.e. American traders).

[15] Traders have been designated with a "T." and marketers with an "M". Both Asian markets (China Hub and Japan LNG) and Latam are OTC market as currently there is no official trading gas hub and the market price is determined (for LNG) by the price of the spot LNG cargoes.

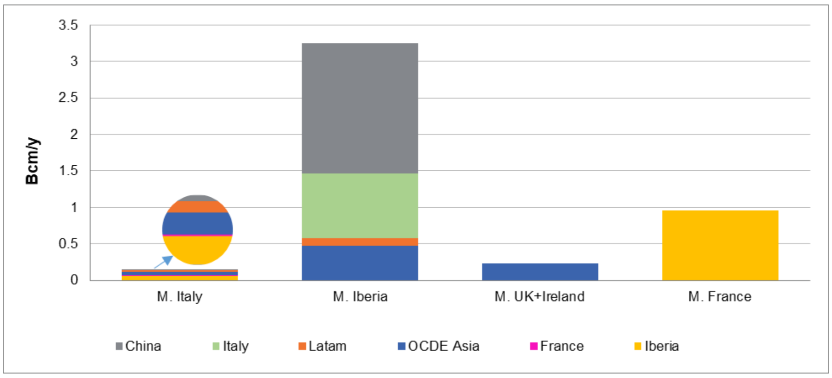

Figure 4-21 – Diverted LNG cargoes. By end-market and marketer. Traders have been designated with a “T” and marketers with an “M”

4.4. Conclusions

Long-term contracts have played a very important role in securing gas supplies and they continue to do so. However, over the past decade, natural gas trading has evolved from being traditionally delivered under long-term, (i.e. with destination clauses, Take-or-Pay commitments and contracts prices linked to oil products) to a more diversified and liquid market where gas is sold on a spot basis (i.e. trading hubs or OTC markets), driving the rise of gas on gas competition pricing for long-term contracts.

This spot market has been supported by a broad supply, the proliferation of suppliers with the emergence of portfolio players and the move to flexible destination contracts; and has been accelerated by demand peaks (mainly in Asia), the emergence of new gas consuming countries and the progressing liberalization in Europe with the consolidation of gas hubs.

In this context, we propose a novel optimization model which captures these new commercial trends for giving insights of the mid-term natural gas market. The model, apart from all the infrastructures involved in the gas chain (i.e. agents and infrastructures), includes the different supply options (i.e. long-term contracts or spot market), modeling the coexistence of oil-indexed and hub pricing mechanism. Traders act as the interface between producers and marketers, supplying gas to marketers under long-term agreements or selling it at hubs. Marketers optimize their gas portfolio for supplying the final gas demand (residential, industrial and power sector), deciding the exerted volumes from long-term contracts and participating in the different hubs either buying or selling gas, taking advantage of market spreads (i.e. moving gas among connected zones by pipeline and diverting LNG cargoes to a more rewarding destinations).

The proposed model is used for the assessment of the global natural gas market in 2020 with a special focus on Europe and monthly detail. An abundant gas and LNG supply together with firm oil prices (assumed Brent 70 USD/bbl), encourage the spot market and flexible imports, especially in Europe where the spot trade in hubs represents a share of 31.5% of total European gas demand. We consider a scenario where Russia follows a volume-based strategy, and export volumes from Russia into Europe accounts for the 44.2% of total European demand increasing its share in 9.2 percentage points from 2018 (i.e. Russian gas accounted for 35% of total European demand in 2018). Long-term oil-linked contracts are only exerted till the ToP, in favor of spot purchases in the hubs or some gas-on gas flexible long-term contracts, especially those ones indexed to the Henry Hub. The European resulting prices are to the level at which it does make sense for North America (US LNG projects) to send gas to Europe on a variable cost basis, representing the 11% of the European spot volumes traded at hubs.

Appendix C: Results 2017

This appendix contains model results for 2017.

Node	Annual demand (Bcm/y)	Node	Annual production (Bcm/y)
Australia	46.6	Australia	119.1
Balkan region	10.9	China	156.7
Baltic region	3.8	Eastern Europe	35.5
Belgium	15.7	FSU	108.2
Central Europe	35.2	Germany	6.7
China	251.1	Italy	5.6
Eastern Europe	76.8	Latam	188.0
France	44.1	Middle East	675.6
FSU	97.2	North of Africa	159.4
Germany	88.6	Netherlands	33.2
Iberian Peninsula	37.0	North America	964.6
Italy	70.4	Northern Region	2.4
Latam	175.7	Norway	119.1
Middle East	543.1	Other Africa	60.6
North of Africa	109.4	Other Asia	362.1
Netherlands	34.9	Russia	637.5
North America	947.0	UK+Ireland	44.0
Northern Region	5.8		
Norway	4.5		
OCDE Asia	166.3		
Other Africa	34.6		
Other Asia	320.3		
Russia	425.9		
Turkey	51.9		
UK+Ireland	81.5		

Table 4-1 – Annual demand (left) and annual production by node for 2017

Node	Jan.	Feb.	Mar.	Apr.	May.	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dic.
Australia	3.7	3.9	3.8	3.7	3.8	3.8	3.9	3.9	4.2	4.2	3.8	4.0
Balkan region	1.3	1.3	1.3	0.8	0.8	0.8	0.6	0.6	0.6	1.0	1.0	1.0
Baltic region	0.4	0.4	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4
Belgium	1.8	1.8	1.8	1.0	1.0	1.0	0.8	0.8	0.8	1.6	1.6	1.6
Central Europe	4.3	4.3	4.3	2.0	2.0	2.0	1.8	1.8	1.8	3.7	3.7	3.7
China	22.0	19.6	20.3	19.9	20.1	19.9	20.2	20.4	19.8	21.0	22.4	25.4
Eastern Europe	8.2	8.2	8.2	5.3	5.3	5.3	4.6	4.6	4.6	7.5	7.5	7.5
France	5.5	5.5	5.5	2.4	2.4	2.4	1.8	1.8	1.8	4.9	4.9	4.9
FSU	12.1	12.1	12.1	8.1	8.1	8.1	4.0	4.0	4.0	8.1	8.1	8.1
Germany	9.7	9.7	9.7	6.2	6.2	6.2	5.5	5.5	5.5	8.1	8.1	8.1
Iberian Peninsula	3.4	3.4	3.4	2.6	2.6	2.6	2.8	2.8	2.8	3.5	3.5	3.5
Italy	8.0	8.0	8.0	4.3	4.3	4.3	4.0	4.0	4.0	7.1	7.1	7.1
Latam	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
Middle East	42.9	45.4	44.6	42.8	43.8	43.8	45.2	45.3	48.8	48.9	44.4	47.0
Netherlands	3.9	3.9	3.9	2.3	2.3	2.3	2.0	2.0	2.0	3.4	3.4	3.4
North America	101.0	89.2	87.3	67.6	64.2	67.0	72.8	71.8	67.4	69.0	83.2	106.6
North of Africa	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Northern Region	0.7	0.7	0.7	0.3	0.3	0.3	0.3	0.3	0.3	0.6	0.6	0.6
Norway	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5	0.5
OCDE Asia	12.4	10.9	12.7	12.7	13.9	14.8	14.9	16.9	15.1	14.9	13.5	13.6
Other Africa	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Other Asia	25.3	26.8	26.3	25.3	25.8	25.8	26.7	26.7	28.8	28.9	26.2	27.7
Russia	53.2	53.2	53.2	35.5	35.5	35.5	17.7	17.7	17.7	35.5	35.5	35.5
Turkey	5.8	5.8	5.8	2.9	2.9	2.9	2.9	2.9	2.9	5.8	5.8	5.8
UK+Ireland	7.2	7.2	7.2	6.1	6.1	6.1	6.7	6.7	6.7	7.2	7.2	7.2

Table 4-2 – Monthly demand by node 2017

LNG flows			LNG flows		
Export node	Import node	Bcm/y	Export node	Import node	Bcm/y
Other Africa	Other Asia	3.3	Middle East	North of Africa	3.5
Other Africa	Balkan region	0.2	Middle East	Netherlands	0.6
Other Africa	Baltic region	0.2	Middle East	UK+Ireland	10.4
Other Africa	China	5.2	North of Africa	Other Asia	0.3
Other Africa	Eastern Europe	1.0	North of Africa	Balkan region	1.0
Other Africa	Iberian Peninsula	1.4	North of Africa	China	0.1
Other Africa	OCDE Asia	11.1	North of Africa	Eastern Europe	3.0
Other Africa	Latam	1.0	North of Africa	France	2.7
Other Africa	Middle East	2.0	North of Africa	Iberian Peninsula	11.7
Other Africa	North of Africa	0.6	North of Africa	Italy	9.0
Other Asia	China	9.9	North of Africa	OCDE Asia	0.3
Other Asia	OCDE Asia	61.4	North of Africa	Latam	0.0
Other Asia	Latam	0.1	North of Africa	Middle East	0.8
Other Asia	North America	0.2	North of Africa	UK+Ireland	0.2
Australia	Other Asia	5.3	North of Africa	Turkey	1.7
Australia	China	23.1	Norway	Other Asia	0.0
Australia	OCDE Asia	43.9	Norway	Baltic region	0.9
Australia	Middle East	0.1	Norway	Belgium	0.0
Latam	Other Asia	0.6	Norway	China	0.1
Latam	China	0.2	Norway	Eastern Europe	0.3
Latam	Eastern Europe	0.3	Norway	France	0.3
Latam	France	0.2	Norway	Iberian Peninsula	0.4
Latam	Iberian Peninsula	3.3	Norway	OCDE Asia	2.8
Latam	Italy	0.2	Norway	Netherlands	0.7
Latam	OCDE Asia	10.7	Norway	UK+Ireland	0.1
Latam	Middle East	0.8	Russia	OCDE Asia	7.0
Latam	North America	1.3	North America	Other Asia	2.6
Middle East	Other Asia	17.5	North America	China	2.7
Middle East	Belgium	0.5	North America	Eastern Europe	0.5
Middle East	China	45.0	North America	OCDE Asia	8.6
Middle East	Eastern Europe	0.9	North America	Latam	3.0
Middle East	France	1.1	North America	Middle East	1.5
Middle East	Italy	3.8			
Middle East	OCDE Asia	21.2			
Middle East	Latam	1.2			

Table 4-3 – LNG flows between nodes 2017

NG flows

Export node	Import node	Bcm/y
Belgium	France	14.99
Belgium	Germany	40.49
Belgium	UK+Ireland	4.01
Central Europe	Germany	17.81
Central Europe	Italy	47.17
Eastern Europe	Central Europe	17.81
Eastern Europe	Germany	6.47
France	Iberian Peninsula	1.60
FSU	China	7.36
FSU	Turkey	5.28
Germany	Belgium	4.37
Germany	Central Europe	82.40
Germany	Eastern Europe	0.40
Germany	France	26.32
Germany	Netherlands	2.30
Middle East	FSU	1.63
Middle East	Turkey	30.28
North of Africa	Iberian Peninsula	18.64
North of Africa	Italy	4.65
Netherlands	Belgium	15.97
Netherlands	Germany	22.19
Netherlands	UK+Ireland	9.81
Norway	Belgium	54.36
Norway	Germany	40.00
Norway	Netherlands	2.40
Norway	UK+Ireland	13.00
Northern Region	Netherlands	43.66
Russia	Balkan region	4.16
Russia	Baltic region	2.76
Russia	China	0.73
Russia	Eastern Europe	59.09
Russia	Germany	60.70
Russia	Northern Region	47.07
Russia	Turkey	20.08
Turkey	Balkan region	5.47

Table 4-4 – NG flows between nodes 2017

Node	Price (USD/MMbtu)	Node	Price (USD/MMbtu)
Australia	4.9	Middle East	2.4
Balkan region	6.8	North of Africa	4.0
Baltic region	7.3	Netherlands	6.5
Belgium	6.6	North America	3.1
Central Europe	6.6	Northern Region	5.1
China	9.1	Norway	5.0
Eastern Europe	5.6	OCDE Asia	9.7
France	6.8	Other Africa	3.5
FSU	3.3	Other Asia	5.0
Germany	5.8	Russia	2.7
Iberian Peninsula	6.9	Turkey	5.1
Italy	7.1	UK+Ireland	7.0
Latam	7.4		

Table 4-5 – Natural gas prices per node in 2017

Hub/spot market	Bcm/y
GRE Hub (OTC)	5.5
Baltic Hub (OTC)	1.0
TGE	0.6
HH	945.6
Turkey Hub (OTC)	16.8
China LNG spot	58.1
OCDE Asia LNG spot	51.1
Latam LNG spot	2.0
MIBGAS	11.3
NBP	49.8
NCG	29.2
PEG	9.1
PSV	19.4
TTF	33.5
Zeebrugge	4.8

Table 4-6 – Natural gas traded at hubs or spot markets (OTC) 2017

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Chapter 5

Multi-objective bilevel optimization problem for the investment in new gas infrastructures

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The creation of the European internal gas market focuses on linking the gas infrastructure of EU countries, requiring of more infrastructure development in order to connect regions currently isolated from European energy markets and strengthen existing cross-border interconnections.

The analysis and results in this section were published in (Del Valle, Reneses, & Wogrin, 2018).

Notation

GASMOPEC model

Sub-indexes

t	Traders
m	Marketers
z, z_1	Zones
p	Periods
K_z^{CN}	Set of consumption nodes
K_z^{T}	Set of traders assigned to node z
K_z^{M}	Set of marketers assigned to node z

Parameters

C_{tp}	Traders' cost per period $(€/\mathrm{bcm})$
$P_{z_1p}^0$	Intercept of demand function per zone and period $(€/\mathrm{bcm})$
α_{z_1p}	Slope of demand per zone and period p $(€/\mathrm{bcm}^2)$
$\bar{Q}_{tp}^{tra}$	Maximum gas volume per trader and period (bcm)
$\bar{Q}_{zz_1p}^{pipe}$	Maximum pipeline capacity per zone and period (bcm)
$\bar{Q}_{zp}^{liq}$	Maximum liquefaction capacity per zone and period (bcm)
$\bar{Q}_{z_1p}^{reg}$	Maximum regasification capacity per zone and period (bcm)
$TC_{zz_1}^{pipe}$	Transport cost by pipeline $(€/\mathrm{bcm\ km})$
$TC_{zz_1}^{ship}$	Transport cost by ship $(€/\mathrm{bcm\ km})$
$COST_{pzz_1}^{invpipe}$	Investment cost in pipelines $(€/\mathrm{bcm\ km})$
$COST_{pz}^{invreg}$	Investment cost in new regasification capacity $(€/\mathrm{bcm})$
$\overline{CAP}_{pzz_1}^{invpipe}$	Maximum investment in new pipeline capacity (bcm)
$\overline{CAP}_{pz}^{invreg}$	Maximum investment in new regasification capacity (bcm)
e_{ij}	Upper and lower reservation levels for each objective function i and case j
$Q_{z_1p}^{ref}$	Reference consumption in node z_1 per period (bcm)
$p_{z_1p}^{ref}$	Reference price in node z_1 per period $(€/\mathrm{bcm})$
ε_{z_1p}	Price elasticity of demand

Variables:

$q_{tz_1zp}^{tNG}$	Natural gas sold per trader, zones and period (bcm)
$q_{tz_1zp}^{tLNG}$	Liquefied natural gas sold per trader, zones and period (bcm)
$q_{tz_1zp}^{tpipe}$	Natural gas transported per trader, between zones and period (bcm)
$q_{tz_1zp}^{tship}$	Liquefied natural gas transported per trader, between zones and period (bcm)
$q_{mzz_1p}^{mak}$	Marketers´ natural gas (bcm)
$q_{mzz_1p}^{mpipe}$	Natural gas transported per marketer, between zones and period (bcm)
$q_{zz_1p}^{totalpipe}$	Natural gas flow by pipeline per period (bcm)
$q_{zz_1p}^{totalship}$	Liquefied natural gas transported per period (bcm)
bp_{z_1p}	Dual variable. Gas border price - between traders and marketers $(€/\mathrm{bcm})$
p_{z_1p}	Price in consumption node $(€/\mathrm{bcm})$
$\mu_{tzz_1p}^{tNG}$	Dual variable. Lower bound on NG exports of traders from node z to z_1 $(\mathrm{q}_{\mathrm{tzz_1p}}^{\mathrm{tNG}})$
$\mu_{tzz_1p}^{tLNG}$	Dual variable. Lower bound on LNG exports of traders from node z to z_1 $(\mathrm{q}_{\mathrm{tzz_1p}}^{\mathrm{tLNG}})$
$\mu_{tzz_1p}^{tpipe}$	Dual variable. Lower bound on NG exports of traders by pipe from z to z_1 $(\mathrm{q}_{\mathrm{tzz_1p}}^{\mathrm{tpipe}})$
$\mu_{tzz_1p}^{tship}$	Dual variable. Lower bound on LNG exports of traders by ship from z to z_1 $(\mathrm{q}_{\mathrm{tzz_1p}}^{\mathrm{tship}})$
ϕ_{tzp}^{tpipe}	Dual variable of traders' NG flow conservation constraint $(€/\mathrm{bcm})$
ϕ_{tzp}^{tship}	Dual variable of traders' LNG flow conservation constraint $(€/\mathrm{bcm})$
λ_{zp}^{tra}	Dual variable. Upper bound on trader's gas available for sale $(€/\mathrm{bcm})$
$\mu_{mzz_1p}^{mak}$	Dual variable. Lower bound on marketer's supplies. $(\mathrm{q}_{\mathrm{mzz_1p}}^{\mathrm{mak}})$
$\mu_{mzz_1p}^{mpipe}$	Dual variable. Lower bound on marketer's NG flows by pipe. $(\mathrm{q}_{\mathrm{mzz_1p}}^{\mathrm{mpipe}})$
ϕ_{mzp}^{mak}	Dual variable of marketers' flow conservation constraint
$\mu_{zz_1p}^{pipe}$	Dual variable. Lower bound on pipeline's NG flow $(\mathrm{q}_{\mathrm{zz_1p}}^{\mathrm{totalpipe}})$
$\lambda_{zz_1p}^{pipe}$	Dual variable. Upper bound on pipeline capacity $(€/\mathrm{bcm})$
$\mu_{zz_1p}^{ship}$	Dual variable. Lower bound on LNG flows by ship $(\mathrm{q}_{\mathrm{zz_1p}}^{\mathrm{totalship}})$
λ_{zp}^{liq}	Dual variable. Upper bound on liquefaction capacity $(€/\mathrm{bcm})$

$\lambda_{z_1 p}^{reg}$	Dual variable. Upper bound on regasification capacity $(€/\mathrm{bcm})$
$cost_{zz_1}^{pipe}$	Dual variable. Total cost NG transport through pipelines $(€/\mathrm{bcm})$
$cost_{zz_1}^{ship}$	Dual variable. Total cost LNG transport by ship $(€/\mathrm{bcm})$
$i_{pzz_1}^{pipe}$	Investment in new pipeline capacity (bcm)
i_{pz}^{reg}	Investment in new regasification capacity (bcm)
$cost_{invpipe}$	Total cost due to investment in new pipeline capacity $(€)$
$cost_{invreg}$	Total cost due to investment in new regasification capacity $(€)$
$U(D)$	Utility of the demand $(€)$
$\Delta p_{zz_1 p}$	Price difference between zone z and zone z_1 $(€)$
$\delta_{zz_1 p}^{tNG}$	Binary variable. $\delta_{\mathrm{zz_1p}}^{\mathrm{tNG}} = 1$ if suppliers t supplies NG from $\mathrm{zz_1}$ in p
$\delta_{zz_1 p}^{tLNG}$	Binary variable. $\delta_{\mathrm{zz_1p}}^{\mathrm{tLNG}} = 1$ if suppliers t supplies LNG from $\mathrm{zz_1}$ in p

This chapter aims at developing the third specific objective of this thesis and it is based on the analysis and results in ***Article IV*** (Del Valle, Reneses, & Wogrin, 2018) as working paper, which is under review at the time of this thesis publication.

5.1. Introduction

In section 5.1.1 we first introduce the context and motivation for developing the model. In section 5.1.2 we present the current status of the literature regarding capacity expansion models in the natural gas arena. Section 5.2 includes the model description and section 5.3 presents the mathematical formulation of the proposed bilevel model. In section 5.4 we present the techniques used for solving the multi-objective bilevel problem. Section 5.5 presets the case study and describe the obtained results, analyzing the optimal infrastructure investment in Western Europe. Finally, section 5.6 provides some relevant conclusions. In Appendix D we present a summary table with the results and the formulation of the proposed Mathematical Problem with Equilibrium Constraints (MPEC) is stated in detail in Appendix E. Appendix F to I are devoted to the definition of basic concepts related to bilevel programming problems and multi objective programming which can help the reader to better understand the proposed model.

5.1.1. European Projects of Common Interest (PCI)

The European Union (EU) has developed a set of energy targets and energy policy in order to help the EU achieve a more competitive, secure and sustainable energy system. All the strategies put energy infrastructures at the forefront for the creation of a pan-European energy market. Furthermore, as Europe dependence on natural gas imports is increasing, due to a decline in indigenous EU natural gas production, Europe needs to seek supplies from new markets and open new routes to enhance security of supply and competition among suppliers.

Additionally, the Third Energy Package addresses the facilitation of cross-border gas trade, the promotion of cross-border collaboration and the investment among the EU countries, as a key point for the completion of the internal gas market. Within this framework, the European Network of Transmission System Operators for Gas (ENTSOG) publishes every year a Ten Year Network Development Plan (TYNDP) which contains the European TSOs' perspective on the potential development of demand, supply and transport capacity and provides a strategic framework for the long term energy infrastructure vision of the EU to ensure the development of a pan-European transmission system.

In this context, the EC has banked on more investments in infrastructure to help EU countries to physically integrate their energy markets, enabling them to diversify their energy sources. As a result, in October 2013, the EC presented a list of energy infrastructure projects (i.e. electricity, gas and oil) that are of common interest (**Projects of Common Interest – PCIs**). Infrastructures priority is based on their economic, social and environmental viability.

Hence PCIs are considered key infrastructure projects in order to help the EU achieve its energy policy and climate objectives. The PCIs list is updated every two years by the EC. Projects with the status of PCI, might benefit from financial support under the Connecting Europe Facility program (CEF)[1] and from accelerated planning and permit granting.

The requirements that projects need to fulfill to become a PCI are: first, to have a heavy impact on market integration in at least two EU countries; second, to boost competition on energy markets; third, to enhance security of supply, and fourth, to add to the EU's climate and energy goals by integrating renewables.

The Regulation (EU) 347/2013 (EC. 2013), gather up the previous requirements in the following four main criteria: market integration, security of supply, competition and sustainability. Additionally, in line with these criteria, ENTSOG published its 1st CBA Methodology (ENTSOG, 2015) updated in its 2nd CBA Methodology (ENTSOG, 2018), which established the main criteria to support the PCI selection process. These criteria are summarized in:

- **Market integration**, in terms of market access diversification, price convergence, and balance in bi-directional capacity.
- **Security of supply**, in terms of resilience in case of disruption, in line with Regulation (EU) 994/2010 (EC. 2010) and Regulation (EU) 1938/2017 (EC. 2017), the level of disrupted demand, remaining flexibility, and number of sources a country can access to.
- **Competition**, in terms of number of gas sources and routes, physical dependence on a single supply source, gas supply costs, and marginal prices.
- **Sustainability**, in terms of CO_2 emissions reduction including replacing more polluting fuels and as a back-up for integration of renewable energy (including biomethane and other synthetic gases).

Therefore, the 2nd CBA Methodology is based on a Multi-Criteria Analysis (MCA), combining monetary elements pertaining to the CBA approach, as well as non-monetary

[1] https://ec.europa.eu/inea/en/connecting-europe-facility/cef-energy

and/or qualitative elements to measure the level of completion of the EU Energy Policy guidelines from an infrastructure perspective. In line with those criteria, the methodology defines a series of potential benefits (i.e. to Europe and Member State (MSs)) for gas infrastructure projects, which are summarized in the table below. Moreover, the definition of a common set of project assessment metrics ensures the comparability among projects.

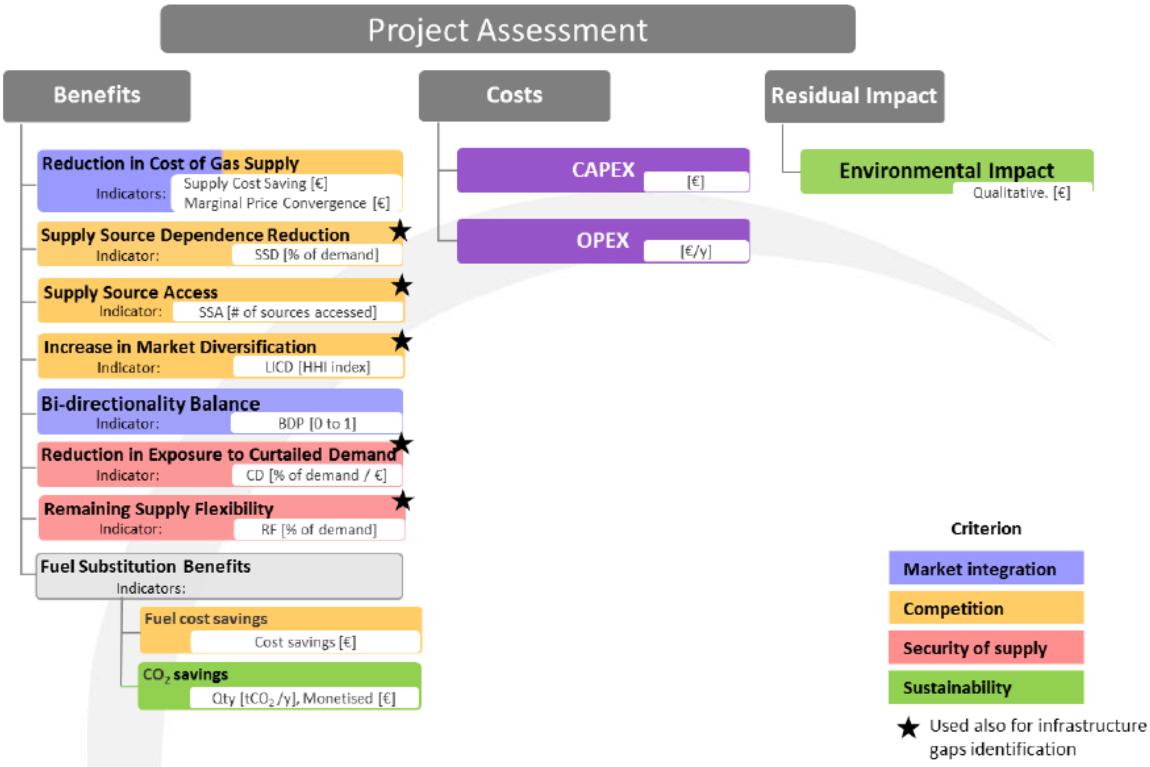

Figure 5-1 – 2nd CBA Methodology. CBA metrics and Regulation criteria. Source: (ENTSOG, 2018)

At the present time, in the context of uncertainty, global relations and liberalized energy markets, the assessment of projects impact and consequently the decision-making process of the EC has been complicated immensely. Therefore, well-working and realistic gas markets models are essential in order to allocate the resources adequately and to provide with proper economic signals to suppliers, investors, consumers, etc. This relevance increases even more when a consumption country lacks domestic production, as it occurs in most of the EU MSs.

For this purpose, the aim of the GASMOPEC model proposed in this chapter is to provide a tool for assisting the investment decision-making process to determine European Commission funding support, analyzing the different investment options. Thus, the objective of this model is to represent a realistic decision-making process for analyzing the optimal infrastructure investments (in natural gas pipelines and regasification terminals) within the EU framework under a market perspective.

We propose a multi-objective bilevel optimization model for representing the investment decision process in the European natural gas market which consists of the objectives of the network planner at the upper level and a lower level that represents the downstream European gas market.

We assume that the EC acts as an independent pipeline network planner (central planner) and is in charge of the optimal network expansion plan (i.e. pipeline and regasification terminals). The capacity expansion problem pertaining to the network planner (i.e. EC) considers an objective function made up of multiple objective optimization functions. The multi-objective jointly minimizes network investment and price difference between zones (i.e. European countries), while maximizing the utility of demand and the number of gas suppliers, resulting in the closest feasible compromise solutions.

The lower level is defined as a generalized Nash-Cournot equilibrium. In the first place, the upstream market is represented through the traders, which act as interface between the upstream and the downstream gas markets, supplying gas to marketers. Second, the wholesale trade within Europe (downstream market) is represented through the marketers, which buy gas to traders to supply final demand. Infrastructure capacities (i.e. from liquefaction and regasification terminals and pipelines) are explicitly included in the lower level.

The list of PCIs has been drawn up under four priority gas corridors[2], defined in the Trans-European Networks for Energy (TEN-E) strategy. The four priority gas corridors are: 1) North-South gas interconnections in Western Europe (‘NSI West Gas’); 2) North-South gas interconnections in Central Eastern and South-Eastern Europe (‘NSI East Gas’); 3) Southern Gas Corridor (‘SGC’); 4) Baltic Energy Market Interconnection Plan in gas (‘BEMIP Gas’).

[2] https://ec.europa.eu/energy/en/topics/infrastructure/trans-european-networks-energy

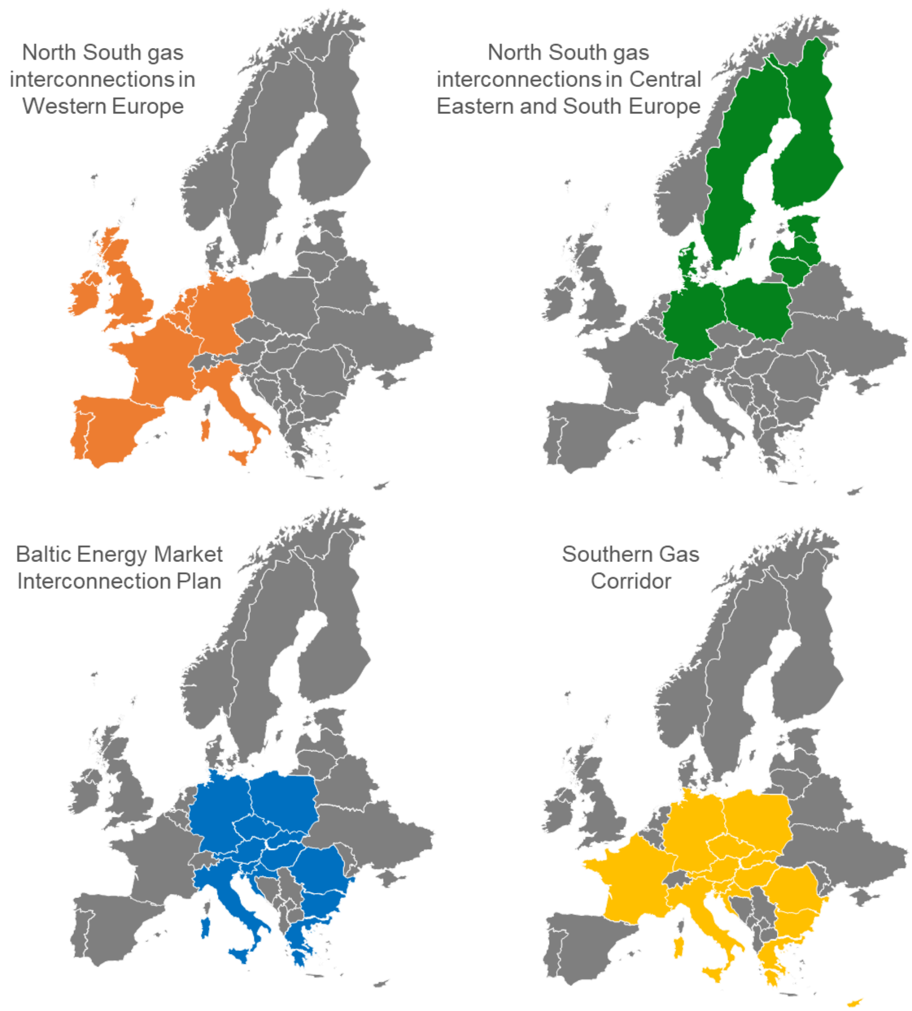

Figure 5-2 – Priority Gas Corridors.

In the case study, the model is used for the assessment of the optimal infrastructure investment in the North-South Gas Interconnections in Western Europe under a market price perspective. NSI West Gas aims to facilitate the transport of gas between Northern and Southern Europe, diversifying supply sources and increasing the availability of gas. The project involves the following countries: Belgium, France, Germany, Ireland, Italy, Luxemburg, Malta, The Netherlands, Portugal, Spain, and the United Kingdom.

5.1.2. Literature review

Models whose objective is to represent the operation and investment decisions of natural gas markets abound in the literature. Some large-scale operations and investment natural gas models focus on a deterministic cost minimization approach such as The Natural Gas Transmission and Distribution Module (**NGTDM**), which is the module that represents the natural gas market of the multi-sector model **National Energy Modeling System (NEMS)** (Gabriel, et al., 2001), (EIA, 2009), developed and used by the US Department of Energy. Another example is the family of models developed by EWI Cologne, **EUGAS** (Perner &

Seeliger, 2004), **MAGELAN** (Lochner & Bothe, 2009) and **TIGER** (Lochner, et al., 2010),(Lochner, 2011), (Dieckhöner, 2012).(Dieckhöner, et al., 2013) All of them have a detailed infrastructure description assuming perfect competitive players. The EUGAS model represents the natural gas market operation and investment decisions and the TIGER model is used to analyze potential investments in gas transportation capacities based on congestion rents and nodal prices. The **RAMONA** model (Hellemo, et al., 2012) formulates the investment problem as mixed-integer quadratic problem, assuming that investment decisions are semi-continuous and adding pressure flow relationships as well as the gas quality. Its stochastic version is presented in (Fodstad, et al., 2016). The **European Gas Market Model (EGMM)** (Kiss, et al., 2016) is a competitive short-run equilibrium model for the natural gas market in Europe developed by the Regional Centre for Energy Policy Research (**REKK**) used for the evaluation of natural gas infrastructure projects contrasting equilibrium outcomes with and without the investments.

However, due to the liberalization of gas markets, the investment and operation decisions have become a more complex problem and agents' interests are no longer driven by a mere cost minimization. Therefore, in order to represent the opportunities in a still imperfect gas market, a profit maximization approach is more suitable. The most commonly used approach for representing the effects of strategic behavior of market agents in the natural gas sector is game theory, which is the technique we used in this model.

Several equilibrium models representing the natural gas market have been developed. The most relevant ones are cited below, with special focus on the ones that endogenously represent both infrastructures capacity expansion and market operation. The **GASTALE** model, (Boots, et al., 2003), (Boots, et al., 2004), (Lise & Hobbs, 2008), **NATGAS** model (Zwart & Mulder, 2006) and **GASMOD** model (Holz, 2009) are game theory equilibrium models of the European natural gas market describing the behavior of gas producers, transmission system operators (TSO), storage system operators (SSO), traders and consumers, and simulating the investment decision-making for additional gas infrastructures i.e. pipelines, LNG (liquefied natural gas) capacity, as well as storage (GASMOD allows endogenous capacity expansions only in new pipeline capacity). The stochastic version of GASTALE (Bornaee, 2012) analyzes investments in the natural gas sector considering uncertainty. The **World Gas Model (WGM)** (Egging & Gabriel, 2006), (Egging et al., 2009), (Egging, 2010) and its stochastic version (Egging, 2013) and the **Global Gas Model (GGM)** (Holz & Von Hirschhausen, 2013) (Holz, et al., 2013), and its stochastic version S-GGM (Egging & Holz, 2016), are multi-period complementarity models for the global natural gas market with explicit consideration of market power. Market players include producers, traders, pipeline and storage operators, LNG liquefiers and regasifiers as well as marketers, and allow for endogenous investments in pipelines and storage capacities, as well as for expansion on regasification and liquefaction capacities. Other works include (Smeers, 2008), that provides an in-depth discussion of the existing models.

The principal advantage of these market equilibrium models (also known as open loop or one stage), modeling investment and operation decisions, is to represent the pipeline network and the access to other infrastructures as regasification terminals or storage under an imperfect competition framework, allowing to simulate the interaction between market power, capacity hoarding, infrastructure bottlenecks and their impact on optimal capacity expansion.

However, all of them simplify the dynamic nature of the operation and investment problem, as expansion and operation decisions are assumed to be taken simultaneously while, in reality, expansion and operation decisions are taken sequentially. The approach that allows to model this type of two-level structure of the investment problem, is referred to as Bilevel Programming Problems (BPPs) (also known as closed-loop or two-stage) and were introduced in the operations research literature in the early 1970s by Bracken and McGill in (Bracken & McGill, 1973), (BrackenJ & McGill. J.T., 1974a), (Bracken & McGill., 1974b). Among the existing bilevel approaches we distinguish between Mathematical Programs with Equilibrium Constraints (MPECs) and Equilibrium Problems with Equilibrium Constraints (EPECs) (Su, 2005). The literature related to bilevel models incorporating investment and operation decisions sequentially is still scarce in natural gas markets. Some examples of bilevel optimization problems in the gas sector are (De Wolf & Smeers, 1997), who developed a stochastic two-stage game for the European Gas Market with Norway as the leader; (Kalashnikov & Ríos-Mercado, 2006), who present a mixed integer bilevel linear programming model in order to analyze shippers' imbalances for reducing the penalties associated to those imbalances; and (Siddiqui & Gabriel, 2013), who propose a new methodology for solving MPECs and applied it to a gas market model. Additionally, in (Li et al., 2017) the total production costs of natural gas and electricity are minimized solving a bilevel problem where the upper level is formulated as an economic dispatch optimization model for the electricity system, while the lower level is an optimal allocation problem for natural gas system. However, this type of models, both MPEC and EPEC approaches, are widely used in other fields like engineering, economics and finance (Fortuny-Amat & McCarl, 1981), (Colson, et al., 2007). For their similarity with the gas sector, we present some examples used in the electricity sector that may be applicable to gas markets. In the electricity sector, MPECs have first been used to formulate electricity markets equilibrium for example by (Cardell, et al.,1997), (Hobbs, et al., 2000), and (Ramos, et al., 1999).

Within the expansion capacity framework, (Wogrin, et al., 2011) presents the uncoupling of investment and generation decisions of generation companies under uncertainty, while (Kazempour, et al., 2013a) (Kazempour, et al., 2013b) in the two-paper series, characterizes generation investment equilibria in a pool-based network-constrained electricity market, where the producers behave strategically. Other contributions take a more centralized approach to expansion planning like the transmission and wind power investment MPEC of (Baringo & Conejo, 2012), where investments are decided in the upper level by minimizing total costs, subject to a lower level that represents the market clearing.

Therefore, the contribution of this model is to cover the gap found in the literature regarding bilevel optimization models applied to the capacity expansion problem in natural gas markets. This contribution is hence three-fold:

1. We introduce the natural sequence of investment and operation decisions into a gas market model (note that the sequentiality has an impact on results).

2. By making this a multi-objective model (MOPEC) we allow for the capacity expansion decision maker to evaluate different expansion plans under different criteria, and to obtain a Pareto front of optimal plans. This is relevant, because when having several decision criteria in mind at the same time, a portfolio of optimal investment solutions might be more desirable to have than just one set of investment decisions.

3. To provide a tool for assisting the investment decision making process to determine European Commission (EC) support, analyzing the different investment options.

To our best knowledge, the existing capacity expansion models in the gas market arena do not account for points 1 and 2. In summary, we propose a multi-objective bilevel optimization model for the representation of the sequential nature of operation and investment decisions in the natural gas market. We define a multi-objective optimization problem (Coello Coello, 2006) in the upper level, considering multiple objective optimization functions for the capacity expansion problem resulting in a set of solutions which represents a good compromise among the objectives, usually known as Edgeworth-Pareto optimum or, simply, Pareto optimum (Edgeworth, 1881), (Pareto, 1896).

Thus, we propose a new multilevel expansion model for the natural gas sector which is formulated as an MPEC to assist investment decision makers in taking their long-term capacity investment decisions (i.e. increasing pipeline or regasification capacity). For further information regarding bilevel programming problems (BPP) and multi-objective programing the reader is referred to Appendix F and Appendix G respectively.

5.2. Model description

The objective of the model is to assist decision makers in the task of capacity expansion, representing the sequential nature of operation and investment decisions in the natural gas market, where investments are decided in the upper level subject to a lower level that represents the gas market operation.

First, the EU gas market consists of traders and marketers, infrastructure operation companies, governmental institutions and regulatory authorities. The market place is where natural gas is traded and supplied and where traders, marketers and consumers operate. Infrastructure operation companies are in charge of gas infrastructure and hold a natural monopoly position. Governmental institutions set market rules in which market players operate and regulatory bodies monitor that market players behave according to the rules settled by the legislation authorities. The model distinguishes among traders, marketers, gas transportation infrastructure operators (i.e. for natural gas and LNG) and final demand (households, electricity sector and industry). Traders act as gas suppliers to marketers, who are the ones supplying the final demand. Natural gas can be transported through the pipeline network defined between nodes or can be shipped, after being compressed in the liquefaction terminal into liquefied natural gas (LNG). Additionally, there is a System Operator (SO), who operates the pipeline network in the lower level and an LNG operator, who is in charge of liquefaction, shipping and regasification activities.

Second, for better representation of the sequential nature of operation and investment decisions and the strategic behavior of market agents in the natural gas sector, the model is formulated as a bilevel optimization problem (Wogrin,et al., 2013), where investment and operation decisions are taken sequentially. In the bilevel model, the network planner chooses capacities that maximize its preferences in the first stage while the second stage represents the Cournot-price-response natural gas market equilibrium. In the one-stage situation (or open-loop model) investment decisions taken by the network planner and the chosen quantities to maximize agents' individual profits are taken simultaneously.

Third, we assume the EC performs the tasks of a system network planner and acts as a decision maker and as leader investing in new pipeline and regasification capacity. The

EC has several criteria that need to be taken into account simultaneously when taking investment decisions. Some criteria that can be highlighted are, total investment costs, utility of demand, price differences between zones, and diversity of suppliers. Depending on the importance assigned to each of these criteria, different optimal investment plans can be obtained. In order to assist the decision maker to explore these different options, we propose an upper level multi-objective problem, considering the previous criteria. Assigning different importance to each criterion we generate non-dominated solutions in accordance with decision maker preferences. Therefore, by varying the weight assigned to the different criteria we can explore the solution space of optimal investment plans.

Fourth, the decisions of the EC (i.e. under the role of network planner) and the market participants, being different entities, are not necessarily going to be the same, and actually might have opposing objectives, such as maximizing social welfare vs maximizing profits of market players. This type of inertia is also captured by a bilevel problem.

Therefore, in order to represent that expansion and operation decisions are taken sequentially, the different interest of market participants and the multiple criteria that need to be achieved simultaneously, we propose a multi-objective bilevel optimization model (GASMOPEC) for representing the investment decision process in the European natural gas market.

The problem consists of the objectives of the network planner at the upper level and a lower level that represents the downstream European gas market. In the lower level, the deregulated natural gas market is represented as an equilibrium, of twosuccessive natural gas trade (i.e. traders representing the upstream and marketers the downstream), in which all agents decide simultaneously and the obtained solution is an equilibrium point so that at optimality no player can perform better by unilaterally altering their choice. The lower level considers investment decisions as known. The problem structure is shown in Figure 5-3.

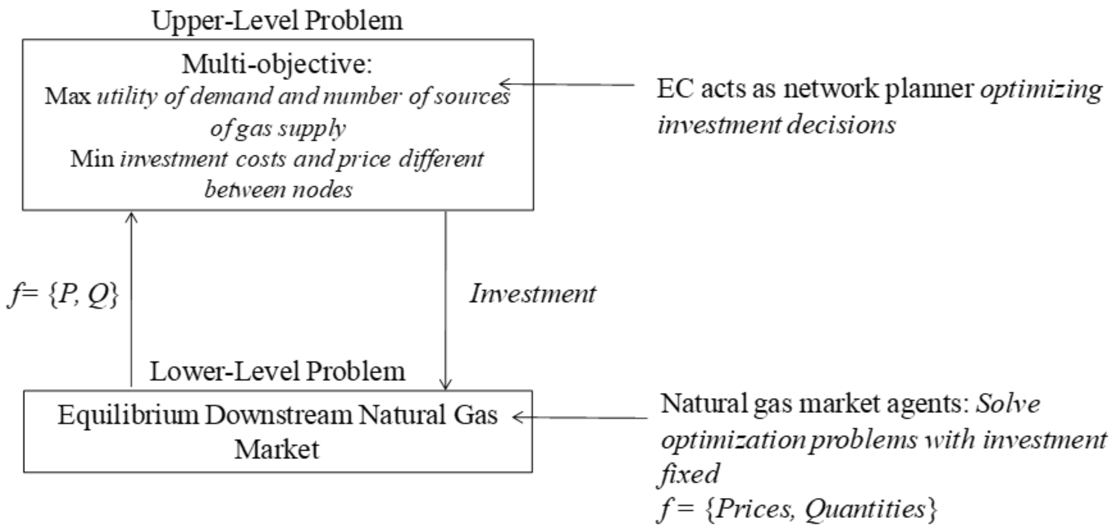

Figure 5-3 – GASMOPEC model structure.

5.3. Mathematical problem

5.3.1. Upper level: System operator investment

The capacity expansion problem is represented as a multi-objective considering four different criteria: investment cost minimization, minimum price differences between zones, utility of the demand maximization, and maximum number of suppliers. The obtained Pareto frontier supplies a set of solutions, allowing the decision maker to select the best choice according to their preferences. The four objective function criteria of the upper level problem are described below.

The first criteria consists of the minimization of the , investment costs for new pipeline capacity $cost_{invpipe}$ and regasification capacity $cost_{invreg}$ .. Additionally, we modeled a maximum capacity expansion constraint, for pipelines $\overline{CAP}_{pzz_1}^{invpipe}$ and for regasification terminals $\overline{CAP}_{pz}^{invreg}$ respectively,

$$cost_{invpipe} = \sum_{p,z,z_1} \left(COST_{pzz_1}^{invpipe} \cdot i_{pzz_1}^{pipe} \right) \tag{5.1}$$

$$i_{pzz_1}^{pipe} \leq \overline{CAP}_{pzz_1}^{invpipe} \quad \forall p, z, z_1 \tag{5.2}$$

$$cost_{invreg} = \sum_{p,z} \left(COST_{pz}^{invreg} \cdot i_{pz}^{reg} \right) \tag{5.3}$$

$$i_{pz}^{reg} \leq \overline{CAP}_{pz}^{invreg} \quad \forall p, z \tag{5.4}$$

The first objective function (f_1) is therefore:

$$Minimize\ (f_1) = Min\left\{cost_{invpipe} + cost_{invreg}\right\} \tag{5.5}$$

In the second criteria, we represent the market integration by minimizing the price difference Δp_{zz_1p} between consumption nodes in the objective function, defining Δp_{zz_1p} as a positive variable, and being $p_{z_1p}$the price in the different consumption nodes z, z_1.

$$\Delta p_{zz_1p} \geq p_{zp} - p_{z_1p} \quad \forall\ z, z_1, p/\{z, z_1 \epsilon K_z^{CN}\} \tag{5.6}$$

$$\Delta p_{zz_1p} \geq p_{z_1p} - p_{zp} \quad \forall\ z, z_1, p/\{z, z_1 \epsilon K_z^{CN}\} \tag{5.7}$$

The second objective function (f_2) is:

$$Minimize(f_2) = Min\left\{\sum_{zz_1p/\{z,z_1\epsilon K_z^{CN}\}} \left(\Delta p_{zz_1p}\right)\right\} \tag{5.8}$$

In the third cirteria, the utility of the demand is maximized, in order to fulfill the competition criteria, achieving lower gas supply costs and marginal prices. The total demand in consumption node z_1 is Q_{z_1p}, which includes power generation, industry and households. We assume the inverse demand function p_{z_1p} to be linear of the following type (5.9).

$$p_{z_1p} = P_{z_1p}^0 - \alpha_{z_1p} \cdot Q_{z_1p} = P_{z_1p}^0 - \alpha_{z_1p} \cdot \sum_{m,z}\left(q_{mzz_1p}^{mak}\right) \quad \forall\ z_1, p \tag{5.9}$$

Where $P_{z_1p}^0$ is the intercept of the demand at node z_1 in period p and α_{z_1p} the slope of the demand curve. Therefore, the third objective function (f_3) is maximizing the utility of the demand $U(D)$.

$$\begin{aligned} Maximize(\ f_3) = Max\ \{U(D)\} &= Max\left\{\int_0^{Q_{z_1p}} p_{z_1p}\left(q_{z_1p}\right) \cdot dq_{z_1p}\right\} \\ &= Max\left\{P_{z_1p}^0 \cdot Q_{z_1p} - \frac{\alpha_{z_1p}}{2} \cdot {Q_{z_1p}}^2\right\} \end{aligned} \tag{5.10}$$

Fourth and last criteria, security of supply is considered by maximizing the number of natural gas supply sources that a country has access to, improving both security of supply and competition. We maximize the number of suppliers that supplies a zone z_1 using the binary variable $\delta_{zz_1p}^{tNG}$ for natural gas supplies and $\delta_{zz_1p}^{tLNG}$ for liquefied natural gas supplies, as follows. For natural gas supplies, conditions described in (5.11) are modeled by constraints (5.12) and (5.13).

$$\delta_{zz_1p}^{tNG} = 1 \leftrightarrow \sum_{t \in z} q_{tzz_1p}^{tNG} \geq b\,;\; \delta_{zz_1p}^{tNG} = 0 \leftrightarrow \sum_{t \in z} q_{tzz_1p}^{tNG} \leq b \tag{5.11}$$

$$\sum_{t \in z} q_{tzz_1p}^{tNG} - b + \varepsilon \leq \delta_{zz_1p}^{tNG} \cdot \left(\left(\bar{Q}_{zz_1p}^{pipe} + \overline{CAP}_{pzz_1}^{invpipe} \right) \right) \; \forall\, z, z_1, p \tag{5.12}$$

$$\sum_{t \in z} q_{tzz_1p}^{tNG} - b \geq \cdot \left(1 - \delta_{zz_1p}^{tNG} \right) \cdot (-b) \; \forall\, z, z_1, p \tag{5.13}$$

Similarly, conditions described in (5.14) for liquefied natural gas supplies are modeled by constraints (5.15) and (5.16).

$$\delta_{zz_1p}^{tLNG} = 1 \leftrightarrow \sum_{t \in z} q_{tzz_1p}^{tLNG} \geq b\,;\; \delta_{zz_1p}^{tLNG} = 0 \leftrightarrow \sum_{t \in z} q_{tzz_1p}^{tLNG} \leq b \tag{5.14}$$

$$\sum_{t \in z} q_{tzz_1p}^{tLNG} - b + \varepsilon \leq \delta_{zz_1p}^{tNG} \cdot \left(\left(\bar{Q}_{z_1p}^{reg} + \overline{CAP}_{z_1P}^{invreg} \right) \right) \; \forall\, z, z_1, p \tag{5.15}$$

$$\sum_{t \in z} q_{tzz_1p}^{tLNG} - b \geq \cdot \left(1 - \delta_{zz_1p}^{tLNG} \right) \cdot (-b) \; \forall\, z, z_1, p \tag{5.16}$$

It is assumed that there is only one trader per supplying (producing) country.

Hence, the fourth objective function (f_4) is:

$$Maximize\ (f_4) = Max \left\{ \sum_{zz_1p/\{z \epsilon K_z^T\} \cap \{z \neq z_1\} \cap \{z_1 \epsilon K_{z_1}^M\}} \left(\delta_{zz_1p}^{tNG} + \delta_{zz_1p}^{tLNG} \right) \right\} \tag{5.17}$$

5.3.2. Lower level: Downstream natural gas market

The lower level represents the downstream natural gas market, modeling traders who supply gas to marketers and marketers who supply final demand. Additionally, we model a System Operator and an LNG operator, responsible for transporting natural gas by pipe or for LNG shipment respectively. Equilibrium prices and quantities in the lower level are determined considering the investment decisions made in the upper level. A schematic picture of the lower level is shown in Figure 5-4.

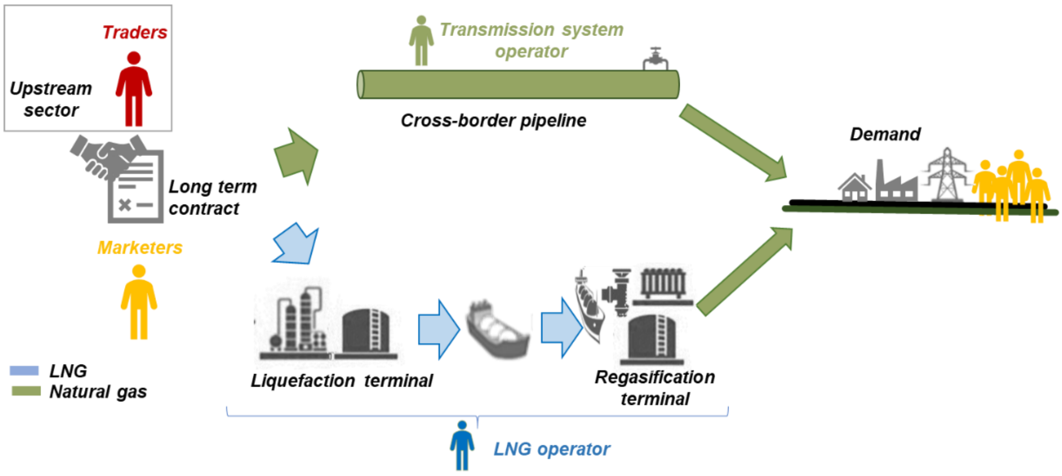

Figure 5-4 – Schematics of the lower level problem

Traders act as an interface between the upstream and the downstream gas market. Traders maximize profits of selling gas (i.e. natural gas $q_{tzz_1p}^{tNG}$ and LNG $q_{tzz_1p}^{tLNG}$) to marketers at a price bp_{z_1p} minus the unitary cost of gas C_{tp} and the transport cost for delivering that gas at marketer node by pipe $cost_{zz_1}^{pipe}$ or ship $cost_{zz_1}^{ship}$subject to a volume constraint. We assumed traders charge a fixed cost for their gas. From now on, the dual variables of each constraint are displayed in parenthesis after the colon.

$$\begin{aligned} Max_{q_{tzz_1p}^{tNG},q_{tzz_1p}^{tLNG},q_{tzz_1p}^{tpipe},q_{tzz_1p}^{tship}} \quad & \Pi_{tzz_1p}^{trader} \\ &= bp_{z_1p} \cdot \left(q_{tzz_1p}^{tNG} + q_{tzz_1p}^{tLNG}\right) - C_{tp} \cdot \left(q_{tzz_1p}^{tNG} + q_{tzz_1p}^{tLNG}\right) \\ &- \sum_{(z,z_1)\epsilon K_{tzz_1p}^{trader}} \left(cost_{zz_1}^{pipe} \cdot q_{tzz_1p}^{tpipe}\right) \\ &- \sum_{(z,z_1)\epsilon K_{tzz_1p}^{trader}} \left(cost_{zz_1}^{ship} \cdot q_{tzz_1p}^{tship}\right) \forall\, t,z,z_1,p \end{aligned} \tag{5.18}$$

s.t.

$$q_{tzz_1p}^{tNG}, q_{tzz_1p}^{tLNG}, q_{tzz_1p}^{tpipe}, q_{tzz_1p}^{tship} \geq 0 : \left(\mu_{tzz_1p}^{tNG}, \mu_{tzz_1p}^{tLNG}, \mu_{tzz_1p}^{tpipe}, \mu_{tzz_1p}^{tship}\right) \forall\, t,z,z_1,p \tag{5.19}$$

The natural gas flow conservation constraint through pipelines for each node z and trader t ensures that the natural gas sold by the traders ($q_{tzz_1p}^{tNG}$) equals natural gas physical flows ($q_{tzz_1p}^{tpipe}$) in all periods p.

$$\left[\sum_{z_1\neq z} q_{tzz_1p}^{tNG} - \sum_{z_1\neq z} q_{tzz_1p}^{tpipe}\right] + \left[\sum_{z_1\neq z} q_{tz_1zp}^{tpipe} - \sum_{z_1\neq z} q_{tz_1zp}^{tNG}\right] = 0 \\ : \left(\phi_{tzp}^{tpipe}\right) \forall\, t,z,p \tag{5.20}$$

The same flow conservation constraint applies to the shipped LNG for each node and trader, ensuring that the natural gas sold by the traders ($q_{tzz_1p}^{tLNG}$) equals natural gas physical flows ($q_{tzz_1p}^{tship}$) .

$$\left[\sum_{z_1 \neq z} q_{tzz_1p}^{tLNG} - \sum_{z_1 \neq z} q_{tzz_1p}^{tship}\right] + \left[\sum_{z_1 \neq z} q_{tz_1zp}^{tship} - \sum_{z_1 \neq z} q_{tz_1zp}^{tLNG}\right] = 0 \quad : \left(\phi_{tzp}^{tship}\right) \; \forall \, t, z, p \tag{5.21}$$

The total volume of gas a trader can sell is constrained by $\bar{Q}_{tp}^{tra}$ that represents the maximum gas available for sale per trader.

$$\sum_{t,z_1} q_{tzz_1p}^{tNG} + \sum_{t,z_1} q_{tzz_1p}^{tLNG} \leq \bar{Q}_{tp}^{tra} \; : \; \left(\lambda_{zp}^{tra}\right) \; \forall \, z, p \tag{5.22}$$

Finally, the market clearing condition between traders and marketers is (5.23), where $q_{mzz_1p}^{mak}$ is marketers' flows of gas per zone and period. The dual variable of the market clearing equation is the agreed price between traders and marketers.

$$\sum_{t,z} q_{tzz_1p}^{tNG} + \sum_{t,z} q_{tzz_1p}^{tLNG} = \sum_{m,z} q_{mzz_1p}^{mak} \; : \; \left(bp_{zp}\right) \; \forall \, z_1, p \tag{5.23}$$

Marketers maximize profits buying gas to traders at bp_{zp}, while supplying their gas demand at price p_{z_1p}. The cost paid by the marketer for transporting gas by pipe from node z to z_1 is $cost_{zz_1}^{pipe}$.

$$\begin{aligned} Max_{q_{mzz_1p}^{mak}, q_{mzz_1p}^{mpipe}} \quad & \Pi_{mzz_1p}^{marketer} \\ & = p_{z_1p} \cdot \left(q_{mzz_1p}^{mak}\right) - bp_{zp} \cdot \left(q_{mzz_1p}^{mak}\right) \\ & - \sum_{(z,z_1) \epsilon K_{mzz_1}^{marketer}} \left(cost_{zz_1}^{pipe} \cdot q_{mzz_1p}^{mpipe}\right) \forall \, m, z, z_1, p \end{aligned} \tag{5.24}$$

s.t.

$$q_{mzz_1p}^{mak}, q_{mzz_1p}^{mpipe} \geq 0 \; : \; \left(\mu_{mzz_1p}^{mak}, \mu_{mzz_1p}^{mpipe}\right) \; \forall \, m, z, z_1, p \tag{5.25}$$

Finally, the natural gas flow conservation constraint (5.26) through pipelines for each node z and marketer ensures that the natural gas sold by the marketers $q_{mzz_1p}^{mak}$ equals natural gas physical flows $q_{mzz_1p}^{mpipe}$ in all periods.

$$\left[\sum_{z_1 \neq z} q_{mzz_1p}^{mak} - \sum_{z_1 \neq z} q_{mzz_1p}^{mpipe}\right] + \left[\sum_{z_1 \neq z} q_{mz_1zp}^{mpipe} - \sum_{z_1 \neq z} q_{mz_1zp}^{mak}\right] = 0 \quad : \left(\phi_{mzp}^{mak}\right) \ \forall\, m, z, p \tag{5.26}$$

We differentiate between the **System Operator (SO)** who is in charge of the pipelines network operation and the **LNG operator** who is responsible of the LNG liquefaction, shipment and regasification. The available capacity is allocated according to the marginal willingness to pay for the transport by each player (i.e. traders and marketers). Third Party Access (TPA) to the gas network is ensured for all traders and marketers and point-to-point pricing of transport is applied.

The maximization problem of the **System Operator** is stated in (5.27). We assume the transport costs to be distance-related $TC_{zz_1}^{pipe}$ and the price charge by the SO for the use of the network ($cost_{zz_1}^{pipe}$) is the dual variable of the market clearing condition (5.30) between SO and pipeline users (i.e. traders and marketers), which includes the transport costs $TC_{zz_1}^{pipe}$ plus a congestion fee.

$$Max_{q_{zz_1p}^{totalpipe}} \quad \Pi_{zz_1p}^{pipe} = cost_{zz_1}^{pipe} \cdot \left(q_{zz_1p}^{totalpipe}\right) - TC_{zz_1}^{pipe} \cdot \left(q_{zz_1p}^{totalpipe}\right) \ \forall\, z, z_1, p \tag{5.27}$$

s.t.

$$q_{zz_1p}^{totalpipe} \geq 0 : \left(\mu_{zz_1p}^{pipe}\right) \ \forall\, z, z_1, p \tag{5.28}$$

The pipeline technical capacity is represented by $\bar{Q}_{zz_1p}^{pipe}$, and $i_{p_1zz_1}^{pipe}$ is the investment in new pipeline capacity.

$$q_{zz_1p}^{totalpipe} \leq \bar{Q}_{zz_1p}^{pipe} + \sum_{p_1/p_1<p} i_{p_1zz_1}^{pipe} : \left(\lambda_{zz_1p}^{pipe}\right) \ \forall\, z, z_1, p \tag{5.29}$$

$$q_{zz_1p}^{totalpipe} = \sum_{m/(z,z_1)\epsilon K_{mzz_1}^{marketer}} \left(q_{mzz_1p}^{mpipe}\right) + \sum_{t/(z,z_1)\epsilon K_{tzz_1}^{trader}} \left(q_{tzz_1zp}^{tpipe}\right) \quad : \left(cost_{zz_1}^{pipe}\right) \ \forall\, z, z_1, p \tag{5.30}$$

The maximization problem of the **LNG operator** is stated in (5.31) We assume that the operation cost $TC_{zz_1}^{ship}$ includes liquefaction, transport and regasification costs. The LNG operator receives for the services $cost_{zz_1}^{ship}$, which includes the operation cost plus the congestion fee and is the dual variable of the market clearing equation (5.35).

$$Max_{q_{zz_1p}^{totalship}} \quad \Pi_{zz_1p}^{ship} = cost_{zz_1}^{ship} \cdot \left(q_{zz_1p}^{totalship}\right) - TC_{zz_1}^{ship} \cdot \left(q_{zz_1p}^{totalship}\right) \forall\, z, z_1, p \tag{5.31}$$

s.t.

$$q_{zz_1p}^{totalship} \geq 0 : \left(\mu_{zz_1p}^{ship}\right) \ \forall\, z, z_1, p \tag{5.32}$$

Upper bound in liquefaction capacity constraint:

$$\sum_{z_1} q_{zz_1p}^{totalship} \leq \bar{Q}_{zp}^{liq} : \left(\lambda_{zp}^{liq}\right) \ \forall\, z, p \tag{5.33}$$

Upper bound in regasification capacity constraint:

$$\sum_{z} q_{zz_1p}^{totalship} \leq \bar{Q}_{z_1p}^{reg} + \sum_{p_1/p_1<p} i_{p_1zz_1}^{reg} : \left(\lambda_{z_1p}^{reg}\right) \ \forall\, z_1, p \tag{5.34}$$

Market clearing condition between traders with the LNG route operator:

$$q_{zz_1p}^{totalship} = \sum_{t/(z,z_1)\epsilon K_{tzz_1}^{trader}} \left(q_{tzz_1zp}^{tship}\right) : \left(cost_{zz_1}^{ship}\right) \ \forall\, z, z_1, p \tag{5.35}$$

The market clearing condition between marketers and the demand is stated in (5.9).

The demand function parameters are obtained using a reference point $\left(Q_{z_{1p}}^{ref}, p_{z_1p}^{ref}\right)$ for supplied gas and price at node z_1 and the curve elasticity, denoted as ε_{z_1p}.

$$\alpha_{z_1p} = \frac{p_{z_1p}^{ref}}{Q_{z_1p}^{ref}} \cdot \frac{1}{\varepsilon_{z_1p}} \tag{5.36}$$

$$P_{z_1p}^{0} = p_{z_1p}^{ref} - \frac{p_{z_1p}^{ref}}{Q_{z_1p}^{ref}} \cdot \frac{1}{\varepsilon_{z_1p}} \cdot Q_{z_{1p}}^{ref} \tag{5.37}$$

5.4. Methodological approach

In this section we present the techniques used for solving the multi-objective bilevel problem. The proposed MPEC problem considers the multiple objectives of the network planner in the upper level and the natural gas market operation in the lower level. The lower-level problem is stated by its Karush-Kuhn-Tucker (KKT) optimality conditions and the problem is reformulated as a mixed-integer quadratic problem (MIQCP) by applying the “Big-M” method- i.e. replacing the equilibrium constraints by integer restrictions in the form of disjunctive constraints.

Additionally, as we are solving a multi-objective problem, the resulting optimal points are the non-dominated solution set of points, which depends on the preferences of the decision maker. It is also important to emphasize that the objectives of the multi-objective optimization problem may be in conflict with each other bringing a set of solutions (trade-off solutions). The procedure used to compute these set of solutions is using scalarizing techniques.

5.4.1. The Big-M relaxation method

Bilevel models are very hard to solve and usually do not allow to scale up to large-scale problem. For that reason, the arising MPEC problem is reformulated as a mixed-integer quadratic problem (MIQCP) by replacing the equilibrium constraints in the lower level by integer restrictions in the form of disjunctive constraints (Fortuny-Amat & McCarl, 1981), (Gabriel, et al., 2010), (Gabriel & Leuthold, 2010). The MIQCP formulation allows solving the problem reliably and the convexity of the problem ensures the globality of the solution. For converting the complementarity conditions in the constraints to MILP formulation, we apply the “Big-M” method for each complementary slackness condition. In Appendix H a general definition of the Big-M relaxation method is provided.

Our MPEC problem considers the multiple objectives of the network planner in the upper level and the natural gas market operation in the lower level. The lower-level problem is stated by its KKT optimality condition and the non-linear complementarity constraints are further handled using the Fortuny-Amat (Fortuny-Amat & McCarl, 1981), mixed-integer reformulation. The procedure is presented in the example below, taken from (Pineda & Morales, 2018).

First, we represent a general bilevel problem structure as follows:

$$\min_{\mathrm{x}\in\mathbb{R}^{\mathrm{n}}} \mathrm{a}^{\mathrm{T}}\mathrm{x}+\mathrm{b}^{\mathrm{T}}\mathrm{y} \tag{5.38}$$

$$\mathrm{s.t.} \qquad \mathrm{c_i}^{\mathrm{T}}\mathrm{x}+\mathrm{d_i}^{\mathrm{T}}\mathrm{y}\leq \mathrm{e_i} \qquad \forall \mathrm{i} \tag{5.39}$$

$$\min_{\mathrm{y}\in\mathbb{R}^{\mathrm{m}}} \mathrm{p}^{\mathrm{T}}\mathrm{x}+\mathrm{q}^{\mathrm{T}}\mathrm{y} \tag{5.40}$$

$$s.t. \qquad {r_j}^{T}x+{s_j}^{T}y\leq t_j \quad :(\lambda_j) \quad \forall j \tag{5.41}$$

Where $a, b, c_i, d_i, p, q,\ r_j\ and\ s_j$ are vectors of appropriate dimensions and $e_i\ and\ t_j$ scalars. And λ_j represents the dual variable of the lower level constraint.

Second, the lower level is replaced by its KKT optimality conditions:

$$\min_{x\in\mathbb{R}^n, y\in\mathbb{R}^m} a^T x + b^T y \tag{5.42}$$

$$\text{s.t.} \qquad c_i{}^T x + d_i{}^T y \leq e_i \qquad \forall i \tag{5.43}$$

$$\text{s.t.} \qquad r_j{}^T x + s_j{}^T y \leq t_j \quad (\lambda_j) \quad \forall j \tag{5.44}$$

$$q + \sum_j \lambda_j s_j = 0 \tag{5.45}$$

$$\lambda_j \geq 0, \qquad \forall j \tag{5.46}$$

$$\lambda_j\left(r_j{}^T x + s_j{}^T y - t_j\right) = 0, \qquad \forall j \tag{5.47}$$

And finally, the problem is reformulated as a MILP, using the Big-M method, for the non-linear complementarity constraints.

$$\min_{x\in\mathbb{R}^n, y\in\mathbb{R}^m} a^T x + b^T y \tag{5.48}$$

$$s.t. \qquad \text{(5.43) - (5.56)}$$

$$\lambda_j \leq \mu_j M_j^D, \qquad \forall j \tag{5.49}$$

$$-r_j{}^T x - s_j{}^T y + t_j \leq (1 - \mu_j) M_j^P, \qquad \forall j \tag{5.50}$$

$$\mu_j \in \{0,1\}, \qquad \forall j \tag{5.51}$$

Being M_j^P and M_j^D large enough constant. These large enough constants are upper and lower bounds for the primal and dual variables of the lower level problem respectively. However, finding the appropriate values for these constants is normally a challenging task, and this methodology will only be competitive when good bounds can be provided for the variables. For assigning these values, we have followed a commonly used the trial and error procedure described in Pineda & Morales, 2018).

5.4.2. Solving multi-objective problem. Scalarizing techniques

For solving the multi-objective problem stated in the upper level and computing the non-dominated solutions, we use scalarizing techniques, which consist of transforming the original multi-objective problem into a single-objective problem which is solved repeatedly with different parameters. The parameters can be interpreted as a measure of importance (or weights) to the decision maker and are used as operational means to generate non-dominated solutions to be proposed to the decision maker, in accordance with their (evolving) preferences. By varying these parameters, we can explore the solution space of optimal investment plans.

The two scalarizing techniques used for solving the multi-objective problem in the upper level are the Weighted-Sum of the Objective and the e-constraint technique. The Weighted-Sum scalarizing technique can be applied to mixed-integer problems, but it does not allow to obtain unsupported non-dominated solutions. Therefore, this scalarizing technique is used at a first stage, for obtaining the feasible upper and lower levels for each objective function in the objective function space, for the e-constraint scalarizing technique. This technique enables us to obtain all non-dominated solutions, (i.e., solutions lying on edges or faces and vertices) of the feasible region of the original multi-objective problem even if the lower level problem has been reformulated as a MIQCP problem. Further information regarding both scalarizing techniques is given in Appendix I.

Therefore, for defining the reservation levels selected for each criterion we model first the multi-objective assigning different weights to each objective function and solve the problem repeatedly varying these weights (i.e. using the weighted method). As the utility of the demand is the criterion with less variation range, it is chosen as the criteria to be optimized in the e-constraint technique. Thus, the utility of the demand is maximized considering the other three objectives (i.e. minimizing investment cost and price difference between zones and maximizing the number of natural gas supply sources) as constraints by specifying the inferior reservation levels.

Therefore, for defining the reservation levels selected for each criterion we model first the multi-objective assigning different weights to each objective function and solve the problem repeatedly varying these weights (i.e. using the weighted method). As the utility of the demand is the criterion with less variation range, it is chosen as the criteria to be optimized in the e-constraint technique. Thus, the utility of the demand is maximized considering the other three objectives (i.e. minimizing investment cost and price difference between zones and maximizing the number of natural gas supply sources) as constraints by specifying the inferior reservation levels.

The GASMOPEC model objective function is defined by:

$$Max\ f_3(x) - \rho_1 \cdot f_1(x) - \rho_2 \cdot f_2(x) + \rho_4 \cdot f_4(x) \tag{5.52}$$

s.t. $x \in X$

$$f_1(x) \leq e_1; \cdot f_2(x) \leq e_2; \cdot f_4(x) \geq e_4 \tag{5.53}$$

The problem is solved repeatedly assigning different parameters for each objective function i and case j, (e_{ij}) to generate non-dominated solutions for the optimal investment plan and can be interpreted as a measure of importance given by the decision maker (network expansion planner). Additionally, as explained above, in order to avoid obtaining weakly efficient solutions the $(i-1)$ objective functions that are set as constraints are included in the objective function multiplied by ρ_i, a small positive scalar.

The MPEC formulation of the problem is described in Appendix E.

5.5. Case study

The proposed model is used for the assessment of the optimal infrastructure investment in the North-South Gas Interconnections in Western Europe (**NSI West Gas priority corridor**) under a market price perspective.

5.5.1. Description

We consider the following nodes of the NSI West Gas corridor: Benelux (The Netherlands, Belgium and Luxemburg) (BE), France (FR), Germany (GE), Italy (IT), Iberia (Spain + Portugal) (IB) and the British Isles (United Kingdom + Ireland) (BI). The most representative exporters (i.e. traders) to the EU are included: Russia (RU), Algeria (DZ), the European producers (Norway (NO) and the Netherlands (NE)) and GNL of Middle East (represented by Qatar (QT)).

The case study data ranges from years 2015 to 2035, in ten-year steps. We use production capacity and consumption demand data from (BP, 2017) for the base year. Production and consumption projections for the ten years forward are based on (IEA, 2015) New Policies Scenario (NPS). Prices are taken from (EC, 2015) and we apply the growth rates published by (OECD 2017). Data on transport capacity and regasification terminals are based on the European Network of Transmission System Operators (ENTSOG, 2017) and (IGU, 2017). We aggregate bilateral transport capacities for pairs of zones. Production costs are taken from (Holz, 2008) and own estimations. As we focus on the long-term, we do not distinguish among seasons and hence the possible arbitrage game of the underground storage is not represented. Transportation costs within Europe are represented as costs per unit of gas and km of average distance between countries as based on (Oostvoorn, 2003) and (Holz, 2008). Investment costs have been taken from (Holz, 2009), assuming them to be a multiple of the short-term transportation costs, both depending on the pipeline length.

As mentioned above, the e-constraint scalarizing technique is used to transform the original multi-objective problem into a single-objective problem. The utility of demand is maximized as it is the criterion with less variation range, while the rest of the objectives (i.e. price differences between zones, investment costs and number of gas suppliers) are considered as constraints by specifying the upper and the lower levels that the decision maker is willing to accept. For computing the non-dominated solutions, the problem is solved repeatedly varying the parameters assigning normalized weights (i.e. [0-1]) to the upper and lower reservation levels. The chosen reservation levels are defined as follows:

- We assume investment can vary from zero (i.e. no investment) to the maximum investment capacity defined for each type of infrastructure (i.e. pipeline or regasification terminal).
- For assigning price difference between zones reservation levels, the problem is run considering this criterion as the unique objective, without allowing any investment. The obtained optimal point will be the maximum price difference allowed between zones. The minimum price difference allowed is calculated also by considering this criterion as the unique objective but allowing maximum for maximum investment capacity.
- The range for the number of suppliers varies from the minimum number of gas suppliers (i.e. NG and LNG), which is determined by running the problem considering this criterion as the unique objective, without allowing any investment, and the maximum which is calculated by multiplying the number of suppliers by the number of zones assuming all suppliers can supply all zones.

The equilibrium problem has been recast as a mixed-integer quadratic problem, implemented in the GAMS language and solved by using Gurobi version 7.5.2.

5.5.2. Results

We run 50 cases $(j = 50)$, varying the upper and lower objective functions (i) reservation levels $\left(e_{ij}\right)$ of the constraints (5.55), (5.56) and (5.57) for computing the non-dominated solutions. The allowed investment (i.e. in pipeline and regasification capacity) is increased from case 1 to 50. For each allowed investment capacity, different reservation levels for the number of gas suppliers and price differences between zones are run. While we decrease the number of gas suppliers, we increase the permitted price difference.

Varying the reservation levels assigned to the investment, the price difference between nodes and the number of gas suppliers (LNG and NG), we obtain the optimal solutions which are the closest feasible compromise solutions, considering the boundary conditions.

It is worth noting that as the problem is reformulated as a mixed-integer problem, the resulting solution space is discrete. Table 5-1 in Appendix D, summarizes the obtained results for total investment in pipeline and regasification capacity, the utility of the demand, the price difference between nodes, and the number of LNG suppliers.

When interpreting the presented results, the following important points need to be borne in mind: First, it should be noted that Western Europe is well interconnected and the model does not invest endogenously in any pipeline or regasification capacity considering all the criteria with the same importance. Moreover, no investment is compensated in terms of utility of the demand. This means that the investment cost exceeds the positive impact in the utility of the demand. Second, some zones have been clustered (i.e. Spain and Portugal or Ireland and UK) and no investment within countries is considered, as bilevel models are very hard to solve and do not allow to scale up to large-scale problems. Third, there are other reasons for investment such as system security and its robustness, which are not considered in the model. Fourth, the obtained optimal solutions by assigning different importance to the different criteria, conform the Pareto front of non-dominated solutions.

In the first ten cases no investment (neither in pipelines nor in regasification capacity) is allowed. From case 1 to 10 the maximum permitted price difference is increased while the requested minimum number of suppliers is diminished. The utility of the demand increases as the average price difference between nodes increases and the number of suppliers decreases. Thus, reducing price difference between nodes, in this case is at the expenses of reducing the utility of the demand (see Figure 5-5). The number of NG suppliers is constant among these cases. Forcing a maximum of LNG suppliers implies that the marketers are obliged to buy gas to other more expensive sources of gas to fulfill this constraint, and as a result we obtained that some marketers import marginal volumes of Norwegian LNG gas, increasing their marginal supply cost.

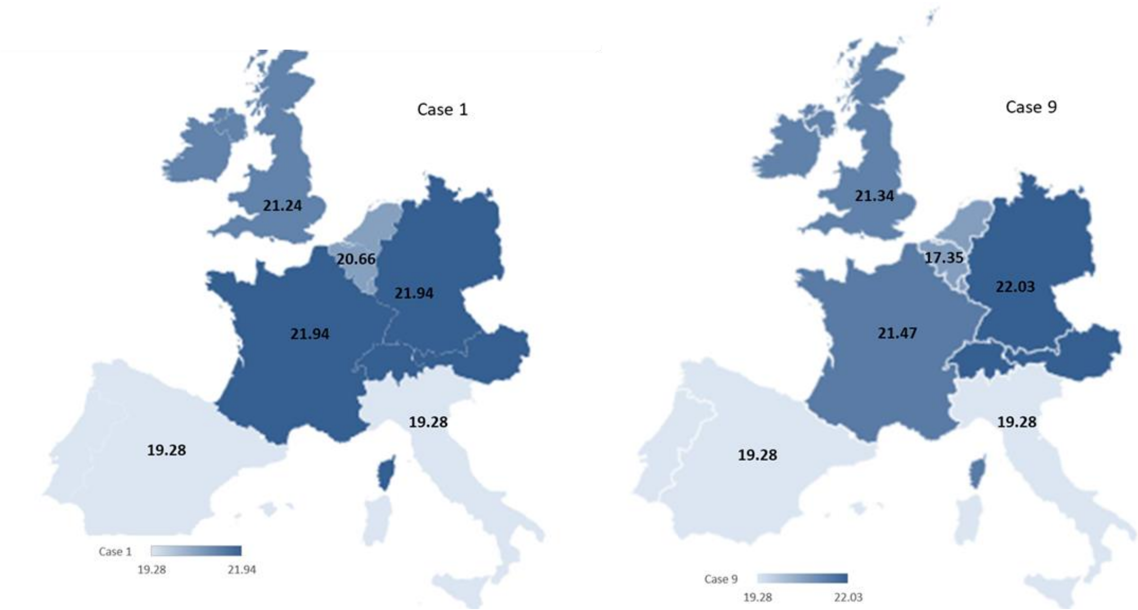

Figure 5-5 –Cases 1 and 9. No investment is allowed while the maximum permitted price difference is increased while the requested minimum number of suppliers is diminished from cases 1 to 10

New investments can affect the utility of the demand by driving changes in the gas supply, by connecting to new sources of gas, by bringing more gas reducing bottlenecks and/or favoring price convergence. When we allow for some investment (cases from 11 to 21) (i.e. defining a maximum in the investment capacity) the model invests in regasification capacity in the British Isles (BI) and France (FR) up to the maximum allowed (6 Bcm/y). Both of them already have regasification capacity (i.e. BI: 48.1 Bcm/y and FR: 21.65 Bcm/y (34.25 Bcm/y in 2025 exogenous expansion)), so that both countries have already access to LNG markets. However, the model doesn't invest in pipeline capacity. The investment in regasification capacity has a positive effect by reducing gas prices in the consumption nodes, as shown in Figure 5-6 (i.e. cases 12 to 20) and therefore increasing the utility of the demand.

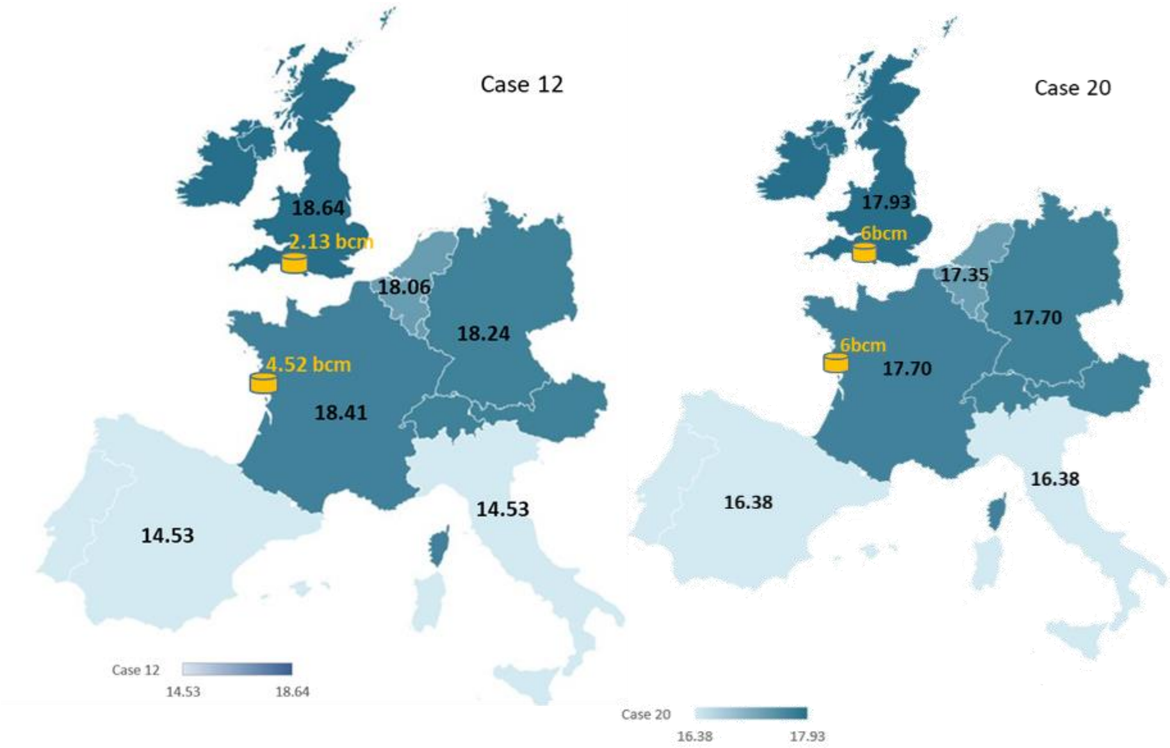

Figure 5-6 –Cases 12 and 20. Prices and investment in pipelines and regasification capacity

As more investment is allowed (cases from 22 to 26), the model invests in new pipeline capacity between Algeria – Iberia (4.95 Bcm/y), Algeria – Italy (7.48 Bcm/y), Italy – Germany (0.22 Bcm/y), Italy – France (8.70 Bcm/y), Norway – Belgium (2.16 Bcm/y)), Russia – Germany (18.64 Bcm/y) and Russia – Italy (7.98 Bcm/y) in addition to the investment in regasification capacity in France and the United Kingdom. These cases present similar weights (i.e. given preference or importance) for the different criteria. The investment in new pipeline capacity reduces price difference between zones but its impact in terms of utility of the demand is almost negligible. Converging prices is a sign of well integrated markets and cooperation between Member States. Prices in Italy and Iberia increased in favor of a price reduction in France and Germany as shown in Figure 5-7. The maximum price differences appear between the Italian and the French market and between the Italian and the British market. In cases from 30 to 32 and from 35 to 36, even if permitted investment is increased, the model invests less globally, reducing the investment among EU countries (i.e. Italy – Germany (0.17 Bcm/y), Norway-Belgium (1.48 Bcm/y)). The price difference is diminished and also the number of LNG suppliers. However, Belgium gas market price increases as it imports less Norwegian gas.

In this case study, when marketers are obliged to diversify their gas supply portfolio, their total costs increase and it is reflected in the market price (i.e. final market prices rise). Additionally, it does not help to price convergence between nodes or the creation of the internal market, as these new suppliers are not reached via pipeline by connecting the

Member States but via regasification capacity (LNG markets) or increasing pipeline capacity with incumbent major gas suppliers (i.e. Algeria and Russia).

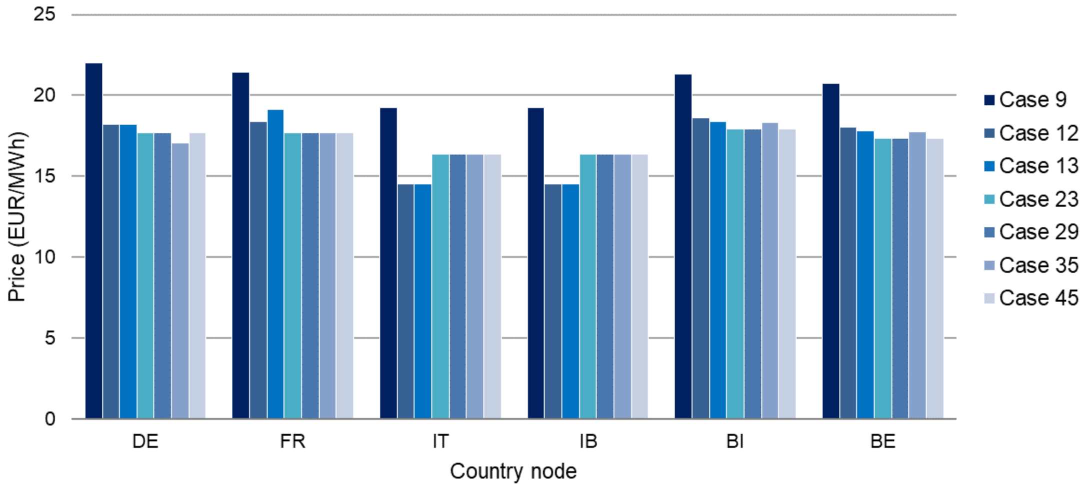

Figure 5-7 – Real prices (EUR/MWh) per country (consumption nodes) in 2035 for some representative cases

In Figure 5-8, cases 26 and 33 are compared. The investment in 8.7 bcm of pipeline capacity between Italy and France, reduces French prices in 0.47 €/MWh increasing flows between Italy and France. In the case of the Benelux zone, prices are reduced 0.45 €/MWh by investing 5.39 bcm in regasification capacity in case 33 instead of investing in additional pipeline capacity with Norway, as in case 26.

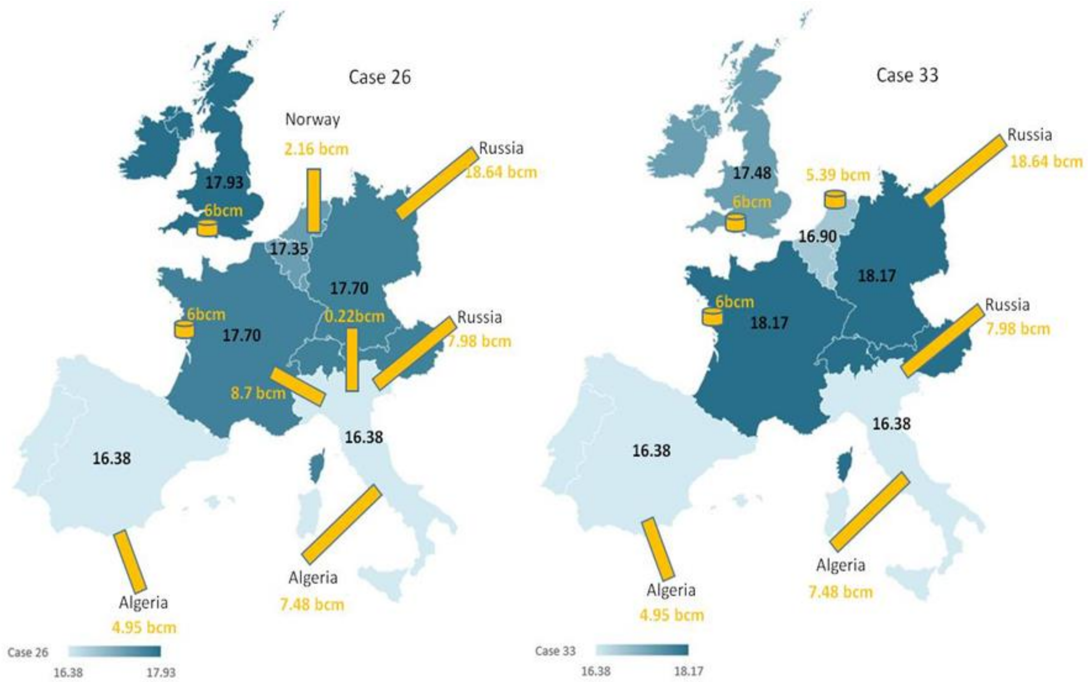

Figure 5-8 – Cases 26 and 33. Prices and investment in pipelines and regasification capacity.

The pipeline from Norway – Belgium is replaced in latter cases by more regasification capacity in Belgium (5.39 Bcm/y) (i.e. cases from 40-50) and the average price convergence is improved. Even if more investment is allowed, from cases 40 to 50, the model does not invest in further additional capacity. This means that up to a certain point investment in new capacity will not add any additional benefit in terms of utility of the demand, price convergence or increasing the number of suppliers. This plateau is represented by the following investments: Algeria – Iberia (4.95 Bcm/y), Algeria – Italy (7.48 Bcm/y), Italy – Germany (0.17 Bcm/y), Italy – France (8.75 Bcm/y), Russia – Germany (18.64 Bcm/y) and Russia – Italy (7.98 Bcm/y), and the following regasification capacity: Belgium (5.39 Bcm/y), France (6 Bcm/y) and United Kingdom (6 Bcm/y).(See Figure 5-9., case 40). For more detailed results, please refer to Table 5-1

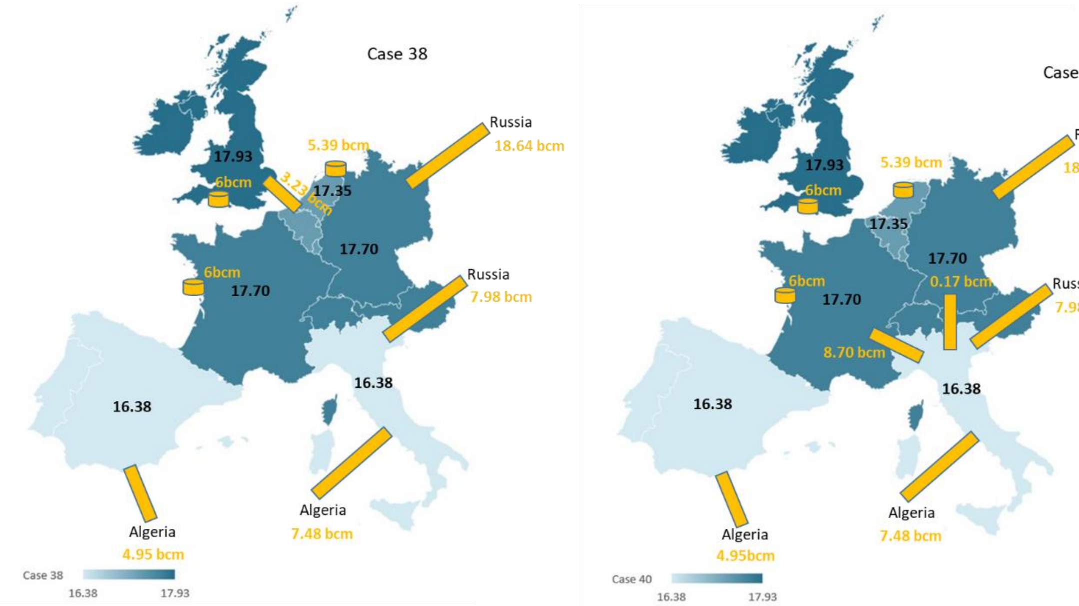

Figure 5-9 –Cases 38 and 40-50. Prices and investment in pipelines and regasification capacity.

5.6. Conclusions

In this chapter we propose a model whose objective is to represent a realistic decision-making process for analyzing the optimal infrastructure investments in natural gas pipelines and regasification terminals within the EU framework under a market perspective. Thus, in order to represent that expansion and operation decisions are taken sequentially, the different interest of market participants and the multiple criteria that need to be achieved simultaneously (i.e. market integration, security of supply, competition), we propose a multi-objective bilevel optimization model for representing the investment decision process in the European natural gas market (GASMOPEC). The model consists of the objectives of the network planner at the upper level optimizing a multi-objective function and a lower level that represents the downstream European gas market. The contribution of this model is three-fold.

First, we introduce the natural sequence of investment and operation decisions into a gas market model covering the existing gap found in the literature regarding bilevel optimization models applied to investment in natural gas markets. The upper level represents the investment decision making process of the network planner while the lower level represents the natural gas market structured as a two successive equilibrium. In the first place, the upstream market is represented through the traders, which act as interface between the upstream and the downstream gas markets, supplying gas to marketers. Second, the wholesale trade within Europe (downstream market) is represented through the marketers, which buy gas to traders in order to supply final demand. Infrastructure capacities (i.e. from liquefaction and regasification terminals and pipelines) are explicitly included in the lower level.

Second, by using a multi-objective model we allow for the capacity expansion decision maker to evaluate different expansion plans under different criteria (i.e. minimizes network investment and price difference between zones and maximizes utility of demand and number of gas suppliers) obtaining a portfolio of optimal investment solutions (i.e. non-dominated solutions of optimal plans).

Third, we provide a tool for assisting the investment decision making process, analyzing the different investment options (i.e. in pipelines and regasification terminals).

The proposed model is used for the assessment of the optimal infrastructure investment in Western Europe. From the simulation and the analysis of the different cases in the case study, we draw several conclusions. First, Western Europe is well interconnected and no investment cost exceeds the positive impact yielded by the investment in terms of the utility of the demand. This means that additional incentives for enhancing investment should be considered for those infrastructures which are considered as key or of common interest. Second, the model invests in two regasification terminals in France and the United Kingdom, improving the utility of the demand. Third, the pipeline capacity with incumbent major gas suppliers (i.e. Algeria and Russia) increases, falling into disfavor with market integration (i.e. connecting Member States) or diversification of sources of gas supply.

Appendix D: Results

The following table shows the obtained results for the 50 cases, presenting the total investment in pipeline and regasification capacity, the utility of the demand, the average price difference between nodes, and the number of LNG suppliers.

<table>
<tr><th>Case</th><th>Pipeline
In-Out nodes
(Bcm annual)</th><th>Reg. Terminal
Node (Bcm annual)</th><th>Utilty of the demand (Million EUR)</th><th>Average price difference (EUR/MWh)</th><th>Supplier*</th></tr>
<tr><td>1</td><td>-</td><td>-</td><td>1.0383</td><td>0.97</td><td>41</td></tr>
<tr><td>2</td><td>-</td><td>-</td><td>1.0384</td><td>1.07</td><td>41</td></tr>
<tr><td>3</td><td>-</td><td>-</td><td>1.0387</td><td>1.31</td><td>39</td></tr>
<tr><td>4, 5, 6, 7</td><td>-</td><td>-</td><td>1.0384</td><td>1.07</td><td>39</td></tr>
<tr><td>8</td><td>-</td><td>-</td><td>1.0387</td><td>1.29</td><td>38</td></tr>
<tr><td>9</td><td>-</td><td>-</td><td>1.0388</td><td>1.37</td><td>38</td></tr>
<tr><td>10</td><td>-</td><td>-</td><td>1.0388</td><td>1.39</td><td>38</td></tr>
<tr><td>11</td><td>-</td><td>FR (2.13); BI (4.52)</td><td>1.0798</td><td>1.22</td><td>38</td></tr>
<tr><td>12</td><td>-</td><td>FR (2.13); BI (4.52)</td><td>1.0820</td><td>1.65</td><td>38</td></tr>
<tr><td rowspan="2">13,14</td><td rowspan="2">-</td><td rowspan="2">FR (0.95); BI (5.71)</td><td>1.0814</td><td>1.26</td><td>38</td></tr>
<tr><td>1.0818</td><td>1.43</td><td>38</td></tr>
<tr><td>15</td><td>-</td><td>FR (3.74); BI (2.92)</td><td>1.0817</td><td>1.49</td><td>38</td></tr>
<tr><td>16, 17</td><td>-</td><td rowspan="2">FR (4.02); BI (2.63)</td><td>1.0818</td><td>1.43</td><td>38</td></tr>
<tr><td>18</td><td>-</td><td>1.0814</td><td>1.26</td><td>38</td></tr>
<tr><td>19</td><td>-</td><td rowspan="2">FR (6.00); BI (6.00)</td><td>1.0805</td><td>0.87</td><td>38</td></tr>
<tr><td>20, 21</td><td>-</td><td>1.0812</td><td>1.24</td><td>38</td></tr>
<tr><td>22,</td><td rowspan="2">DZ-IB (4.95); DZ-IT (7.48); IT-DE (0.22); IT-FR (8.70); NO-BE (2.16); RU-DE (18.64); RU-IT (7.98);</td><td rowspan="2">FR (6.00); BI (6.00)</td><td rowspan="2">1.0813</td><td rowspan="2">1.23</td><td>36</td></tr>
<tr><td>23, 24, 25, 26</td><td>37</td></tr>
<tr><td>27, 33</td><td rowspan="2">DZ-IB (4.95); DZ-IT (7.48); RU-DE (18.64); RU-IT (7.98)</td><td rowspan="2">BE (5.39);FR (6.00); BI (6.00)</td><td>1.0808</td><td>1.04</td><td>35</td></tr>
<tr><td>28</td><td>1.0813</td><td>1.24</td><td>35</td></tr>
<tr><td>29</td><td rowspan="7">DZ-IB (4.95); DZ-IT (7.48); IT-DE (0.17); IT-FR (8.70); RU-DE (18.64); RU-IT (7.98)</td><td rowspan="7">BE (5.39); FR (6.00); BI (6.00)</td><td>1.0811</td><td>0.93</td><td>35</td></tr>
<tr><td>39</td><td>1.0815</td><td>1.33</td><td>35</td></tr>
<tr><td>40,44, 47,50</td><td>1.0820</td><td>1.59</td><td>35</td></tr>
<tr><td>41, 45</td><td>1.0820</td><td>1.61</td><td>35</td></tr>
<tr><td>42, 48</td><td>1.0817</td><td>1.39</td><td>35</td></tr>
<tr><td>43, 46</td><td>1.0809</td><td>0.99</td><td>35</td></tr>
<tr><td>49</td><td>1.0811</td><td>1.04</td><td>35</td></tr>
<tr><td>30, 31, 32, 35</td><td rowspan="3">DZ-IB (4.95); DZ-IT (7.48); IT-DE (0.17);IT-FR (8.70); NO-BE (1.48); RU-DE (18.64); RU-IT (7.98)</td><td rowspan="3">FR (6.00); BI (6.00)</td><td>1.0810</td><td>0.93</td><td>34</td></tr>
<tr><td>36</td><td>1.0808</td><td>1.01</td><td>34</td></tr>
<tr><td>37</td><td>1.0810</td><td>0.98</td><td>34</td></tr>
<tr><td>34</td><td>DZ-IB (4.95); DZ-IT (7.48);IT-DE (0.18); RU-DE (18.64); RU-IT (7.98)</td><td>BE (5.39);FR (6.00); BI (6.00)</td><td>1.0813</td><td>1.23</td><td>34</td></tr>
<tr><td>38</td><td>DZ-IB (4.95); DZ-IT (7.48); RU-DE(18.64); RU-IT(7.98); BI-BE(3.23)</td><td>BE (5.39);FR (6.00); BI (6.00)</td><td>1.0811</td><td>1.02</td><td>35</td></tr>
</table>

Table 5-1 – Results.

^Notes to table: The number of LNG suppliers is the summation of the number of suppliers in the three periods. The number of NG suppliers is 34 for cases from 1 to 28 and 31 for cases from 29 to 50. Cases which yield the same solutions have been clustered.

Appendix E: Problem formulation

This section contains the MPEC formulation of the problem described above.

Upper level problem

The upper level problem formulation is described below.

$$Max\ U(D)\ -\rho_1\left(cost_{invpipe}+cost_{invreg}\right)-\ \rho_2\cdot\left(\sum_{zz_1p/\{z,z_1\epsilon K_z^{CN}\}}\left(\Delta p_{zz_1p}\right)\right) + \rho_4\cdot\left(\sum_{zz_1p/\{z\epsilon K_z^T\}\cap\{z\neq z_1\}\cap\{z_1\epsilon K_{z_1}^M\}}\left(\delta_{zz_1p}^{tNG}+\delta_{zz_1p}^{tLNG}\right)\right) \tag{5.54}$$

s.t.

$$\left(\sum_{pzz_1} i_{pzz_1}^{pipe}+\sum_{pz} i_{pz}^{reg}\right)\leq e_1 \tag{5.55}$$

$$\left(\sum_{zz_1p/\{z,z_1\epsilon K_z^{CN}\}}\left(\Delta p_{zz_1p}\right)\right)\leq e_2 \tag{5.56}$$

$$\left(\sum_{zz_1p/\{z\epsilon K_z^T\}\cap\{z\neq z_1\}\cap\{z_1\epsilon K_{z_1}^M\}}\left(\delta_{zz_1p}^{tNG}+\delta_{zz_1p}^{tLNG}\right)\right)\geq e_4 \tag{5.57}$$

Together with the equations (5.1), (5.3), and the constraints (5.2), (5.4), (5.6), (5.7), (5.12), (5.13), (5.15) and (5.16).

The Karush-Kuhn-Tucker Conditions (KKT). Lower Level.

The Karush-Kuhn-Tucker Conditions (KKT) of the lower level problems is described below.

KKT conditions for the marketer´s problem

$$-bp_{z_1p}+C_{tp}+\lambda_{zp}^{tra}+\phi_{tzp}^{tpipe}-\phi_{tz_1p}^{tpipe}-\mu_{tzz_1p}^{tNG}\geq 0\quad\perp q_{tzz_1p}^{tNG}\geq 0 \tag{5.58}$$

$$-bp_{z_1p}+C_{tp}+\lambda_{zp}^{tra}+\phi_{tzp}^{tship}-\phi_{tz_1p}^{tship}-\ \mu_{tzz_1p}^{tLNG}\geq 0\quad\perp q_{tzz_1p}^{tLNG}\geq 0 \tag{5.59}$$

$$cost_{zz_1}^{pipe} - \phi_{tzp}^{tpipe} + \phi_{tz_1p}^{tpipe} - \mu_{tzz_1p}^{tpipe} \geq 0 \quad \perp q_{tzz_1p}^{tpipe} \geq 0 \tag{5.60}$$

$$cost_{zz_1}^{ship} - \phi_{tzp}^{tship} + \phi_{tz_1p}^{tship} - \mu_{tzz_1p}^{tship} \geq 0 \quad \perp q_{tzz_1p}^{tship} \geq 0 \tag{5.61}$$

$$\bar{Q}_{tp}^{tra} - \left(\sum_{t,z_1} q_{tzz_1p}^{tNG} + \sum_{t,z_1} q_{tzz_1p}^{tLNG} \right) \geq 0 \quad \perp \lambda_{zp}^{tra} \geq 0 \tag{5.62}$$

$$\left[\sum_{z_1 \neq z} q_{tzz_1p}^{tNG} - \sum_{z_1 \neq z} q_{tzz_1p}^{tpipe} \right] + \left[\sum_{z_1 \neq z} q_{tz_1zp}^{tpipe} - \sum_{z_1 \neq z} q_{tz_1zp}^{tNG} \right] = 0 \quad \perp \phi_{tzp}^{tpipe} \tag{5.63}$$

$$\left[\sum_{z_1 \neq z} q_{tzz_1p}^{tLNG} - \sum_{z_1 \neq z} q_{tzz_1p}^{tship} \right] + \left[\sum_{z_1 \neq z} q_{tz_1zp}^{tship} - \sum_{z_1 \neq z} q_{tz_1zp}^{tLNG} \right] = 0 \quad \perp \phi_{tzp}^{tship} \tag{5.64}$$

Market clearing condition (5.23)

KKT conditions for the marketer´s problem

$$-p_{z_1p} + bp_{z_1p} + \phi_{mzp}^{mak} - \phi_{mz_1p}^{mak} - \mu_{mzz_1p}^{mak} \geq 0 \quad \perp q_{mzz_1p}^{mak} \geq 0 \tag{5.65}$$

$$cost_{zz_1}^{pipe} - \phi_{mzp}^{mak} + \phi_{mz_1p}^{mak} - \mu_{mzz_1p}^{mpipe} \geq 0 \quad \perp q_{mzz_1p}^{mpipe} \geq 0 \tag{5.66}$$

$$\left[\sum_{z_1 \neq z} q_{mzz_1p}^{mak} - \sum_{z_1 \neq z} q_{mzz_1p}^{mpipe} \right] + \left[\sum_{z_1 \neq z} q_{mz_1zp}^{mpipe} - \sum_{z_1 \neq z} q_{mz_1zp}^{mak} \right] = 0 \quad \perp \phi_{mzp}^{mak} \tag{5.67}$$

Market clearing condition (5.9)

KKT conditions for the network operator´s problem

$$-cost_{zz_1}^{pipe} + TC_{zz_1}^{pipe} + \lambda_{zz_1p}^{pipe} - \mu_{zz_1p}^{pipe} \geq 0 \quad \perp q_{zz_1p}^{totalpipe} \geq 0 \tag{5.68}$$

$$\left(\bar{Q}_{zz_1p}^{pipe} + \sum_{p_1/p_1<p} i_{p_1zz_1}^{pipe} \right) - q_{zz_1p}^{totalpipe} \geq 0 \quad \perp \lambda_{zz_1p}^{pipe} \geq 0 \tag{5.69}$$

Market clearing condition between marketers and traders with the network operator (5.30).

KKT conditions for the LNG operator´s problem

$$-cost_{zz_1}^{ship} + TC_{zz_1}^{ship} + \lambda_{zp}^{liq} + \lambda_{z_1p}^{reg} - \mu_{zz_1p}^{ship} \geq 0 \quad \perp q_{tzz_1zp}^{tship} \geq 0 \tag{5.70}$$

$$\bar{Q}_{zp}^{liq} - \sum_{z_1} q_{tzz_1zp}^{tship} \geq 0 \quad \perp \lambda_{zp}^{liq} \geq 0 \tag{5.71}$$

$$\bar{Q}_{z_1 p}^{reg} - \sum_{z} q_{tzz_1 zp}^{tship} \geq 0 \quad \perp \lambda_{z_1 p}^{reg} \geq 0 \tag{5.72}$$

Market clearing condition between traders with the LNG route operator (5.35).

Appendix F: Bilevel Programming Problems (BPP)

In this section we briefly introduce bilevel programming problems (BPP) and characterize the general form of Mathematical Program with Equilibrium Constraints (MPEC).

Bilevel programs, also known as mathematical programs with optimization problems in the constraints (OPcOP), were initially considered by Bracken and McGill in (Bracken & McGill, 1973), (Bracken & McGill., 1974), (Bracken & McGill., 1974).

The major feature of bilevel problems is the structural hierarchy, as they include two mathematical problems where one of these problems (the lower level problem) is being part of the constraints of the other one (the upper level problem).That is, the upper level problem is subject to a lower level problem or to multiple lower level problems, but not the other way around (Gabriel, et. al., 2013). The general formulation of a bilevel programming problem (BPP) is taken from (Colson, et al., 2007) and stated below:

$$\min_{x\in X,y} F(x,y) \tag{5.73}$$

$$s.t. \quad G(x,y) \leq 0, \tag{5.74}$$

$$\min_{y} f(x,y) \tag{5.75}$$

$$s.t. \quad g(x,y) \leq 0, \tag{5.76}$$

Where $x\epsilon\mathbb{R}^{n_1}$ and $y\epsilon\mathbb{R}^{n_2}$. Equations (5.73) - (5.74) represent the upper level problem, while equations (5.75) - (5.76) define the constraining lower-level problem. The upper level variables are $x\epsilon\mathbb{R}^{n_1}$ and the lower level variables $y\epsilon\mathbb{R}^{n_2}$. Similarly, the functions $F: \mathbb{R}^{n_1} \times \mathbb{R}^{n_2} \rightarrow \mathbb{R}$ and $f: \mathbb{R}^{n_1} \times \mathbb{R}^{n_2} \rightarrow \mathbb{R}$ are the upper and lower level objective functions respectively, and $G: \mathbb{R}^{n_1} \times \mathbb{R}^{n_2} \rightarrow \mathbb{R}^{m_1}$ and $g: \mathbb{R}^{n_1} \times \mathbb{R}^{n_2} \rightarrow \mathbb{R}^{m_2}$ are the upper and lower constraints, respectively. Therefore, the upper level constraints involve variables from both levels. That is, the dual variables of the constraining problems affect the upper level problem but the dual variables of the upper level problem do not directly affect the lower level problems. It is also important to note that the objective function of the upper and the lower level should be conflicting, as otherwise the bilevel problem is reduced to a single level problem. For further details on BPPs the reader is referred to (Cardell, et al.,1997) and (Colson, et al., 2007).

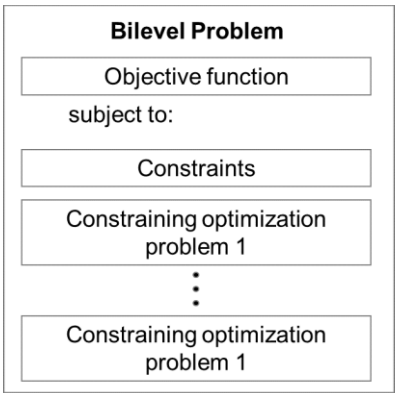

Figure 5-10 – Bilevel problem. Optimization problem constrained by a number of interrelated optimization problems. Source: Own elaboration based on (Gabriel, et. al., 2013).

Once we have characterized a general BPPs problem, we define Mathematical Program with Equilibrium Constraints (MPEC), as a bilevel problem where the constraining problems are transformed into a set of equilibrium constraints. That is, an optimization problem in which the essential constraints are defined by a complementarity system as in (Cottle et al., 1992) (e.g. a mixed complementarity problem (MCP)), or by a parametric variational inequality[3] as in (Facchinei & Pang., 2003a) and (Facchinei & Pang., 2003b). Furthermore, the MPEC, in addition to the optimality conditions, can include other constraints.

Finally, a complementarity problem can be defined as a problem which includes complementarity conditions. That is, given a $F(y): \mathbb{R}^n \rightarrow \mathbb{R}^n$, find a $y \in \mathbb{R}^n$ that satisfies $y \geq 0, \;\; F(y) \geq 0, \;\; y^T \cdot F(y) = 0$ (i.e. the product of two or more non-negative quantities should be zero). For a more detailed formulation as well as the definition of its corresponding Karush-Kuhn-Tucker conditions (KKT), the reader is referred to section Appendix B.

Historically, bilevel optimization has been closely related to the Stackelberg economic problem (Stackelberg, 1952) in the game theory field. The problem considers two interacting agents at two different levels: the leader, who decides first, and the follower i.e., moves sequentially. The leader is assumed to anticipate the reactions of the followers which allows him to choose his best or optimal strategy accordingly.

However, bilevel programs have been applicated in several fields, for solving real-world problems involving a hierarchical relationship between two decision levels. These are

[3] A variational inequality is an inequality involving a functional, which has to be solved for all the values of a given variable, usually belonging to a convex set

encountered in fields as diverse as management, engineering, economics, environmental sciences, finance etc. (Fortuny-Amat & McCarl, 1981) and (Colson, et al., 2007).

Last, the bilevel formulation allows for the uncoupling of investment and operation decisions, with investment decisions taken in the upper level and in the lower level market participants' operation decisions.

Appendix G: Multi-objective problems

This section is devoted to multi-objective programming (MOP), i.e. models in which multiple objective functions are explicitly considered.

Real-world problems usually involve multiple perspectives in order to assess the merits of the potential solutions. However, if these perspectives are conflicting, the concept of optimal solution no longer makes sense, since, in general, there is no feasible solution that simultaneously optimizes all objective functions. Pareto, (Pareto, 1896) defined the concept of Pareto optimal solution (also named efficient, non-dominated solution), as a solution such that there is no other feasible solution that simultaneously improves all the objective function values. Thus, improving one criterion entails deteriorating, at least, one of the other objective function values.

Therefore, multiple objective models enlarge the range of solutions under analysis (i.e. not just a single optimal solution), revealing trade-offs and compromises between the conflicting aspects of evaluation. Moreover, the set of trade-off optimal solutions offers the decision maker (hereafter, DM) an operational environment for better understanding the decision problem and thus, results can serve as a reference and contribute to shape and make the DM's preferences.

In this type of problems, it is necessary to incorporate all the qualitative aspects associated with the preferences of the DM into the decision process. This articulation of preferences can be made a priori (i.e. assigning values /utility to the different objective function) or it can be done progressively (i.e. using interactive methods, in which the intervention of the DM is used to guide the interactive decision process, thus reducing the scope of the search).

A generic formulation of a multi-objective linear problem (MOLP) with *p* objective functions and *m* constraints is stated below based on (Antunes, et al., 2016), in order to introduce the reader in some fundamental concepts that will be use later.

$$\max z_1 = f_1(x) = c_1 x = \sum_{j=1}^{n} c_{1j} x_j \tag{5.77}$$

$$\vdots$$

$$\max z_p = f_p(x) = c_p x = \sum_{j=1}^{n} c_{pj} x_j \tag{5.78}$$

$$s.t. \quad \sum_{j=1}^{n} a_{ij}x_j = b_i \quad i = 1 \cdots m \tag{5.79}$$

$$x_j \geq 0 \quad j = 1 \cdots n \tag{5.80}$$

Where $c_k\ with\ k = 1 \cdots p$ corresponds to the coefficients of the objective function. In the multi-objective decision problem, the solution space (i.e. called objective function space) is mapped onto a p-dimensional space $Z = \{z = f(x) \in \mathbb{R}^p; x \in X\}$. In this space each potential solution $x \in X$ is represented by a vector $z = (z_1, \cdots, z_p) = f(x) = (f_1(x), \cdots, f_p(x))$, which components are the values of each objective function for solution x of the feasible region. As in general the objective functions are conflicting, there is no feasible solution $x \in X$ hat simultaneously optimizes all objective functions.

Hence, a solution is called efficient, when it is not dominated by any other feasible solution. Following the definition stated at (Antunes, et al., 2016), a solution $x_1 \in X$ is called efficient if and only if there is no other solution $x \in X$ such that $f_k(x) \geq f_k(x_1)$ for all k $k = 1 \cdots p$, the inequality being strict for at least one k $f_k(x) > f_k(x_1)$. X_E denotes the set of all efficient solutions.

In general, while the designation of efficient solution is referred to points in the decision variable space, the designation of non-dominated solution is used for points in the objective function space. Therefore, a point $z = (f_1(x), \cdots, f_p(x)) \in Z$ in the objective function space is non-dominated if and only if x is efficient. That is $Z_E = \{z = f(x) \in Z\ x \in X_E\}$.

As example for further clarifying these concepts, in Figure 5-11 we illustrate efficient and non-efficient solutions for a bi-objective LP. In this example, there is no feasible solution that simultaneously optimizes the two objective functions. Point A reflects the optimal solution for $f_2(x)$, while objective function $f_1(x)$ is optimized in point C. Point B is an intermediate solution, which is better than C in $f_2(x)$ and worse in $f_1(x)$ and the other way round in the case of point A – i.e. better in $f_1(x)$ and worse in in $f_2(x)$ (see Figure 5-11, 1). These three points and thus, any solution on the edges [AB]-[BC] is an efficient solution, as there is no other feasible solution that performs equal or better for both objective functions, and strictly better for at least one of those objective functions. Moreover, as can be seen in the point C of the first figure, the efficient solution is also identified by the dominance cone associated with the objective function gradients. In the second and third figures from Figure 5-12, points D and E are examples of non-efficient solutions since there are feasible solutions dominating them (i.e. there are other feasible solutions that improve simultaneously both objective functions). The solutions that dominate D and E lay on the intersection of the respective dominance cones emanating from D and E with the feasible region.

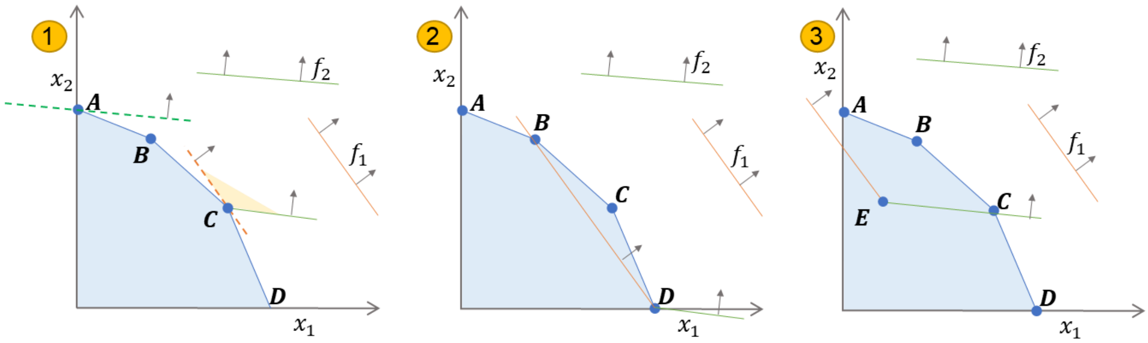

Figure 5-11 – Examples of efficient and non-efficient solutions. Source: Own elaboration based on (Antunes, et al., 2016)

Additionally, a solution $x_1 \in X$ is called weakly efficient/non-dominated solution if and only if there is no other solution $x \in X$ such that $f_k(x) > f_k(x_1)$ for all k $k = 1 \cdots p$. X_{WE} denotes the set of weakly efficient solutions. A point in the objective function space $z = \left(f_1(x), \cdots, f_p(x)\right) \in Z$ is called weakly non-dominated if and only if $x \in X_{WE}$, that is $Z_{WE} = \{z = f(x) \in Z\ x \in X_{WE}\}$. That is, a solution is weakly efficient if and only if there is no other feasible solution that strictly improves the value of all objective functions. In Figure 5-12 - 1, we illustrate this concept for a bi-objective problem. Solutions on the edges [AB] and [CD] are weakly non-dominated, i.e., except the points B and C, while solutions on the edges [BC] are strictly non-dominated.

If a non-dominated solution $z \in Z_E$ is dominated by an infeasible convex combination of solutions belonging to Z_E, the solution is an unsupported efficient/non-dominated solution. In MOLP models all non-dominated solutions are supported. However, in mixed integer multi-objective problems, unsupported non-dominated solutions may exist. An example of unsupported non-dominated solutions in a bi-objective integer problem is shown in Figure 5-12 - 2. Points A and C are supported non-dominated solutions while B is unsupported, because it is dominated by an infeasible convex combination of A and C. Thus, B lies on the convex hull defined by the supported solutions.

Finally, an ideal solution $z^* = \left(z_1^* \cdots, z_p^*\right)$ is defined as the solution that would simultaneously optimize all objective functions. Thus, the ideal solution encompasses the individual optimal values to each objective function in the feasible region, although, generally, the ideal solution does not belong to the feasible region.

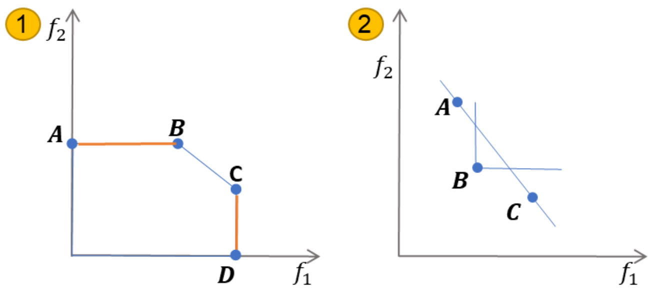

Figure 5-12 – Examples of weakly efficient (1) and unsupported solutions (2).

Appendix H: Definition of the Big-M relaxation method

A general definition of the Big-M relaxation method is provided below taken from (Vecchietti, et. al., 2003). The disjunctive set F can be expressed as a set of constraints separated by the or (∨) operator, as the following nonlinear disjunction:

$$F = \bigvee_{i \in D} [h_i(x) \leq 0] \quad x \in \mathbb{R}^n \tag{5.81}$$

F can be considered as a logical expression, which enforces only one set of inequalities. It is assumed that $h_i(x)$ is a non-linear continuous convex function[4]. The Big-M relaxation of (5.81) is given by:

$$h_i(x) \leq M_i(1 - y_i) \qquad i \in D \tag{5.82}$$

$$\sum_{i \in D} y_i = 1 \tag{5.83}$$

$$0 \leq y_i \leq 1, \qquad i \in D \tag{5.84}$$

The tightest value for M_i can be calculated from:

$$M_i = max\{h_i(x) | x^L \leq x \leq x^U\} \tag{5.85}$$

[4] For simplicity, it is assumed that each term in the disjunctive equation has only one inequality constraint, without loss of generality

Appendix I: Scalarizing techniques

In this Appendix we describe the two scalarizing techniques used for solving the multi-objective problem in the upper level. For further information regarding scalarizing techniques the reader is referred to (Antunes, et al., 2016).

The first scalarizing technique used for the computation of efficient solutions is the Weighted-Sum of the Objective Functions, which consists in building a new objective function, built up with the weighted sum of the p original objective functions with positive weights (λ_k).

$$Max\ z_\lambda = \sum_{k=1}^{p} \lambda_k f_k(x) \tag{5.86}$$

s.t. $x \in X$

This scalarizing technique can be applied to mixed-integer problems, but it does not allow to obtain unsupported non-dominated solutions. Therefore, this scalarizing technique is used at a first stage, for obtaining the feasible upper and lower levels for each objective function in the objective function space, for the e-constraint scalarizing technique.

The second selected scalarizing technique is the e-constraint technique, which enables us to obtain all non-dominated solutions, (i.e., solutions lying on edges or faces and vertices) of the feasible region of the original multi-objective problem even if the resulting decision space is discrete (after applying the Big-M method, the problems turns out in a MIQCP problem). This scalarization technique selects one of the i objective functions (f_i) to be optimized considering the other $(i-1)$ objectives as constraints by specifying the upper and the lower levels that the decision maker is willing to accept. That is, if x_1 is the single optimal solution for some i to the problem[5]

$$Max\ f_i(x) \tag{5.87}$$

s.t. $x \in X$

$$f_k(x) \geq e_k \quad k = 1, \cdots, i-1, i+1, \cdots, p \tag{5.88}$$

[5] The formulation has been taken from (Antunes, et al., 2016).

However, if the condition of a single optimal solution had not been imposed, weakly efficient solutions could appear. For overcoming this issue, we replace the objective function stated in (5.87) by:

$$Max\ f_i(x) + \sum_{k \neq i}^{p} \rho_k f_k(x) \tag{5.89}$$

Where ρ_k is a small positive scalar.

This scalarizing procedure is illustrated in Figure 5-13, for a bi-objective LP problem, where $f_1(x)$ and $f_2(x)$ are maximized. In this example, the efficient frontier of the feasible region is made up of the solutions on edges [AB] - [BC]. When applying the e-scalarizing technique, optimizing $f_2(x)$ and imposing $f_1(x) \geq e_1$, the efficient solution E is obtained. In the case of the edge [CD], all the points in the edge are optimal, but only point C is strictly efficient (i.e. rest of the solutions on the edge [CD] are weakly efficient solutions).

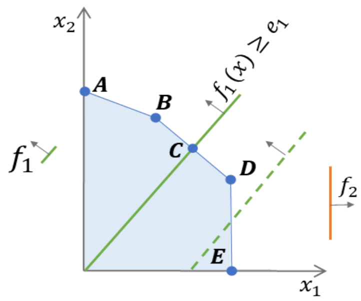

Figure 5-13 – e-constraint scalarizing technique for computing efficient and weakly solutions. The figure represents a bi-objective LP model One of the objective functions is optimize while the remaining objectives are transformed into constraints.

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Chapter 6

Conclusions, original contributions and future research guidelines

In order to evaluate the achievement of a competitive European gas market, at the present time, in the context of global relations and liberalized energy markets, well-working and realistic gas markets models are essential in order to allocate the resources adequately and to provide the proper economic signals to suppliers, investors, consumers, etc.

6.1. Thesis Summary

During the last decade, major transformations have shaped the evolution of global natural gas markets altering the supply/demand balance. In the supply side, an ample supply due to the exploration of unconventional gas sources has brought up new producers into the market and a surge in global liquefaction capacity. Additionally, an increase in the LNG trade has favored the globalization of the natural gas market. The demand side has kept growing due to demand shocks such as the accident at Fukushima in 2011 and China clean air policies in 2017, and the continued expansion of liquefied natural gas market opening new emerging markets. These changes have highlighted the necessity for a more flexible natural gas market, which has been reflected in an increased spot market together with a tendency towards more flexible long-term contracts and new pricing mechanisms involving gas-on-gas competition. Moreover, macroeconomics and political choices have shore up this trend.

In Europe, gas market fundamentals have also undergone a significant shift. This has been triggered by the aforementioned global dynamics and supported by the natural gas market liberalization and Europe's ambitious targets of a net zero-carbon economy by 2050. In this context, the European Union is building its internal natural gas market under an entry-exit scheme, which comprises balancing zones with liquid virtual trading points, where market integration is served by appropriate levels of infrastructure.

This thesis develops different optimization models in order to carry out relevant studies for the assessment of the EU internal gas market while contributing to the research field of global gas market modeling. The proposed optimization models improve current natural gas market mid-term operation tools by 1) a better consideration of natural gas long-term supply contracts; 2) including a variety of supply options (i.e. long-term supply contracts, spot market and secondary market representing wholesale markets); and 3) modeling the coexistence of oil-indexed and hub-pricing mechanism. Three tools are developed for this aim. First, we develop four academic equilibrium models in order to represent the implementation and evolution of virtual natural gas hubs in Europe. Second, we advance in the natural gas modeling, by proposing a global gas model (GasValem GoG) which captures in detail all the new commercial trends (i.e. spot market vs. long-term contracts) considering different pricing options, providing insights of the mid-term natural gas market. Third, this thesis also tackles the capacity investment problem, improving the existing investment planning tools, considering sequentiality in the operation-expansion decision problem and the multiple criteria that need to be achieved simultaneously. For this aim, the GASMOPEC model is developed.

The aforementioned contributions are gathered and summarized in the following three specific objectives:

- **Objective (1):** Analysis of the implementation and development of natural gas hubs.
- **Objective (2):** GasValem – GoG. Development of a novel global gas model for accurately representing natural gas market commercial trends, including natural gas hubs and gas-on-gas competition.
- **Objective (3):** GASMOPEC. Development of a tool for representing a realistic decision-making process for analyzing the optimal infrastructure investments inside the EU.

The developed models constitute a valuable tool to assist industry players, system operators, planning entities, regulatory authorities or Governments in order to:

- First, to better understand the global natural gas dynamics and supply and demand fundamentals.
- Second, to conduct a detailed analysis of the new competitive internal gas market within the European regulatory framework (i.e., subject to entry-exit access systems).
- Third, to take infrastructure expansion decisions efficiently for allocate their resources in a highly competitive global setting.

6.2. Original contributions

In this section, we now gather and highlight the original contributions of this dissertation. Throughout this thesis, we have proposed different optimization models in order to improve current operational and investment planning tools in the natural gas sector arena. The main contributions of this work have been gathered in 4 articles. These articles are listed below and are assigned to the specific objectives that have been established in this thesis in Figure 6-1.

Journal Articles

Article I. del Valle, A., Reneses, J., Wogrin, S., 2018. “La creación de un mercado único de gas natural en Europa.” Anales.

Article II del Valle, A., Dueñas, P., Wogrin, S., & Reneses, J., 2017. "*A fundamental analysis on the implementation and development of virtual natural gas hubs*," Energy Economics, Elsevier, vol. 67(C), pages 520-532.

Article III del Valle, A., Reneses, J., Wogrin, S., April 2019. “*A global gas market model to deal with the new commercial trends in the natural gas market*.” (currently under review in Energy - The International Journal).

Article IV del Valle, A., Reneses, J., Wogrin, S., 2018. "*Multi-objective bi-level optimization model for the investment in gas infrastructures*". Working Paper IIT-18-008A (currently under review in Energy Strategy Reviews July 2018).

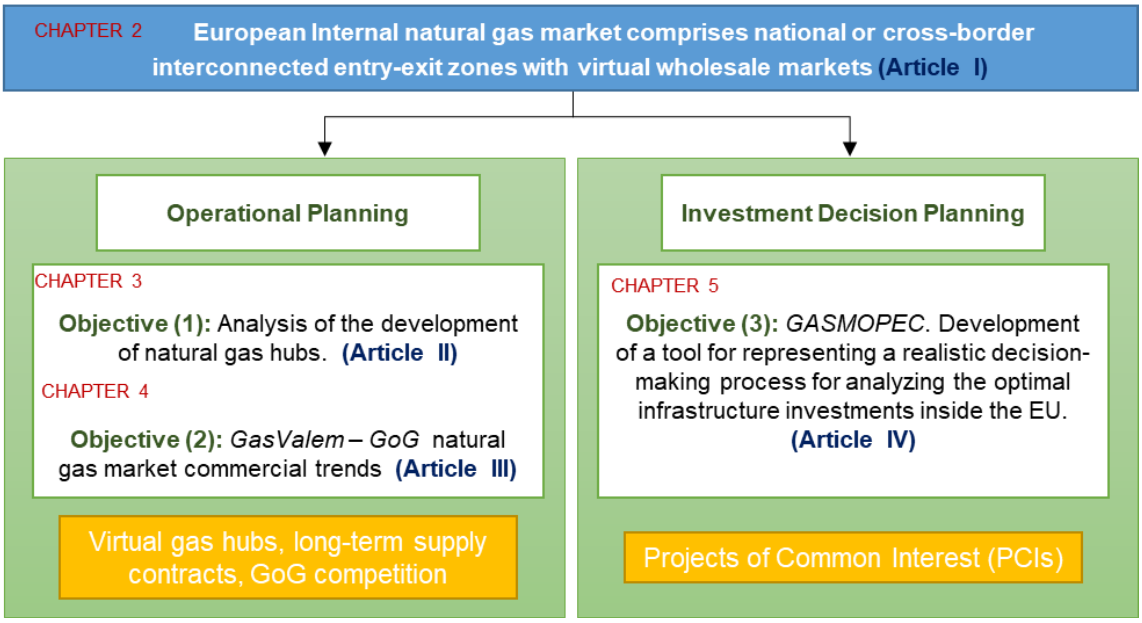

Figure 6-1 – Specific objectives and chapters of this thesis

The following subsections contain a summary of the main results of this thesis and the most relevant conclusions that can be drawn from the presented research, according to the main chapters in this thesis, with an special emphasis on its contributions.

6.2.1. Implementation and development of virtual natural gas hubs

The development of virtual gas hubs in Europe has brought up a new competitive environment in which shippers must adapt their behavior to the changing conditions. During the hub implementation and development, the following questions arise: how do shippers behave at the different levels of hub maturity? And, to what extent does the implementation of virtual hubs in entry-exit systems diminish the barriers to entry of new market players, provides more flexibility and fosters competition? With this aim, the decision-making process of the different shippers is simulated under different market structures, representing four stages of the market liberalization process at different levels of hub maturity.

6.2.1.1. Modeling contributions

- We propose a novel representation of shippers' strategic behavior during the implementation of virtual hubs at the different levels of hub maturity in entry-exit system.

- For this purpose, we present a new approach that represents the development of a hub in four stages, under a market equilibrium perspective.
    - First, the proto-liberalization case includes the global LNG spot market which is represented as a perfectly competitive market, the electricity market which is represented as an oligopoly, and the conventional demand which is assumed to be captive (i.e., monopolized).
    - Second, a hub is implemented, which provides transparency and reduces information costs by revealing the gas price.
    - Third, switching rates are expected to grow as consumers have access to a transparent gas price; hence, the conventional demand is no longer considered as captive.
    - Fourth, wholesale (procurement) and retail activities are unbundled, and a wholesale market is established where the retailers presumably buy gas.

6.2.1.2. Regulatory analysis and conclusions

From the simulation and the analysis of the different market equilibria, we draw several general conclusions that apply to the implementation of any virtual hub. Therefore, it should be in particular interest for stakeholders that are planning to follow the same path pursued by the EU during the last decade.

- Prior to the implementation of a gas hub:
    - Prior to the implementation of the hub, independently of the behavior in each market (i.e., monopoly, oligopoly or perfect competition), the marginal cost of each shipper is equal to the marginal income from the market.
    - As the global LNG market price is maintained constant, all marginal costs and marginal incomes will reach this value as long as the transportation constraint is not binding. Therefore, the global LNG market price is transferred to the conventional demand and the electricity sector.
    - However, as the global LNG market presents some transportation constraints due to the limited fleet of LNG carriers, the LNG market price might not necessarily be directly applied to the conventional demand. In the case that the LNG fleet would be large enough, the price would equal the shippers' apparent cost and would be transferred to the household consumers and the electricity sector.

  - It is worth noting that an integrated global gas market can work as a price stabilizer. However, it undoubtedly requires of sufficient liquefaction and regasification capacity as well as of a large enough LNG fleet.

- Emerging gas hub:

  - With the introduction of a hub, the shippers have another source of gas procurement and gain flexibility as they have the possibility of buying and selling gas in the gas hub. As a result, the marginal cost of all shippers reaches a unique value, which coincides with the gas hub price as long as supply constraints are not binding.
  - Furthermore, with the implementation of a hub, the aggregated profit of the shippers may increase even when anticompetitive behavior is not explicitly represented due to the gained flexibility by the agents in the hub and the oligopolistic nature of the gas and electricity markets.
  - Therefore, the development of gas virtual hubs increases market interactions among shippers, but the oligopolistic market structure may give room for strategic behavior. This means that the hub constitution is a necessary, but not sufficient solution to encourage competition.
  - However, even if with the hub the shippers' total profit increases, not all the agents increase their profits with their participation in the hub. Besides, there is a clear trend of reducing market shares of large participants in favor of small ones.
  - Last, as the marginal cost of all shippers converges to a unique value, some conventional consumers might lose wealth if their current supplier has lower marginal costs than other shippers in the market. In this case, the shipper might sell gas to other shippers in the hub rather than supply its gas to its conventional demand.

- Introduction of competition in conventional demand:

  - As time since market liberalization increases, conventional demand switching rates tend to be higher.
  - Additionally, thanks to the transparency of gas prices in the hub, during the evolution from monopolized demand to a Cournot oligopoly, the price paid by the conventional demand is reduced as shippers compete among them to supply the demand, thus, reducing market power.

- Unbundling of wholesale and retail activities:

- We obliged the unbundling of wholesale and retail activities, in order to favor the entry of new participants and guarantee the competition. Hence, with the entry of new retailers, market power in the conventional demand segment decreases, delivery prices lower, and consumer surplus increases.
- However, if the market is not able to attract new agents it might end up in successive oligopoly, which yields higher prices.

6.2.2. New commercial trends in the natural gas market

Over the last years, natural gas trading has evolved from being traditionally delivered under long-term, (i.e. with destination clauses, take-or-pay commitments and contracts prices linked to oil products) to a more diversified and liquid market where gas is sold on a spot basis (i.e. trading hubs or OTC markets), driving the rise of gas-on-gas competition pricing for long-term contracts.

6.2.2.1. Modeling contributions

We extend the literature in natural gas market models, by proposing a novel mid-term optimization model (GasValem-GoG), which captures these new commercial trends in the natural gas market. The main contributions of the model are:

- The model represents in detail all the agents and infrastructures involved in the gas chain from the wellhead to the consumer. The production wells are operated by producers. Producers interact with the rest of the system through traders, which are dedicated trading companies for each producer. Traders can sell gas domestically or use the pipeline transmission system or the liquefied natural infrastructure to export gas to other zones and sell it to marketers (either through long-term supply contracts or in the spot market). Marketers optimize their gas portfolio for supplying the final gas demand (residential, industrial and power sector). Marketers have the possibility of storing the gas in the tanks of regasification terminals or in underground storages. For each infrastructure, technical constraints, congestions, gas balance equations considering losses and operational cost are modeled.

- Players optimize their natural gas portfolio, choosing between buying or selling gas at the different hubs and the exerted volume above the long-term contract ToP clause, taking advantage of market spreads (i.e. moving gas among connected zones by pipeline and diverting LNG cargoes to more rewarding destinations).

- The relevance of this model is that it is at the cutting edge of knowledge about the representation of different supply options (i.e. long-term contracts or spot market), modeling the coexistence of different pricing mechanisms. The representation of the different flexible supply options and pricing mechanism allows us to analyze their role on the final gas price formation.

- The model includes a variety of **supply options**, representing in detail the main long-term contract clauses and spot trade in wholesale markets (including secondary market among marketers).
    - We have modeled carefully all the characteristics of **long-term supply** contracts (origin and destiny nodes/ports, involved agents in the trade (trader-marketer), duration time, take-or-pay clauses, destination clauses and pricing formulas). This is important because long-term supply contracts still determine the market results in several places, and thus, they need to be represented with accuracy in order to get real insights of the natural gas market.
    - Moreover, contracted LNG cargoes with no destination clause under long-term arrangement can be diverted to a more rewarding destination. This allows marketers to profit from arbitrage opportunities.
    - We include natural gas **wholesale markets**, where marketers can trade gas among them (i.e. secondary market), and traders can sell their gas on spot basis.
- We have extended the current literature by distinguishing **four** major **pricing mechanism** for the international natural gas market: Oil price scalation (OPE), gas-on-gas competition (GoG), including hybrid pricing formulas which contemplates both OPE and GoG pricing, regulated prices and netback pricing.
    - GoG competition is represented using an iterative process where the long-term contract price formula is linked to the resulting natural gas hubs prices, allowing to explore the impact of the growing GoG competition on the resulting prices.

- Another key characteristic of the model is its mid-term scope and monthly granularity. The monthly detail allows to accurately represent the seasonal spreads. Additionally, within this time frame, we allow for the optimization of marketers' use of the underground storage and the LNG tanks for seasonal price arbitrage.

6.2.2.2. Global natural gas market assessment

In addition to the modeling contribution, another major contribution is to build up a realistic global gas market case studies for the mid-long-term. This has encompassed a deep analysis of the global natural gas market performance together with a heavy data mining task among research centers, International Institutions and Public Institutions, and an intensive model calibration process.

- In particular, the proposed model is used for the assessment of the global natural gas market in 2020 with a special focus in Europe.

6.2.3. Multi-objective bilevel optimization problem for the investment in new gas infrastructures

The European Commission (EC) has put infrastructures at the forefront for the creation of the internal natural gas market and has proposed a list of key energy infrastructure projects (i.e. electricity, gas and oil) that are of common interest (Projects of Common Interest – PCIs). The EC defines a common set of project assessment metrics in order to ensure the comparability among projects and measure their potential benefits, based on their economic, social and environmental viability. Therefore, our objective is to provide a tool for assisting the investment decision-making process to determine EC financial support, analyzing the different investment options.

6.2.3.1. Modeling contributions

We propose a multi-objective bilevel optimization model (MOPEC) for the representation of the sequential nature of operation and investment decisions to the capacity expansion problem in the natural gas market.

- We introduce the natural sequence of investment and operation decisions into a gas market model by representing the capacity expansion problem as a bilevel problem. That is, instead of considering all decisions to be taken simultaneously (i.e. single level), first investments are decided and then the market equilibrium takes place.

- Moreover, this problem structure captures the strategic behavior and the different interests of market participants, which do not necessarily have to be the same, and actually might have opposing objectives, such as maximizing social welfare vs maximizing profits of market players. In this case, the network planner chooses capacities that maximize its preferences in the first stage (upper level) while the second stage (lower level) represents the Cournot-price-response natural gas market equilibrium.

- We propose a multi-objective model in order to allow the capacity expansion decision maker to evaluate different expansion plans under different criteria, and to obtain a portfolio of optimal investment solutions (i.e. the Pareto front of optimal plans).
    - We assume the EC performs the tasks of a system network planner and acts as a decision maker and as leader investing in new pipeline and regasification capacity.
    - The EC preferences for the PCI assessment have been captured by the following criteria: total investment costs, utility of demand, price differences between zones, and diversity of suppliers. Depending on the importance assigned to each of these criteria, different optimal investment plans can be obtained. By varying the importance assigned to the different criterion (i.e. in accordance with decision maker preferences) we can explore the solution space of optimal investment plans, enlarging the range of solutions under analysis (i.e. not just a single optimal solution), revealing trade-offs and compromises between the conflicting aspects of evaluation.
- The model will therefore assist the decision maker to explore the different options and offers a better understanding of the decision problem and thus, results can serve as reference and contribute to shape the decision maker's preferences.

- The lower level represents the downstream natural gas market structured as follows: traders represent the interface with the upstream sector and marketers the downstream market, supplying final demand. In the lower level market agents (i.e. traders, marketers & TSOs) maximize their profits, taking the investment capacities as fixed.

- The model is used for the assessment of the optimal infrastructure investment in the North-South Gas Interconnections in Western Europe.

6.3. Future Research

To conclude this thesis, we summarize some interesting topics for future research, which have arisen throughout this document. We classify them into two main groups: on the one hand, modeling improvements; on the other, market assessment and regulatory analysis.

6.3.1. Modeling improvements

As throughout this thesis, we have proposed optimization models in order to improve current operational and investment planning tools in the natural gas sector arena. We classify modeling improvements under different categories.

6.3.1.1. Operational Planning

For a more accurate representation and assessment of the implementation of virtual natural gas hubs, further research lines could include an improved definition of the elasticities and, in particular the cross-price elasticities with substitute goods and the consumers' switching behavior. Additionally, there is a "virtuous-cycle" effect when the volatility of hub prices goes down, as it stimulates the shift from long-term contracts with fixed prices to hub-based pricing. It would be of interest to study this implication during the different proposed stages for the development of virtual natural gas hubs.

Other hypotheses of our model that could be addressed in future research are

- To include a simplified representation of the network to study the influence of network congestions.
- To include natural gas storage and assess its influence on the gas market prices.
- To study the potential benefits of hubs increasing efficiency of resource allocation.

Regarding the mid-term optimization model GasValem-GoG, it could bring extra added value if we take into account the following topics:

- Model calibration has been done using field data to estimate the unknown parameters of the model. This task might be complicated by discrepancy between the model and reality, and by possible bias in the data. In this sense, in would be interesting to apply calibration techniques and a robust calibration methodology in order to improve the model data calibration process and satisfactorily internalize the strategic component of market players as response to certain reference variables.
- As the role of gas in the future energy mix is not clear, uncertainty can be introduced in the model using a probabilistic or a stochastic approach. This would enrich the model, allowing to examine the effects of uncertainty in the natural gas market prices and delivered volumes. Uncertainty can be introduced for example in recoverable reserves and production rates, in future demand volumes, and/or in oil commodity prices.

- Endogenously modeling short-term contracts (from months up to 5 years) contracting. Therefore, shippers could choose between contracting gas in advance under a short-term arrangement or going to the spot market. Moreover, shippers should be also able to choose between gas forward and oil-indexed contracts.
- Moreover, another challenge is to adapt the GasValem-GoG model into a bilevel programming model, in order to consider the nature sequence of contracting some volumes in advance (endogenously) and the market clearance. That is, shippers would decide how much gas to contract under short-term contracts in the first stage while in the second stage shippers optimize their gas portfolio, by selling and buying gas in the hubs and the exerted volume above the long-term contract. Moreover, by making it an equilibrium, gas-on-gas pricing in supply contract will be automatically integrated into the problem without the need to resort to an iterative process to solve this issue. Also, the equilibrium model will also allow for endogenously capturing the strategic behavior in contracts negotiation. However, the large size of the problem, due to its detailed representation of agents and infrastructures, and its granularity might complicate the task immensely, as current equilibrium solvers are not yet prepared for large-scale problems.

6.3.1.2. Investment decision planning

From the modeling point of view, the challenge here are:

- First, to enrich the GAMOPEC model with further criteria that need to consider by the decision maker for assessing the investment decision problem.
- Second, considering the level of uncertainty that accompanies any long-term decision, and having in mind that natural gas infrastructures are cost intensive, we propose introducing a probabilistic or a stochastic approach.

6.3.2. *Market assessment and regulatory analysis*

As the general objective of this Thesis is to advance research in global gas markets modeling by developing realistic models, in order to carry out relevant studies for the assessment of the EU internal gas market, several market assessment and regulatory analysis can be proposed. Moreover, it is important to highlight that our models do not only satisfy academic purposes, but also industry objectives. Thus, our models are valuable tools for any gas market stakeholder such as market participants, regulatory authorities, or system operators. Some examples of complementary analyses are mentioned below:

Projects of Common Interest:

- An assessment of the different priority gas corridors, in order to evaluate the different infrastructures options and take infrastructure expansion decisions efficiently, allocating their resources in a highly competitive global setting. Moreover, as natural gas infrastructures are capital intensive and on the other hand natural gas is considered as a transition fuel in Europe, we suggest exploring different scenarios in order to evaluate Projects of Common Interest impact.

Natural gas hubs:

- Natural gas hubs are transforming the way natural gas is trade and consequently, reducing long-term contracts volumes in favor of spot transactions. The proposed models in this thesis can be an option to carry out exhaustive analysis focusing on the evolution of hubs, their degree of competition and their impact in the resulting market prices and their volatility.

Global gas market assessment:

- In addition, the GasValem-GoG model developed in this thesis may also be useful to give insights of the future near-term global gas market dynamics. Therefore, it is a valuable tool in order to perform scenario analysis and to assess the impact of the different natural gas dynamics. Examples of sensitivities which can be explore are: the impact of gas-on-gas pricing versus oil indexed, by a sensitivity analysis on oil prices, the impact of the new coming liquefaction capacity in North America, or the impact of US-China Trade War in LNG exports.