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Bridging the Atlantic

The Integration of European and North American Natural Gas Markets

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Executive Summary:

The purpose of this thesis is to answer the question whether the transatlantic market for natural gas is integrated or not. The driving forces that are presently influencing the market and which forces might influence the market in the future are also investigated.

Regulatory efforts, the growth of LNG trade, and the shale gas revolution have been some of the most influential factors on the natural gas market in the previous two decades. While the exact future role of natural gas is unclear, it is a key component of many technological applications. Most recently, the COVID-19 pandemic has changed economic conditions around the world dramatically and is one of the causes for the 2021 global natural gas price surge.

We analyze daily price data from six gas trading hubs, two in North America and four in Europe, between January 2016 and November 2021. The analysis consists of bivariate cointegration tests developed by Engle and Granger, and the multivariate cointegration test developed by Johansen. Additionally, we test for Granger causality.

The cointegration tests indicate that there is a long-term relationship between the prices at all the analyzed trading hubs. Interestingly, not all hubs show significant adjustment tendencies towards the long-term equilibrium. Furthermore, we do not find any Granger causality between hubs on different continents. These mixed results do not allow us to conclude that the markets are perfectly integrated, but a certain degree of integration is undeniable.

Moreover, the research done for this thesis has provided an optimal opportunity to critically examine and discuss the future role of natural gas. The future development of the market for natural gas is likely to be influenced by its role in a transition to a low carbon emission economy. The utilization of natural gas as a bridge fuel or its relation to hydrogen could justify the further development of natural gas markets and efforts towards more market integration.

List of abbreviations

€/MWh	Euro per Megawatt hour
ADF test	augmented Dickey Fuller test
AIC	Akaike Information Criterion
alpha	adjustment speed parameter in an (V)ECM
AR(n)-model	autoregressive model of order n
atm	Atmosphere
BCM	Billion cubic meters
BIC	Schwarz-Bayesian information criterion
C02	Carbon dioxide
C2H6	Ethane
C3H6	Cyclopropane
C3H8	Propane
C4H10	Butane
C5H12	Pentane
C6H12	Cyclohexane
C6H14	Hexane
C6H6	Benzene
CCUS	Carbon capture utilization and storage
CH2	Compressed hydrogen
CH3OH	Methanol
CH4	Methane
CIS	Commonwealth of Independent States
CNG	Compressed natural gas
CO	Carbon monoxide
CO(NH2)2	Urea
COVID-19	Coronavirus disease of 2019
DAP	Diammonium Phosphate
Dawn	Enbridge Gas Dawn Hub
ECM	error correction model
EIA	United States Energy Information Administration
EPA	United States Environmental Protection Agency
EU	European Union
FCVs	Hydrogen fuel cell vehicles
FERC	The Federal Energy Regulatory Commission
FLNG	floating liquified natural gas
FPC	The Federal Power Commission
g	gram
GC	Granger causality
GHG	Greenhouse gasses
GIIGNL	the International Group of Liquefied Natural Gas Importers
GTL	Gas to liquid

GTS	gas to solid
GTW	Gas to wire
GWP	Global warming potential
H2	Hydrogen
H2O	Water, dihydrogen monoxide
H2S	Hydrogen sulfide
He	Helium
HH	Henry Hub
HQIC	Hannan-Quinn information criterion
I(n)	integrated of order n
IEA	International Energy Agency
IGU	The International Gas Union
IPCC	inter-governmental panel on climate change
kg	kilogram
KT	Kiloton
LH2	Liquid hydrogen
LNG	Liquid natural gas
log	natural logarithm
m	meter
MAP	Monoammonium Phosphate
MCM	million cubic meters
MJ	million Joule
MMBtu	million British thermal units
Mt	Million tons
MWH	megawatt hour (3,6*10^9 Joules)
N2	Nitrogen
N2O	nitrous oxide
NBP	National Balancing Point
NCG	NetConnect Germany
NH3	Ammonia
NH4NO3	ammonium nitrate
^{O}C	Celsius
THE	Trading Hub Europe
TTF	Title Transfer Facility
UK	United Kingdom
US	United States
US$	United States Dollar
VAR(p)-model	vector autoregressive model of order p
VECM	vector error correction model
VLCC	very large crude carriers
ZEE	Zeebrugge hub

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1. Introduction

The topic of this thesis is the integration of international natural gas markets, particularly in North America and Europe. We aim to answer the question whether these two markets are integrated or not. The question is of relevance since a large integrated market with a higher number of suppliers increases supply security and decreases price volatility, at least in theory. Furthermore, an increased level of competition is expected to lower prices which benefits consumers. Additionally, we also examine the driving forces that are presently influencing the market and which forces might influence the market in the future.

Recent developments in the markets for natural gas have made the topic of market integration relevant to public discourse. There has been a steady increase in gas exports from the US to Europe in recent years, that could strengthen the link between the two markets. This trend in exports is part of a global rise in LNG trade (BP, 2021). Another aspect that makes studying the integration of natural gas markets valuable is the tremendous increase of natural gas prices in Europe, as the prices have multiplied within months. In addition to that, a globally integrated market would make natural gas more attractive in comparison to other fossil fuels such as coal and oil, which are regarded as worse for the environment.

Recent studies have concluded that global gas markets are not integrated. (Nakajima & Toyoshima, 2019). However, there are signs of a tendency towards more integration of the European and North American market (Chiappini et al., 2019). In order to answer our research question, we will make use of methods that are well established in the market integration literature, namely the Engle-Granger and Johansen tests for cointegration, as well as Granger causality tests.

This paper adds value to the existing literature by including data from the years that were affected by the COVID-19 pandemic, as well as by including the price data at one of the largest Canadian gas hubs in the analysis, which has not been done before in papers about transatlantic gas market integration. Also to the best of our knowledge, there are no papers that have used a multivariate vector error correction models in similar settings.

The following part of the introduction will provide a definition of market integration as a concept, as well as the theoretical and political motivation for market integration. The next three parts of the thesis (two to four) will provide an overview of the technical aspects, the market changes, and trade flows of natural gas. The middle parts of the thesis (five to eight) focus on the main analysis, they provide a literature review, a data description, a description of methodology, and lastly the results of the analysis. The final two parts (nine and ten) of the thesis are dedicated to a discussion part and the thesis conclusion.

1.1 Market integration definition

Market integration is a broad concept but it is often linked to the absence of arbitrage possibilities and to the existence of the law of one price, as defined by Chen and Knez (1995). The law of one price states that prices of a homogenous good in the same market differ only by transaction costs. Reiterated for spatial trade, the law of one price states that when two or more markets interact in spatial trade of a homogenous good, their prices for the good will only differ by transaction and transmission costs (Persson, 2008).

This principle is also referred to in studies about gas market integration, for example by Siliverstovs et al. (2005) and Broadstock et al.(2020). Most studies about market integration focus on price data only, but some exceptions like Wakamatsu & Aruga (2013) do exist. As Grossman (1976) mentions, the reason for the use of prices is that they reveal and aggregate market information. The assumption of prices revealing and aggregating market information is also at the core of the efficient market hypothesis (Fama, 1970).

1.2 Theoretical motivation for market integration

The theoretical motivation for market integrating policies is to create efficient markets by increasing competition to counteract the market power of natural monopolies.

The regulation of the natural gas industry in Europe and Unites States (US) is underpinned by natural monopoly theory. The development of natural gas fields and transportation infrastructure have high initial fixed capital costs that discourage competition. Therefore, it is efficient for a single producer to supply the entire market output, characterizing the natural gas development and infrastructure market as natural monopolies.

Instead of offering the most efficient price the natural monopoly can provide, the break-even price (where the demand curve intersects the average/unit cost), monopolies will use their market power to set a monopoly price (where the marginal cost curve intersects the marginal revenue curve) that maximizes the producer surplus on the expense of the consumer surplus (Hannesson, 1998, pp. 37–43).

The social surplus (the sum of the producer and consumer surplus) is smaller when monopolists set the monopoly price compared to a price set by a market with perfect competition (where the demand curve intersects marginal cost curve). Regulators often justify the promotion of competition with the goal of increasing social surplus because competition prevents the use of monopoly prices, but this is not without issues (Goolsbee Austan et al., 2016, pp. 539–587).

Due to the high initial fixed capital costs of developing a natural gas field and its infrastructure, the natural monopolist needs to charge a break-even price to cover the initial capital investment. If market integration introduces competition to a natural monopoly, the competitive natural gas price might be lower than the break-even price of the natural monopolist (Hannesson, 1998, pp. 37–43).

Regulators that promote market integration need to evaluate if the social surplus gained by increasing competition is larger than the reduction of the producer surplus accrued by monopolists when competition is increased. Said differently, the maximization of the social surplus depends on the monopoly price, the break-even price, and the price set by perfect competition. Integrating a monopoly market will lower the natural gas price due to competition. Generally, the price set by perfect competition is the lowest, and the break-even price is lower than the monopolist's price. In comparison to the social surplus at the break-even price, there will be a reduction of consumer surplus if the monopolist price is set and a reduction of producer surplus if the price is set by perfect competition. Therefore, the optimal degree of market integration depends on the size comparison of the producer and consumer surplus as the market price decreases due to competition.

In closing, it is important to mention that market integration is one of many tools used to increase competition and thereby reduce the market power of monopolies by regulators. Direct price regulation and anti-trust laws are also common approaches (Goolsbee Austan et al., 2016, pp. 539–587).

1.3 European policy for market integration

Policy makers intend to promote market integration, because it can lead to better diversification of supply and dampen the impact of supply disruptions. Furthermore, a larger integrated market would increase competition between suppliers, which is especially important in the gas market, since it is characterized by a rather small number of suppliers.

Increased competition between suppliers would reduce prices and benefit consumers. The three gas directives by the European Commission (1998, 2003, 2009) are aimed at building a transparent and integrated market for natural gas in Europe by aligning market interests and reducing market barriers. The 1998 and 2003 directives objective were to gradually bring in competition and to develop an internal gas market in the EU. Policies were targeted towards gas facilities, retail supply of gas, gas transmission, and gas distribution. The directives also used measures to unbundle supply chains and to regulate the market in a progressive manner. The third directive in 2009, aimed to further unbundle vertically integrated operations, but also tightened the requirements on the separation of network from supply and production activities. Lastly, it also established “The Agency for the Cooperation of Energy Regulators” in order to monitor and regulate international network operators and energy trading practices.

As mentioned in Broadstock et al. (2020), trading blocks like the EU also want to integrate their market because it can increase the ability to bargain with large external suppliers of gas for the trading block. For the EU, The Russian Federation represents such a large external supplier of natural gas.

1.4 American liberalization and market integration

In comparison to Europe, the integration of natural gas markets in the US has taken a different approach. The regulation and later liberalization of The US gas markets started earlier than the European Union (EU) and can historically be split roughly into three main periods. The early natural gas period before the natural gas act of 1938, the period after the natural gas act of 1938, regulated by The Federal Power Commission (FPC), and the period from 1978 until today where natural gas is regulated by The Federal Energy Regulatory Commission (FERC). With regards to market integration, the last period is the most relevant, as it has several directives that liberalize the use of pipelines. The motivation for liberalizing the pipelines of the US natural gas market came from the common carriage approach already in use in the railroad, trucking, and oil pipeline industry. The natural gas pipelines had a merchant carrier approach, meaning that transmissions and transactions were bundled, in contrast an open access common carriage approach would mean that transactions and transmissions would be decoupled. (Oliver & Mason, 2018)

In 1985 FERC issued order No. 436 (followed by several smaller rulings), giving existing pipeline operators the option to apply for "blanket transportation certificates" allowing shippers of natural gas to have open access to their pipelines, with transport capacity allocated on a non-discriminatory, first come first serve basis (McGrew, 2009, p. 119).

Order No. 436 would also make the FERC provide optional expedited certification of a proposed pipeline, if the pipeline project was open access and transportation only. The expedited certification process could in some cases reduce the certification process of a pipeline by years.

Later in 1992 the FERC issued order No. 636, that continued the natural gas market liberalizations that order No. 436 started. Order No. 636 required all inter-state pipeline providers to offer a publicly accessible "electronic bulletin board" to provide customers with updated prices and other operations information. Another provision of Order No. 636 would be to standardize pipeline tariffs (Oliver & Mason, 2018).

While market liberalization is not directly market integrations, as it does not integrate previously disconnected markets, the liberalization of gas pipelines has similar implications as it connects producers to consumers previously unavailable to them. Market integration and liberalization both aim to stabilize natural gas trade flows, increase competition, and to decrease monopolistic behavior.

2. Overview of technical details:

2.1 Motivation for technical part

The overview of technical details serves a dual purpose for this thesis. Primarily it provides a technical background for the natural gas supply chain. Secondarily it provides definitions, explanations, and context for terms used later. The overview of technical details will elaborate the technical facilitators and challenges relevant to natural gas market integration.

Natural gas is an abundant fossil fuel with a wide variety of applications. The uses for natural gas include electric power generation, heating, fuel for transportation, as a chemical feedstock, and a variety of industrial uses. Because of the wide variety of natural gas uses, priority has been given to applications relevant to market integration.

2.2 Categories:

2.2.1 Conventional and unconventional

Natural gas is a large term, encompassing many different categories of gas. Like crude oil, natural gas is commonly divided into two categories, conventional and unconventional. The main distinction being that conventional can be found in reservoirs, and extracted by conventional methods, mostly vertical drilling, while unconventional cannot be extracted by conventional methods. Unconventional methods include horizontal drilling and multiple-well pads (Mokhatab et al., 2019, p. 21). However, it is important to note that the boundary between conventional and unconventional natural gas is not well defined because it depends on a continuum of geological conditions.

Coal seam gas (coal bed methane), tight gas, and shale gas are placed in the unconventional category due to them being extracted unconventionally, yet they are produced in large significant quantities, and are regarded as the main forms of unconventional gas (Mokhatab et al., 2019, p. 3).

Within the category of conventional natural gas, one can further divide into associated or dissolved natural gas, and non-associated natural gas (also know as gas well gas). Associated natural gas is natural gas that is found in reservoirs together with petroleum, either as free gas or as a dissolved gas, dissolved in a petroleum solution (Mokhatab et al., 2019, p. 21).

2.2.2 Composition of raw natural gas:

The general way of categorizing the components of raw natural gas is hydrocarbons, dilutants, and contaminants (Speight, 2019, p. 100).

Table 2.1

Composition of associated natural gas from a petroleum well

Category	Component	Amount (%)
Paraffinic	Methane (CH_4)	70—98
	Ethane (C_2H_6)	1—10
Cyclic Aromatic Nonhydrocarbon	Propane (C_3H_8)	Trace—5
	Butane (C_4H_{10})	Trace—2
	Pentane (C_5H_{12})	Trace—I
	Hexane (C_6H_{14})	Trace-0.5
Cyclic	Cyclopropane (C_3H_6)	Traces
	Cyclohexane (C_6H_{12})	Traces
Aromatic Nonhy-drocarbon	Benzene (C_6H_6), others	Traces
	Nitrogen (N_2)	Trace—15
	Carbon dioxide (C02)	Trace — 1
	Hydrogen sulfide (H_2S)	Trace occasionally
	Helium (He)	Trace—5
	Other sulfur and nitrogen com-pounds	Trace occasionally
	Water (H_2O)	Trace—5

Note: “Trace” refers to a small amount less than a percentage. Adapted from Speight, J. G. (2019). *Natural gas: A basic handbook (Second edition)*, (p.100). Copyright 2019, Gulf Professional Publishing, Elsevier INC. Accessed with license provided by Norwegian School of Economics (in digital library).

Raw natural gas is categorized by its composition of hydrocarbons. The main hydrocarbon components of raw natural gas are methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and pentane (C_5H_{12}), but trace components of hexane (C_6H_{14}) and heavier hydrocarbons do also occur. The hydrocarbons are the components of interest during natural gas production, mostly due to them being combustible, but other uses are also applicable. nitrogen(N_2), carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other sulfides are the main non-hydrocarbon components. N_2 and CO_2 are considered dilutants while, H_2S can be considered a contaminant (Mokhatab et al., 2019, pp. 4–5).

When the composition of the raw natural gas consists almost completely of CH_4, it is referred to as “dry gas”, if the composition includes heavier hydrocarbons, it might form liquids under production, and is referred to as “wet gas”. If there are liquids in the natural gas reservoir, they are referred to as “gas condensate”, the liquids occur due to the raw natural gas having a large share of relatively heavy liquid hydrocarbons.

Other terms used to describe raw natural gas composition are “lean”, and “rich”, referring to the amount of recoverable liquids from the natural gas well. Usually the recoverable liquids are propane, and heavier hydrocarbons. Lastly, when raw natural gas is described as “sweet” or “sour” it is a reference to the H_2S share of the composition. If the natural gas is “sour” it has a H_2S content that is unacceptable and needs to be removed before further processing (Mokhatab et al., 2019, pp. 4–5).

2.3 Sources of Natural gas:

2.3.1 Conventional

Conventional natural gas stems from three processes: (1) primary thermogenic degradation of organic matter, (2) secondary thermogenic decomposition of petroleum, (3) biogenic degradation of organic matter. It is also worth mentioning that gas stemming from the biogenic and thermogenic pathways, can be found in the same shale reservoirs (Speight, 2019, pp. 26–28).

2.3.2 Unconventional

There are many sources of unconventional natural gas, roughly 11 according to Speight (2019, p. 59). The main unconventional sources for natural gas are; coalbed methane, natural gas that occurs in conjunction with coal seams, tight gas and shale gas, which is natural gas recovered through hydraulic fracturing from shale and tight sand formations.

2.3.3 Conventional natural gas extraction

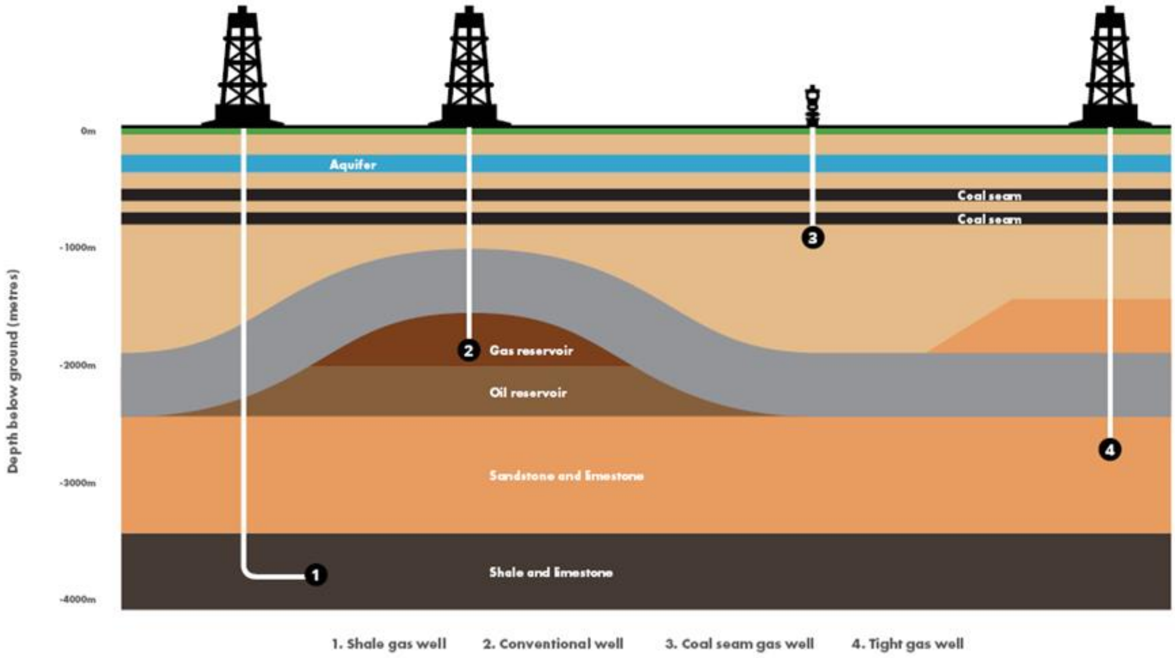
Very simplified, conventional extraction of natural gas happens after a seismic survey has identified a natural gas reservoir. The reservoirs can be found in many different types of rock strata, at varying approximate depths between 300 meters to 6000 meters. The wellbore may pass through several layers of oil and gas before reaching its targeted reservoir. The well drilling is a mechanically complex task, even more so if the well is offshore. The well is vertical, if one or more productive reservoirs are found a steel pipe is used for casing the wellbore and cemented into it. Finally, a wellhead is placed on top of the wellbore which is an assembly of control valves to control the flow from the well (Mokhatab et al., 2019, pp. 17–18).

2.3.4 Unconventional Natural gas extraction

There are too many types of unconventional extraction of natural gas, only hydraulic fracturing and vertical drilling will be described, because they extract the largest quantity of unconventional natural gas. Shale gas is usually extracted from shales at depths greater than 1500 meters, which have naturally low permeability. The extraction is done by hydraulic fracturing, large quantities of water, some chemicals, and sand (proppants) are pumped at high pressure into the shale gas well to fracture the shale. The shale gas is contained in free spaces or tiny voids spaces, pores, in the shale and are accessed by the generated fracture. The sand in the proppant prevents the soft parts of the shale from closing the newly created fractures. To increase the shale gas production from a single well, the contact area between the well and shale is increased by horizontal drilling after reaching the desired depth of the well. In the horizontal part of the well several fracturing procedures are performed. Lastly, the wellbore is cased and a wellhead is installed. Hydraulic fracturing is commonly referred to as “fracking” and is used both for shale and tight gas (Mokhatab et al., 2019, p. 3,21,22).

Figure 2.1

Types of gas wells



Note: Figure shows 4 different types of natural gas wells: 1) is an unconventional shale gas well, 2) is a conventional oil associated natural gas well, 3) is an unconventional coal seam gas well, and 4) is unconventional tight (sand) gas well. Adapted from Energy Information Australia. (2020). *Types of gas wells*. https://energyinformationaustralia.com.au/oil-and-gas-explained/formation-and-extraction/. Copyright 2020 Energy Information Australia. Published with permission (in public domain).

2.4 Transportation of natural gas

Natural gas can be stored, transported, and used in many different forms, there are six main methods used to transport natural gas over large distances. Natural gas can be transported through pipelines, as liquified natural gas (LNG) in carrier ships, as gas to liquid in carrier ships, as gas to solid in carrier ships, as compressed natural gas in containers, or as gas to wire though an electric grid.

2.4.1 Gas to liquid (GTL)

Without going into much detail, gas to liquid (GTL) is an umbrella term for converting natural gas into liquid fuels. Gasoline, kerosine, propane, butane, ammonia (NH3), methanol (CH3OH), precursors to plastic manufacture, chemical feedstocks, or lubricants are some examples of gas to liquid products. LNG is not in this category because it is mostly the same chemical as natural gas. This variety of liquid products is achieved by converting the natural gas first into synthetic gas (a mixture of CO and H2), by one of many pathways with a suitable catalyst technology. Secondly, the synthetic gas is further converted to the desired liquid by either the Fischer-Tropsch process, or by mixing the synthetic gas with oxygen (oxygenation). Each method requires specific catalysts to achieve one of the desired liquids (Mokhatab et al., 2019, pp. 4–5).

2.4.2 Gas to solid (GTS)

Gas to solid (GTS) is the conversion of natural gas to a solid natural gas hydrate, this is done by exposing the natural gas to water at low temperatures and high pressures. This can be described a frozen state of natural gas (Mokhatab et al., 2019, pp. 4–5).

2.4.3 Compressed natural gas (CNG)

Compressed natural gas (CNG) is natural gas compressed by 123 to 245 atmospheres (atm), depending on the purity of the CH4. A higher percentage of CH4 requires more compression (Mokhatab et al., 2019, pp. 4–5).

2.4.4 Gas to wire (GTW)

A large amount of transported natural gas is fuel for electricity generation. In some cases, the electricity generation can occur at the gas reservoir source and can be transported through the electrical grid from there. For instance, offshore gas can be transported to close shores by wire if the electricity can be generated offshore too, eliminating the need for pipelines or shipping (Mokhatab et al., 2019, pp. 24–31).

2.4.5 Pipelines

There are three major types of pipeline systems; gathering pipeline systems, transmission pipeline systems (interstate), and distribution pipeline systems. Furthermore, there are onshore and offshore pipelines, which have various sizes and varying pressure. Before continuing, it is important to note that while raw natural gas has the beforementioned composition (Table 2.1), natural gas refined for consumption is almost completely composed of CH4. The precise composition depends on the legal, technical, and qualitative standard of major transmission and distribution companies (Speight, 2019, p. 169).

2.4.6 Liquified natural gas

LNG is composed almost entirely of CH4 gas that is liquified by being cooled with an approximate temperature of -1620 ^{O}C. The precise temperature depends on the CH4 share of the composition. At a temperature of -162 ^{O}C and a pressure of 1atm, the LNG has approximately 600 times less volume than natural gas at 0 ^{O}C (also at 1atm) and weighs approximately 45% as much as the same quantity of water. LNG is impractical as fuel for small vehicles due to it requiring cryogenic infrastructure and cryogenic tanks to be used, but it is practical for the transportation and storage of natural gas. The composition of LNG varies in different markets (Table 2.2) (Engineering Toolbox, 2008; GIIGNL, 2008; Mokhatab et al., 2019, pp. 25–26; Speight, 2019, p. 169).

Table 2.2

Composition of liquefied natural gas in various markets

	Composition (mole percent)				
Source	CH4	CH6	CH8	CH10	N2
Alaska	99.72	0.06	0.0005	0.0005	0.20
Algeria	86.98	9.35	2.33	0.63	0.71
Baltimore	93.32	4.65	0.84	0.18	1.01
New York City	98.00	1.40	0.40	0.10	0.10
San Diego	92.00	6.00	1.00		1.00

Note: mole is a unit used to measure substance amounts. Adapted from Speight, J. G. (2019). *Natural gas: A basic handbook (Second edition)*, (p.169). Copyright 2019 Gulf Professional Publishing, Elsevier INC. Accessed with license provided by Norwegian School of Economics (in digital library).

LNG is not only used for the same applications as natural gas after regasification, but can also be used as a fuel for a vareity of transportation application (Ogden et al., 2018). As a fuel, its most prominent in the use of marine transportation and transport by heavy duty trucks. Table 2.3 adpated from Ogden et al. (2018) shows the feasible utilization of natural gas compared with hydrogen (H2) in liquid and compressed state for transportation applications. Some of the applications are only feasible, as the applications have only seen limited adoption or prototype uses. A good example is aviation, where both LNG and Liquid hydrogen (LH2) are feasible but only prototype aircraft have ever existed (Dahal et al., 2021). The reason for compairing LNG with LH2 is because of technological intersections between natural gas and H2.

Table 2.3

Transportation applications for natural gas and H2.

Application	NG		H2	
	CNG	LNG	CH2	LH2
Light duty vehicles	x		x	
Buses	x		x	
Med duty trucks	x		x	
Heavy duty trucks	x	x	x	x
Rail		x		x
Marine		x		x
Aviation		x		x

Note: CNG is compressed natural gas, LNG is liquefied natural gas, CH2 is compressed hydrogen gas, LH2 is liquid hydrogen. Adapted from Ogden, J., Jaffe, A. M., Scheitrum, D., McDonald, Z., & Miller, M. (2018). *Natural gas as a bridge to hydrogen transportation fuel: Insights from the literature*. Energy Policy, 115, 317–329. https://doi.org/10.1016/j.enpol.2017.12.049. Copyright Elsevier. Accessed through Norwegian School of Economics license for Science Direct, Elsevier.

2.4.7 LNG ships

LNG is transported in specialized LNG tanker ships, which carry LNG from a liquification facility to a regasification facility in cryogenic tanks. After regasification the natural gas is usualy either consumed, or transported further by pipeline. The typical modern LNG tanker is in construction between 20 to 36 months, is 300 meters long, 43 meters wide, and has a capacity between 125000 to 175000 cubic meters of storage. The cost of a 175000 cubic meter LNG tanker ship is aproximatley 185 million dollars. There are many purpose built LNG carriers that are meant to be able to cross the Panama or Suez canal, and some rare types, like icebreakers for arctic regions. Most tankers have either a spherical tank design, refferd to as moss sphere design, or a membrane tank designs (GIIGNL, 2019). The global LNG tanker fleet consisted of 642 vessels by the end of 2020, and had a total cargo capacity of 95,2 million cubic meters (MCM). In compariosn the global oil tanker fleet is estimated to consist of 1200 tankers, of which 800 are classified as very large crude carriers (VLCC), meaning that each can carry aproximatley 320000 cubic meters of crude oil. In 2020, 47 LNG vessels were added to the global fleet, and 40 more were ordered, the newer ships have generally larger capacity than older ships (GIIGNL, 2021, p. 18).

2.4.8 FLNG:

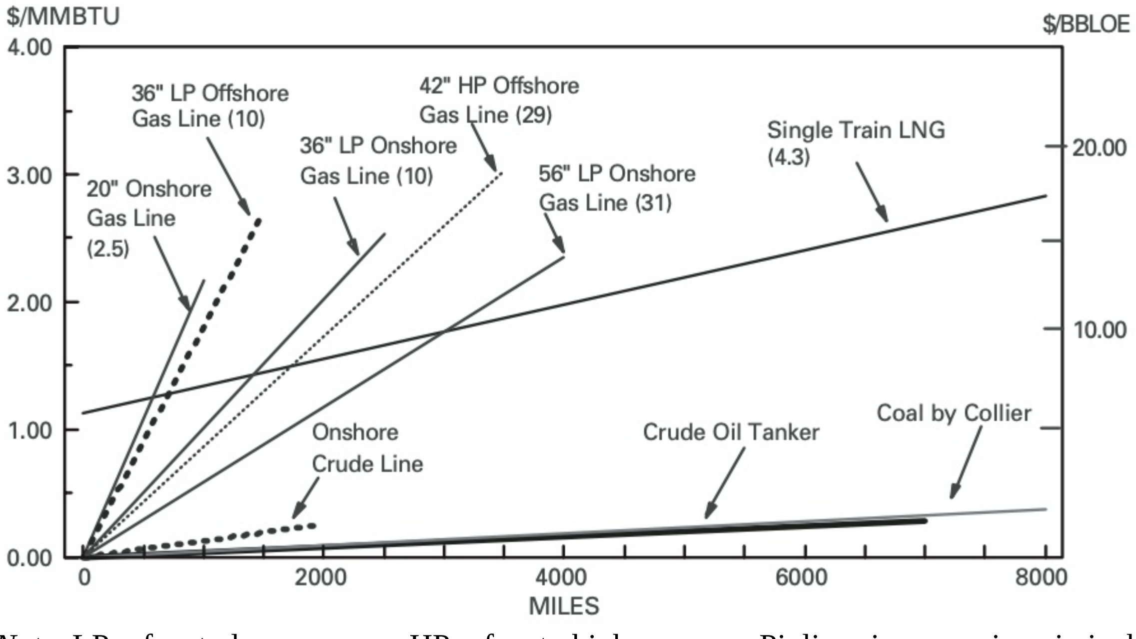
The most recent devlopment for LNG ships has been the introduction of floating liquified natural gas (FLNG) ships. FLNG ships, do not transport LNG, they produce and store LNG at distant offshore natural gas fields. They act more like self moving offshore platforms than ships. FLNG ships reduce the need for offshore plattforms, offshore pipelines, and onshore liquification facilities. To date few FLNG ships exist due to their massive cost and technical complexity (Mokhatab et al., 2019, p. 40).

2.5 Comparison of transportation methods

Of the six most common methods for transporting natural gas, pipelines and LNG are the most prevalant. The reason for this is that pipelines and LNG are the most mature technologies and commercially viable. GTL and GTW are both mature, but lack efficiency in comparison. CNG and GTS are not as mature technologically as LNG and pipelines, and require further research and development to become commercially viable for transportation of natural gas over long distances (Mokhatab et al., 2019, pp. 24–31). The commercial comparison of the different transportation methods depends on distance, volume, technology, geography, logisitcs, legal, and political factors. In other words, the costeffectivness of any gas transportation system differs from project to project. Some general insights can still be drawn, when examining the cost effectivness of transporting natural gas by pipeline or LNG. Usually, LNG is more cost effective at longer distances than pipelines. However, the distance at which LNG becomes more cost effective than pipeline transportation, differs due to all the previously mention factors (Ulvestad & Overland, 2012). Some estimates under differing circustances are listed below. Tongia and Arunachalam (1999) estimate that LNG is more cost effective than pipelines at distances over 3219 kilometers (km), while Cornot-Gandolphe et al. (2003) estimated 4500 km in 2003, Quintana (2003), argued that the distance would be 4000 km, and Paul Stevens (2009) estimated 5000 km. Mäkinen (2010) claimed that LNG would be cost competitive against land based pipelines with a distance between 3000-4000 km, or against offshore pipelines with a distance of 2000 km. Hannesson (1998) claimed that LNG typycally is cost competitive against offshore pipelines at distances over 1500 km, and onshore at over 3500 km. Lastly, James T. Jensen (2004) made figure 2.2 of his estimates for the costs associated with transporting various fossil fuels over long distances in comparison to pipelines and LNG.

Figure 2.2

Illustrative costs of gas, oil, and coal transportation.



Note: LP refers to low pressure. HP refers to high pressure. Pipline sizes are given in inches. The numbers in brackets show gas delivery capacity in BCM. MMBTU refers to metric million British thermal unit. BBLOE reffers to billion barrels of oil equivalent, miles are road miles, not nautical miles. $ refers to the United States dollar with the valutation of the time of writing. Adapted from Jensen, J. T. & Oxford Institute for Energy Studies. (2004). *The development of a global LNG market: Is it likely? If so, when?* Oxford Institute for Energy Studies. Copyright 2004 Oxford Institute for Energy Studies. Published with permission (publicly available).

2.6 Natural gas storage

The main motivation for storing natural gas is to meet seasonal demand, smoothing out daily fluctuations in natural gas consumption, and as an insurance against any type of natural gas supply disruption. Natural gas storage facilities are usually divided between peak load storage and base load storage. Base load storage refers to storage facilities with low delivery rate, they are mostly used to meet seasonal demand in the winter and are filled in the summer. Peak load storage facilities have a high delivery rate and are used to smooth out short-term supply and demand fluctuations. Base load facilities have turnover rates of typically one year while, peak load facilities have turnover rates of days or weeks. Most Natural gas storage happens in underground facilities. The main types of underground natural gas storage facilities are depleted reservoirs of oil or natural gas, aquifers, and salt cavern formations. Abandoned mines or rock caverns are less likely to be used. Natural gas can also be stored in liquid or gaseous form in above ground storage tanks. Above ground tanks are usually cheaper and have better deliverability rate (also known as withdrawal rate) but lack the capacity of underground storage (Mokhatab et al., 2019, p. 33). Table 2.4 shows storage values for some countries relevant to transatlantic market integration (IEA, 2019a, pp. 95–101).

Table 2.4

Storage capacity, and peak daily output for selected countries

Country	Working capacity (MCM)	Peak output (MCM/day)	Share of region	Storage capacity in days at peak output
Germany	24265,00	653,00	22,27%	37,16
Belgium	680,00	15,00	0,62%	45,33
Netherlands	13967,00	268,00	12,82%	52,12
United Kingdom	1440,00	117,10	1,32%	12,30
Europe total	108978,00	2058,00	100,00%	52,95
Canada	23924,00	329,60	14,83%	72,58
Total USA	137358,00	3371,10	85,17%	40,75
North America total	161282,00	3700,70	100,00%	43,58

Note: MCM refers to million cubic meters of natural gas. The energy content per cubic meter of natural gas is approximately 41,25 million Joule (MJ). share of region and storage capacity in days at peak output is calculated from Working capacity and Peak output. Working capacity and Peak output are adapted from IEA. (2019). *Natural Gas Information 2019*. International Energy Agency. https://www.oecd-ilibrary.org/energy/natural-gas-information-2019_4d2f3232-en. (pp.95-100). Copyright 2019 IEA. Published with permission (publicly available).

2.7 Gas to power conversion

2.7.1 Heating value and energy content

Natural gas measurement units are usually converted from the gross heating value, also known as the energy content of the natural gas. The energy content refers to the gross heat energy that is released when the natural gas is combusted under ideal conditions. This is the preferred way of quantifying natural gas because it is related to the main uses of natural gas, electricity generation and heating. If natural gas is used for electricity generation the amount of electric (or mechanical) energy gained from combustion is less than the energy content, this efficiency of energy conversion is referred to as Carnot efficiency. This thesis uses mostly (unless stated otherwise) BPs energy content definition of natural gas of approximately 40 MJ per cubic meter of natural gas (BP, 2021). It is important to note that different markets have different standards for energy content per cubic meter of natural gas as the precise composition of the natural gas is dependent on the qualitative standard of major transmission and distribution companies. For example, Hungary has a standard of 34.12 MJ per cubic meter of natural gas. Another important detail is that different journals and reports may also use different energy content per cubic meter, therefore these need to be checked if comparisons are to be made (MET Group, 2021).

2.7.2 Single and combined cycle turbines

The electric power generation is usually facilitated by a single cycle gas turbine plant or a combined cycle gas turbine plant. A single cycle gas turbine does only utilize the initial combustion of natural gas to generate electric power. Combined cycle gas turbine plants can utilize the exhaust heat from the initial gas turbine combustion, to make steam, that can be further be utilized in a steam turbine. Combined cycle gas turbine plants are more expensive to build than single cycle gas turbine plants, but they are more efficient in extracting energy form natural gas (Petrowiki, 2015). The precise efficiency of a gas power plant depends on many factors. In general a single cycle gas turbine can generate electirc power from the energy content of natural gas with an Carnot efficiency of 30-40%, while a combined cycle gas power plant might reach efficiencies of 55- 60% (Wärtsilä, 2021).

2.8 Natural gas trading hubs and pricing mechanisms

2.8.1 Virtual and physical trading hubs

A natural gas trading hub brings together many buyers and sellers, it helps to match supply and demand at low transaction costs. Hubs also provide their customers with reliable price signals in a liquid market. Modern hubs do not require the physical attendance of their customers as they provide internet-based trading platforms, this expedites and improves the natural gas transportation process. Hubs also provide a price benchmark for a given region (Zhu, 2014).

There are many hub concepts for natural gas and for other activities. Benchmark hubs, financial hubs, balancing hubs, virtual hubs, physical hubs, risk management hubs, and exchanges, are all used in literature, unfortunately the terminology often overlaps or is inconsistent. For example, many natural gas hubs are labeled as trading hubs, regardless of their liquidity or the existence of financial trading. (Shi & Variam, 2018). The most common classifications of natural gas trading hubs are physical and virtual trading hubs. A physical trading hub for natural gas is a centrally located and sufficiently interconnected network point, where a price is set and delivered from that central point. A virtual trading hub (also referred to as a virtual trading point), is a market area where gas enters and exits, one or several network operators may deliver gas to exit points as part of the virtual hub. (Shi & Variam, 2018). In Europe, virtual hubs often overlap national borders, for example National Balancing point (NBP) overlaps the entire British geographic area (IEA, 2013).

2.8.2 Pricing mechanisms

At the physical and virtual hubs, the pricing mechanism for natural gas may differ, the international gas union (IGU) has identified three major market pricing mechanisms covering OECD and non-OECD countries.

1) Oil indexation or product indexation refers to gas prices that are linked to other fuel prices. These other fuel prices are mostly crude oil, refinery products, or coal.
2) Gas to gas competition refers to spot prices that reflect the supply and demand for natural gas in the market.
3) Netback from final product refers to contracts where the gas price is linked to the price of a final product in the value chain of natural gas, a good example of this would be the price of NH3.

In addition to the previously mentioned pricing mechanism, there are some pricing mechanisms that are not facilitated in hubs, but by governments or by large market actors.

1) A bilateral monopoly refers to one large buyer and one large seller who usually determined a fixed price over a certain time period.
2) Regulated cost of service refers to a gas price determined by a governmental directive, as a tool to recover investment costs of a natural gas related activity at a reasonable rate.

3) Regulation below cost refers to a gas price determined by a governmental directive, set below the average price of natural gas production. This is often done to subsidize natural gas consumption.
4) Regulation according to social or political circumstances refers to a gas price determined by a governmental directive, with a purpose of serving some political or social purpose (IGU, 2016, p. 11).

2.8.3 Evaluating hubs

Natural gas hubs can be compared with numerous metrics, the most usual are total traded volume, number of financial products available, number of active market participants, and “churn” rate. The total traded volume, and the number of active participants are used to measure the size of a hub while, number of available financial products at a hub are a sign of the hub being mature and trusted. The gross “churn” rate is an expression used for the total traded volume divided by the physical demand or throughput. The net “churn” rate is an expression for the total traded volume divided by consumption. Put simply, the “churn” rate indicates how many times traded gas has been re-traded before it is finally sold or consumed. The churn rate is not only an indicator of market liquidity but also of hub maturity. A churn rate above 10 is considered to be a sign of a mature hub, with many traders (Heather & Oxford Institute for Energy Studies, 2021, pp. 7–9).

2.9 Natural gas and Hydrogen

2.9.1 Hydrogen Production

One of the most important products derived from natural gas is H2. Presently, most H2 is produced by steam reforming of natural gas (Mosca et al., 2020; Yilmaz & Selbaş, 2017). There are many current and potential uses of H2, that are therefore also relevant for natural gas. H2 is produced by reacting the CH4 in natural gas with water vapor at high temperatures. This reaction is followed by a water gas shift reaction. The simplified chemical equation for these two reactions is the following:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad \text{(Steam-methane reforming reaction)}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \text{(Water-gas shift reaction)}$$

H2 is a versatile gas that can be used in oil refining, plastic production, NH3 production for use in fertilizers, and in other applications (Speight, 2019, p. 111). According to the International Energy Agency (IEA) (2019b) nearly all industrial H2 is produced from fossil fuels feedstocks, either directly or indirectly. The global production of pure H2 was around 70 million tons in 2018, and natural gas represented around three quarters of the feedstock. Of the approximately 70 million tons (Mt), around 32 Mt was used for NH3 production, and 38 Mt for oil refining. The large feedstock share of natural gas in H2 production suggests that the price of H2 is either linked to natural gas, or to coal the second largest feedstock for H2 production with a share of 23% (IEA, 2019b, pp. 18–38).

2.9.2 Different classifications of hydrogen:

H2 cannot only be mass produced from natural gas, but also from other fossil feedstocks like coal. However, there are other production methods with less carbon emissions that are regarded as expensive and have not seen mass use yet. Using the same system of definition as Yu et al. (2021), H2 can be classified by its production in relation to greenhouse gas emission, nicknamed with different colors.

1) "Black H2" refers to H2 produced from coal.
2) "Grey H2" refers to H2 produced by the steam reforming of natural gas.
3) "Blue H2" refers to grey or black H2 produced with carbon capture, utilization, and storage (CCUS).
4) "Green H2" refers to H2 that is produced by electrolysis of water with electricity from renewable resources, with no CO2 emissions.

Its important to note that CCUS refers to a suite of technologies, and not to a singular technology, meant to capture, store, and utilize CO2 (IEA, 2021a).

2.9.3 H2 as fuel

Another use of H2 is as fuel for hydrogen fuel cell vehicles (FCVs). When reacted with oxygen in a fuel cell, H2 generates electric power, water, and heat (Speight, 2019, p. 20).

$$2H_2 + O_2 \rightarrow 2H_2O + Heat + Electic\ power$$

FCVs have been proposed as the future of personal transport because of their potential to reduce greenhouse gas emissions and air pollution (Nguyen, 2013), but have not seen mass use yet. PR Newswire (2017), estimated that 5500 FCVs were in use by 2017 globally, Ogden et al. (2018) points out that a major reason for this low adoption rate is the lack of widespread H2 infrastructure for consumers, which is seen as risky and expensive to implement.

2.9.4 Natural gas as a chemical feedstock for fertilizer

The production of H2 from natural gas is a very important pathway to several technologies and products, but another product related to H2 desserves mentioning, NH3. The production of NH3 has similar first steps as the production of H2. In order of brevity and simplicity the chemical equations will not be shown (the chemical equations can be found in the refferenced document) (van Nieuwenhuyse, 2000, pp. 7–17). The seven steps for NH3 production from natural gas are:

1) Desulfurization of natural gas – the removal of sulfur from the natural gas

2) Primary reforming – CH4 reforming, endoterm reaction.

3) Secondary reforming – CH4 reforming, exoterm reaction.

4) Shift conversion – CO is removed in endoterm reaction.

5) CO2 removal.

6) Methanation – the conversion of leftover CO and CO2 to CH4.

7) NH3 synthesis through the Haber-Bosch process, NH3 is produced from N2 and 3H2.

NH3 is the main input for all N2 based fertilizers, and is therfore important for food production. NH3 can itself be used as a chemical fertilizer or be the chemical feedstock for producing urea (CO(NH2)2), ammonium nitrate (NH4NO3), other nitrogen soultuions, or more complex nitrogen fertilizers like Diamonium Phosphate (DAP) and Monammonium Phosphate (MAP) (Huang, 2007). Thus, a change in NH3 prices leads to a price change for all N2 based fertilisers. Natural gas accounts for 72-85% of the production cost of NH3, depending on the size of the NH3 production plant. Therfore, the price of natural gas will also influence the price of all N2 based fertilizers. Approximately 33 MMBTU of natural gas are needed to produce 1 ton of NH_3. Between 1985 and 2006 the price of NH_3 correlated with the price of natural gas in the U.S (Huang, 2007).

2.10 Environmental concerns:

The environmental concerns surrounding fossil fuel use and production is a field of science with many nuances and complicated technical details. Because all the concerns are beyond the scope of this thesis, this section will examine some of the most prominent concerns relevant to the global market for natural gas. The motivation behind the chosen concerns is to provide an overview of factors that might affect decision making in the natural gas sector, and by extension the entire fossil fuel sector.

2.10.1 Greenhouse gases (GHG) potentials:

Most natural gas is utilized by combustion, which releases greenhouse gasses (GHG) into the atmosphere. GHG absorb infrared radiation and thereby trap heat in the atmosphere of the planet. This can happen directly, when the gas emitted absorbs radiation, or indirectly, when the emitted gas transforms chemically into a greenhouse gas, when the emitted gas influences the atmospheric lifetime of other gasses, or when the emitted gas affects atmospheric processes that alter the radiative balance of the planet (EPA, 2020, pp. 1–4). The United States Environmental Protection Agency (EPA) (2020) uses global warming potential (GWP) scale defined by the inter-governmental panel on climate change (IPCC) (2013), to assess the potency of various gasses. The scale uses CO_2 as its comparative unit, and has a 100-year time span, because gasses decay over time in the atmosphere at different rates. Table 2.5 presented below lists the most common GHG, and their global warming potential. CO_2, CH_4, and N_2O being the most common (*Framework Convention on Climate Change*, 2013, p. 24).

Table 2.5

Global Warming Potentials (100-Year Time Horizon)

Gas	GWP
CO2	1,00
CH4	25,00
N20	298,00

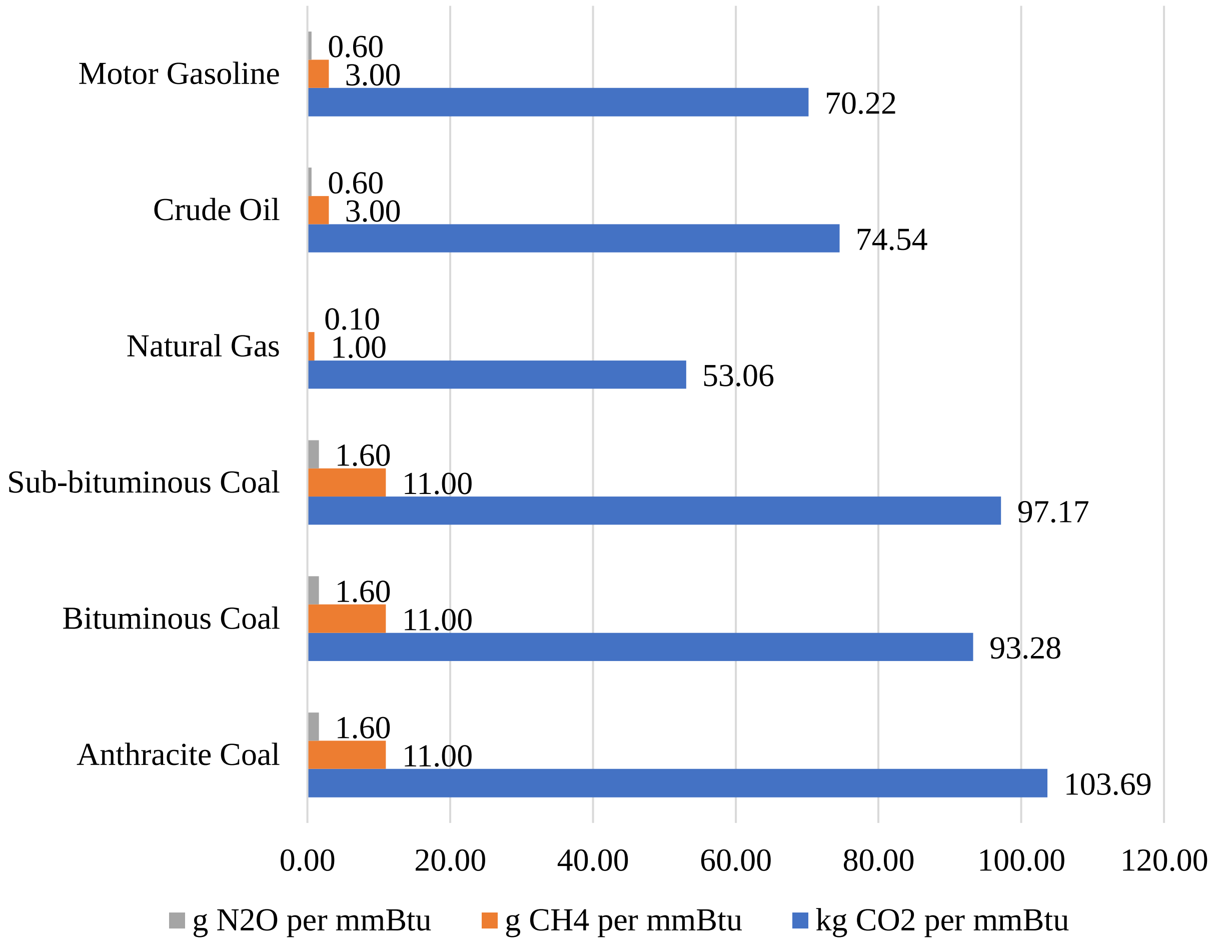
Note: GWP is global warming potential. The GWP of CH4 includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to production of C02 is not included. Adapted from *Framework Convention on Climate Change*, 2013, (p. 24). Copyright 2013 UNFCC. Published with permission (publicly available).

2.10.2 Emission comparison of fossil fuels

Comparing the most common emissions and heating value from the combustion of the most common fossil fuels yields Figure 2.3 (EPA, 2021b). All emissions from the combustion of natural gas are lower than from other fossil fuels. This is the likeley reason natural gas has been precived as the least emmiting fossil fuel, and promoted as a “bridge fuel” to a renewable energy economy. Coal is divided into 3 of its 4 categories, they differ in many aspects, also when it comes to emissions. (USGS, 2020). Natural gas emits less GHG than other fossil fuels per MMBTU, but it is still a large contributor to global GHG emissions due to its abundant use. Examining estimated global CO2 emission by fuel from the IEA gives an indication of its emissions compared to oil and coals emissions (IEA, 2021d).

Figure 2.3

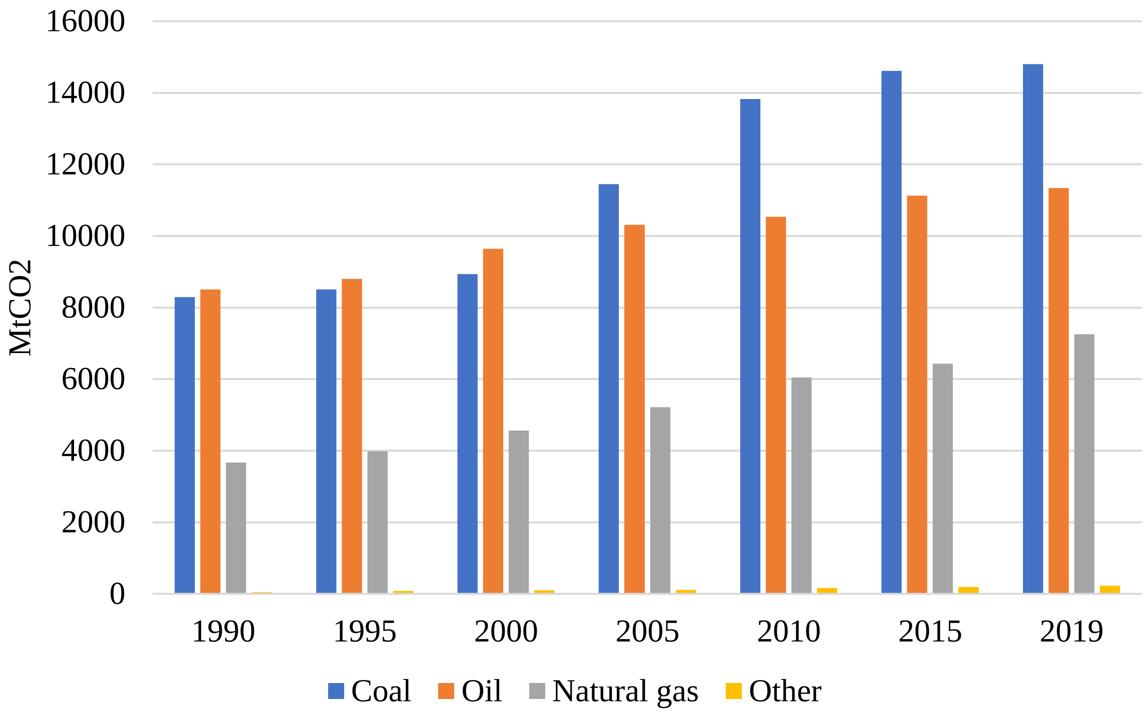
Emissions per MMBtu



Note: There is a large difference in emissions as kg of CO_2 are compared to grams (g) of CH_4 and N_2O. MMBTU refers to metric million British thermal unit. Motor gasoline is gasoline refined from crude oil. Adapted from EPA. (2021). *GHG Emission Factors Hub*. https://www.epa.gov/climateleadership/ghg-emission-factors-hub. Copyright 2021 EPA. Adapted with permission (publicly available).

Figure 2.4

Global CO2 emissions from combustion of fuel (MtCO2)



Note: Mt refers to million tons. Adapted from IEA. (2021). *Greenhouse Gas Emissions from Energy, GHG emissions from fuel combustion*. https://www.iea.org/data-and-statistics/data-product/greenhouse-gas-emissions-from-energy#ghg-emissions-from-fuel-combustion. Copyright 2021 IEA. Accessed with license provided by Norwegian School of Economics.

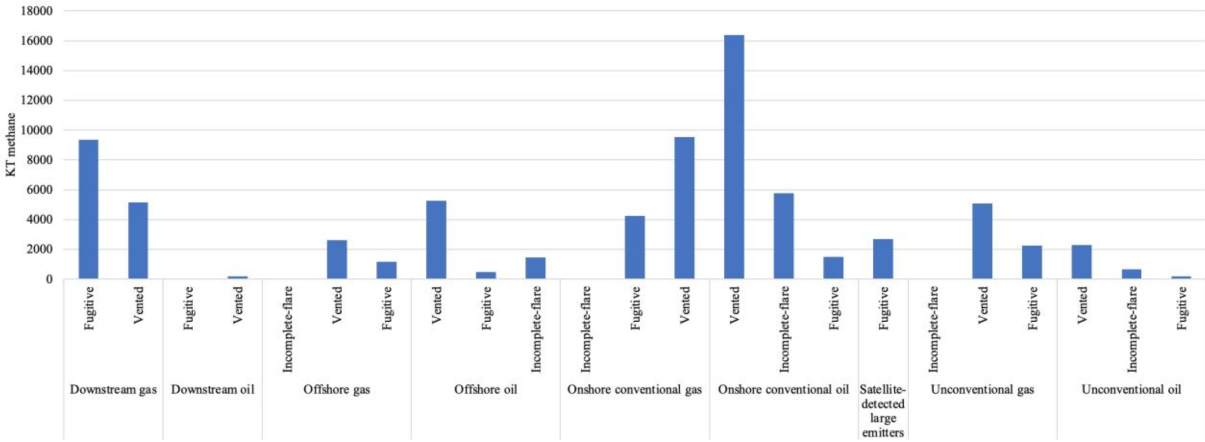
2.10.3 Flaring, venting, and methane emissions

Natural gas emits less CO2 than other fossil fuels when combusted, but during production and transportation significant CH4 emissions can occur. Flaring describes the controlled incineration of natural gas during oil and natural gas extraction. Flaring happens usually, but not exclusively, on the extraction site and is caused by a variety of reasons when further processing of oil and gas is halted. Another reason for flaring is the mitigation of harmful chemicals that otherwise would be released through venting. Venting being the direct release of raw natural gas into the air, a practice which used to be common a few decades ago. Depending on the flaring technology of a particular site, incomplete flaring might occur because of less efficient lower temperature flares. These lower efficiency flares are usually older flares that emit more harmful chemicals like hydrocarbons, H2S, and other particles during incomplete incineration (Speight, 2019, p. 371). While flaring is preferable to venting and incomplete flaring, flaring does create emissions such as nitrogen oxides, sulfur oxides, GHG, and volatile organic compounds (Mokhatab et al., 2019, p. 571).

In the US the natural gas and oil industry is the largest source of emitted volatile organic compounds, and the second largest source of CH4 emissions (EPA, 2021d). Volatile organic compounds can contribute to the formation of ground level ozone smog (EPA, 2021a) that effects children by increasing breathing, hematological, and skin problems (EPA, 2021c). Estimating the released CH4 emissions during oil and gas extraction is difficult, and estimates vary greatly. Anyhow, the IEA estimates that the total global CH4 emissions from oil and gas are 7 6394 000 tons in 2020. Most of these emissions are either from venting or from incomplete flaring (IEA, 2021e).

Figure 2.5

Global CH4 emissions from oil and gas (KT)



Note: KT refers to kiloton. Adapted from IEA. (IEA, 2021e). *Methane Tracker Database*. https://www.iea.org/articles/methane-tracker-database. Copyright 2021 IEA. Adapted with permission (publicly available).

2.10.4 Hydraulic fracturing and vertical drilling.

There are many types of unconventional natural gas that have specific environmental concerns tied to their extraction, production, transportation, and consumption. In this thesis, the primary consideration is given to shale gas due to “the shale revolution”, but hydraulic fracturing is also relevant for shale oil, tight oil, and tight gas.

Hydraulic fracturing is a controversial extraction method for unconventional gas and there has been considerable public opposition (Clarke et al., 2015). In the US, the oil and gas industry has been successful in overcoming the public opposition to hydraulic fracturing in many but not all states. (Nolon & Gavin, 2013). The success of shale gas extraction together with conventional forms of natural gas, has led the US to become the world’s largest producer of natural gas. (BP, 2021). The main concerns with hydraulic fracturing can be placed in 4 categories, some of which are shared by other types of natural gas wells:

2.10.5 Casing and cementing

If the casing and cementing of the shale gas well walls is faulty, contaminants will leak from the shale gas well. In the US it has been found that drinking water sources with close proximity to shale gas wells, might get contaminated with fluids from the fracturing process and CH4 (Brantley et al., 2014; Osborn et al., 2011; Vengosh et al., 2013). Jackson et al. (2013) found that the proximity from a faulty shale gas well to drinking water could statistically explain the CH4 contamination of drinking water, for sources of drinking water less than 1km form the shale gas well. Since shale gas is extracted from depths greater than 1500 meters, there should not be any contamination of groundwaters unless there is faulty cementing or casing (Darrah et al., 2014).

2.10.6 Wastewater handling

Generally, the chemicals used during hydraulic fracturing may contain toxic substances and the fluids exiting the well may also contain toxic substances from the rock strata. (Vengosh et al., 2014; Werner et al., 2015). These fluids must be handled with care, accidents or faulty storage poses a risk of releasing these toxins.

2.10.7 Seismic events

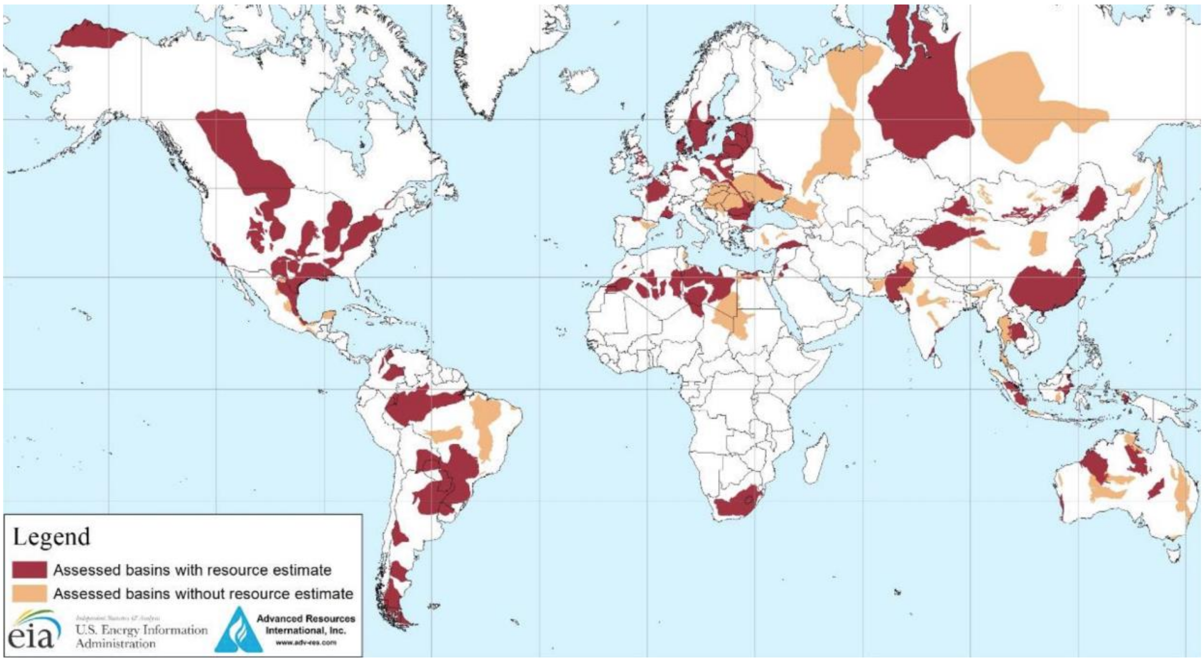
The probability for a major seismic event from hydraulic fracturing is low, yet there is research linking increased seismic activity with injection wells. The research suggests that the few seismic events mostly depend on geological conditions, surrounding injection wells. (Frohlich, 2012; Rubinstein & Mahani, 2015). The extraction of liquids from oil and gas wells, can in rare cases increase seismic activity as well (Frohlich & Brunt, 2013). Injection wells are a general term for reservoirs that are used to be injected with fluids. Their applications include the production of geothermal energy, secondary recovery in oil and gas fields, disposal of waste fluids (often from hydraulic fracturing), and hydraulic fracturing (Frohlich, 2012).

2.10.8 Emissions

Faulty equipment, flaring, and venting, can all emit harmful chemicals into the atmosphere. This does not only include CH4, but also toluene, ethylene, benzene, xylenes, nitrous oxides, other volatile organic compounds, and fine particulate matter (EPA, 2013, p. 3).

Figure 2.6

Map of basins with assessed shale oil and gas formation as of may 2013.



Note: Figure shows assessed basins with shale oil and gas estimate in red, and basins assumed to have shale oil and gas without assessed estimate in yellow. Assessment was released in 2013. Adapted from EIA. (2013). *Technically Recoverable Shale Oil and Shale Gas Resources*. U.S. Energy Information Administration. https://www.eia.gov/analysis/studies/worldshalegas/archive/2013/pdf/fullreport_2013.pdf. Adapted with permission (publicly available).

2.10.9 Solutions to concerns

The above-mentioned concerns related hydraulic fracturing are many, but there are technological and regulatory strategies that can mitigate or eliminate these concerns through careful strategic regulation by governmental institutions and private actors. Centner (2016) lists several possible strategies and currently established regulations that minimize risks and hazards from the shale gas extraction. In addition to this, Werner et al. (2015) concludes that there is a lack of direct evidence linking shale gas extraction directly to health outcomes, yet they note that more research is needed, and that absence of evidence does not mean evidence of absence.

Lastly, many countries have shale oil, shale gas, tight oil, and tight gas resources (figure 2.6) (EIA, 2013, p. 4), but many of them have banned or prohibited extraction because of environmental, political, or other reasons. Even some shale rich states of the US have banned or prohibited shale extraction (Hess et al., 2018; Nolon & Gavin, 2013).

2.10.10 Accidents and safety

Generally accidents related to natural gas, and other fossil fuels, can be triggered by natural hazards, technological failures, purposed malicious action, and human errors. (Burgherr et al., 2012). The environmental and societal risks associated with any energy technology do not only occur during the actual energy generation, but at all stages of the energy chains. Burgherr et al. (2012) finds that in comparison to coal and oil, natural gas has generally the lowest expected fatality rates from accidents in a historical perspective. Coal accidents having generally the highest expected fatality rate, and oil the second highest. Burgherr et al. (2012) also claims that natural gas is the safest of the three, when considering the maximum consequences of single accidents, coal being the second safest, and oil the least safe.

3. Overview of changes in global natural gas trade

The motivation for this part is to provide an overview of the changes that are relevant for the present global natural gas trade. The changes encompass technological, organizational, and regulative changes.

3.1 Oil indexation of natural gas

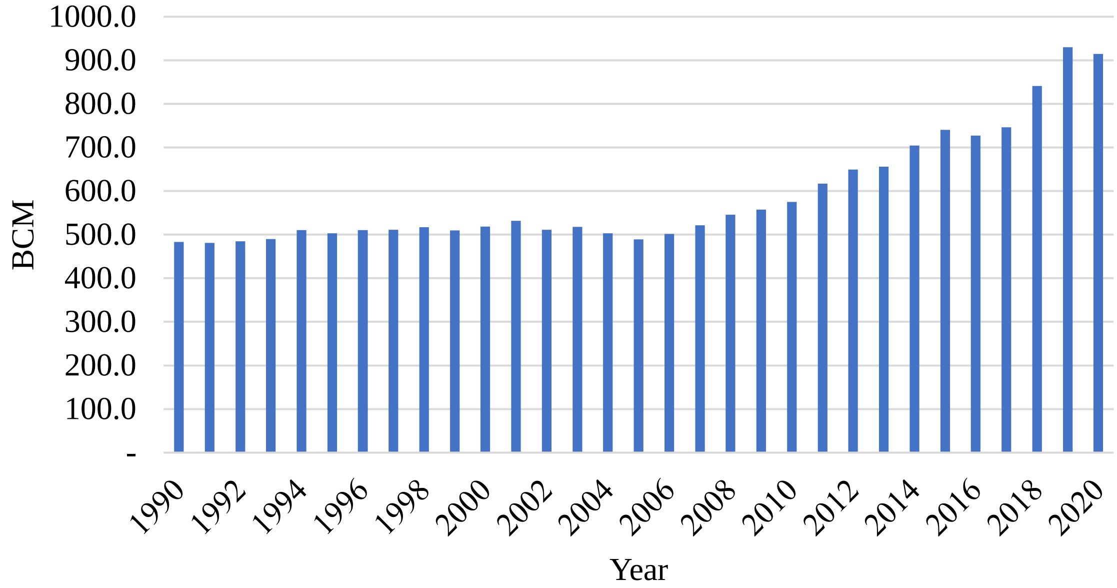
Oil indexations of natural gas refers to the price of natural gas being adjusted in accordance to the crude oil price. Oil price indexation is sometimes also referred to as oil and gas price coupling or linking. Most natural gas traded in Europe and the Asia-Pacific region was priced with oil indexation until (but not limited to) 2014, even when some evidence of price decoupling has been found (Zhang & Ji, 2018). A survey published by the international gas union (IGU) accounts that 59% of natural gas imports to Asia were oil indexed in 2015 (IGU, 2016, p. 45). Oil indexation persists because natural gas and crude oil are to some degree substitutes regarding transportation, industrial power generation, and heating (Serletis et al., 2011). Generally, the crude oil price for a given market is considered to be exogenous, because the crude oil price is influenced by global supply and demand. The natural gas price for a given market is subject to local and reginal market conditions. A study about the German natural gas market concluded that in the short-term natural gas prices were effected by local market conditions like temperature, storage, and supply shortfalls. The same study also found that in the long term global economic conditions, the price of oil and coal, and the substitutive relationship between natural gas and other energy commodities played a significant role (Nick & Thoenes, 2014). Recently the relationship between oil and natural gas has become debatable due to a series of findings. One of the main question is if natural gas should remain or return to oil indexation as it has been in the 1970s-1990s in Europe, or if hub-pricing, would be a better alternative, being a better indicator for the fundamental value of natural gas (Zhang & Ji, 2018). Stern (2014) finds that hub-pricing would be a likely answer to this question for the European and Asian market. The European markets had already implemented hub-based pricing by 2013, the Asian markets were lagging behind at that time. Stern (2014) also points out that hub pricing solutions may differ across countries. Several papers have published findings in favor of the hub-pricing alternative using a variety of different methods. Erdős (2012) finds that the US and the United Kingdom (UK) both had a long term price equilibrium between oil and gas until 2009, but after 2009 the relationship between gas and oil in the US decoupled (until but not limited to 2012), although the long term duration of the decoupling is still questioned. The long-term price coupling between crude oil and natural gas has also been shown to be unstable by 2014 (Batten et al., 2017). Zhang & Ji (2018) find that the US oil and gas relationship is completely decoupled by 2015. Conversely, the Asian and European oil gas relationship seems to exhibit temporary decoupling over time, but the overall relationship still favors the assumption of oil and gas being substitutes. Ji et al.(2014) find that the main drivers of the US natural gas price are primarily global economic conditions, while the main driver of the European and Asian natural gas price is the global crude oil price. Under the assumption that oil and gas are substitutes and that the oil price is exogenous in comparison to regional gas markets, the finding that the US gas market is decoupled from the crude oil price is surprising. The most prominent explanation for the US gas market to have this distinguished condition, is the shale gas revolution.

3.2 Shale gas revolution

Between 2000 and 2010 the US increased their gas production from shale gas to account from 1% to 20% of total domestic gas production. The increase in production has pressured gas prices to decline worldwide (Stevens, 2012). The increased output from developing and improving hydraulic fracturing and directional drilling has led the US to become the leading producer of natural gas in the world, surpassing the Russian Federation in 2009 (Pirog & Ratner, 2012, p. 2). This significant increase in natural gas production that took place in the mid-2000s is now known as the shale gas revolution (Stevens & Royal Institute of International Affairs, 2010). The shale gas revolution has changed the US gas markets relation to the global oil and gas market by making the gas market independent from international oil and foreign gas markets. Firstly, Aruga (2016) finds that the US natural gas price was linked to the European and Japanese gas price before the shale gas revolution, but that this linkage is severed after the shale gas revolution. Secondly, as mentioned in the previous section, the shale gas revolution seems to disrupt the long-term price coupling between crude oil and gas in the US. It is found that the decoupling happened after 2007 (Batten et al., 2017).

Figure 3.1

US natural gas production (BCM)



Note: Figure shows US natural gas production over time, there is an increasing trend after 2005, this is a result of the shale gas revolution. Values are provided in billion cubic meters of natural gas (BCM). Adapted from data accompanying BP (2021). *BP Statistical Review of World Energy 2021*. https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

3.3 Changes from LNG

The development of LNG and LNG carriers have opened new markets for natural gas to locations where pipelines do not reach. As mentioned in the technical overview (figure 2.2), transporting natural gas as LNG is more cost effective than transporting it by pipelines over long distances. LNG is approximately more cost effective than offshore pipelines at distances over 1500 kilometers and onshore at 3500 kilometers, these numbers are approximate because they change depending on many circumstances. In 2016 the IEA interpreted the growth and production of LNG technologies as the second gas revolution, in context of the shale gas revolution being the first revolution (IEA, 2016). In 2018, the IEA (2018) forecasted LNG to be 60% of world natural gas trade by 2040. In general, the market for LNG can be split into two large segments, the Atlantic markets, which includes the Mediterranean markets, and the Asia Pacific markets. The Atlantic markets have the largest exporters, while the Asia pacific markets have the largest importers, usually the Asia pacific markets takes a larger share of the international LNG trade (Varahrami & Haghighat, 2018). According to Ritz (2014), the widespread conjecture used to be that sea based LNG trade would connect the previously segmented markets of the US, Europe, and Asia, linking their pricing in the process. Newer evidence suggests that the price interdependence between Europe and America is increasing as of 2018 (Chiappini et al., 2019). Many developments have led LNG to become prominent factor for cointegrating gas markets. Barnes&Bosworth, Neumann, Siliverstovs et al., (2015; 2009; 2005) use a variety of models to analyze the LNG market, and find evidence that the development of LNG trade leads to a de-regionalization of the natural gas markets. On the other hand, there are several factors that have prevented international LNG trade from creating a globally integrated market for natural gas. Ritz (2014) points out that there are technical limitations that could have an restricting effect on the LNG import and export capacity of certain countries and markets. Another reason could be the exercising of market power by exporting countries.

3.3.1 LNG contracts and pricing.

Traditionally LNG trade has been based on long-term bilateral trade contracts. The contracts had often destination restrictions and prices were usually linked to oil prices. Around the timeframe of the shale gas revolution, the LNG market has become more liberalized. LNG suppliers have become more flexible by having short-term contracts, prices linked to gas hubs are more common, and many destination restrictions have been relaxed or eliminated entirely (*IGU Annual Report 2019*, 2019; *The LNG Industry-GIIGNL Annual Report 2018.*, 2018). LNG trade contracts are often divided into three categories: spot contracts (when a trade is made at a current market price and delivered immediately, or as soon as possible), short-term contracts with a duration of 2-5 years, and long term contracts of over 5 years in duration (R. Chen et al., 2021). Today, gas to gas price competition is the pricing mechanism for LNG spot trading, while short- and long-term contracts can also have an oil indexed pricing mechanism. Historically, the international LNG trade started with fixed prices in the late 1960s, as there was no international consensus on pricing principles, nor price anchoring benchmark standards. Buyers would make offers referring to domestic gas costs and terminal gas costs, while sellers would consider upstream production costs, liquification costs, and shipping costs when bargaining. Later, between the 1970s and the 2000s, oil indexation was popularized since natural gas and oil were substitutes in many contexts. From the 2010s until today several pricing mechanisms have developed for LNG. Oil indexation still exists, yet gas to gas price competition has become more popular in many parts of the world, meaning that LNG prices were compared to pipeline gas prices and LNG prices from other providers. Additionally, there are several pricing mechanisms that link the LNG price with competing fuels or hybrid indexes of several competing fuels in few cases (R. Chen et al., 2021). Globally, there is no unified pricing mechanism for LNG today. The US was the first country to introduce gas to gas competition pricing for LNG on a broad scale, starting gas market liberalizing reforms by the late 1970s. Europe followed, with three major natural gas market reforms in 1998, 2003, and 2009, that promoted integrated gas markets, and thereby paved the way for gas to gas pricing mechanisms. The Asian countries are lagging behind Europe with liberalizing gas market reforms. Today, 100% of the North American LNG prices use the gas to gas pricing mechanism, compared to 68% in Europe, and 29% in Asia, the rest being oil indexed (R. Chen et al., 2021).

3.4 Climate change and natural gas as a “bridge fuel”

Natural gas could serve many applications in a potential energy transition to a low carbon, renewable energy future. The number of governments willing to mitigating climate change is increasing, climate policies have and may change the global natural gas trade (UN news, 2021). Today, many countries have implemented, or have scheduled the future implementation of carbon taxation or an emissions trading system (The World Bank, 2021). Renewable energy is an essential tool for the green energy transition and the various sustainable development goals which are necessary to mitigate climate change. The global economy, however, remains heavily dependent on energy generated from fossil fuels (Najm & Matsumoto, 2020). The global demand for natural gas has had an increasing trend between 2007-2018. Fossil fuels represent 84,7% of global primary energy consumption in 2018, of which the share of natural gas was 28,2% (*BP Statistical Review of World Energy*, 2019). The IEA estimated that in 2018 natural gas represented 21,5% of global CO2 emissions from fossil fuels, while coal and oil representing 44,1% and 34,4 respectively (IEA, 2020). Natural gas has been described as a “bridge fuel” due to it being the least polluting fossil fuel, it represents the least polluting way of bridging the gap between the fossil fuel based present and a future of renewable energy. While the term “bridge fuel” has been used in many contexts (Delborne et al., 2020), the interpretation of natural gas being the least polluting fossil fuel to use until a there is a sufficient amount of renewable energy to phase out fossil fuels is used in this paper and section.
The term “bridge fuel” has been used in many contexts about natural gas and other fossil fuels (Delborne et al., 2020). In this thesis the bridge fuel interpretation that natural gas is the least polluting fossil fuel to use until there is a sufficient amount of renewable energy to phase out fossil fuels. While the production and use of conventional natural gas releases less greenhouse

gas emissions than other fossil fuels, some studies have found that the CH_4 leakages during the production of natural gas from shale might increase its greenhouse gas emissions to the same level as other fossil fuels, depending on the surpassing of certain leakage thresholds (Howarth et al., 2011). The IEA (2020, p. 8) estimates that the most cost effective way to reduce greenhouse gas emissions is by minimizing flaring, minimizing venting of CO_2 gas, and reducing CH_4 leaks, of which reducing CH_4 leaks is the most cost effective.

3.4.1 Costs and emissions of hydrogen production

H_2 has been proposed as a clean energy carrier by researchers and policymakers to prevent climate change (Ball & Weeda, 2015) and is likely going to be an important part of the energy mix in a hypothetical low-carbon energy future (Nicodemus, 2018). As mentioned in the technical overview, presently most H_2 is produced from natural gas, but there are several production methods which have less emissions or are completely emission free. If H_2 as an energy carrier achieves mass production and adoption, grey and blue H_2 might ensure the future mass use of natural gas until green H_2 phases out their use in the long term. This hypothetical situation would make natural gas very attractive to green policy makers in the present, having a wide range of consequences for natural gas prices. Unfortunately, present CCUS-technologies have severe challenges, and it is uncertain whether it will insure coal and natural gas a position in a hypothetical low carbon emitting energy mix of the future. Firstly, the environmental impact and feasibility of CCUS is uncertain (Moliner et al., 2016). Secondly, the CCUS processes are not emission free, they capture between 80-95% of the CO_2 emissions (Ozawa et al., 2018). Thirdly, CCUS technologies have high costs (Wang et al., 2018). The following table, reprinted from Yu et al. (2021), shows a cost comparison of different types of H_2 production in different regions. Making any comparisons based on table 3.1 is difficult because it's summarized from several papers, written in differing years. Nevertheless, it implies that there is a definitive difference between the price intervals of green H_2, and any of the other types of H_2. It also opens up for speculation if blue H_2 will see mass adoption before green H_2. The following tables (table 3.1 and table 3.2) show the cost and emission differences of the different types of H_2 as summarized by Yu et al. (2021):

Table 3.1

Summary of H2 production costs for different technology options.

US$/kgH2				
Methods	Energy Source	Location	H2 cost	Reference
Black H2 (without CCUS)	Coal	Canada	1.35	(Olateju & Kumar, 2013)
Grey H2 (without CCUS)	Natural gas	Canada	1.31	(Olateju & Kumar, 2013)
		Canada	0.67-1.05	(Ewing, 2021)
Blue H2 (with CCUS)	Coal	Canada	1.60-2.05	(Olateju & Kumar, 2013)
	Natural gas	Canada	1.62—1.83	(Olateju & Kumar, 2013)
		Canada	0.99—1.36	(Ewing, 2021)
Green H2	Renewable electricity	Canada	7.39	(Olateju & Kumar, 2011)
		Canada	2.56—6.84	(Olateju et al., 2016)
		Canada	2.28—3.69	(Ewing, 2021)
		Japan	5.5	(Heuser et al., 2019)
		Europe	2.24-7.84	(Blanco et al., 2018)
		Australia	4.78-7.43	(Milani et al., 2020)

Note: Different currencies involved and converted with March 2021 exchange rates. CCUS refers to carbon capture utilization and storage. Table adapted from Yu, M., Wang, K., & Vredenburg, H. (2021). *Insights into low-carbon hydrogen production methods: Green, blue, and aqua hydrogen*. International Journal of Hydrogen Energy, 46(41), 21261–21273. https://doi.org/10.1016/j.ijhydene.2021.04.016. Copyright 2021 Elsevier. Accessed with license provided by the Norwegian School of Economics.

Before making any judgements based on the table by Yu et al. (2021), table 3.3 shows the CO_2 intensity of the different types of H_2 production. Unfortunately, it is uncertain whether the carbon intensity of blue H2 can justify the current price gap between green and blue H2. To what degree the prices of blue and green H2 can change from investing in research and development is also uncertain. The question, whether H2 production from natural gas will ensure the mass use of natural gas in a hypothetical low carbon emitting energy future, is left open.

Table 3.2

C02 intensity of H2 production.

kg CO2/kg H2			
Black H2	Grey H2	Blue H2 (Coal with CCUS, 90% capture rate)	Blue H2 (Natural gas with CCUS, 90% capture rate)
20.00	8.5	2.4	1.00

Note: Table adapted from IEA (2019). *The Future of Hydrogen* (Report Prepared by the IEA for the G20, Japan, p. 203). Page 53, International Energy Agency. https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499 7ca48e357561/The_Future_of_Hydrogen.pdf. Copyright 2019 IEA. Printed with permission (publicly available).

3.4.2 Repurposing natural gas infrastructure for hydrogen use

Another application of natural gas in relation to climate change is the repurposing of natural gas pipelines and other infrastructure to be used for green H2. In California it has been found that natural gas pipelines cannot be repurposed for pure H2, but it is possible to use a blend of natural gas and H2, where H2 has a minor share of the blend (Jaffe, 2017). Ogden et al. (2018), find that it is possible to use natural gas pipelines to transport H2 in a blended form where the percentage of H2 can be 5 to 15% by volume without increasing any risks. Ogden et al. (2018) point out that the blending proportion is dependent on the type of natural gas pipeline network, which would require an expensive case by case assessment. Furthermore, Ogden et al. (2018) also state that LNG facilities cannot technically be repurposed to be used for LH2 and that converting or overbuilding compressed natural gas for H2 use is technically possible, but expensive and economically unattractive. In addition, a German case study found that the blend limit of H2 in natural gas for diverse types of equipment used in end applications of existing natural gas networks varies widely depending on the application (Schiebahn et al., 2015). This indicates that reducing greenhouse gas emissions by blending H2 into natural gas is not an option unless the end use application is made to be compatible with a higher H2 share of the blend (Wang et al., 2018). A related question might be whether natural gas pipelines potentially could be repurposed to transport H2 for FCVs. Ogden et al. (2018) conclude that unless a cost effective way of separating green H2 from natural gas can be found the emission reduction from using natural gas pipelines as refueling infrastructure for FCVs, in comparison to building dedicated H2 refueling infrastructure, is negligible.

3.5 COVID-19 and the 2021 natural gas price surge

COVID-19 has led to a global pandemic with wide reaching economic consequences, which are ongoing and will most likely be ongoing as this thesis is being completed. It is difficult to describe an ongoing situation as information is coming out continuously and future information may change the current interpretation of the situation. It is too early to discuss permanent consequences of the pandemic on natural gas markets.

3.5.1 Timeline of events and gas price:

The starting point for the global pandemic can be discussed, but for brevity the date at which the World Health Organizations (WHO) characterized the COVID-19 outbreak as a pandemic is used as a starting point: The 11th of March 2020 (WHO, 2020).

Khan et al. (2021) have analyzed the consequences of the pandemic on oil and gas prices in the short, medium, and long term for the period between January 2020 and May 2021. In context of the paper, the short-term refers to the price variation in a 1-16 day interval, the medium term refers to price variation in a 32-64 day interval, and the long term refers to price variation in a 128-256 day interval. Khan et al. (2021) find that the natural gas price (daily Henry Hub data) is very negatively affected by the pandemic in the short-term as governments impose lockdowns and other restrictions are implemented, inhibiting natural gas consumption. In the medium term the natural gas prices are slightly negatively affected and in the long term they are very positively affected by the reopening after the first winter of the pandemic. Khan et al. (2021) note that this large increase in the long term prices is normal as the natural gas prices recover from the rapid decline in the short-term, based on the dataset ending in May 2021. As it is now known, the natural gas price has surpassed pre-pandemic price levels in Europe as well as in North America. The precise prices of different hubs at different dates during COVID-19 can be found in the Data description part (Figure 6.1). In September 2021 the IEA released a statement on the developments in the natural gas and electricity markets, followed by a gas market report in October 2021. The global natural gas prices have surged due to a variety of reasons. The price surge is driven by a combination of a strong recovery in demand after the lifting of COVID-19 lockdowns and restrictions by governments after the winter of 2020 as well as weather related factors (IEA, 2021f). The price surges partially represent increased demand from global weather trends, as there were cold spells in North America and East Asia in the first quarter of 2021. The cold spells were followed by heatwaves in Asia and droughts in hydro-power rich markets like Brazil, California, and Turkey. Lower electricity generation from wind power also played a role in certain markets (IEA, 2021f). The IEA (2021f) mentions that the Japanese, Korean, and Chinese demand for LNG has remained strong during the pandemic, and that LNG production has been lower than expected from 2020 and onward, due to unplanned outages and delays of various kinds. There is a link between gas and electricity prices due to gas being used to balance electricity supply in many markets. Germany and Spain have seen their electricity prices tripled and quadrupled compared to their 2019 and 2020 averages. The surge in European natural gas prices has also led many countries to switch their electricity generation from gas to coal (IEA, 2021f).

3.5.2 Consequences of the 2021 gas price surge

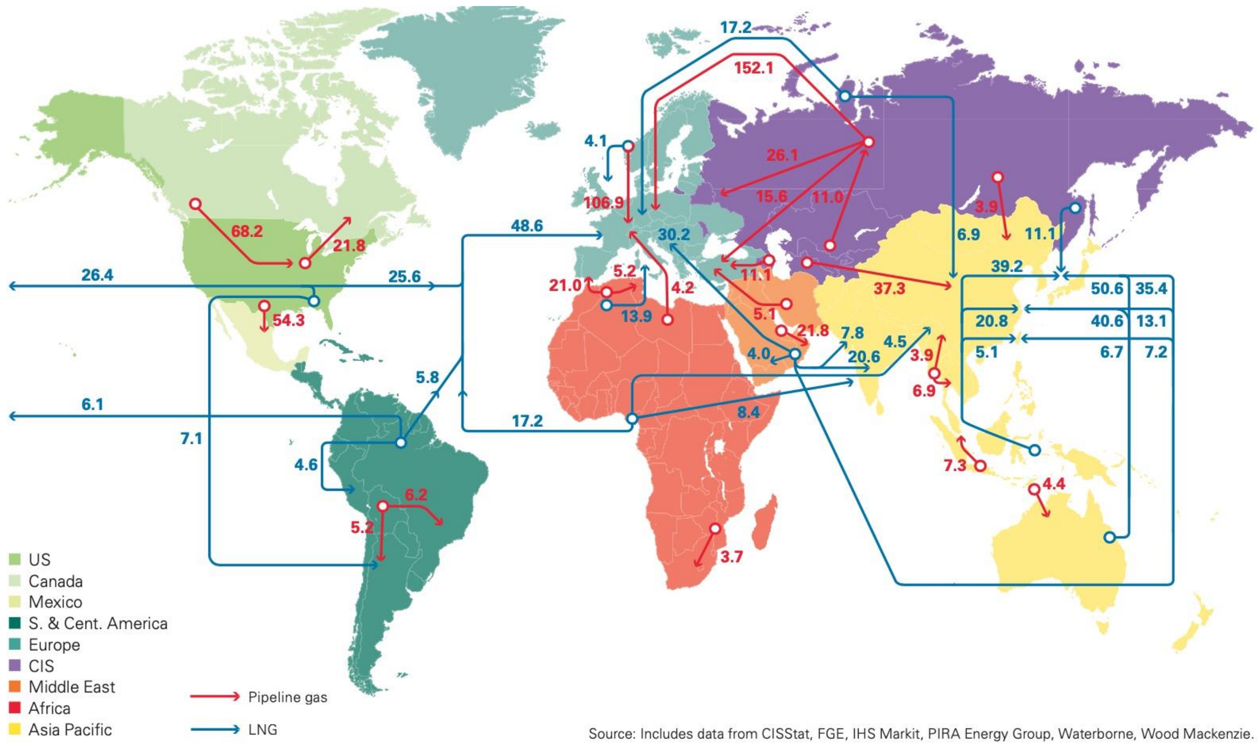
First and foremost, it is obvious that any kind of natural gas intensive activity has become more expensive as the natural gas prices have surged, this affects both consumers and industry. In the UK 19 energy suppliers have gone out of business since August 2021 as a result of the high natural gas prices, as their price promises to customers were undeliverable. Most of these 19 companies were small energy companies, but combined they had above 2 million customers (BBC, 2021). Norway, a country with an abundance of natural gas, oil, and hydro-electric power should be a clear profiter of the natural gas price surge. This is confirmed by the Norwegian business newspaper E24, according to their reporting and interpretation of statistics provided by Statistics Norway (Statistisk Sentralbyrå). Record high revenues for the gas, oil, and power exporting sectors in Norway have made the trade surplus of September 2021 the largest in recorded history (E24, 2021a). However, the revenue from the electricity export is problematic. As a result of the electric power export, domestic electricity prices have surged. This should not be a problem since the revenue from exporting is larger than the savings from not exporting, but there is disagreement on if, when, and how the revenue should be distributed by the government (NRK, 2021). Most Norwegian electricity producers and exporters are partially or fully publicly owned (Per Sanderud et al., 2019). The US has seen a large natural gas price increase in the past year, but a relatively small one compared to the surge in Europe. A news article by Reuters published on 19th of October 2021 describes the US inflation adjusted natural gas prices to be the highest in a decade. The article claims that the prices are relatively low compared to Asian and European markets due to them being consumer markets for natural gas while the US is an exporter. It is also pointed out that the future prices for importing regions in the US have far higher prices than the exporting regions (Kemp, 2021). It is also important to mention that before the global natural gas price surge after the summer of 2021, the South-Central region of the US had its own price surge around February 2021. The storm called Uri caused cold weather that resulted in a natural gas price surge in February 2021. The increased electricity demand from the cold weather increased both natural gas and electricity prices to a degree that rotating power cuts were introduced between 15th of February 2021 and 19th of February 2021 (IEA, 2021g, p. 21). The surging gas prices can have many complicated consequences due to the versatile use of natural gas and its related products. The US Energy Information Administration (EIA) reports that one of the consequences of the recent price spread between sweet crude oil and sour crude oil is the surge in natural gas prices. Sweet and sour refer to the sulfur content of the crude oil, it is used in a similar manner for natural gas. The reason for the price spread is that H2, a product derived from natural gas, is used to remove the sulfur content of sour crude oil (EIA, 2021c). Two examples of sour crude oil are Federal Offshore Gulf of Mexico crude oil and Dubai crude oil, while Magellan East Huston crude oil and Brent crude oil are regarded as sweet crude oils (EIA, 2021c). Another consequence of the surging natural gas prices is that the NH3 price have followed, meaning that chemical fertilizers will become more expensive. NH3 is a product derived from natural gas and the main chemical feedstock for N2 based chemical fertilizers. Yara, one of Europe's largest industrial natural gas buyers, announced on 17th of September 2021, that it would reduce its NH3 production due to the high natural gas costs (E24, 2021b). Later on the 20th of September 2021 the CEO of Yara expressed his concern that the surging natural gas prices will increase chemical fertilizer prices and thereby threaten global food security for the poorest countries (E24, 2021c). There are many other consequences of the recent partially COVID-19 induced gas price surge that deserve mentioning, but these are beyond the scope of this thesis.

4. Overview of global trade flows

The purpose of this part is to create a general overview of the global natural gas trade. The overview will focus on trends for the global gas market and the reasons for these trends. In the end of the section net importers and exporter regions will be identified. All data used is sourced from BP (BP, 2021). The data accompanying the Statistical review has more data than the review itself. In contrast to previous sections the data will be shown in billion cubic meters of natural gas (BCM), for ease of sourcing, graphing, and comparison. As far as possible, the data has a conversion rate of approximately 40 million joule per cubic meter of natural gas, at 15C° and 1Atm /1,013 bar. The conversion rate is derived directly from measures of energy content of the natural gas (BP, 2021). Figure 4.1 (BP, 2021, p. 45) below shows a simplified overview of global natural gas trade traffic. The major trade regions for natural gas are colorized.

Figure 4.1

Major trade movements 2020



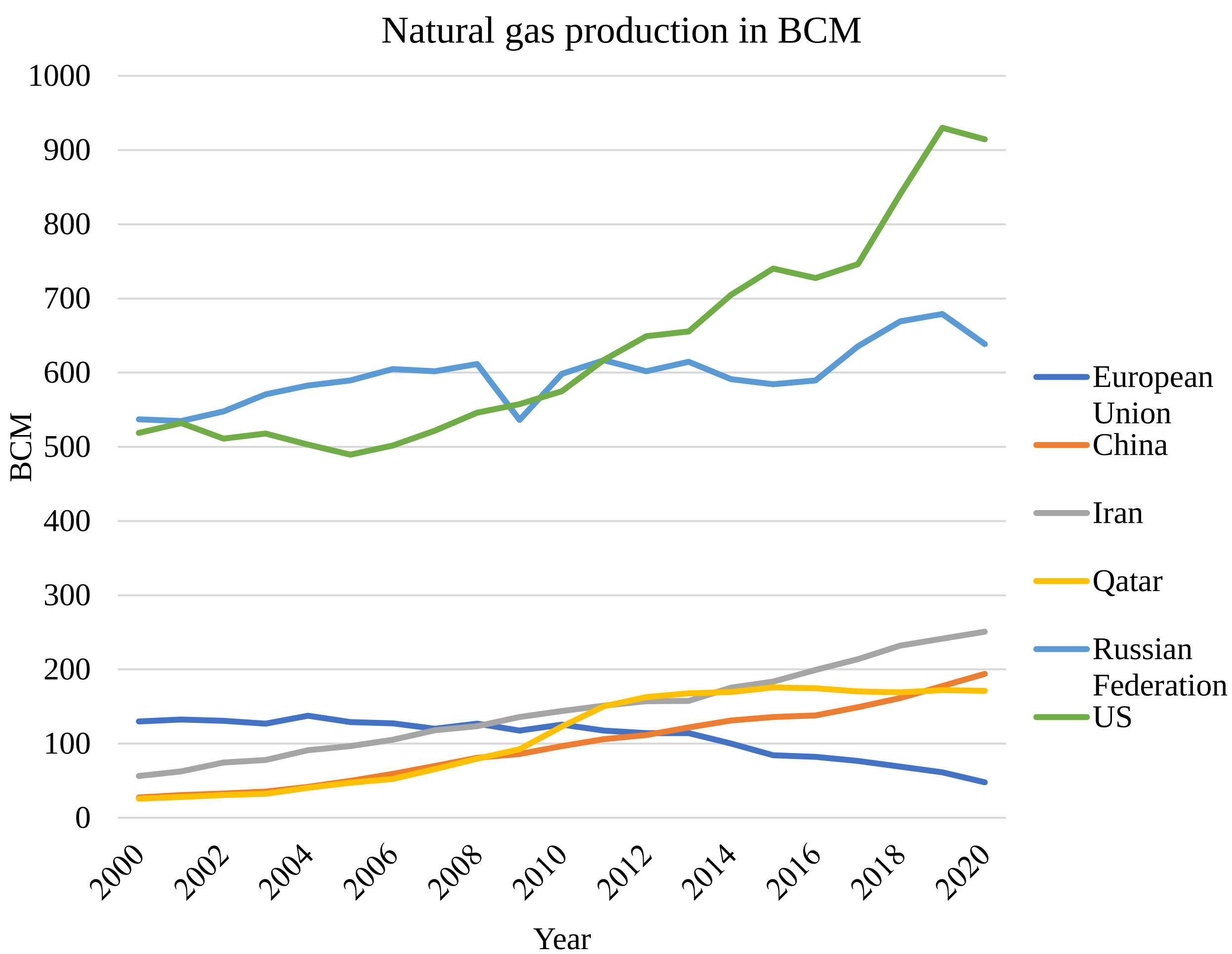
Note: Values are provided in billion cubic meters of natural gas (BCM). Red lines represent pipeline traffic, blue lines represent LNG traffic. Reprinted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.1 Gas production

The global gas production has an increasing trend over time, with notable declines in certain years. The decline in 2009 is due to the global financial crisis (IEA, 2010), while the decline in 2020 is due to the COVID-19 pandemic (IGU, 2020, p. 14). Examining the top gas producers of 2020 over the last 20 years, reveals that the US has overtaken the Russian Federation as the top gas producer of the world by the year 2011. This is a result of the shale gas revolution, which will be described in a section of its own. The rise of Chinese gas production is also notable as it passes Qatar in 2019, if this is permanent or only due to COVID-19 is uncertain.

Figure 4.2

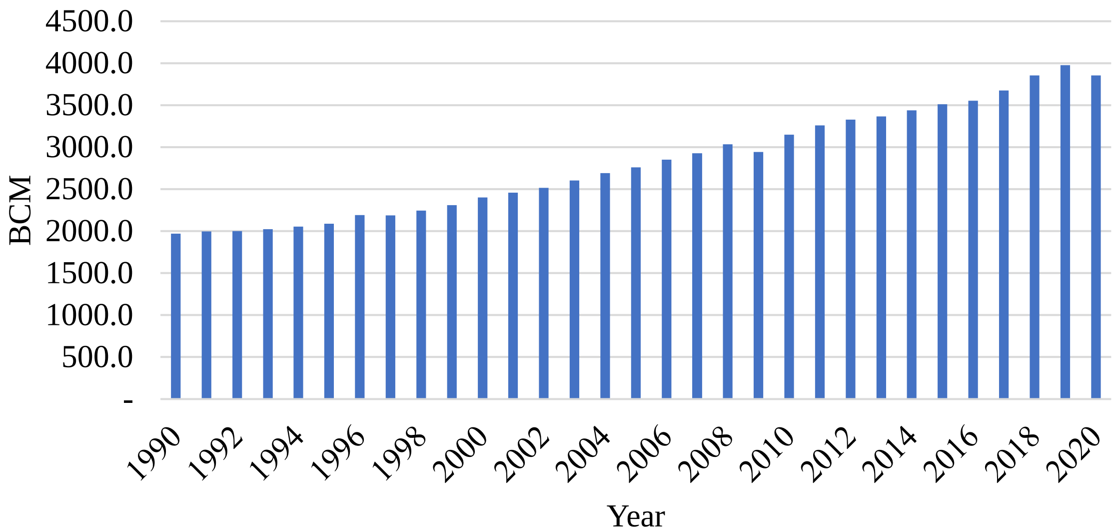
Natural gas production in BCM



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.36) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Figure 4.3

Global natural gas production in BCM



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.36) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

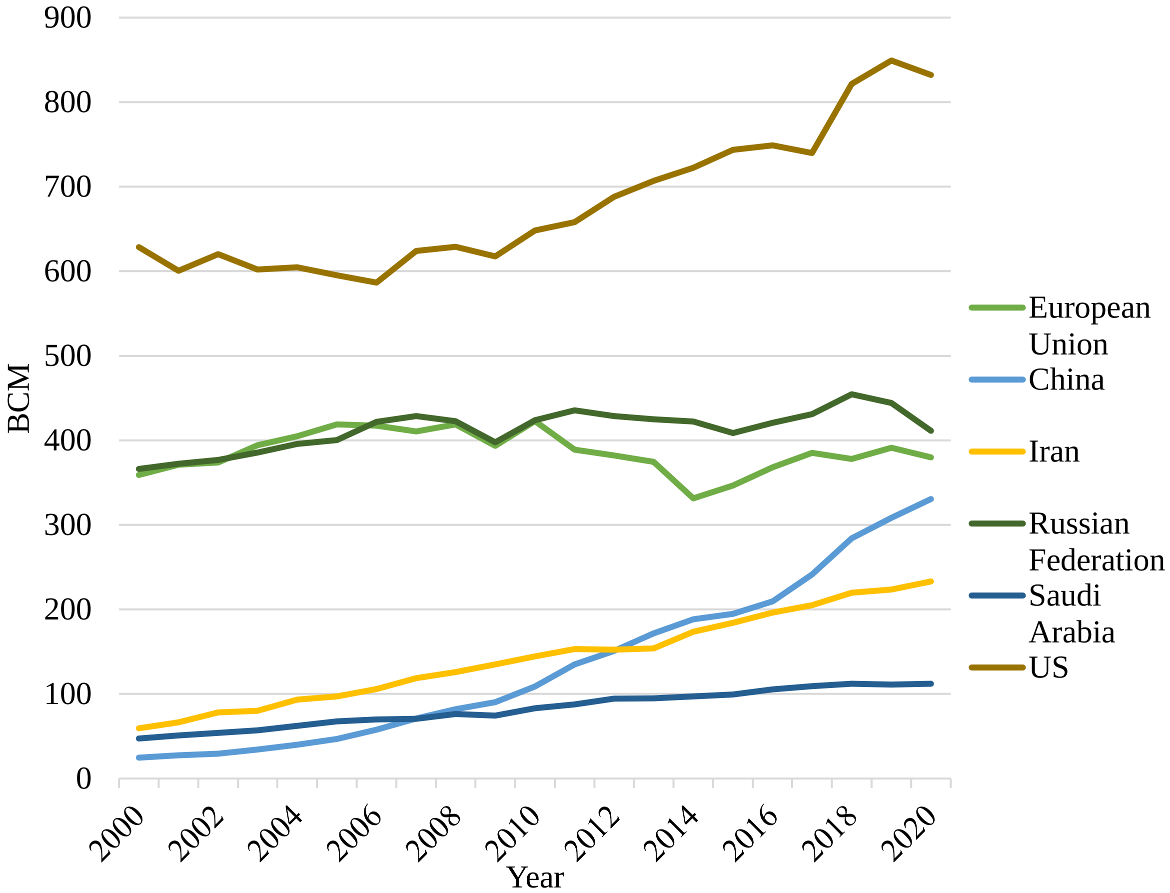
4.2 Gas consumption

Like the global natural gas production, the global natural gas consumption has an increasing trend over time with declines in certain years. It is reasonable to assume that global consumption and production are related, since they share the same years of decline for the same reasons, the financial crisis of 2009 and the COVID-19 pandemic for 2020. Comparing global gas production and consumption reveals that they are not identical. This implies that there are inter-year differences for when gas is produced and consumed. The likely reason for these inter-year differences is gas being produced, stored, and consumed at a later point in time. The less likely reason for the differences in production and consumption might be that gas is lost after production because of technical reasons or major accidents. Accounting issues may also play a role. Examining the top gas consumers of 2020 over a 20-year period reveals that they are, with the exception of Saudi Arabia, the same as the producers. This indicates that gas produced in a region is also consumed in the same region, an indication that makes sense knowing that gas transportation is often difficult and problematic over vast distances in comparison to other fossil fuels. The reason for Qatar not being on the list of top gas consumers is most likely its relatively small population and its large exports of 20,2 BCM to the United Arab Emirates.

Also notable is the increase in Chinese gas consumption, surpassing both Saudi Arabia and Iran in the previous 15 years **(**Figure 4.4) (BP, 2021, pp. 38–41).

Figure 4.4

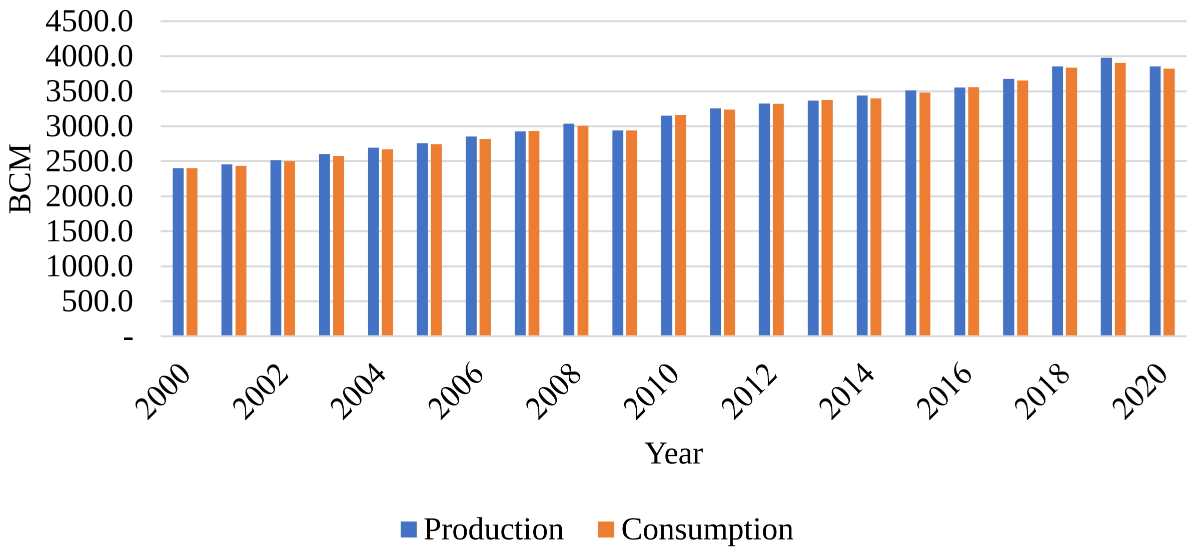
Natural gas consumption in BCM



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.38-41) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world en-ergy.html. Copyright 2021 BP. Printed with permission (publicly available).

Figure 4.5

Global natural gas production and consumption in BCM



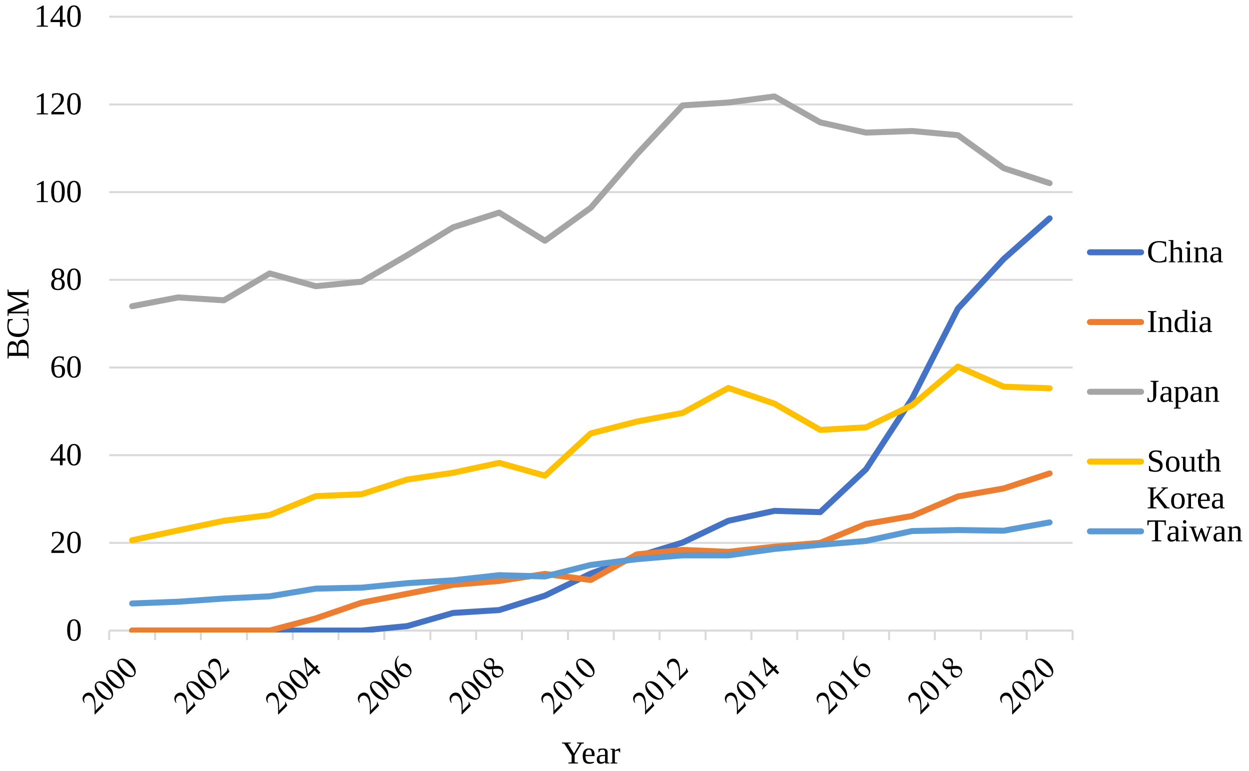
Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.38-41) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.3 LNG imports

Global LNG imports are increasing over the 20-year period of the data, with the exception of one year of decline in 2012. Another notable detail is the large increase of 52,65 billion cubic meters between 2009 and 2010, the largest increase in the dataset. Examining the top LNG importers of 2020 over a 20-year period reveals that most LNG is imported by countries in the Asia-Pacific region (figure 4.6) (BP, 2021, p. 43). Japan lacks any significant production of natural gas and has to import most of their demand (IEA & KEEI, 2019, p. 23). Another notable trend for Japan's LNG import is the rise around 2011, this was due to nuclear power being replaced with power generated partially from LNG after the Fukushima disaster (IEA & KEEI, 2019, p. 6). As mentioned during the section about gas consumption (figure 4.4), Chinas increasing consumption of LNG is drastic, surpassing India, Taiwan, and South Korea by 2017. The growth of Chinese LNG imports will most likely rival Japanese imports in the near future (IEA & KEEI, 2019, p. 19).

Figure 4.6

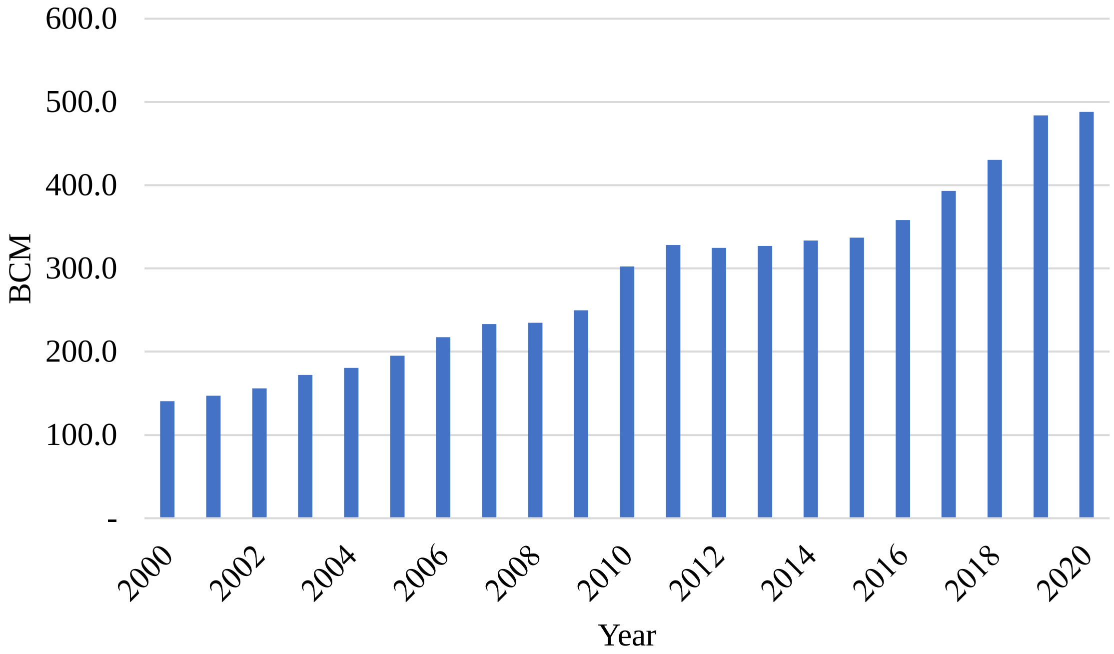
LNG import in BCM



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Figure 4.7

Global LNG import in BCM



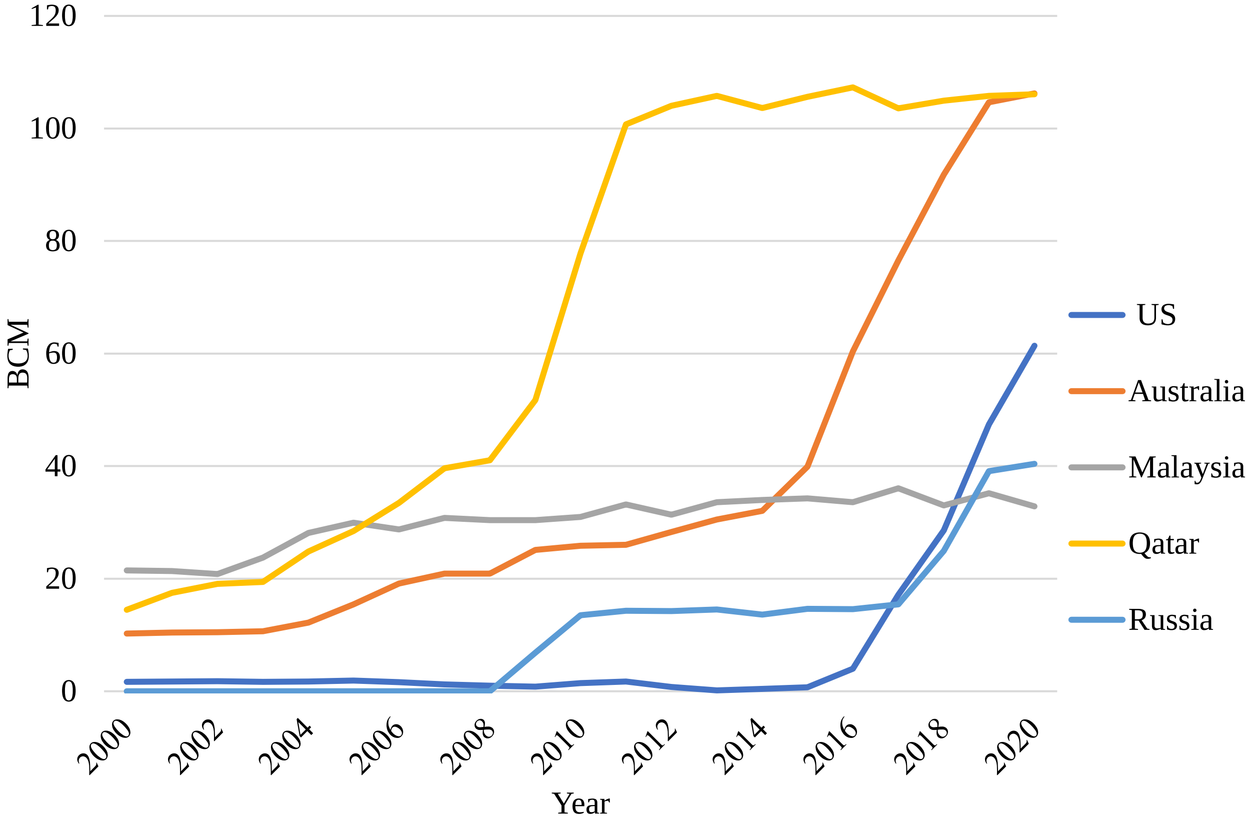
Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.4 LNG exports

The global LNG exports over the 20-year period of the data have an increasing trend with one decline in 2012, identical to the global LNG imports. LNG imports and exports are the same over the duration of the data, this indicates that no major inter-year delays or major LNG accidents have occurred. Examining the top LNG exporters of 2020 over time reveals that they are the same as the top gas producer with the exception of Australia and Malaysia. The trends also indicate when the LNG infrastructure of specific countries becomes operational by their almost linear increases in certain years. For example, Australia sees a dramatic increase in LNG exports after 2014, while the US has a large increase after 2016, this is due to liquification capacity expansion (IEA & KEEI, 2019, p. 8). Qatar's increased exports between 2009 and 2011 are due to liquification terminals being completed and Japan's increased demand for LNG after the Fukushima incident in 2011 being met by Qatar (IEA & KEEI, 2019, p. 6). The data shows a trend resulting of LNG technology maturing and the global LNG market becoming more deregulated in the early to late 2010s.

Figure 4.8

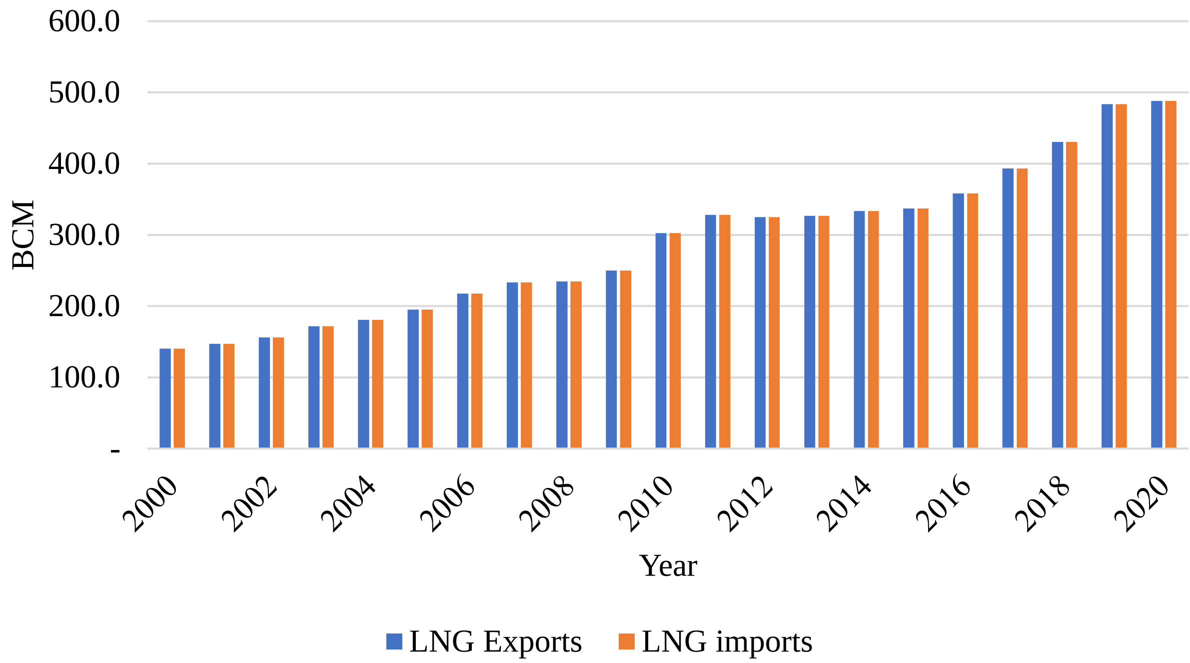
LNG exports in BCM



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-44) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Figure 4.9

Global LNG export and import in BCM



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-44) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

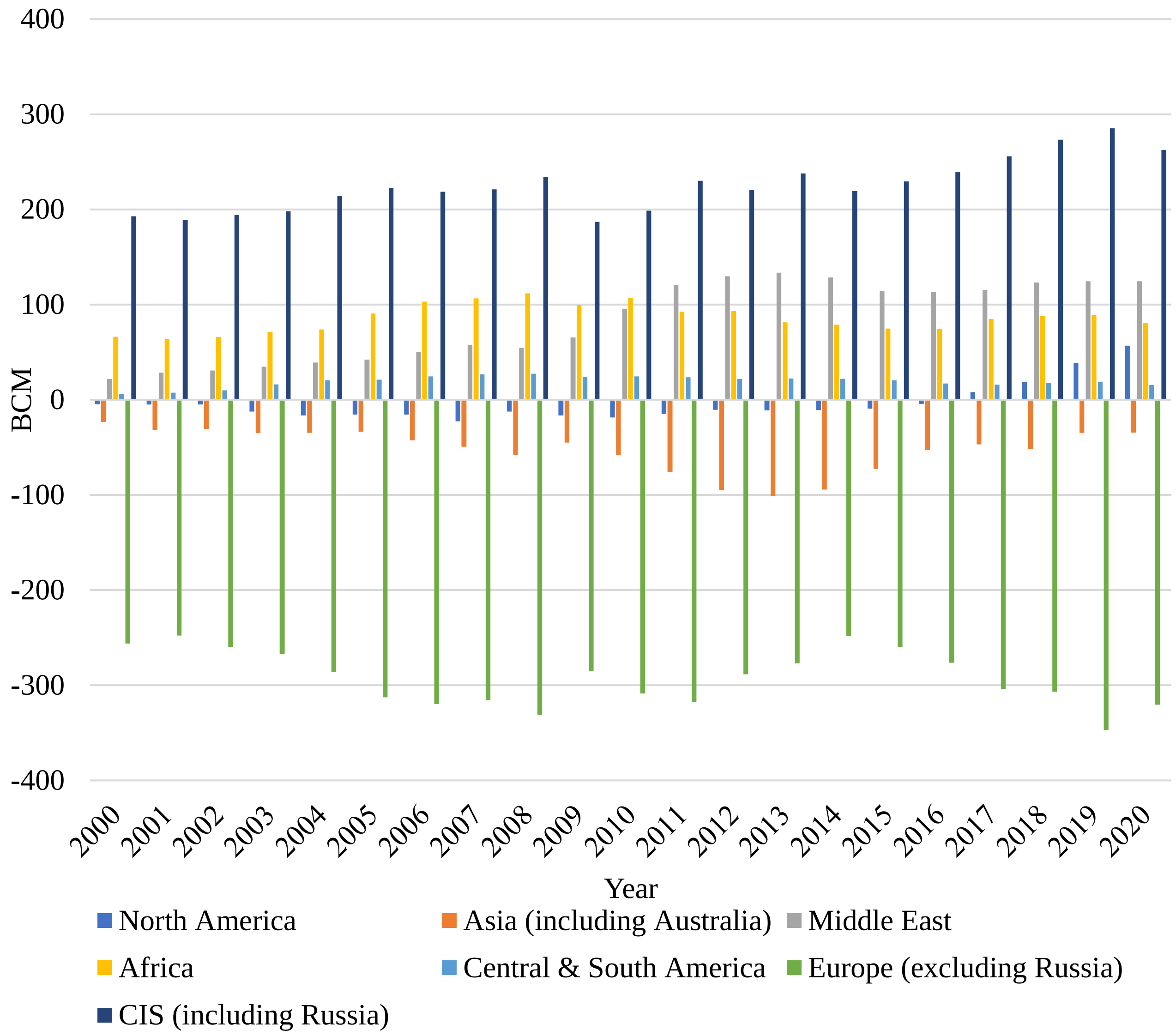
4.5 Net trade flows by region

For simplicity the global data from BP has been divided into regions. The regions consist of countries located on their respective continents with the following exceptions: Australia is grouped together with Asia in one region, the Commonwealth of Independent States (CIS) being defined as a separate region from Europe and Asia, Central America being grouped together with South America, and the Middle East is defined as a region. These simplifying groupings are made in order to reflect the global trade flows of natural gas. Figure 4.1 shows a map of the different regions. Examining the net trade flows by region reveals that Europe (excluding Russia) and Asia (including Australia) are net importers of natural gas, while the CIS, North America, South & Central America, The Middle East, and Africa are net exporters of natural gas. Europe imports the most followed by Asia. The exporters change over time, Africa being overtaken as the second largest exporter in 2012 by the Middle East, while North America changes from being a net importer to a net exporter in and after 2017. The CIS is the largest net exporter, due to the Russian exports to Europe. The region of Central & South

America is the smallest net exporter by region. Only examining the trade flows by region is misleading because it does not provide an overview of the inter-regional trade within each region, as shown below. Some countries are major traders of their regions and supply the demand of their region and external regions. For example, Asia might be a net importer of natural gas, but Australia is a net exporter to that same region. Comparing 2020 pipeline and LNG imports for the regions reveals which countries are major traders within and between regions.

Figure 4.10

Net trade flows by region



Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.42) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.5.1 Europe (excluding Russia)

The Russian Federation, Norway, and the Netherlands are the main exporters by pipeline. Qatar, the US, and Russia are the main exporters of LNG. The largest import of LNG by country, from Qatar, surpasses the pipeline imports from the Netherlands. The inter-regional pipeline trade is small relative to the regional pipeline trade, but not insignificant. The top inter-regional pipeline exporters are Algeria, Azerbaijan, Iran, and Libya. Europe imports more natural gas through pipelines than LNG

Table 4.1

Pipeline imports by Europe in 2020

Origin of import	BCM	Share of total import
Netherlands	28.1	6%
Norway	106.9	24%
Other Europe	100.7	23%
Azerbaijan	13.4	3%
Russian Federation	167.7	38%
Iran	5.1	1%
Algeria	21.0	5%
Libya	4.2	1%
Total	447.1	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Table 4.2

LNG imported by Europe in 2020

Origin of import	BCM	Share of total import
US	25.6	22%
Peru	0.4	0%
Trinidad & Tobago	5.2	5%
Other Americas	0.2	0%
Norway	4.1	4%
Other Europe	0.3	0%
Russian	17.2	15%
Qatar	30.2	26%
Algeria	13.9	12%
Angola	1.1	1%
Egypt	0.4	0%
Nigeria	14.6	13%
Africa	1.6	1%
Total	114.8	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.5.2 North America

Almost all of the natural gas exported to North America comes from the US and Canada, while Mexico is the largest pipeline net importer of the region. The US and Canada are both very large countries and trade large amounts of natural gas through pipelines with each other, but between the two the US is the net importer, while Canada is the net exporter. Because Canada and the US are very large exporters of natural gas, there is relatively little LNG imports in comparison to pipeline imports to the North American region.

Table 4.3

Pipeline imports by North America in 2020

Origin of import	BCM	Share of total import
Canada	68.15	47%
Mexico	0.05	0%
US	76.11	53%
Total	144.31	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Table 4.4

LNG imported by North America in 2020

Origin of import	BCM	Share of total import
US	0.94	20%
Peru	0.10	2%
Trinidad & Tobago	2.46	53%
Other Americas	0.00	0%
Norway	0.09	2%
Other Europe	0.08	2%
Nigeria	0.41	9%
Africa	0.09	2%
Australia	0.11	2%
Indonesia	0.35	7%
Total	4.6	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.5.3 Asia (including Australia)

In Asia, Turkmenistan, Myanmar, and Kazakhstan are the top exporters of natural gas by pipeline. The top exporters of LNG to the Asian region are Australia, Qatar, and Malaysia. In contrast to Europe and North America, the LNG imports in Asia are vastly larger than the pipeline imports. Another interesting contrast to the European and the North American region is that main consumers of natural gas are not the same as the main exporters. China, being the only major producer and consumer in the region, is not exporting any of its own production, while Japan and South Korea are major importers in the region without having significant natural gas production of their own. These observations further underline that Asia as a region is a net importer of natural gas. Australia is the largest exporter of the region and Qatar is the largest external exporter to the region. Australia and Qatar both export natural gas by using LNG.

Table 4.5

Pipeline imports by Asia and Australia in 2020

Origin of import	BCM	Share of total import
Kazakhstan	6.8	10%
Russian Federation	3.9	6%
Turkmenistan	27.2	42%
Uzbekistan	3.3	5%
Indonesia	7.3	11%
Myanmar	10.8	17%
Other Asia Pacific	5.9	9%
total	65.2	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Table 4.6

LNG imported by Asia and Australia in 2020

Origin of import	BCM	Share of total import
US	26.40	8%
Peru	4.56	1%
Trinidad & Tobago	1.50	0%
Other Americas	0.00	0%
Other Europe	0.75	0%
Russian Federation	22.45	6%
Oman	12.70	4%
Qatar	71.78	21%
United Arab Emirates	7.61	2%
Algeria	0.88	0%
Angola	4.37	1%
Egypt	1.29	0%
Nigeria	11.92	3%
Other Africa	2.53	1%
Australia	106.03	31%
Brunei	8.45	2%
Indonesia	16.44	5%
Malaysia	32.83	10%
Papua New Guinea	11.54	3%
Other Asia Pacific	1.43	0%
Total	345.44	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.5.4 Middle East & Africa

The Middle East and Africa are both net exporters of natural gas and have little imports in comparison to the other regions. The largest pipeline exporters within the region, Qatar, exports almost all of its share (20.2 of 21.8 BCM) to the United Arab Emirates. Iran, the second largest exporter, exports to several middle eastern countries.

Table 4.7

Pipeline imports by Middle East region in 2020

Origin of import	BCM	Share of total import
Azerbaijan	0.2	1%
Iran	10.3	29%
Qatar	21.8	62%
Other Middle East	2.1	6%
Other Africa	0.9	3%
Total	35.3	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Table 4.8

Pipeline imports by Africa in 2020

Origin of import	BCM	Share of total import
Other Middle East	2.1	17%
Algeria	5.2	43%
Other Africa	4.7	39%
Total	11.9	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

The top African pipeline exporter within the region is Algeria, while South Africa is the largest importer in the region (3.7 BCM). All of the inter-regional trade in Africa is relatively small compared to the other regions. The LNG imports in the Middle East and Africa are relatively small due to the large production capacity in the regions. The main imports come from within the region, more specifically from Qatar and Nigeria, while the US is the largest inter-regional exporter to Africa and the Middle East.

Table 4.9

LNG imported by the Middle East & Africa in 2020

Origin of import	BCM	Share of total import
US	1.3	15%
Trinidad & Tobago	0.9	10%
Other Europe	0.2	2%
Russian Federation	0.6	7%
Oman	0.5	6%
Qatar	3.2	35%
Algeria	0.1	1%
Angola	0.5	6%
Egypt	0.1	1%
Nigeria	1.5	16%
Other Africa	0.2	2%
Total	9.2	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.5.5 South & Central America

In the South & Central American region LNG imports are slightly larger than the imports by pipeline (13.9 BCM vs 12.5 BCM). The region is a net exporter of natural gas and has relatively little inter-regional trade in comparison to North America and Europe. The top intra-regional pipeline trade in South & Central America is from Bolivia to Argentina (5.2 BCM) and to Brazil (6.2 BCM), the largest importers of the region. The top LNG exporter to the South & Central American region is the US, while the second largest exporter is Trinidad & Tobago, located within the region. It is unusual that one of the top LNG exporters to a region is located within it, but in the case of South & Central America it makes sense because of the lacking pipeline infrastructure.

Table 4.10

Pipeline imports by Central & South America in 2020

Origin of import	BCM	Share of total import
Bolivia	11.4	91%
Other S. & Cent. America	1.1	9%
Total	12.5	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

Table 4.11

LNG imported by Central & South America in 2020

Origin of import	BCM	Share of total import
US	7.14	51%
Trinidad & Tobago	4.22	30%
Other Americas	0.36	3%
Norway	0.10	1%
Other Europe	0.04	0%
Russian Federation	0.11	1%
Qatar	0.88	6%
Algeria	0.08	1%
Angola	0.09	1%
Nigeria	0.02	0%
Other Africa	0.73	5%
Australia	0.09	1%
Total	13.87	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

4.5.6 Commonwealth of Independent States.

In comparison to the other regions there is no LNG import data for the Commonwealth of Independent States region provided by BP. The reason for this is unclear, but it could be that the LNG imports are not significant because most of the member states are either land-locked, or net exporters of natural gas. All the natural gas trade in this region is conducted via pipeline and the imports are regional, except for imports from Iran. The Russian federation is the largest exporter within the region (26.1 BCM), followed by Kazakhstan (7.2 BCM), and Turkmenistan (4.3 BCM).

Table 4.12

Pipeline imports by Commonwealth of Independent States in 2020

Origin of import	BCM	Share of total import
Kazakhstan	7.2	18%
Russian Federation	26.1	66%
Turkmenistan	4.3	11%
Uzbekistan	1.3	3%
Iran	0.5	1%
Total	39.5	100%

Note: Values are provided in billion cubic meters of natural gas (BCM). Adapted from BP (2021). *BP Statistical Review of World Energy 2021*. (p.43-45) https://www.bp.com/en/global/corporate/energy-economics/statistical-review-of world energy.html. Copyright 2021 BP. Printed with permission (publicly available).

5. Literature Review

The integration of natural gas markets has been the subject of various studies in the past. While some of them examine the integration of national gas markets, others aim at identifying market integration in a pan-continental or even global context. Since the topic of this thesis is the integration of markets on two different continents, the focus of this literature review is placed on international market integration. Several different approaches have been used to identify market integration, with cointegration analysis, spillover indexes and the Kalman filter being three popular methods. Dukhanina and Massol (2018) have compiled a comprehensive literature review, that differentiates between the different methods used. The cointegration approach is based on the works by Johansen (1988, 1991, 1995) and Engle and Granger (1987), whereas spillover indexes were developed by Diebold and Yilmaz (2009, 2012; 2014). A field of literature that is closely related to gas market integration is that about the integration between oil and gas prices.

5.1 Integration of markets in North America, Europe, and Asia

One of the first and most influential papers about global gas market integration is the one by Siliverstovs et al. (2005). The authors use cointegration tests and principal component analysis to investigate whether gas markets are integrated or not in the period from 1990 until 2004. They conclude that European markets are integrated with each other and with Asian markets, while the American market is not cointegrated with either the European or Asian gas market. A study by Erdős and Ormos (2012) found similar results with regard to the integration of Asian and European markets. However, they find evidence for a partial integration of European and American gas markets. Another aspect of their study is the relation between oil and gas prices. The relative price of oil and gas was found to fluctuate around the thermal parity, which means that the same amount of energy costs the same in both markets. This link was found to weaken in the years after 2002, with gas prices being completely decoupled from oil prices in America. A difference in behavior between gas prices in America on the on hand and Europe and Asia on the other was also found by Li et al. (2014), who identify contractual specifications as a possible reason. Contracts for gas delivery in Europe and Asia are more likely to have prices that are indexed to the oil price than contracts in America.

Contrasting results were found by Kapusuzoglu et al. (2016), who used methods that are based on Siliverstovs et al. (2005) in addition to Granger causality tests. They conclude that European and Asian markets are not cointegrated, and that the gas price in the US has a causal impact on prices in Europe. Their findings that the market in America is a regional market that is not influenced by other markets and the observation that the European market is influenced by the oil price is in line with earlier research. In the same year, Aruga (2016) investigated the impact of US shale gas production on global gas markets. He finds that the US market was connected to foreign gas markets before the shale gas revolution, but became independent after the shale gas revolution. An impact of US shale revolution on foreign markets was not found for the period under investigation (1992-2012). More recent papers by Chiappini et al. (2019) and Nakajima and Toyoshima (2019) find that global gas markets are not fully integrated, but that there is a tendency towards increasing levels of integration (Chiappini et al., 2019). The paper by Nakajima and Toyoshima also concludes that volatility is more internationally integrated than returns, while Chiappini et al. find asymmetric reversions to long-term equilibria, which means that deviations from the long run relation in one direction are faster corrected than deviations in the other direction.

5.2 Integration of markets in Europe and North America

The transatlantic gas price relationships were studied by various papers that also considered the shale gas revolution and the increased trade in LNG. Brown and Yücel (2009) state that the growth in global LNG trade should lead to more arbitrage opportunities and more integrated markets. A bivariate test showed that there is causality between the price at the Henry Hub (HH) and the NBP. Even so, their findings suggest that the oil price is the main driver of price co-movements in gas markets, since prices at both gas markets are cointegrated with the oil price. Increased convergence in transatlantic gas markets was found by Neumann (2009) who used a Kalman filter on daily price data from 1999 until 2008. Interesting findings have also been made by Nick and Tischler (2014). They use threshold cointegration tests that account for transport costs in addition to standard cointegration tests and conclude that gas prices in the US and the UK have been integrated in the period from 2000-2012. It is important to note that they started to decouple in 2009, with increasing price spreads in the period thereafter. Standard cointegration tests did not suggest the existence of cointegration in the subsample from 2009-2012, while the threshold cointegration test did so. Anyhow, they did not account for the influence of oil prices. Geng et al. (2016) studied the impact of the shale gas revolution on gas and oil markets in the US and the UK. They find that the impact on the prices at the Henry Hub is stronger than at the NBP, and that oil and gas prices in the US have decoupled while the Brent price and the gas price at the NBP still seem to have a long-term relation. A strong degree of disconnection from other markets in case of the Henry Hub is also found by Chulia et al. (2019), who investigate volatility spillovers between different energy markets with the methodology developed by Diebold and Yilmaz (2009, 2012). They conclude that the TTF hub is the European reference hub (in contrast to NBP in many other studies) and that the gas price is starting to replace the oil price as the global energy benchmark. The authors also find evidence for strong links between European gas markets and other energy markets, even though the volatility in the own respective sector remains the main source of fluctuations.

5.3 Integration of markets in Asia and either Europe or North America

The relation between European and Asian gas markets has been studied, among others, by Kim and Kim (2019) who used a vector error correction model and found cointegration of Asian and European gas markets, with Asia being the price leader until 2011 and Europe in the period after 2011. Kim et al. (2020) focused on the role of swing suppliers, such as Qatar and Russia, who can export gas to both markets. They found, using error correction models and Engle-Granger cointegration tests, that swing suppliers have promoted the integration of Asian with European markets. The paper also mentions that European and American markets have been integrated in the 00´s. Perifanis and Dagoumas (2020) investigated the price and volatility spillovers between oil and gas markets in Europe and Asia. They found that gas prices in Europe are not subject to price spillovers from the oil market, which points towards increased independence of European gas prices from oil prices. This is, according to them, not the case in Asia. Wakamatsu and Aruga (2013) investigate the impact of increased shale gas production in the US on the gas markets in the US and Asia. By using tests for structural breaks and market integration analysis, they find that the shale revolution caused a break in the relationship between Asian and American gas prices already in 2005. Prior to that, the US price had an influence on the prices in Japan. This was not the case after the break. The employed methodology included a complex vector autoregression model that also included gas import quantities, income, and oil prices, instead of only gas prices.

5.4 Integration of markets in North America

Most studies about international gas market integration focus on the HH as the reference price for North America, as it is the most liquid and largest hub. Nevertheless, it should not be forgotten that there are several gas trading hubs in the US and Canada and that they are subject to local influences on supply and demand, which makes the investigation of market integration relevant. The first study that describes the dynamic interactions in the North American gas market is the one by Park et al. (2008). They use a combination of causal flow modeling and time series techniques such as vector error correction models and conclude that the North American gas market is one single integrated market. Olsen et al. (2014) also employ the VECM methodology and impulse response functions to examine the price building process and the degree of market integration for hubs in the US and Canada. They find that the closer two hubs are, the stronger is the relationship between their prices. However, they do not find a clear price leader. Scarcioffolo and Etienne (2019) investigated the connectedness of US gas markets with the spillover method by Diebold and Yilmaz (2012; 2014). They find evidence for solid integration of markets in the short run as well as in the long run. The HH, which is also included in our analysis, is identified as a net information transmitter, which means that it transmits more information to other hubs than they receive from others in the process of price discovery. On the other hand, the study also suggest that the shale gas boom has led to a decline in connectivity. In general, the North American gas market can be described as a well-integrated market that is more flexible than markets in Europe or Asia (Nakajima & Toyoshima, 2019).

5.5 Integration of markets in Europe

The European market is of particular interest for studies about market integration, since the EU (EU Commission) has explicitly stated that its goal is the creation of an integrated market to the benefit of the consumers (European Commission, 1998, 2003, 2009). There are several trading hubs, especially in Western Europe, with the NBP and the Dutch Title Transfer Facility (TTF) being the largest and most liquid. Early evidence for market integration in Europe was found by Asche et al. (2000). The paper focuses on French gas imports and the integration between French, German, and Belgian markets. The authors conclude that the market is integrated. The price discovery process in European gas markets was investigated by Schultz and Swieringa (2013), who focused on the relation between spot and forward prices and found that futures contracts with different expiration dates show stronger connectedness than spot prices at different locations and that futures are an important aspect in the price discovery process. A study by Bastianin et al. (2019) finds evidence for price growth convergence in European gas markets and attributes this to market characteristics such as interconnectedness between trading hubs. The degree of market integration in Europe was also investigated by Broadstock et al. (2020) and Jotanovic and D’Ecclesia (2020). While the former uses wavelet transformations on price return and volatility data, the latter employs Engle-Granger and Johansen tests, among other methods. Broadstock et al. (2020) arrive at the conclusion that market integration is present but that it is not complete yet. They also do not find a price leader. Jotanovic and D’Ecclesia (2020) find evidence for a high degree of integration and identify the TTF as the reference hub.

5.6 Integration of markets for oil and gas

Several of the aforementioned studies find that there is or has been a strong connection between oil and gas prices. This is also very intuitive, since both commodities are used for energy generation and can therefore assumed to be substitutes for one another, at least to a certain extent. As, for example, Chiappini et al. (2019) write, two gas markets can't really be considered integrated if they only move together because of their common link to the oil price. So, in order for a true cointegration relationship to exist, it would be optimal if gas prices were independent from oil prices. In 2008, Brown and Yücel concluded that the oil price has a strong influence on gas prices if one controls for weather, gas inventories, seasonality, and supply disruptions. Asche et al. (2012) find that the gas price in the UK is determined by the oil price and that the relative price of oil and gas fluctuates around a constant average. Batten et al. (2017) write that oil and gas prices are independent of each other instead of having a stable relationship. They also write that the gas price was leading the oil price in the period from 1999-2006, which is contrary to other literature. Perifanis and Dagoumas (2020) also support the hypothesis that European and American gas prices are independent from the oil price, in the sense that there are no price spillovers, but the gas price in Japan is not. A paper by Aguiar-Conraria (2021) challenges this view and concludes that only the US gas price is independent from the oil price, while the oil price is linking the other gas markets, which are independent from each other if one accounts for the effect of oil.

6. Data Description

We use daily data on day-ahead prices for natural gas at the following six trading hubs in Europe and North America:

Table 6.1

Abbreviations and Locations of Different Trading Hubs

Hub	Location	Abbreviation
Henry Hub	Louisiana, USA	HH
Enbridge Gas Dawn Hub	Ontario, Canada	Dawn
Title Transfer Facility	Netherlands	TTF
National Balancing Point	United Kingdom	NBP
Zeebrugge Hub	Belgium	ZEE
NetConnect Germany	Germany	NCG

"Day ahead" means that the price is the one for gas delivered on the next day. Note that NCG merged with another large hub in Germany, Gaspool, with effect from October 1st 2021. The new combined market area is called "Trading Hub Europe" (Trading Hub Europe, 2021). This means that the prices reported for NCG from October 1st 2021 onwards are the ones from the Trading Hub Europe. We have chosen the TTF and NBP, since they are the two largest and most liquid hubs in Europe and regarded as the benchmark hubs for Europe in many other papers. NCG is chosen because it represents the largest economy in Europe. The Zeebrugge hub is shown here since it acts like a link between the continental European market and the market in the UK, which is due to the fact that ZEE is directly connected to the NBP via the "Interconnector" pipeline (Fluxys Group, 2021). We use data from the Henry Hub since it is the largest and most liquid hub in the US and, similar to NBP and TTF, regarded as a benchmark for the American market (McHich, 2021). Dawn is chosen because it is also a very liquid hub in a densely populated region of Canada (Enbridge Gas, 2021). The largest Canadian hub, AECO in Alberta, is not considered in this analysis because there have been regulatory changes with regard to pipeline maintenance that induced severe increases in volatility for almost two years (Leith Wheeler Investment Counsel Ltd., 2019). This increased volatility would make the time series unrepresentative for the whole Canadian market. The period of consideration starts on the 1st of January 2016 and ends on the 2nd of November in 2021. We decided to use 2016 as our starting point, since this was the year in which the LNG exports from the US started to increase drastically (EIA, 2021a). Additionally, in 2016 the global LNG trade volume started to further increase after a plateau phase in the years before (BP, 2021). Another important timestamp included in our analysis is the year 2017, when the US became a net exporter of natural gas for the first time since 1956 (EIA, 2021a). The data is received from Refinitiv with prices being converted into Euro per Megawatt hour (€/MWh) by the program. Refinitiv is a global provider of market data and part of the London Stock Exchange Group, that offers not only commodity prices, but also prices and market information for equities, bonds and macroeconomic as well as industry specific data and analyses (Refinitiv, 2021). We have obtained the license to use Refinitiv from NHH-Norwegian School of Economics. Descriptive statistics for the price series are presented in table 6.2.

Table 6.2

Descriptive Statistics

Hub	Obs	Mean	Std. Dev.	Min	Max
Dawn	1,467	8.602	2.558	3.135	29.742
HH	1,468	8.385	2.822	3.859	67.642
NBP	1,499	18.678	12.169	3.25	111.89
NCG	1,498	18.648	12.442	3.5	115.88
TTF	1,508	18.443	12.437	3.1	115.8
ZEE	1,248	18.229	11.694	3.84	113.89

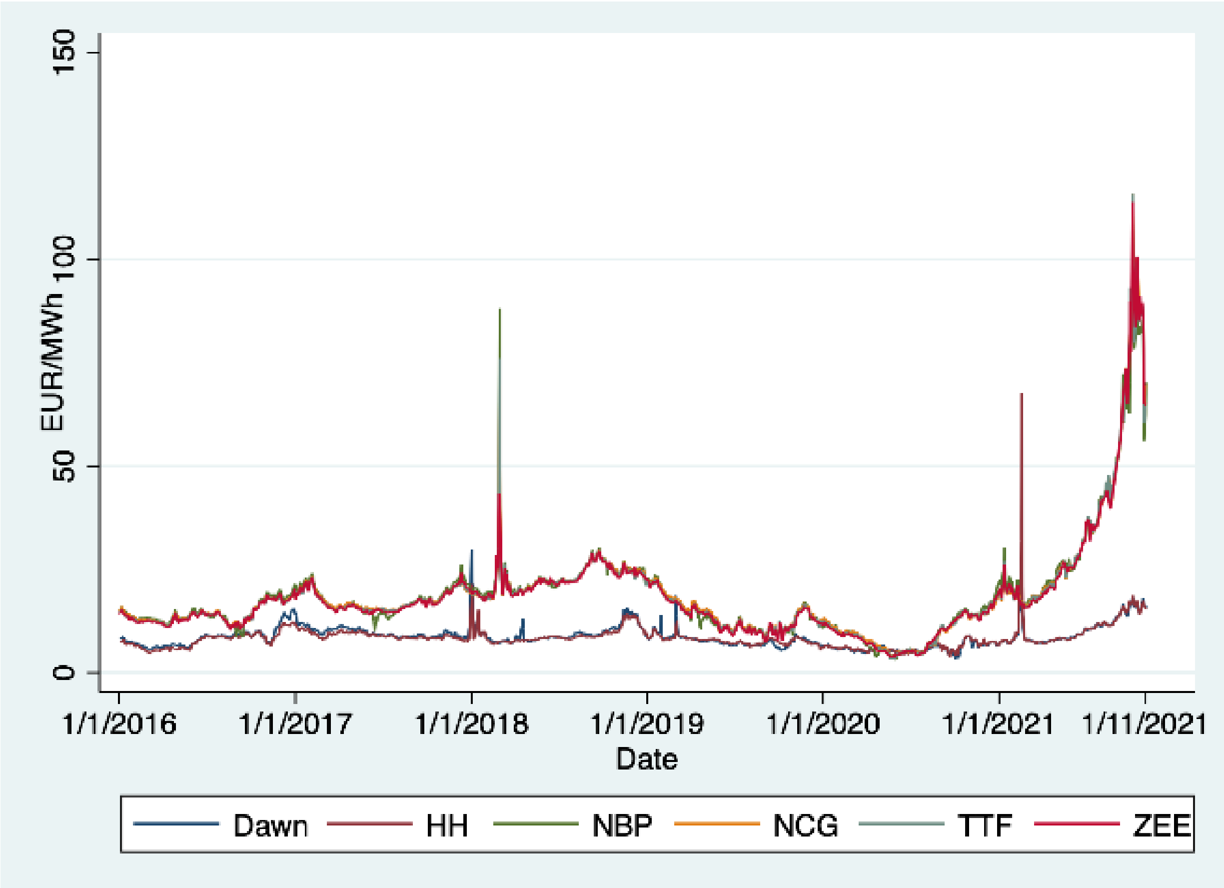
Note: Prices are reported in Euro per megawatt hour and obtained from "[Day ahead prices for natural gas at the trading hubs Henry Hub, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. The table reports the number of observations, the mean, maximum, and minimum prices as well as the standard deviation of the prices.

We have gathered almost 1.500 observations, before interpolating, for each hub. An exception is ZEE, where only approximately 1.200 observations were available in the period of interest. European hubs clearly have higher mean prices at over 18€/MWh than the hubs in North

America. The Henry Hub has an average price of 8,4 €/MWh while the mean price at the Dawn Hub is only slightly higher at 8,6 €/MWh. The NCG and the TTF appear to be the most volatile hubs in absolute terms. North American hubs are generally characterized by a narrower price range. As figure 6.1 shows, the prices on each of the two continents have always been very close to each other during the whole period. There have been two short lived large spikes in prices, occurring around the 1st of March 2018 in Europe and around the 17th of February 2021 in North America. Both spikes were caused by extremely cold weather conditions (EIA, 2021b; Reuters, 2021). It is also interesting to note that since the middle of 2020 prices at European hubs have surged until late October 2021, while the prices in North America grew only moderately.

Figure 6.1

Price series at different gas trading hubs

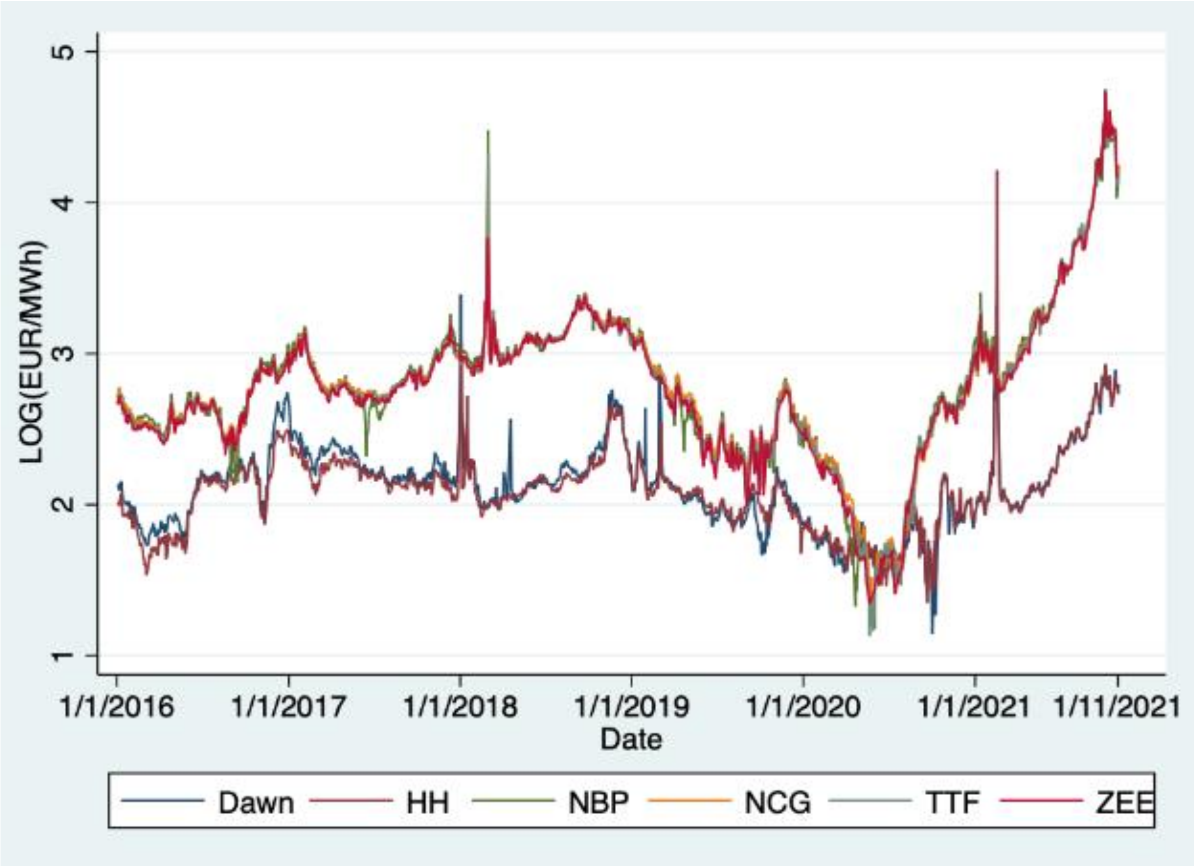


Note: The data is from "[Day ahead prices for natural gas at the trading hubs Henry Hub, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021.

This has led to the largest difference in prices between the two continents during the observation period. Just before this trend began, in the middle of 2020, the prices at all hubs were the closest to each other they have ever been in the study period. This was during a time when many countries eased the restrictions on economical and social life, which were in place in order to stop the spread of the Corona virus (Brandon, 2020; Kottasová & Croker, 2020). These lockdowns have caused the demand for gas to drop substantially, which explains the low price level (Dubreuil et al., 2020). On the weekends there is no price data for any hub and for some hub-date combinations there are other missing values. We treat these missing values in the following way: We used the “dow()” function in Stata to identify and drop all the weekends. Then, we created a variable that counts all remaining observations, starting at the first observation on January 1st 2016. This variable is used as the time variable. The other missing values are imputed with the “ipolate” function from Stata which uses linear interpolation to fill in missing values. When replacing missing values, we do not have to be concerned with seasonality because we are dealing with missing daily values in a time span of several years. This means that one observation has only little influence on the whole series and there is little possibility that the choice of the imputation method has an impact on the results of our analysis or that the imputed values will cause any kind of bias. Another concern is the occurrence of extreme spikes in the prices that might distort the distribution of the variables. Therefore, we have used the natural logarithm (log) of the time series in our analysis. Figure 6.2 shows the log transformed price series for the six hubs.

Figure 6.2

Logarithm of price for the different hubs



Note: The data is from "[Day ahead prices for natural gas at the trading hubs Henry Hub, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021.

We now take a closer look at the price development in 2021. The recovery of the global economy in the third quarter of 2020 (J. K. Jackson et al., 2021), after many Covid-19 induced lockdowns have been lifted, has also increased the demand for natural gas (IEA, 2021b). This has then caused the prices, especially in Europe, to reach levels that were not achieved previously for such a long time. The increase in prices in Europe has already started in the second half of 2020, after they had declined for approximately two years and reached the lowest values of the observation period. Since early 2021 the prices at the European hubs have increased in a seemingly exponential manner. From an average price of 20,5 €/MWh on the 4th of January 2021, they rose to peak values in the range between 111 €/MWh and 116 €/MWh on the 5th of October 2021. The IEA (2021c) has identified three main causes for this. There was an increase in demand after lockdowns have been lifted, extreme weather events, and relatively limited supply. A price increase in a comparable order was not observed in North America.

The US prices peaked in February during a spike that was caused by an extremely cold winter storm (EIA, 2021b). In addition, the American hubs also saw their prices steadily increase over the course of 2021. 2021 has so far been the year with the highest average price in the observation period. The average price in 2021 quadrupled compared to 2020 in Europe and almost doubled in North America, as reported in table 6.3.

Table 6.3

Average Prices at the Different Trading Hubs for Different Years

Year	Dawn	HH	TTF	NCG	NBP	ZEE
2016	8,4	7,8	14,0	14,2	14,4	14,0
2017	9,7	9,0	17,3	17,6	17,5	17,2
2018	9,6	9,2	22,9	23,0	23,3	22,5
2019	7,7	7,8	13,6	14,0	13,6	13,0
2020	5,9	6,0	9,4	9,6	9,6	10,0
2021	10,6	10,9	36,6	36,8	36,7	35,9

Note: Prices are reported in Euro per megawatt hour and obtained from “[Day ahead prices for natural gas at the trading hubs Henry Hub, Dawn, NBP, TTF, NCG, and ZEE]”, by Refinitiv Eikon, 2021.

7. Methodology

To answer the question whether North American and European markets for natural gas are integrated, we will test whether the price series of the markets are cointegrated. To reduce the influence of large outliers, we have used the log transformed price series in our analysis. Two time series are cointegrated if there is a long-term relationship between them (Engle & Granger, 1987). In order to test this, we will use the Engle-Granger cointegration test (Engle & Granger, 1987), and the Johansen test for cointegration (Johansen, 1988, 1991, 1995). We will also test for Granger causality (C. W. J. Granger, 1969) in order to find out whether price information from one hub can be used to forecast price developments at another. The presence of a long-term relation would indicate that the prices move together which would imply that they are affected by the same influences and differences are attributable to transaction and transportation costs. In this case, the markets could be considered as one integrated market. Another aspect that is closely related to the long-run relationship is the speed of adjustment towards the equilibrium. Prices in an integrated market can be expected to adjust towards the equilibrium whenever they are in disequilibrium, due to forces of arbitrage.

7.1 Stationarity and Unit Root

A basic concept that one must be familiar with to study time series is the concept of stationarity. It is described in various textbooks such as the one by (Wooldridge, 2020). A time series is stationary if its mean and variance are constant, and the covariance of observations only depends on the length of the time span between them and not on the point in time. Time series that are not stationary are said to have a "unit root". In that case, they can be described by an AR(1) model with independent and identically distributed errors in which ρ is equal to one:

$$y_t = \alpha + \rho * y_{t-1} + e_t$$

If α is equal to zero, the process is a random walk without drift, otherwise it is a random walk with drift. Random walks have an increasing variance and are therefore not stationary. A time series that is stationary is also called integrated of order zero. If the first difference of a non-stationary time series is stationary then the time series is integrated of order one, often described as I(0). In general, a time series is integrated of order n if the n^{th} difference is the first stationary version of the time series. Testing for integration is important because the results of a regression of two time series that are integrated of order one on each other are likely to be spurious (C. W. Granger & Newbold, 1974). One way to handle this issue is using the first differences of the time series in the regression, but we will shortly introduce a different approach. Another issue with non-stationary time series is that standard approaches for inference do not work.

7.2 How to Test for Unit Root

There is a variety of procedures that can be used to test for stationarity/the presence of a unit root. One of the most popular ones is the (augmented) Dickey-Fuller test (Dickey & Fuller, 1979), (A)DF test for short. The ADF test tests the null hypothesis of unit root against the alternative of no unit root, it also accounts for autocorrelation in the error terms. It takes the first difference of a time series and describes it as a function of the previous value and the lagged differences.

$$\Delta y_t = \alpha + \theta y_{t-1} + \sum_{i=1}^{k} \gamma_i * \Delta y_{t-i} + e_t$$

θ is calculated as 1 – ρ and under the null hypothesis of the test, the presence of unit root, θ is equal to zero. The lags are included to account for serial correlation between the errors. If the time series has a clear time trend, one needs to account for that in the test by including a time trend coefficient. The decision on that is mostly based on intuition. It is also possible to remove the intercept term, but that is very uncommon in practice. An important aspect of the test is the number of lags. Choosing an inappropriate number of lags can lead change the outcome of the test. The optimal number of lags can be chosen with help from several information criteria. Popular ones are the Akaike information criterion (AIC) (Akaike, 1973), the Schwarz-Bayesian information criterion (BIC) (Gideon Schwarz, 1978), and the Hannan-Quinn information criterion (HQIC) (Hannan & Quinn, 1979). Information criteria basically measure the quality of a model. A good fit to the data increases the quality of a model, whereas a high number of parameters reduces the quality. Information criteria evaluate how well the model fits the data while simultaneously including a penalty term that increases with the number of parameters. We have used Statas “varsoc” command on each time series to find the optimal lag length.

7.3 The Concept of Cointegration

When two time series that both have a unit root are regressed on each other, the results are likely to be spurious; one solution to this is regressing the first differences of the time series on each other in order to investigate the relationship between them, but there is also a different approach. The concept of cointegration was formally treated for the first time in by Engle and Granger (1987). The following explanation, as well as the section about the Engle-Granger test for cointegration, is based on the textbook by Wooldridge (2020). Two time series, denoted by x_t and y_t, are cointegrated if a linear combination of them is integrated of a lower degree than the two time series of interest. It is important that the time series are integrated of the same order, with two I(1) processes being a common case. So, if the two series are cointegrated there must be a so called cointegration parameter β that is unequal to zero, such that

$$y_t = \beta * x_t + e_t$$

with e_t being a stationary process with a mean of zero. If this is the case, x_t and y_t have a long-term relationship that they are always pulled towards to.

7.4 The Engle-Granger Test for Cointegration

If there is a known theoretical value for beta, the test for cointegration is very straightforward. Define s as follows:

$$s = y_t - \beta * x_t$$

and test s for stationarity. If the null hypothesis of unit root is rejected, x_t and y_t are cointegrated with the cointegration parameter β. However, if β is not known, it must be estimated before we test for cointegration. The first step is running an OLS regression of y_t on x_t. This regression may also include a trend. The second step is then to check whether the errors of that regression are stationary. This is done with an ADF test that uses special critical values as reported in MacKinnon (2010). This is necessary since we have a spurious regression under the null hypothesis. If stationary errors are found, we can estimate an error correction model (ECM) that describes the relationship between x_t and y_t. The ECM has the first difference of y_t or x_t as the depedent variable on the left-hand side. On the right-hand side, there is the cointegration relationship calculated with the previous periods values and multiplied with a parameter that describes the speed of adjustment towards the equilibrium, as well as an intercept and the lagged differences of y_t and x_t. $\epsilon_{y,t}$ and $\epsilon_{x,t}$ describe error terms that have a mean of zero.

$$\Delta y_t = v + \alpha_1[y_{t-1} - \beta_1 * x_{t-1} - d_1] + \sum_{i=1}^{K} c_{1,i}\, \Delta y_{t-i} + \sum_{j=1}^{L} c_{2,j}\, \Delta x_{t-j} + \epsilon_{y,t}$$

$$\Delta x_t = v + \alpha_2[x_{t-1} - \beta_2 * y_{t-1} - d_2] + \sum_{i=1}^{K} e_{1,i}\, \Delta x_{t-i} + \sum_{j=1}^{L} e_{2,j}\, \Delta y_{t-j} + \epsilon_{x,t}$$

The benefit of such a model is that it differentiates between the long-term relation between the variables, described by the cointegration relation, and the short-term fluctuations, represented by the coefficients of the lagged differences. A limitation of the Engle-Granger procedure is that it only works for bivariate settings.

7.5 The Johansen Method

The Johansen method (1988, 1991, 1995) is, in contrast to the Engle-Granger test, a one-step procedure and able to handle multivariate cointegration relations. It starts with a vector autoregressive model of order p (VAR(p)-model):

$$Y_t = v + A_1 * Y_{t-1} + \cdots + A_p * Y_{t-p} + \epsilon_t$$

Y_t is a K*1 vector of variables, v is a K*1 vector of constant parameters, and A_j is a K*K matrix of coefficients, while the last part is an error term that is independent and identically normally distributed with a mean of 0. The VAR(p)-model can be transformed into a vector error correction model (VECM), which follows a similar logic as the ECM in the Engle-Granger approach. It can handle more than two variables and uses matrix notation. The general model looks like this:

$$\Delta y_t = v + \Pi y_{t-1} + \sum_{i=1}^{p-1} \Gamma_i * \Delta y_{t-i} + \epsilon_t$$

Π is in this case $\sum_{j=1}^{j=p} A_j - I_k$, where I_k is an identity matrix with k rows and columns and can also be described as the product of two matrixes: one with the cointegration parameters beta and one with the adjustment speed parameters alpha. The optimal number of lags is determined with the help of information criteria. The change in each variable in this model therefore depends on the adjustment towards the cointegration relation, which is the long-run influence, and on the lagged changes of every variable, which are the short-term influences.

The number of cointegration relationships between the variables is then tested by testing the rank of Π. Johansen provided two tests for this: the trace test and the maximum eigenvalue test. Both aim at determining the number of non-zero eigenvalues of the matrix. The estimated eigenvalues are ordered by size and the H_0 hypothesis that there are at most r cointegrating vectors (non-zero eigenvalues) is tested for values for r from 0 to K – 1 by testing whether eigenvalue_{r+1} is zero. The two tests differ in the calculation of the test statistic and their respective alternative hypothesis: H_1 in the trace test is “more than r cointegration relationships” and for the maximum eigenvalue test it is “r+1 cointegration relationships”. There can be not more than K – 1 cointegration relationships, which would mean that the system is fully integrated, but it is also possible to estimate the VECM of a fully integrated system with one cointegration equation that includes all cointegrated variables. This does not change the results, but it makes the interpretation easier. Therefore, we will use this approach in our analysis.

7.6 One Note on Vector Error Correction Models

Error correction models, or vector error correction models in the context of the Johansen methodology, describe a long run relation between the level values of two variables and the speed of adjustment towards the equilibrium. Let X_t and Y_t be two time series that are cointegrated so that the following two equations describe the long run equilibrium, where beta is the cointegration parameter and c_1 and c_2 are constants:

$$y_t = \beta_1 * x_t + c_1$$

$$x_t = \beta_2 * y_t + c_2$$

In a (V)ECM, the right-hand side would be subtracted from the left-hand side to capture the disequilibrium in any given period. The result would be multiplied with the parameter alpha that describes the speed of adjustment to the equilibrium. Take, for example, an error correction term from the ECM estimated after the Engle-Granger procedure from the equation that describes the change of y in period t:

$$\alpha_1[y_{t-1} - \beta_1 * x_{t-1} - c_1]$$

If y was above its equilibrium value in the previous period, an adjustment towards the equilibrium would require alpha to be negative, ceteris paribus. So far, this is very intuitive. Interestingly, as we will see in the results chapter, some estimates of alpha are positive, which does not seem reasonable at first sight, since one would expect in that case a further movement away from the equilibrium if y was in disequilibrium in the preceding period. There can, at least to the best of our knowledge, still be convergence towards the equilibrium relation of the two time series.

Such a convergence would only require that the alpha in the equation that describes the change in the other variable, x, (here $alpha_2$) to be negative and to have a higher value in absolute terms than $alpha_1$:

$$\alpha_2[x_{t-1} - \beta_2 * y_{t-1} - c_2]$$

If these conditions are met, then x moves faster towards the equilibrium than y moves away from it. That would, ceteris paribus, reduce the disequilibrium in the next periods, until x and y arrive at their equilibrium levels sooner or later, given the absence of any other shocks or lagged value effects. In the Johansen framework, it is in fact usual that some of the alphas are positive. For example, in the bivariate model there is the following cointegration relation:

$$ce = y_{t-1} - \beta * x_{t-1} - c$$

The "standard" values for $alpha_x$ and $alpha_y$ would be positive, and negative respectively and between 0 and 1 in absolute values. In that case, both variables would move towards the equilibrium and convergence towards it would be certain. Still, one of the alphas may have a "non-standard" sign. If the other alpha, the one with the "standard" sign, has a larger absolute value, the two time series still converge towards their long-run relation. This reasoning can also be extended to multivariate settings.

7.7 Granger Causality

It is important to note that the concept of Granger causality, introduced by Granger (C. W. J. Granger, 1969), is not equal to causality. A variable X Granger-causes another variable Y, if including X in the model for Y improves the predictions of Y. One could say in that case that X precedes Y. The test starts with finding the best autoregressive model for Y. In the next step, lagged values of variable X, which is assumed to Granger-cause Y, are added to the model. It is necessary that both variables are stationary. F-tests and t-tests are then used to check whether the coefficients of the included values of X have a significant influence on Y. If any significant coefficients for values of X are found, then X Granger-causes Y. Granger-causality can be unidirectional, so from X to Y or Y to X, or bidirectional, so X Granger-causes Y and Y Granger-causes X.

7.8 Other Methods Used in the Research on Market Integration

Even though the methods described above belong to the most popular ones in the field of market integration today, there are also other approaches. Diebold and Yilmaz (2009, 2012; 2014) developed spillover indexes based on VAR(p)-models, that focus more on return and volatility interdependences and less on the long-term relation between variables. They are also more concerned with forecasts and forecast error variance decomposition. Another method that is used to analyze prize convergence is the Kalman filter, as for example used by Neumann (2009) and Li et al. (2014), with the mathematics behind it being quite complicated. Early papers about price relations in different markets have, for example, used time series models that describe the price change at on location as a function of the price change at the other location and the change in the exchange rate (Jain, 1981; Richardson, 1978). We have chosen our methods because they are well established in the research on market integration and because the statistical concepts that they are built on are intuitive. Furthermore, we are interested in the long-term relationship between the different markets, which is explicitly included in the models. If there is a stable long-term relation between the markets, this is a sign that the law of one price holds, which means that prices only vary because of transaction and transportation costs and that the markets are integrated.

8. Results

8.1 Results of Information Criteria and ADF Tests

The HQIC suggested eight lags for the ADF test in the case of the European hubs, seven lags for the HH and five for Dawn. The results of the ADF test for the suggested lag lengths are presented in table 8.1. We were not able to reject the null hypothesis of a unit root for any of the time series at the suggested lag length, with all tests being conducted at a 1% significance level. All results were robust to changes in the lag length, which was tested by reducing and increasing the lag length used in the test by two, and to the inclusion of trends, except for the Henry Hub and Dawn. In these cases, reducing the number of lags by two resulted in a rejection of the unit root hypothesis when no trend was included. This was not the case for the suggested or the increased number of lags. When a trend was included, the unit root hypothesis could only be rejected for Dawn when the reduced lag length was used. Since all price series are non-stationary at the suggested lag length, we continue with testing the first differenced data for unit root.

Table 8.1

ADF Test on the Log-Transformed Price Series

	Constant, no Trend		Constant and Trend	
Hub	Test Statistic	1% Critical Value	Test Statistic	1% Critical Value
HH	-2.961	-3.430	-2.965	-3.960
Dawn	-3.251	-3.430	-3.193	-3.960
TTF	-0.054	-3.430	-0.188	-3.960
NBP	-0.461	-3.430	-0.579	-3.960
ZEE	-0.204	-3.430	-0.325	-3.960
NCG	0.091	-3.430	-0.057	-3.960

Note: Results are based on own calculations. The data is from “[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]”, by Refinitiv Eikon, 2021. A test statistic that is lower than the critical value means that we reject the null hypothesis of the presence of a unit root at the 1% significance level.

8.2 Results of ADF Tests on First Differences

The HQIC suggests seven lags for the European price series, six for the HH and four for Dawn. The hypothesis of a unit root is rejected in all tests with and without a trend and the test statistics are robust to variations in the lag length. We therefore conclude that all price series are integrated of order 1. Table 8.2 presents the results for the suggested lag length.

Table 8.2

ADF Test on the First Difference of the Log-Transformed Price Series

	Constant, no Trend		Constant and Trend	
Hub	Test Statistic	1% Critical Value	Test Statistic	1% Critical Value
HH	-19.200	-3.430	-19.204	-3.960
Dawn	-20.301	-3.430	-20.307	-3.960
TTF	-15.239	-3.430	-15.327	-3.960
NBP	-14.971	-3.430	-15.044	-3.960
ZEE	-13.870	-3.430	-13.956	-3.960
NCG	-15.554	-3.430	-15.653	-3.960

Note: Results are based on own calculations. The data is from "[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. A test statistic that is lower than the critical value means that we reject the null hypothesis of the presence of a unit root at the 1% significance level.

8.3 Results of Engle-Granger Test

We will not consider the Zeebrugge hub in the following parts of our analysis since it has too many interpolated values. For the sake of brevity, we will also not consider NCG in this analysis. Including it would increase the number of hub combinations from six to ten and we do not think that it would add any value, since the price series in Europe move very closely to each other. Therefore, we have the following six pairs: TTF – NBP, TTF – Dawn, NBP – Dawn, HH – TTF, HH – Dawn, and HH – NBP. In order to run the Engle-Granger test, we used the Stata code developed by Schaffer (2010). The HQIC suggests using five lags for the pairs TTF – NBP, Dawn – TTF, and NBP – Dawn and seven lags for Dawn – HH, NBP – HH, and TTF – HH. In the following, we will focus our attention on the results of the cointegration tests and the size and significance of the adjustment speed parameters, and less on the coefficients of the lagged values. We have decided to not include a time trend in the first step regression of the Engle-Granger test, since a stable trend in the difference between any of the hub combinations is not identifiable from looking at the time series plots. Table 8.3 presents the results of the test for cointegration, while table 8.4 presents the estimated adjustment speed parameters. The layout of table 8.4 is inspired by table 11 in Jotanovic and D'Ecclesia (2021).

Table 8.3

Results of the Engle - Granger Test for Cointegration

Hub Pair	Test Statistic	1% Critical Value	Hub Pair	Test Statistic	1% Critical Value
TTF - NBP	-7.003	-3.904	NBP - TTF	-7.100	-3.904
Dawn - TTF	-5.851	-3.904	TTF - Dawn	-4.367	-3.904
NBP - Dawn	-4.457	-3.904	Dawn - NBP	-5.835	-3.904
TTF - HH	-4.063	-3.904	HH - TTF	-5.569	-3.904
Dawn - HH	-6.840	-3.904	HH - Dawn	-7.071	-3.904
NBP - HH	-4.134	-3.904	HH - Dawn	-5.534	-3.904

Note: Results are based on calculations with the Stata code developed by Schaffer (2010). The data is from "[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. A test statistic that is lower than the critical value means that we reject the null hypothesis of no cointegration at the 1% significance level.

Recall that the error correction model has the following form, as described in the methodology section:

$$\Delta y_t = v + \boldsymbol{\alpha}_1[y_{t-1} - \beta_1 * x_{t-1} - d_1] + \sum_{i=1}^{K} c_{1,i}\,\Delta y_{t-i} + \sum_{j=1}^{L} c_{2,j}\,\Delta x_{t-j} + \epsilon_{y,t}$$

Table 8.4

Estimated Adjustment Speed Parameters

Δy	Δx	α	p-value
TTF	NBP	-.0248682	0.351
NBP	TTF	-.0825833	0.005
Dawn	TTF	-.0533512	0.000
TTF	Dawn	-.0003095	0.942
NBP	Dawn	-.0032619	0.474
Dawn	NBP	-.0512696	0.000
TTF	HH	-.0013844	0.749
HH	TTF	-.0556025	0.000
Dawn	HH	-.0466392	0.030
HH	Dawn	-.1236267	0.000
NBP	HH	-.0040646	0.379
HH	NBP	-.0531382	0.000

Note: Results are based on calculations with the Stata code developed by Schaffer (2010). The data is from “[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]”, by Refinitiv Eikon, 2021. A p-value of less than 0.05 indicates that the adjustment speed parameter α is statistically significant.

8.3.1 TTF – NBP

The Engle-Granger test rejects the null hypothesis of no cointegration. This does not come very surprising, since the European market is considered integrated, see for example Jotanovic and D'Ecclesia (2021). If we estimate the error correction model with TTF as the dependent variable, we observe that the parameter which describes the speed towards the long-run equilibrium (in the following "alpha") is not statistically significant. If we estimate the model with NBP as the dependent variable, alpha is not only larger in absolute values, which indicates a stronger reversion towards the equilibrium, but also statistically significant. It therefore seems that prices at NBP react faster to deviations from the long-run equilibrium than prices at the TTF.

8.3.2 Dawn – HH

We also find evidence for cointegration between the prices at the HH and Dawn. If we estimate the error correction model with Dawn as the dependent variable, we obtain an, in absolute terms, much lower value for alpha then when we estimate the model with HH as the dependent variable. Both alphas are statistically significant which indicates that the North American market is integrated. The estimates for alpha indicate that prices at both hubs adjust towards the long-run equilibrium, but that this happens faster at the HH. The North American market also exhibits stronger adjustment tendencies than the European market, which is reflected in the magnitude of the alpha parameters.

8.3.3 Dawn – TTF and HH – TTF

The Engle Granger test also shows that the prices at Dawn and at the TTF cointegrated. The model with Dawn as the dependent variable has a significant alpha, while this is not the case if TTF is the dependent variable. Thus, Dawn reacts stronger to deviations from the equilibrium price relation. The results for HH and TTF are similar to those from Dawn – TTF. TTF does not have a significant alpha, while HH does.

8.3.4 NBP – Dawn and NBP – HH

The results of the tests for cointegration between NBP and the North American hubs are similar to the results of the tests with TTF and the North American hubs. NBP does not have a significant alpha parameter in both tests, while the Dawn and HH do have a significant alpha parameter.

8.3.5 Postestimation diagnostics

While our tests have resulted in some interesting findings, they must be interpreted with caution. For all estimated error correction models we have found evidence for heteroskedastic and non-normally distributed errors. We also found evidence for serial correlation between the error terms, even after increasing the lag length. These findings can invalidate the statements about the significance of the estimated alphas, since they violate the assumptions of the models. Further information on the impact of violations of model assumptions can be found in textbooks, such as the one by Wooldridge (2020). The postestimation diagnostics were carried out with the Stata commands “swilk”, “wntestq”, and “estat hettest”. The command “swilk” performs the Shapiro-Wilk test for normality, developed by Shapiro and Wilk (1965), on the residuals with the null hypothesis of normally distributed errors. The “wntestq” command runs a Portmanteau test on the residuals to test for autocorrelation. The test was introduced by Box and Pierce (1970) and further developed by Ljung and Box (1978). Finally, “estat hettest” tests for heteroskedasticity of the error terms. It uses the Breusch-Pagan / Cook-Weisberg test for heteroskedasticity (Breusch and Pagan, 1979; Cook and Weisberg, 1983). Exact definitions of the tests and the calculations of the corresponding statistics can be found in the respective papers.

8.3.6 Remarks and Interpretation

The Engle-Granger tests provided evidence for cointegration between all of the considered time series, which can be considered as arguments in favor of the presence of an integrated market for natural gas in Europe and North America. An interesting finding is, that the prices in North America seem to be the ones that adjust if there is a disequilibrium, while the adjustment speed parameters for the European hubs are smaller and often insignificant. This insignificance is not in line with what would be expected from an integrated market. Furthermore, the properties of the error terms of the error correction models cast doubt on the reliability of the results. In order to address the issue of serial correlation, we have done the same tests and estimations with more lags. The exact number of lags was based on the AIC and the likelihood ratio that were also reported in the output of the “varsoc” command. Conducting the tests with the increased number of lags did in most cases not change the results of the cointegration test. The only exception is the combination of Dawn and TTF, where there was no cointegration at the 1% significance level, but only at the 5% significance level, when eight lags were used. In the case of Dawn and HH, the alpha of Dawn was no longer statistically significant when 18 lags were used. Similar results were found for the NBP, that did not have a significant adjustment speed parameter towards the long-run relation with TTF when 16 lags were included. For the sake of brevity, we have not included a table of those results here.

8.4 Result of the Johansen Test for Cointegration:

We choose NBP, TTF, HH, and Dawn for the Johansen test, which is conducted with the “vecrank” command in Stata. The trace test and the maximum eigenvalue test both suggest that there are three cointegration relationships between the four variables if five lags are included as suggested by the HQIC. This means that they are all cointegrated with each other and that they share one common stochastic trend. A “restricted constant” is specified as trend restriction, which is appropriate if there is no clear time trend in the levels data. Changing this for allowing a linear trend in the cointegrating relation or a linear trend in the data did not lead to significant differences in the results. It should be mentioned that we specified the VECM with one cointegration equation to make the interpretation easier. Expressing it with three equations is also possible and would give the same results. Table 8.5 presents the results of the trace test and the maximum eigenvalue test.

Table 8.5

Johansen Tests for Cointegration, Trace and Maximum Eigenvalue Test with five Lags

Trend: rconstant					Number of obs = 1516
Sample: 7 - 1522					Lags = 5
Maximum Rank	Parms	LL	Eigenvalue	Trace Statistic	5% Critical Value
0	64	10001.646	.	185.8809	53.12
1	72	10048.839	0.06036	91.4957	34.91
2	78	10075.387	0.03442	38.3992	19.96
3	82	10094.081	0.02436	1.0115*	9.42
4	84	10094.587	0.00067		
Maximum Rank	Parms	LL	Eigenvalue	Max Statistic	5% Critical Value
0	64	10001.646	.	94.3852	28.14
1	72	10048.839	0.06036	53.0964	22.00
2	78	10075.387	0.03442	37.3877	15.67
3	82	10094.081	0.02436	1.0115	9.24
4	84	10094.587	0.00067		

Note: Results are based on own calculations. The data is from “[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]”, by Refinitiv Eikon, 2021. The results are reported for a test with the "restricted constant" specification. The null hypothesis of at most "maximum rank" cointegration relations is rejected when the Trace/Max statistic is higher than the critical value.

Table 8.6 reports the estimated cointegration equation and the adjustment speed parameters. The cointegration equation, where the abbreviations stand for the log of the price at the respective hub, is therefore:

$$ce = HH + 0{,}556487 * NBP - 0{,}7615114 * Dawn - 0{,}6359742 * TTF - 0{,}2638509$$

This term is equal to zero in the equilibrium and the reaction of the price at the different hubs is captured in the parameter alpha, as described in the methodology section.

Table 8.6

Estimated Cointegration Equation and Adjustment Speed Parameters with five Lags

Hub/Variable	β (coefficient)	p-value	α	p-value
HH	1		-.1744807	0.000
NBP	.556487	0.000	-.0103509	0.632
Dawn	-.7615114	0.000	-.0189857	0.380
TTF	-.6359742	0.000	.0234463	0.226
constant	-.2638509	0.000		

Note: Results are based on own calculations. The data is from "[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. The β for HH does not have a p-value, since it is a priori specified to be equal to one in order to make identification of the other coefficients possible. The constant part of the cointegration equation does not have a α-value, since it is constant by definition. A p-value of less than 0.05 indicates that the adjustment speed parameter α is statistically significant.

The alphas for TTF, NBP, and Dawn are smaller than 0,03 in absolute terms and not statistically significant, while the parameter for HH has a much larger absolute value than the others and is also statistically significant. This finding corresponds to the findings of the bivariate models discussed above, where the HH usually had larger alphas, in absolute terms, than the other hubs. The alpha of Dawn has a "non-standard" sign, as discussed in the methodology section, so the price at Dawn moves further away from equilibrium if there is a disequilibrium, ceteris paribus. This observation is not what we would expect in an integrated market. However, the sum of the absolute values of the statistically significant "standard" sign alphas is larger than the coefficient of Dawn. Therefore, there is an adjustment towards the long-run equilibrium in total, mainly due to the large alpha of the HH. Postestimation diagnostics showed that, as in the bivariate models, the errors are serially correlated and not normally distributed. The presence of serial correlation was tested by using the "veclmar" command, which conducts the Lagrange multiplier test for autocorrelation in the residuals, as described in Johansen (1995). We tested the distribution of the errors by using the "vecnorm" command. This command computes the kurtosis and skewness values, as well as the Jarque-Bera statistic, which combines skewness and kurtosis measures into a single measure that is used in a test for normality (Jarque and Bera, 1987).

In order to address the issue of serial correlation, we increase the number of lags to seven, as suggested by the AIC. There is again full integration between the time series, as reported in table 8.7.

Table 8.7

Johansen Tests for Cointegration, Trace and Maximum Eigenvalue Test with seven Lags

Trend: rconstant					Number of obs = 1514
Sample: 9 - 1522					Lags = 7
Maximum Rank	Parms	LL	Eigenvalue	Trace Statistic	5% Critical Value
0	96	10047.087	.	146.9730	53.12
1	104	10081.633	0.04461	77.8817	34.91
2	110	10104.903	0.03027	31.3410	19.96
3	114	10119.973	0.01971	1.2022*	9.42
4	116	10120.574	0.00079		
Maximum Rank	Parms	LL	Eigenvalue	Max Statistic	5% Critical Value
0	96	10047.087	.	69.0913	28.14
1	104	10081.633	0.04461	46.5407	22.00
2	110	10104.903	0.03027	30.1388	15.67
3	114	10119.973	0.01971	1.2022	9.24
4	116	10120.574	0.00079		

Note: Results are based on own calculations. The data is from “[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]”, by Refinitiv Eikon, 2021. The results are reported for a test with the "restricted constant" specification. The null hypothesis of at most "maximum rank" cointegration relations is rejected when the Trace/Max statistic is higher than the critical value.

An interesting observation is, that the adjustment speed parameter of Dawn now has a “standard” sign. Also, it is still not statistically significant, just like the alphas for NBP and TTF. HH is the only hub with a significant alpha. The cointegration equation and alphas are reported in table 8.8.

Table 8.8

Estimated Cointegration Equation and Adjustment Speed Parameters with seven Lags

Hub/Variable	β (coefficient)	p-value	α	p-value
HH	1		-.1306104	0.000
NBP	.6871804	0.000	-.0102795	0.646
Dawn	-.8580427	0.000	.0140772	0.531
TTF	-.726792	0.000	.0293831	0.143
constant	-.1708628	0.009		

Note: Results are based on own calculations. The data is from "[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. The β for HH does not have a p-value, since it is a priori specified to be equal to one in order to make identification of the other coefficients possible. The constant part of the cointegration equation does not have a α-value, since it is constant by definition. A p-value of less than 0.05 indicates that the adjustment speed parameter α is statistically significant.

The postestimation results are similar to the model with five lags: the residuals are non-normally distributed and there is still evidence for autocorrelation. Since the Likelihood ratio suggested a lag length of seventeen, we will also estimate the model with seventeen lags in order to see if it has any influence on the properties of the residuals. In fact, autocorrelation is no longer present, except for the 12^{th} and 13^{th} lag. The residuals are still not normally distributed. The trace and maximum eigenvalue test suggest full cointegration, as reported in table 8.9. The adjustment speed parameters have the same properties as in the model with five lags. HH has the largest and the only, apparently, statistically significant alpha. The alpha of Dawn has a "non-standard" sign. Results are presented in table 8.10. We therefore conclude that the presence of a single integrated market in an economical sense is arguable. Even though there is a long-run relation between the price levels, most prices do not adjust with a significant speed. Furthermore, the presence of non-normally distributed errors makes the significance of the estimated parameters questionable.

Table 8.9

Johansen Tests for Cointegration, Trace and Maximum Eigenvalue Test with seventeen Lags

Trend: rconstant					Number of obs = 1504
Sample: 19 - 1522					Lags = 17
Maximum Rank	Parms	LL	Eigenvalue	Trace Statistic	5% Critical Value
0	256	10106.129	.	102.0778	53.12
1	264	10129.428	0.03051	55.4801	34.91
2	270	10145.399	0.02101	23.5385	19.96
3	274	10156.477	0.01462	1.3827*	9.42
4	276	10157.168	0.00092		
Maximum Rank	Parms	LL	Eigenvalue	Max Statistic	5% Critical Value
0	256	10106.129	.	46.5977	28.14
1	264	10129.428	0.03051	31.9417	22.00
2	270	10145.399	0.02101	22.1558	15.67
3	274	10156.477	0.01462	1.3827	9.24
4	276	10157.168	0.00092		

Note: Results are based on own calculations. The data is from “[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]”, by Refinitiv Eikon, 2021. The results are reported for a test with the "restricted constant" specification. The null hypothesis of at most "maximum rank" cointegration relations is rejected when the Trace/Max statistic is higher than the critical value.

Table 8.10

Estimated Cointegration Equation and Adjustment Speed Parameters with seventeen Lags

Hub/Variable	β (coefficient)	p-value	α	p-value
HH	1		-.093653	0.000
NBP	1.203896	0.000	-.0108059	0.626
Dawn	-.7148153	0.000	-.0257574	0.249
TTF	-1.30319	0.000	.0386122	0.052
constant	-.3109351	0.000		

Note: Results are based on own calculations. The data is from "[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. The β for HH does not have a p-value since it is a priori specified to be equal to one in order to make identification of the other coefficients possible. The constant part of the cointegration equation does not have a α-value since it is constant by definition. A p-value of less than 0.05 indicates that the adjustment speed parameter α is statistically significant.

8.5 Results of Granger Causality Tests on First Differences:

To test the null hypothesis of no Granger causality between two hubs we need stationary time series. Therefore, we have used the first differences of the log transformed price. The results are reported in table 8.11. We can see that there is only Granger causality for hubs that are located on the same continent. There do not seem to be linkages across the Atlantic Ocean. This finding is interesting, since it presents a contrast to the findings from the cointegration tests, which found long-run relationships between all-time series. Nevertheless, since the tests have different hypotheses and use different time series, the results do not necessarily need to be the same.

Table 8.11

Results of the Granger - Causality Test

Hub Pair	Result	Hub Pair	Result
HH - Dawn	GC both ways	Dawn - TTF	no GC
HH - NBP	no GC	Dawn - NCG	no GC
HH - TTF	no GC	TTF - NBP	GC both ways
HH - NCG	no GC	TTF - NCG	GC both ways
Dawn - NBP	no GC	NBP - NCG	GC both ways

Note: Results are based on own calculations. The data is from "[Day ahead prices for natural gas at the trading hubs HH, Dawn, NBP, TTF, NCG, and ZEE]", by Refinitiv Eikon, 2021. "GC both ways" means that the first hub Granger - causes the second and the second Granger - causes the first. Tests were conducted at a 5% significance level.

9. Discussion

9.1 Critical assesment of empirical results

The Engle-Granger test and the Johansen test suggest that cointegration, and therefore a long-run relationship, between all price series considered in this analysis is present. This can be seen as evidence in favor of an integrated market for natural gas in Europe and North America. However, there remain doubts about this since many adjustment speed parameters were found to be not statistically significant. Also, due to the non-normality and autocorrelation of the residuals in the (vector) error correction models, statements about the significance of those parameters are not reliable. Unfortunately, we cannot compare our postestimation results to others because the reviewed literature did not report any. At most, there were hints that post-estimation diagnostics were considered in some model estimations. Siliverstovs et al. (2005) use dummy variables to control for the effect of shocks and mention the influence of such shocks on the residuals of the model. They also mention that their lag length selection depends on residual diagnostics. The Granger causality test supports the findings of a connection between different markets, but only for hub combinations on the same continent. It did not find any Granger causality between hubs on different continents, which is contrary to the findings from the Engle-Granger test and the Johansen test, both suggest that European and North American markets are connected. More meaningful results could possibly be reached by employing other, more sophisticated, methods. Nick and Tischler (2014) use threshold cointegration tests in their analysis of the gas market that also account for transaction costs, while Chiappini et al. (2019) have not only used threshold cointegration tests but also asymmetric error correction models. Additionally, they consider structural breaks in the time series. A precise definition of these methods can be found in the respective papers and their references. Our results indicate that it is difficult to tell whether markets for natural gas are integrated across the Atlantic or not, even though indications of connectedness between the markets have been found. Recent papers like Chiappini et al. (2019) did also not conclude that European and North American markets are perfectly integrated. Our results are therefore in line with the reviewed literature. There seems to be a long-term relationship between the hubs, but in many cases no significant adjustments if there is a deviation from the equilibrium. The question arises whether oil, or another exogenous factor, is influencing the gas prices globally. Even though oil indexed contracts are not as common nowadays as in previous years, the oil price might still influence the price of gas due to their substitutability. Aguiar-Conraria et al. (2021), for example, provide evidence for strong links between oil and gas markets.

9.2 Feasible methods to increase market integration

One way of increasing natural gas market integration over vast distances would be to standardize and increase the traded quantity of LNG. There is a global crude oil market while the natural gas market is segmented into 3 major market regions. Arguably, one of the main reasons for a singular market for crude oil is that the shipped quantity is large and flexible enough to utilize global arbitrage opportunities. Apart from increased trade and the related infrastructure investment required, the adjustment of contract duration for LNG suppliers could further promote transatlantic market integration. By promoting short-term instead of long-term contracts, suppliers would be able to react faster to sudden changes in the market, making the LNG market more liquid. On the other hand, the shortening of trade contracts could increase supply insecurity in countries that are dependent on LNG imports. Another way to further increase market integration is the use of regulatory tools. The EU has promoted the cooperation of energy regulators by establishing an agency, as well as promoted the unbundling of the natural gas supply chains. In comparison, the US has a more indirect approach because it didn’t promote the integration of separate markets by pipeline, but it promoted the liberalization of natural gas pipeline markets, allowing previously disconnected producer and consumers to engage in trade. The continuation of the EU and U.S approach towards market integration is still relevant today. Establishing and liberalizing the use of natural gas pipelines may work to promote market integration for markets that are close in proximity, but for distant markets that use LNG shipments a different approach is needed. Summed up, for the transatlantic market analyzed in this thesis, except for increasing the global LNG shipping capacity, the relevant methods of increasing market integration are technical standardization and contract shortening because natural gas is only traded in the form of LNG between North America and Europe.

9.3 Future assessment of natural gas in relation to other fossil fuels

Presently, fossil fuels dominate the global energy market. Natural gas is the cleanest fossil fuel when combusted and might be the cleanest fossil fuel when considering its entire supply chain. Nevertheless, it does have many downsides like its environmental concerns and CH4 leaks in its supply chain, but in comparison to other fossil fuels it seems to be superior in almost every way except price and ease of handling. The promotion of more efficient natural gas markets through market integration, or through other means, to make natural gas more competitive is arguably good. The reason for this is that natural gas could become more competitive against less efficient and more polluting fossil fuels. The promotion of natural gas as a “bridge fuel” is thereby legitimized, but the question of where this figurative bridge will lead precisely, or how fast, is still open, making the question of how long to promote natural gas difficult.

9.4 Future assessment of natural gas in relation to hydrogen

As an increasing number of governments are taking actions to mitigate climate change, the search for low emission and renewable energy technologies is in progress. There are several technologies that could potentially replace fossil fuels and create a new energy economy based on renewable resources. Natural gas is at the intersection of many present and some future technologies. While renewable resources are not discussed in this thesis, their potential energy carrier, H2, is discussed due to its close relation to natural gas. H2-based technologies that are supposed to replace fossil fuels are still too expensive for general use and lack infrastructure. Hypothetically, if H2 would replace fossil fuels as an energy carrier, natural gas could still be used to produce H2 when demand cannot be met, or to provide electric power on short notice. Currently, the natural gas-based methods of H2 production (blue and gray) are cost competitive against green H2, but it is uncertain how the production methods will compare if H2 sees mass adoption. Another H2 related aspect of natural gas is the overlap in technology and infrastructure. There is some technological overlap between H2 and natural gas technology, but H2 will need dedicated infrastructure if it is to be mass adopted. The overlapping natural gas infrastructure and technology may play a transitional or complementary role leading up to the potential mass adoption of H2. Summarized, if H2 sees mass adoption as an energy carrier in the future, natural gas will most likely play a significant role in the transition, due to its production capabilities, its technological overlaps, and infrastructural overlaps. It is less likely, but still possible, that natural gas might play a role in the hypothetical future where H2 is an established energy carrier. Either way, if H2 does not achieve mass adoption natural gas is still the least emitting fossil fuel, securing its position as a bridge fuel for any type of transition to low emission energy sources. Natural gas being the least emitting fossil fuel will also secure it as the top fossil fuel for emergency and peak energy demand smoothing in a future where the minimization of emissions is a priority.

9.5 Assesment of COVID-19´s causal relation to the 2021 price surge

Whether and how the COVID-19 pandemic has had a permanent influence on the international markets for natural gas cannot be determined before the pandemic has ended, which is still not the case in December 2021. What can be said is that both, the lowest and the highest prices of our period of interest were observed during the pandemic and that this is likely related to the consequences of the pandemic. The surge to record highs was caused by a strong demand recovery after lockdowns have been lifted, but also to weather related factors. Additionally, natural gas demand in Asia has remained high during the pandemic, depleting the European market of redirected LNG shipments. LNG supply side disruptions further supported the upward trend in prices. COVID-19 is therefore a significant contributor to the ongoing surge of natural gas prices, but it is not the only cause.

9.6 Feasibility of market integration as a tool to prevent price surges

The question whether market integration is an appropriate way of preventing future price surges deserves discussion. One of the main arguments by governments for implementing policy to promote natural gas market integration is to reduce the price volatility of natural gas. While no estimates of how much freely traded natural gas could have prevented the ongoing price surge has been examined, it might also be premature to get a viable estimate. There is no doubt that the market integration of natural gas, and also electricity market integration, will theoretically dampen any energy price surge, the question is only if it would be enough to prevent such developments as in the autumn of 2021. Due to the alignment of many causal factors and the occurrence of natural gas price surges in many countries simultaneously, the integration of more markets would most likely not prevent the ongoing price surge. Integrated markets cannot prevent a price surge, just distribute the surge among the integrated markets, in this case too many markets are affected simultaneously. When there is no unaffected integrated market to distribute the price surge to, all integrated markets will experience a dampened price surge. Integrated markets are, at least in theory, better at preventing a localized price surge as unaffected integrated markets will neutralize the surge because it is an arbitrage opportunity to them. In reality, the data shows that there can still be localized price hikes, for example due to weather events.

Said simply, integrated markets for natural gas might have prevented the ongoing price surge from being worse than it is, but the magnitude of the ongoing price surge is too large to be prevented by the current degree of market integration alone.

10. Conclusion

The main goal of this thesis was to identify whether the markets for natural gas in North America and Europe are integrated. This question has been addressed in several papers which came to different conclusions, depending on the time period of investigation. Nonetheless, the question is still relevant, because of the distinctive nature of the natural gas industry and especially because of the changes that it has seen in the last decades which affected the fundamental aspects of the market. The natural gas industry is characterized by the need of large investments in exploration projects and infrastructure such as pipelines and tanker ships. These high fixed investment costs generally favor the existence of a monopoly, or at least prevent easy market access. This, and the fact that the complicated transportation of gas has made long-distance trade unattractive for many years, does not favor the existence of an integrated market. On the other hand, there have been significant changes in the last 20 years. The European Commission has enacted three directives that aim at liberalizing and integrating the market for natural gas in Europe. The US have become the world's largest producer of natural gas due to the shale gas revolution and have switched from being a net importer to being a net exporter. Global trade in natural gas has increased constantly, which was especially promoted by trade in LNG, that makes it possible to transport gas over longer distances and between points that cannot be connected via pipelines. Nevertheless, looking at the prices for natural gas at different trading hubs revealed that local shocks, for example extreme weather conditions, can have a tremendous short-term impact on the hubs in one region, but no or little impact on hubs elsewhere. Whether the COVID-19 pandemic and the recent surge in gas prices, especially in Europe, has had a permanent impact on the market structure and the degree of integration can only be determined after more time has passed and reactions have been implemented. Especially the recent development of gas prices, a product of increased demand and a weaker supply side, can be seen as a stress test for the global gas markets that could reveal deficiencies in connectedness. Our analysis, that made use of well-known and established methods, had mixed results. On the one hand, the Engle-Granger test and the Johansen test found evidence for a long-term relation between the prices in Europe and North America. Prices in North America seem to adjust faster to disequilibria than those in Europe. On the other hand, there was often no significant adjustment towards the equilibrium and there was no Granger-causality between hubs on different continents. Furthermore, the properties of the residuals of our models impede the reliability of statements about the estimated parameters. That said, there are indicators of an integrated market in Europe and North America, but we do not conclude that the markets are completely integrated. The use of more advanced methods might provide a clearer picture of the complex interactions in the gas market. Whether the market will become more integrated in the future or not also depends on to what extend policymakers in different countries want to rely on natural gas in their energy policy. Fighting climate change requires a reduction in CO_2 emissions, which, at first sight, would necessitate a reduction in the consumption of natural gas. This would then be expected to make further efforts towards market integration less important. However, natural gas is the cleanest of all fossil fuels and can therefore be expected to have a longer remaining life than oil or coal. In addition to that, natural gas is used in the production of H_2 and fertilizers. Therefore, it will be in demand even if the world completely shifts to renewable energy sources in the electricity and heating sector.

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