Natural gas, liquefied natural gas and electricity markets

Natural Gas, Liquefied Natural Gas and Electricity Markets

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Declaration of originality

I confirm that the work presented in this thesis is my own. Where information has been derived from other sources, this has been indicated by appropriate author citations.

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Abstract

Three empirical chapters related to natural gas, liquefied natural gas, and electricity markets are presented in this thesis.

In Chapter 2, we analyze the main natural gas indexes in Western Europe that prevailed after the deregulation of their natural gas markets. The United Kingdom was the first European country to deregulate its natural gas market in the 1980s, followed by continental European countries in the late 1990s. We first examine the integration of natural gas markets in Western Europe by conducting cointegration tests, both in the spot and the forward market, of the main gas indexes. We then revisit the Theory of Storage by analysing the relationship between inventory and the slope of the natural gas forward curve of the two most mature natural gas markets in Europe, namely the United Kingdom and the Netherlands. The results confirm an increased market integration in the spot market as well as in the forward market, with a particular role played by the Netherlands. Lastly, we find a positive relationship between the inventory and the slope of the natural gas forward curves in the United Kingdom and the Netherlands.

Chapter 3 focuses on the LNG market, in which a growing trading activity in short-term contracts has been observed over the last few years, with long-term contracts being replaced by short-term ones and optionalities granted by suppliers, in a context of a large increase of natural gas production. Flexible LNG contracts give buyers the option to redirect a given cargo if they identify a higher spot price at a point different from the original destination. Firstly, we describe the new outlook of LNG markets, which has become more and more spot-centric, with Asian LNG Futures bringing transparency to spot and forward prices. Secondly, we address the valuation of the rerouting option, a number that must be accounted for by the buyer when assessing the profitability of a given cargo. As an example, we apply the rerouting

option valuation methodology to the scenario where the supplier is the United States, the original destination is Germany, and the alternative destination is Japan; we assume the rerouting of the vessel takes place when the cargo reaches the waters of Germany. This approach can be used for any group of three countries by adjusting the transportation costs. The profitability behind the optionality being embedded in a purchase contract as well as its sensitivity to the transportation costs, price volatility and spikes is also exhibited.

In Chapter 4, we turn our attention to the new developments in the UK electricity market, related to the government's decarbonisation targets. Renewable energy has attracted a lot of attention from the public and significant capital from investors since the Paris agreement in 2015. The United Kingdom is one of the pioneer countries in decarbonising its electricity market, with its energy-related CO2 emissions decreasing to the lowest levels since 1888. We present and analyze the new developments in the UK electricity market, where we specifically focus on the valuation of two government support schemes, namely the Contracts for Difference scheme and the Great Britain Capacity Market scheme. We propose a swap valuation methodology for the Contracts for Differences, a scheme which demonstrates the government's incentive towards low carbon electricity generators. We then suggest a simple, but novel to our knowledge, valuation methodology for the Great Britain Capacity Market, by representing the capacity option as a series of daily European call options.

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Chapter 1. Introduction

1. Motivation

World natural gas markets have changed remarkably over the last decade. The demand for natural gas has been growing substantially, mainly because of the coal-to-gas switch regime that has been adopted by many countries across the world in order to reduce their carbon emissions. Consequently, natural gas has become a necessary source in the power generation mix, as a substitute for oil and coal, as well as a backup fuel for renewables, due to their intermittent nature. Specifically, in 2019, natural gas reached a market share level of 23% in the global energy mix - a historic high level (IEA Global Energy Review 2019).

Similarly, global LNG trading has also been rapidly growing, reaching a 13% year-on-year growth in 2019, marking the sixth year of consecutive growth (IGU 2020). The shale gas revolution transformed the United States into a major gas exporter, the third largest in 2019, following Australia and Qatar, changing the dynamics of the market. China recently entered the LNG market, following the implementation of the coal-to-gas switch regime, and has since become a major LNG importer together with Japan and Korea. In terms of natural gas consumption, the United States and China were the main growth drivers in 2019, accounting together for over two thirds of the increase in global natural gas consumption (IEA Global Energy Review 2019).

In Europe, LNG imports expanded in 2019, for the fifth consecutive year, increasing the market share from 16% in 2018 to 24% in 2019, accounting for 90% of the increase in global LNG trade. Some of the reasons behind the increase in European LNG imports are the decline of natural gas domestic production in the Netherlands and the United Kingdom, an increase in electricity production from gas fired plants, and an increase in the use of storage (IGU 2020).

With oversupply in the market, greater competition and an increased LNG shipping fleet, LNG buyers have been pushing for more flexibility. These market developments led to a decline in long-term oil-indexed LNG trading and a subsequent increase in short-term LNG trading. As a result of the rise in spot LNG trading, the LNG market is now becoming an independent commodity in its own right, with an increased trading activity in Platt's JKM index, whilst new indexes and financial products are now emerging, such as options on tanker redirection and LNG freight Futures.

Following the Paris agreement (COP21) that took place in 2015, electricity markets across the world are under transformation. The legally binding climate change agreement aims at limiting the global average temperature increase below 2° C during this century. Accordingly, renewables, such as solar and wind, are attracting a lot of attention and investment during the global attempt of reducing greenhouse emissions. Specifically, in 2019, the global share of renewables in electricity generation reached 27% - the highest level ever recorded (IEA Renewables Power 2020).

2. Structure of the thesis

In this thesis, we address some of the significant market changes in the global natural gas, LNG, and electricity markets. More specifically, we examine and analyze spot and Futures contracts traded on gas Exchanges in Europe and propose a novel valuation methodology for the rerouting option, an optionality that has emerged from spot LNG trading. Lastly, we propose valuation methodologies for two government incentive schemes which are currently implemented in the United Kingdom.

Chapter 2 addresses European natural gas markets after their deregulation. We provide an overview of the major European natural gas markets namely, the United Kingdom,

the Netherlands, Germany, and France and analyze gas futures prices in the spot and forward market, with the aim to identify whether a regional market integration has taken place. We employ cointegration tests and analyze the relationship of the major European gas indexes through VECM estimation, residuals correlations and VAR Granger causality tests. Our results confirm an increased market integration, while at the same time we identify the rapid development of the Dutch TTF in recent years. Jotanovic and D'Ecclesia (2021) who study the evolution of natural gas prices in Europe, also find that market integration exists between the studied European gas markets but exhibit that the convergence to a single European price has not occurred yet, whilst their results indicate that TTF may now be considered the benchmark price for Europe. Additionally, we revisit the Theory of Storage, introduced by Kaldor (1939), Working (1949), Brennan (1958) and Telser (1958), on the two most developed European natural gas markets, namely the United Kingdom and the Netherlands, where we find a positive relationship between inventory and the slope of the natural gas forward curve.

In Chapter 3, we turn our attention to the global LNG market and the recent growth in short-term LNG trading. Over the last few years, long term oil-indexed contracts are in decline, while new short-term LNG contracts are increasing in popularity. These new contracts give buyers the option to redirect a given cargo if they identify a higher spot price at an alternative destination. We first present an overview of the LNG market, before providing a valuation methodology for the rerouting option, which is often included in short-term contracts. We represent the rerouting option as a spread option, one in the family of real options, introduced by Dixit and Pyndick (1994). Our approach can be used for any group of three countries by adjusting the transportation cost. Lastly, we show the rerouting option's price sensitivity to the volatility and the LNG transportation cost.

Chapter 4 examines the new developments currently implemented in the British electricity market. In 2019, the United Kingdom set a new target of reducing all greenhouse emissions to net zero by 2050, while in 2013 the United Kingdom's government had

implemented the Electricity Market Reform (EMR); a series of interventions that will help manage the transition to a decarbonised electricity market through incentivised investment in low-carbon power, affordable to consumers. We provide an overview of the new developments in the British electricity market and study two government incentive schemes, that aim to promote the use of renewables in power generation. We propose a swap valuation methodology for the Contracts for Difference scheme, in which we identify the government's incentive towards power generators of low carbon electricity. We then propose to represent the Great Britain Capacity Market as a series of daily European call options for one year. In the case of a stress event, the system operator can exercise the option on the day, while the electricity generator must provide the agreed capacity at the predetermined price K.

Lastly, in Chapter 5 we present our main findings, concluding remarks and ideas for future research.

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Chapter 2. European gas markets: An analysis of main indexes and forward spreads

1. Introduction

During the last decade, global natural gas production has been increasing at a steady annually compounded growth rate of 2.7%, as natural gas became a strictly more popular source of energy than crude oil, because it produces fewer emissions. In 2019, natural gas production hit a new high, with an increase of 3.3% from 2018. Similarly, global natural gas demand increased by 1.5% in 2019, compared to 2018, with China playing an important role behind this increase while trying to reduce its coal consumption. The Covid-19 pandemic impacted natural gas demand with a decrease of 4% in 2020; however, it is expected that the natural gas market will progressively recover and return to pre-pandemic levels in 2021. Global natural gas imports are also increasing, with LNG as the main driver. Australia and Qatar were the two largest LNG exporters in 2019; however, since the shale gas revolution the United States is becoming a major LNG exporter, the third largest in 2019 (IEA Natural Gas Information: Overview 2020; IEA Gas Market Report, Q1-2021).

In this Chapter, we focus our attention on European natural gas markets which are being greatly transformed, with new gas hubs emerging across different countries. The trading activity in gas Exchanges is quickly increasing, both in the spot and forward markets, while long term oil-indexed natural gas contracts are rapidly decreasing.

Indigenous gas production in Europe is in decline, meaning that Europe will inevitably become heavily dependent on imports in the future. Given Europe's goal of reducing its dependency on Russian gas supply, prices will be affected by elements like LNG imports and gas imports from countries other than Russia. There will be a large competition between Russia, Qatar, and the US, which in turn will increase the liquidity in hubs.

The rest of the Chapter is structured as follows. Section 2 provides an overview of European gas markets. Section 3 investigates the price co-movements between the various European gas indexes by employing cointegration tests, VECM estimation and VAR Granger causality tests. Section 4 revisits the Theory of Storage, by analysing the relationship between inventory and the slope of the natural gas forward curve in the United Kingdom and the Netherlands, the two most mature natural gas markets in Europe. Section 5 concludes.

2. European gas markets overview

Over the last decades, European countries have been deregulating their natural gas markets with the goal of increasing market competition. The transformation was initiated in the United Kingdom with the privatisation of British Gas in the 1980s. Continental Europe followed in the late 1990s, with the implementation of the first European gas directive in 1998 (98/20EC), which entailed a vision to create a competitive and secure European gas market, although, significant results of the transition to liberalisation were evident only after 2005.

Heather (2015) investigates the progress of European gas markets in the liberalisation process. The author concludes that, with the exception of the well-established Dutch gas market, the liberalisation process was still underway in Western Continental Europe in the mid-2010s. Furthermore, the author identified that the transformation process in Eastern Continental Europe was far behind, with an evidently high dependence on Russian gas. Nevertheless, the author noted that the transition from monopolistic to competitive markets was on the way on the Continent and observes that in the United Kingdom the liberalisation process took around 15 years before the market became competitive, both at a wholesale and a retail level.

Since the deregulation of European gas markets, natural gas hubs, both virtual and physical points, where spots and Futures contracts are traded, emerged across Europe. The

most developed gas hubs are the British National Balancing Point (NBP), which trades in pence/therm and was established in 1996, and the Dutch Tile Transfer Facility (TTF), which trades in €/MWh and was established in 2003. In Germany, there are two gas hubs, namely Gaspool (GPL) and NetConnect Germany (NCG), both created in 2007 and trade in €/MWh. The French Point d'Echange de Gaz Nord (PEGN), which also trades in €/MWh, came to existence in 2004, while the French Trading Region South (TRS) was established in 2015. A single market zone was created in France, in November 2018, with the merger of PEGN and TRS to Trading Region France (TRF), in which there is one virtual gas trading point called PEG.

The remaining gas hubs are based in the following countries: Zeebrugge Hub (ZEE) and Zeebrugge Trading Point (ZTP), both established in Belgium in 2000 and 2012, respectively; Punto di Scambio Virtuale (PSV) operates in Italy since 2003; Central European Gas Hub (CEGH) was established in Austria in 2005; Almacenamiento Operativo Comercial (AOC) was established in Spain in 2004; Gas Transfer Facility (GTF) was established in Denmark in 2004; Virtuální Obchodní Bod (POV) was established in the Czech Republic in 2011; and Virtual Point Gaz-System (VPGS) which was established in Poland in 2014.

Germany, Europe's largest gas consuming market, is currently focused on employing renewables in its electricity production as well as phasing out the use of nuclear and coal in the power sector, by substituting them with natural gas. As such, natural gas is rapidly becoming a major component of Germany's energy mix as it will be used both in the electricity production as well as a backup fuel for renewables, due to their intermittent nature (IEA Germany 2020 Energy Policy Review 2020). Germany relies heavily on gas imports, with around 93% of its gas supply imported mainly from Russia, followed by the Netherlands and Norway, with the use of an extensive system of pipelines that assists in importing natural gas as well as distributing around the country. Russian gas is imported via the Yamal-Europe pipeline that has a capacity of around thirty-three billion cubic metres and from the Ukrainian

gas transmission system that has a capacity of approximately one-hundred-twenty billion cubic metres. Imports from Norway are imported via three pipelines, namely Norpipe, Europipe I, and Europipe II, with a total capacity of fifty-four billion cubic metres. Germany and the Netherlands are connected via many pipelines, including gas imported from the Groningen gas field. Germany has the largest gas storage capacity in Europe and the fourth worldwide, with fifty-one gas storage facilities that have a maximum volume of usable working gas of 24.6 million cubic meters. The first German LNG terminal is currently under development in Brunsbüttel (Federal Ministry for Economic Affairs and Energy, Germany).

France imports around 98% of its gas demand via pipelines and four LNG terminals. There are two natural gas transmission system operators (TSOs) in France, namely GRTgaz which operates the low-calorific value gas network in Northern France and TIGF which operates the high-calorific value gas network in South-Western France. French gas consumers are supplied by twenty-six natural gas distribution system operators (DSOs). France has fourteen gas storage sites, of which twelve are operated by Storengy and two by TIGF (Commission de Régulation de l' Énergie, France).

The British gas market is the oldest, most developed, and competitive gas market in Europe. Indigenous gas production from the UK Continental Shelf (UKSC) has been in decline since 2000, however, it was still able to meet around 50% of the country's gas demand in 2019. In the United Kingdom, natural gas plays an important role in the country's power generation mix, accounting for 40%. In 2019, the composition of imports changed significantly with large amounts of imported LNG from Qatar, the United Kingdom's largest LNG supplier. The remaining gas is imported via pipelines from Norway, the Netherlands and Belgium. The United Kingdom currently has a storage capacity of 1.3 billion cubic meters, after the closure of the Rough storage facility in 2017 for safety concerns. Rough was the largest gas storage facility in the United Kingdom with a storage capacity of 3.1 billion cubic meters (BEIS 2020).

The Netherlands owns a very large natural gas field, namely the Groningen field, making it the second largest gas exporter in Europe after Norway. However, following the phasing out of natural gas production from the Groningen field, because of earth tremors and fears over the safety of the residents, domestic gas supply and gas exports are rapidly declining. The Netherlands has five natural gas storage sites with a total capacity of around fifteen billion cubic meters, where Norg and Bergermeer are the two largest sites, with seven billion cubic meters and four billion cubic meters working capacity, respectively (Honore 2017).

3. Co-movement analysis of European natural gas indexes

3.1. Review of the literature

Researchers analysed in the past the convergence of natural gas prices in different regions. Neumann et al (2006) applied the time varying Kalman filter analysis to test the convergence of European natural gas spot prices. They exhibit full convergence between NBP and Zeebrugge following the construction of the Interconnector, and divergence in periods when it was either shut down or transporting at almost full capacity in one direction. Geman and Liu (2014) examine whether the gas markets of the United States and the United Kingdom are moving towards integration, by studying the Henry Hub and National Balancing Point indexes through spot prices as well as distances between forward curves over the period 2001 to 2013; they reach the conclusion of absence of convergence at that point in time.

Asche et al (2013) measure the degree of market integration between three European spot markets: TTF in the Netherlands, ZEE in Belgium and NBP in the United Kingdom. The results indicate a highly integrated market, with some gas prices at the time defined by oil prices. Kuper and Mulder (2013) evaluate the relationship between regulatory mechanisms, cross-border country constraints and integration of the Dutch-German gas market. They find

that the strengthening of connections with the UK market and the Russian supply have a negative effect on market integration between the Dutch and the German NCG market.

Petrovich (2013) examines the integration level of eight European spot and forward hub prices (NBP, TTF, ZEE, CEGH, GPL, NCG, PEG and PSV) for the period 2007- 2012. The results suggest that European gas hubs were integrated during the period of analysis. Our own study extends the analysis to the recent period, where oil indexation has been disappearing in new contracts. Jotanovic and D'Ecclesia (2021) study the evolution of natural gas prices in Europe. They find that market integration exists between the studied European gas markets but exhibit that the convergence to a single European price has not occurred yet. Finally, they conclude that NBP and TTF are the price setting hubs of the forward markets and identify that since 2014, TTF gas prices show an increased correlation with the other hubs whereas NBP gas prices are less correlated, indicating that TTF may now be considered the benchmark price for Europe.

3.2. Data description

For the analysis we use weekly spot and forward prices, provided by the Exchanges ICE and PEGAS, and accessed through Bloomberg. For the spot price we use the first nearby Futures contract for the British NBP, the Dutch TTF, the two German indexes GPL and NCG and the French PEGN. To represent a "distant" forward price, we use the three months ahead Futures contract, as it is the only maturity for which liquidity in the most mature European gas indexes exists. Notably, we exclude the German NCG and the French PEGN from the forward market analysis as these two indexes are not very liquid in the forward market. NBP trades in pence/therm, while the other indexes trade in €/MWh, therefore, we convert NBP prices to €/MWh at each date of analysis.

A summary of data availability is presented in Table 2.1 for spot prices and in Table 2.2 for forward prices. The period of analysis varies for each gas index as they all have different operation start dates. The spot and forward prices are plotted in Figure 2.1 and Figure 2.2, respectively. The period of analysis for spot and forward prices is 02/04/2010 - 12/03/2021.

Table 2.1. Spot prices data availability

Data availability for spot prices at the five European gas indexes.

Gas Index	Exchange	From	To
NBP	ICE	17/03/2000	12/03/2021
TTF	ICE	01/07/2005	12/03/2021
GPL	PEGAS	28/08/2009	12/03/2021
NCG	PEGAS	28/08/2009	12/03/2021
PEGN	PEGAS	02/04/2010	12/03/2021

Source: Bloomberg

Table 2.2. Forward prices data availability

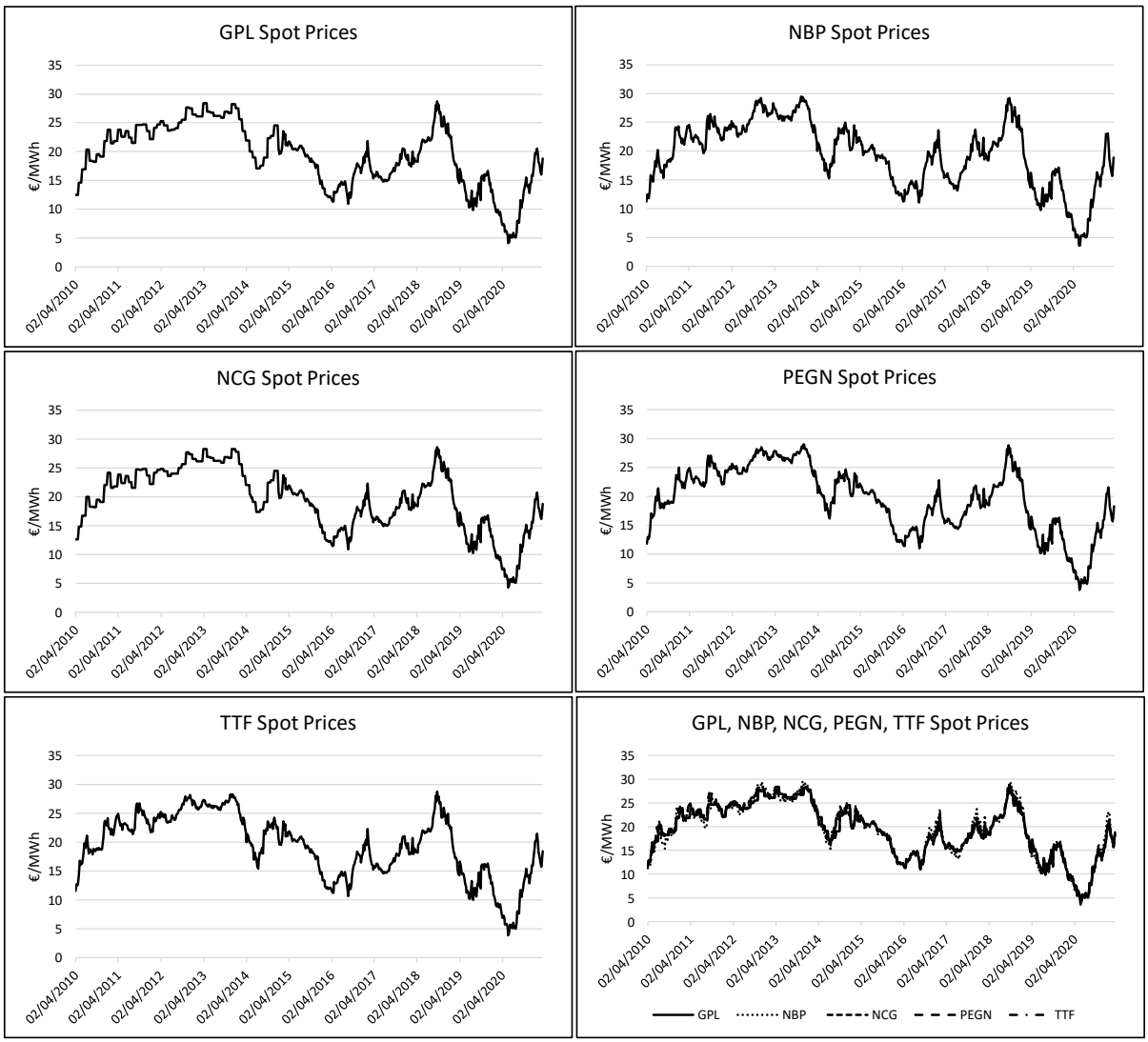
Data availability for forward prices at the three European gas indexes.

Gas Index	Exchange	From	To
NBP	ICE	17/03/2000	12/03/2021
TTF	ICE	01/07/2005	12/03/2021
GPL	PEGAS	03/07/2009	12/03/2021

Source: Bloomberg

Figure 2.1. Spot price trajectories for NBP, TTF, GPL, NCG and PEGN

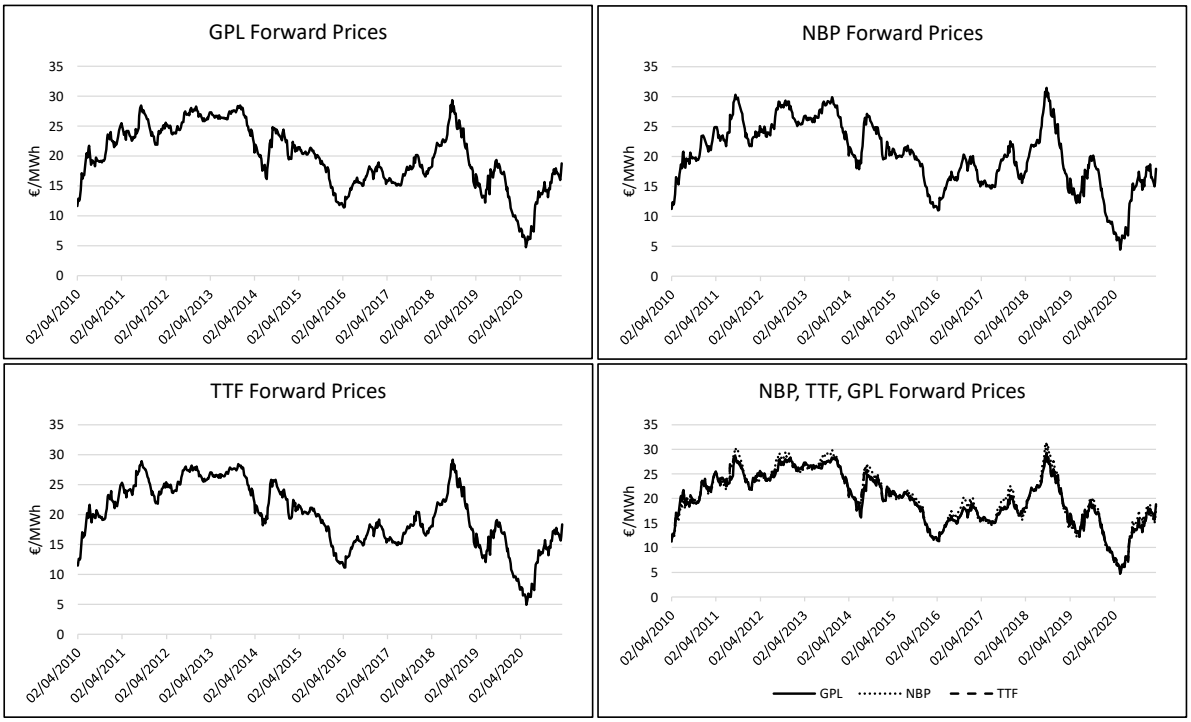
Weekly spot prices for the five European gas indexes in €/MWh for the period 02/04/2010 - 12/03/2021



Source: Bloomberg

Figure 2.2. Forward price trajectories for NBP, TTF and GPL

Weekly forward prices for the three European gas indexes in €/MWh for the period 02/04/2010 - 12/03/2021.



Source: Bloomberg

3.3. Unit root and cointegration tests

We note that spot and forward prices in the various European gas indexes graphically exhibit a common price pattern as well as non-stationarity (see Figure 2.1 and Figure 2.2). Firstly, we examine whether the price series have a unit root, using the Augmented Dickey Fuller test on the logarithms of both spot and forward prices

$$\Delta Y_t = \alpha + \beta Y_{t-1} + \sum_{i=1}^{p} \delta_i \Delta Y_{t-1} + \varepsilon_t \qquad [1]$$

where ε_t is a white noise standard error and p is the number of lagged differences, chosen according to the Schwarz Information Criterion (SIC) in order to remove any serial correlation from the residuals.

The null hypothesis of the ADF unit root test is $\beta = 0$, against the alternative $\beta < 0$. If we fail to reject the null hypothesis, we conclude that the time series has a unit root, and it is therefore non-stationary. In the alternative case, we conclude that the times series does not have a unit root, and it is therefore stationary. A variable is said to be integrated of order d if it is stationary after being differenced d times.

The results of the ADF test, presented in Table 2.3 for spot price series and Table 2.4 for forward price series, show that all price series are integrated of order 1 and stationarity is achieved after differencing one time. The price series are therefore $I(1)$ processes.

Table 2.3. ADF test results for spot prices

Augmented Dickey Fuller unit root test for spot prices for NBP, TTF, GPL, NCG and PEGN where the lag length is based on the Schwarz Information Criterion (SIC).

	Level		First Difference	
Variable	T-Statistic	P-Value	T-Statistic	P-Value
NBP	-2.709232	0.0730	-9.535102	0.0000
TTF	-2.699738	0.0746	-8.322619	0.0000
GPL	-2.714019	0.0722	-7.860060	0.0000
NCG	-2.674015	0.0792	-9.644858	0.0000
PEGN	-2.427905	0.1345	-8.359632	0.0000

Table 2.4. ADF test results for forward prices

Augmented Dickey Fuller unit root test for forward prices for NBP, TTF and GPL where the lag length is based on the Schwarz Information Criterion (SIC).

	Level		First Difference	
Variable	T-Statistic	P-Value	T-Statistic	P-Value
NBP	-3.130311	0.0250	-7.271510	0.0000
TTF	-2.757991	0.0651	-7.387668	0.0000
GPL	-2.855071	0.0514	-7.362507	0.0000

Since all price series are non-stationary, we implement the Johansen cointegration test (Johansen 1991) to investigate the relationship between the European gas price series. The Johansen cointegration test operates in a VAR context

$$Y_t = A_0 + A_1 Y_{t-1} + \ldots + A_p Y_{t-p} + \varepsilon_t \qquad [2]$$

where, Y_t is a $mx1$ vector, a is a $mx1$ vector, $A_1, A_2, \ldots A_p$ are mxm matrices and $\varepsilon_t \sim N(0, \Sigma)$; Σ is a mxm matrix with elements σ_{ij}. Reparametrizing Equation (2) we get

$$\Delta Y_t = A_0 - \Pi Y_{t-1} + \sum_{i=1}^{p-1} \Gamma_i Y_{t-1} + \varepsilon_t \qquad [3]$$

where, $\Pi = \sum_{i=1}^{p} I - A_j$ and $\Gamma_i = -\sum_{j=i+1}^{p} A_j$.

If all m elements of Y_t are $I(0)$ processes, then Π is a full rank matrix. If all m elements of Y_t are $I(1)$ and not cointegrated then $\Pi = 0$. If all m elements of Y_t are $I(1)$ and cointegrated

with r cointegrating vectors, then Π is a reduced rank matrix $r < m$, with r cointegrating combinations of Y_t that are $I(0)$ such that

$$\Pi = \alpha\beta' \qquad [4]$$

where, α is a $m\ x\ r$ matrix of adjustment coefficients that measures the speed of adjustment back to the equilibrium and β' is a $r\ x\ m$ matrix. If cointegration exists between the variables, which are the m elements of Y_t, then Equation (3) can be written as

$$\Delta Y_t = a - \alpha\beta' Y_{t-1} + \sum_{i=1}^{p-1} \Gamma_i Y_{t-1} + \varepsilon_t \qquad [5]$$

In this case, Y_t is determined by $m - r$ stochastic trends and there must be some Granger causality in the system of variables. The system can be analysed either in terms of the unrestricted VAR or the VECM, which imposes the economic relationships. In this case, one would expect the stationary $\beta' Y_t$ to be spreads.

In our analysis, we implement the Johansen cointegration test at a regional level to investigate whether a long-run relationship exists in Western European natural gas spot and forward markets. Our results, presented in Table 2.5 and Table 2.6, show that there exists a single stochastic trend among the European gas spot and forward markets that generates the random walk $I(1)$ behaviour.

Specifically, for spot price series, where the number of variables m is equal to 5, we find $r = 4$ cointegrating vectors indicating that there is one stochastic trend driving the five $I(1)$ price series. Similarly, for the cointegration test results for forward prices, where the number of variables m is equal to 3, there exists $r = 2$ cointegrating vectors suggesting that

there is one stochastic trend driving the three $I(1)$ price series. Although all the series are $I(1)$, they stay together and do not diverge from each other very much.

Table 2.5. Regional Johansen cointegration test results for spot prices

Multivariate cointegration test results for spot prices for NBP, GPL, NCG, TTF and PEGN. The lag length is based on the Schwarz Information Criterion (* denotes the rejection of the null hypothesis at the 1% significance level; the Johansen cointegration test is run with intercept and no trend in cointegrating equation and VAR).

Hypothesized No. of CE	Eigenvalue	Trace statistic	Critical value (0.01)	Max-Eigen Statistic	Critical value (0.01)
None*	0.175884	258.5129	77.81884	110.2629	39.37013
At most 1*	0.114623	148.2500	54.68150	69.39263	32.71527
At most 2*	0.081979	78.85738	35.45817	48.75486	25.86121
At most 3*	0.041770	30.10252	19.93711	24.32048	18.52001
At most 4	0.010093	5.782045	6.634897	5.782045	6.634897

Table 2.6. Regional Johansen cointegration test results for forward prices

Multivariate cointegration test results for forward prices for GPL, NBP and TTF. The lag length is based on the Schwarz Information Criterion (* denotes the rejection of the null hypothesis at the 1% significance level; the Johansen cointegration test is run with intercept and no trend in cointegrating equation and VAR).

Hypothesized No. of CE	Eigenvalue	Trace statistic	Critical value (0.01)	Max-Eigen Statistic	Critical value (0.01)
None*	0.068784	69.67323	35.45817	40.62054	25.86121
At most 1*	0.042782	29.05269	19.93711	24.92267	18.52001
At most 2	0.007219	4.130016	6.634897	4.130016	6.634897

3.4. Vector Error Correction Model (VECM) estimation

To investigate the long and short run adjustments between the European gas indexes, we estimate a vector error correction model (VECM). Our results are presented in Table 2.7 and Table 2.8 for spot and forward prices, respectively.

The British NBP had been considered the European gas benchmark over the years, since it is the oldest and most mature gas hub in Europe. However, the Dutch TTF has been substantially developing over the last decade and has had a remarkable growth since 2016, where its number of market participants as well as its trading volumes were greater than all other European gas hubs, including the British NBP, making TTF a supreme traded gas hub in Europe as well as a global price reference (see Heather 2020).

We therefore choose to normalise on TTF for both VECMs. If the cointegrating equations, the long run relationships, correspond to stationary spreads, the coefficients on TTF should be close to -1. This is in fact the case and all the coefficients on TTF are very close to -1.

For spot prices, there are four cointegrating equations, the long-run relationships corresponding to stationary spreads. When examining the error correction adjustment that maintains the long-run relationships, we find that TTF is responding to its spread against all other indexes except for NBP. PEGN is responding to the spreads of the two German indexes against TTF, while NCG is not responding on any of the other European indexes' spreads. Finally, NBP and GPL are responding to the NCG and PEGN spreads against TTF.

There is also some short-term adjustment of the changes to lagged changes. All indexes respond negatively to the French PEGN and positively to the German NCG, whereas none of the European indexes respond to NBP. The German GPL, the British NBP and the

French PEGN respond positively to TTF, whereas PEGN is the only index that is affected by GPL in the short run.

We conclude that for spot prices there is a quite complicated adjustment process where all indexes are affected by at least one other index, both in the long run as well as in the short run. Therefore, the results of the VECM, for the specific period of analysis, indicate that there isn't a leading index among the European gas indexes.

Turning to the European gas forward market, again, we find that the long run cointegrating relationships correspond to spreads. In the error correcting adjustment processes, we find that all indexes are responding to GPL's spread, but none is responding to NBP's spread. In the short run responses to changes to lagged changes, none of the other indexes are responding to GPL, NBP negatively responds to TTF, and they all positively respond to NBP. Similar to the spot market analysis, we fail to identify a leader between the three gas indexes in the forward market in the VECM setting, as they all respond to each other.

Table 2.7. VECM for regional spot prices for the period 02/04/2010 - 12/03/2021

Vector error correction model estimation results for the five spot price series in which TTF is chosen as a base; t-statistics are presented in [ ].

Cointegrating Equation	**Equation 1**	**Equation 2**	**Equation 3**	**Equation 4**	
GPL	1.000000	0.000000	0.000000	0.000000	
NBP	0.000000	1.000000	0.000000	0.000000	
NCG	0.000000	0.000000	1.000000	0.000000	
PEGN	0.000000	0.000000	0.000000	1.000000	
TTF	-0.987551 [-119.310]	-1.007806 [-41.6518]	-0.971134 [-119.507]	-1.024954 [-237.810]	
C	-0.036555	0.017426	-0.090505	0.064328	
Error Correction	**D(GPL)**	**D(NBP)**	**D(NCG)**	**D(PEGN)**	**D(TTF)**
Cointegrating Equation 1	0.182470 [0.73543]	0.500352 [1.73196]	0.377008 [1.53791]	0.538380 [2.00601]	0.577464 [2.15468]
Cointegrating Equation 2	0.010211 [0.18611]	-0.112937 [-1.76787]	0.016627 [0.30672]	-0.008633 [-0.14547]	-0.013312 [-0.22463]
Cointegrating Equation 3	-0.706336 [-2.86034]	-0.745842 [-2.59400]	-0.893264 [-3.66117]	-0.778092 [-2.91296]	-0.796865 [-2.98747]
Cointegrating Equation 4	0.398920 [2.00396]	0.759356 [3.27615]	0.385997 [1.96254]	0.356102 [1.65377]	0.663814 [3.08717]
D(GPL(-1))	-0.827369 [-2.50179]	-0.599468 [-1.55680]	-0.602750 [-1.84468]	-0.866684 [-2.42276]	-0.664588 [-1.86044]
D(NBP(-1))	-0.103491 [-0.86352]	-0.240328 [-1.72224]	-0.051396 [-0.43405]	-0.103733 [-0.80018]	-0.084400 [-0.65197]
D(NCG(-1))	0.899391 [2.66255]	0.829313 [2.10855]	0.665129 [1.99291]	1.028066 [2.81364]	0.834565 [2.28729]
D(PEGN(-1))	-0.468158 [-2.18869]	-0.498184 [-2.00030]	-0.497401 [-2.35359]	-0.838785 [-3.62526]	-0.540246 [-2.33827]
D(TTF(-1))	0.476302 [2.02638]	0.567323 [2.07293]	0.445720 [1.91926]	0.787570 [3.09760]	0.450303 [1.77360]
C	0.000741 [0.32846]	0.000716 [0.27270]	0.000721 [0.32333]	0.000597 [0.24483]	0.000664 [0.27253]
Log Likelihood	7498.314				

Table 2.8. VECM for regional forward prices for the period 02/04/2010 - 12/03/2021

Vector error correction model estimation results for the three forward price series in which TTF is chosen as a base; t-statistics are presented in [ ].

Cointegrating Equation	**Equation 1**	**Equation 2**	
GPL	1.000000	0.000000	
NBP	0.000000	1.000000	
TTF	-0.980589 [-80.8402]	-0.985812 [-38.0687]	
C	-0.055283	-0.055061	
Error Correction	**D(GPL)**	**D(NBP)**	**D(TTF)**
Cointegrating Equation 1	-0.345296 [-4.16692]	-0.300959 [-3.20317]	-0.225855 [-2.74873]
Cointegrating Equation 2	-0.045064 [-0.90657]	-0.150112 [-2.66342]	-0.070831 [-1.43707]
D(GPL(-1))	0.065433 [0.43022]	0.300130 [1.74041]	0.240839 [1.59697]
D(NBP(-1))	0.280590 [2.23924]	0.208777 [1.46948]	0.318541 [2.56374]
D(TTF(-1))	-0.392321 [-1.94992]	-0.533824 [-2.34004]	-0.596184 [-2.98836]
C	0.000701 [0.34618]	0.000675 [0.29399]	0.000694 [0.34561]
Log Likelihood	4137.699		

Moreover, Figures 2.1 and 2.2 suggest that there may be a structural break in 2015. Therefore, we test for a structural break in the spot market as well as in the forward market. We perform a Chow type likelihood ratio test to examine whether a structural break has taken place in the European gas spot and forward market in 2015, by splitting the estimation of the VECM in two periods: 02/04/2010 – 12/03/2015 for the first period and 12/03/2015 – 12/03/2021 for the second period.

For the spot market, the VECM log-likelihood for the whole period is 7498.314, whereas the sum of log-likelihoods of the two subperiods is 8012.112, allowing for a structural break (see Table 2.15 and Table 2.16 in the Appendix for the VECM estimation of the two subperiods). Twice the difference in log-likelihoods, which equals to 1027.596, is $\chi^2(54)$. The critical value for 1% $\chi^2(54)$ is 81.069. Thus, structural stability is clearly rejected. Most of the change is possibly in the short run components, the adjustment coefficients, and the lagged changes. The long run coefficients of TTF are close to -1, except for NBP which is -1.44 in the first period.

Similarly, for the forward market, the VECM log-likelihood for the whole period is 4137.699, while the sum of log-likelihoods of the two periods is 4280.711 (see Table 2.17 and Table 2.18 in the Appendix for the VECM estimation of the two subperiods). Twice the difference in log-likelihoods, which equals to 286.024, is $\chi^2(20)$. The critical value for 1% $\chi^2(20)$ is 37.566, hence, structural stability is rejected in the forward market as well. Interestingly, results are quite different for the two sub-periods in the European gas forward market. In the early period, 2010 - 2015, the long run coefficients of TTF are significantly different from -1, which could be a result of the market not being so well integrated at the time, whereas in the second period, 2015 - 2021, the long run coefficients of TTF are close to -1 suggesting that the market is well integrated in the latest period.

Furthermore, we examine the impulse response and variance decomposition of spot and forward prices, see Figure 2.11, Figure 2.12, Figure 2.13 and Figure 2.14 in the Appendix. The impulse response results show that a positive response to one gas index creates a positive response to all other gas indexes, both in the spot market as well as in the forward market. The responses stabilise in the long run, where sometimes the short run response is larger than the long run response and other times the long run response is larger than the short run response. In the spot market , the variance decomposition analysis shows that GPL accounts for around 60% of the variance of all the other gas indexes, NBP and PEGN account for around 20%, whilst NCG and TTF do not account for any of the variance of the other European gas indexes. In the forward market, GPL accounts for around 60% of the variance of the other two gas indexes, NBP accounts for less than 10% and TTF accounts for nearly 40%.

The VAR and VECM measure the response to lagged variables, but we can also examine responses by looking at the residual correlations. There are very high residual correlations between the European gas indexes for spot and forward markets. The correlations, presented in Table 2.9 and Table 2.10 for spot and forward markets, respectively, show a correlation rate of over 86%. More specifically, for spot prices, gas markets in the Continent show a correlation rate 90% or more. Similarly, in the forward market the correlation rate between the three countries is 92% or more.

Table 2.9. Residual correlations matrix for spot prices

Residual correlations for the five spot price series.

	GPL	NBP	NCG	PEGN	TTF
GPL	1	86%	99%	90%	90%
NBP	86%	1	86%	94%	95%
NCG	99%	86%	1	90%	90%
PEGN	90%	94%	90%	1	98%
TTF	90%	95%	90%	98%	1

Table 2.10. Residual correlations matrix for forward prices

Residual correlations for the three forward price series.

	GPL	NBP	TTF
GPL	1	92%	96%
NBP	92%	1	95%
TTF	96%	96%	1

3.5. Vector Autoregression (VAR) Granger Causality

To further investigate the existence of a leading index among the European gas indexes, we carry out a VAR Granger Causality test (Granger 1969), that measures whether one variable predicts another. Given that the VAR environment is unrestricted, it gives us the opportunity to examine the unrestricted relationships between the European gas indexes without imposing an economic interpretation, in terms of adjustment to equilibrium spreads.

We choose to employ the Granger causality test on first nearby prices because of their liquidity; note that for the recent period 2016-2021, it is believed that TTF has surpassed NBP in trading activity.

The results, presented in Table 2.11, suggest that there is a one directional Granger causality relationship between TTF and all other European gas hubs in the Continent, in which TTF is the leader. At the 5% level, none of the other indexes predict TTF; TTF predicts GPL, NCG and PEGN, but not NBP. While TTF does not predict NBP directly, it does so indirectly, since NCG and PEGN, which are predicted by TTF, do predict NBP at the 5% level. Interestingly, we find that NBP, which is considered the most matured European gas index as well as the European gas benchmark, no longer predicts the prices of the other European indexes, including the prices of the Dutch TTF.

These results reveal the rapid development of TTF in recent years and indicate a possible stronger integration between gas indexes in Continental Europe with a potential future disintegration of the British NBP from the European gas system. The increased trading activity at the Dutch TTF, which seems to be the preferred one instead of the British NBP, could be a result of its price relevance across continental Europe, together with the fact that northern continental Europe is a very large market. The use of TTF has also grown because it has become a European reference point for LNG market participants (Spilker 2019).

Table 2.11. VAR Granger causality test results

VAR Granger causality results for the five spot price series for the period 2016 - 2021.

Dependent Variable	Independent Variable	Chi-sq	P - Value
GPL	NBP	0.051374	0.8207
	NCG	2.440500	0.1182
	PEGN	0.427647	0.5131
	TTF	4.121321	0.0423
NBP	GPL	0.027911	0.8673
	NCG	4.699493	0.0302
	PEGN	5.301046	0.0213
	TTF	0.653594	0.4188
NCG	GPL	0.055612	0.8136
	NBP	0.048005	0.8266
	PEGN	0.393860	0.5303
	TTF	4.267054	0.0389
PEGN	GPL	0.333615	0.5635
	NBP	0.001474	0.9694
	NCG	2.316370	0.1280
	TTF	3.924407	0.0476
TTF	GPL	0.002770	0.9580
	NBP	0.001427	0.9699
	NCG	3.194400	0.0739
	PEGN	2.572354	0.1087

4. Forward spread and inventory relationship

4.1. Forward spreads economic background

The Theory of Storage introduced by Kaldor (1939), Working (1949), Brennan (1958) and Telser (1958) emphasizes the importance of holding the physical commodity in order to better manage sudden shocks in supply and demand. This benefit, known as the convenience yield, is embedded in the spot - forward relationship

$$f^T(\mathrm{t}) = \mathrm{S}(\mathrm{t})[1 + (\mathrm{r}(\mathrm{t},\mathrm{T}) + \mathrm{c}(\mathrm{t},\mathrm{T}) - \mathrm{y}(\mathrm{t},\mathrm{T}))(\mathrm{T} - \mathrm{t})] \qquad [6]$$

where, $f^T(t)$ is the price of the Futures contract at time t maturing at time T, $\mathrm{S}(\mathrm{t})$ is the spot price or the first nearby, $\mathrm{r}(\mathrm{t},\mathrm{T})$ is the interest rate for the period (t,T), $\mathrm{c}(\mathrm{t},\mathrm{T})$ is the marginal cost of storage for the period (t,T), and $\mathrm{y}(\mathrm{t},\mathrm{T})$ is the marginal convenience yield for the period (t,T).

The slope of the forward curve, also known as forward spread (or “basis”), is defined as follows in the founding paper of Working (1949)

$$Forward\ Spread = \frac{f^T(t) - S(t)}{S(t)} \qquad [7]$$

The maturity T of the Futures contract is usually six months. Working (1949) shows that this forward spread is strongly correlated to inventory, a property taken as a given by Fama and French (1987).

4.2. Review of the literature

The inventory - forward spread relationship has been analysed in a large number of studies, in the context of different commodities. Brennan (1958) and Telser (1958) analyse agricultural commodities and conclude that a negative relationship between convenience yield and inventories exists. In periods of low inventories, the convenience yield is high and the spot price is greater than the futures price, resulting in a negative spread. Fama and French (1987) study the behaviour of 21 commodities using the adjusted spread, where the slope of the forward curve is a proxy for inventory when inventory data are not available.

Ng and Pirrong (1994) analyse metals using the same proxy and obtain results consistent with the Theory of Storage, namely that spot and forward return dynamics are strongly related to variations in fundamental supply and demand conditions. Geman and Ohana (2009) examine in the case of oil and natural gas in the United States, the relationship between the slope of the forward curve and inventory. Additionally, they directly analyse the relationship between inventory and volatility. They find that the negative correlation between price volatility and inventory was significant for crude oil, while in the gas market this negative correlation was only significant during periods of scarcity, particularly during winter periods.

Symeonidis et al (2012) employ inventory data on twenty-one different commodities and analyse the relationship between inventory and the shape of the forward curve. Their results validate the Theory of Storage. They also show that price volatility is a decreasing function of inventory for the majority of the commodities used in the analysis, a result already exhibited in Geman and Nguyen (2005) who introduced a three-state variable model for soybean prices, where the stochastic volatility of spot prices is driven by inventory.

4.3. Forward spread and inventory data description

In our analysis, we use the first nearby Futures contract for the spot price, same as in the co-movement analysis. For the forward maturity T of the Futures contract, we use the thirteen months ahead Futures contract to filter out seasonality, same as in Geman and Ohana (2009). Among the European gas indexes, only the British NBP and the Dutch TTF trade natural gas on the thirteen months Futures contracts, therefore, we exclude the other indexes for this analysis; note that we convert spot and forward prices for NBP from pence/therm to €/MWh. The period of analysis, based on data availability for both gas indexes and inventories in the two European countries, is 02/01/2015 - 12/03/2021.

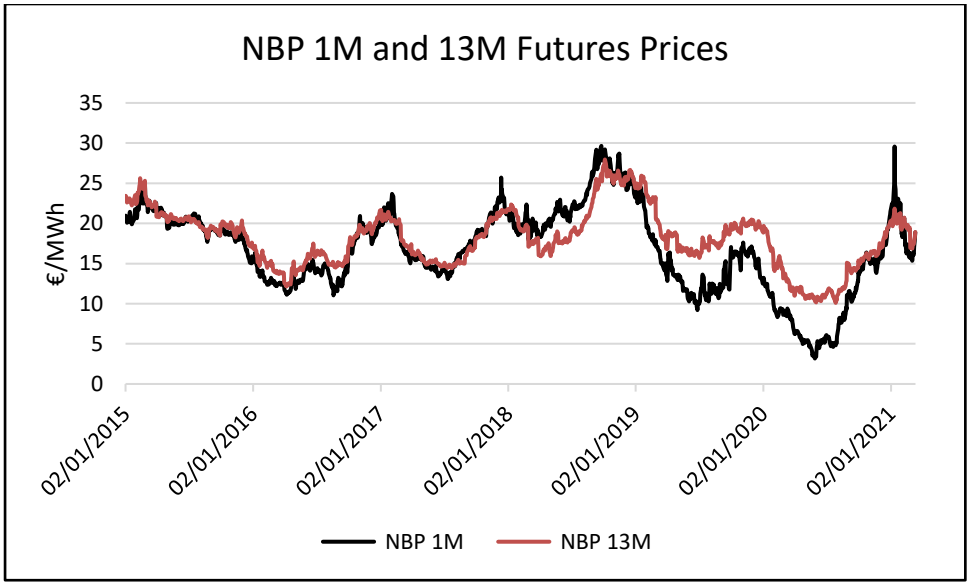
The daily price trajectories for the one month and thirteen months Futures contracts for NBP and TTF are presented in Figure 2.3 and Figure 2.4, respectively. Accordingly, the weekly forward spreads for NBP and TTF are computed as the mean of daily forward spreads for the given calendar week and are presented in Figure 2.5 and Figure 2.6, respectively.

For both gas indexes, forward prices are in principle higher than spot prices for most of the period of analysis. However, at certain periods spot prices are higher than forward prices and this translates to a negative forward spread. We also notice that the forward spread for both indexes grows substantially large at the beginning of 2020, before returning to its average levels towards the end of 2020 - which shows the effect of the Covid-19 pandemic on European natural gas prices.

Similarly, we collect daily inventory data provided by National Grid for the United Kingdom and Grid Infrastructure Europe (GIE) for the Netherlands, accessed through Bloomberg; note that we convert inventory data for the United Kingdom from GWh to TWh. The weekly inventory volumes for the two countries, presented in Figure 2.7 and Figure 2.8, are computed as the mean of daily inventory volumes for the given calendar week.

Figure 2.3. Spot and forward price trajectories for NBP

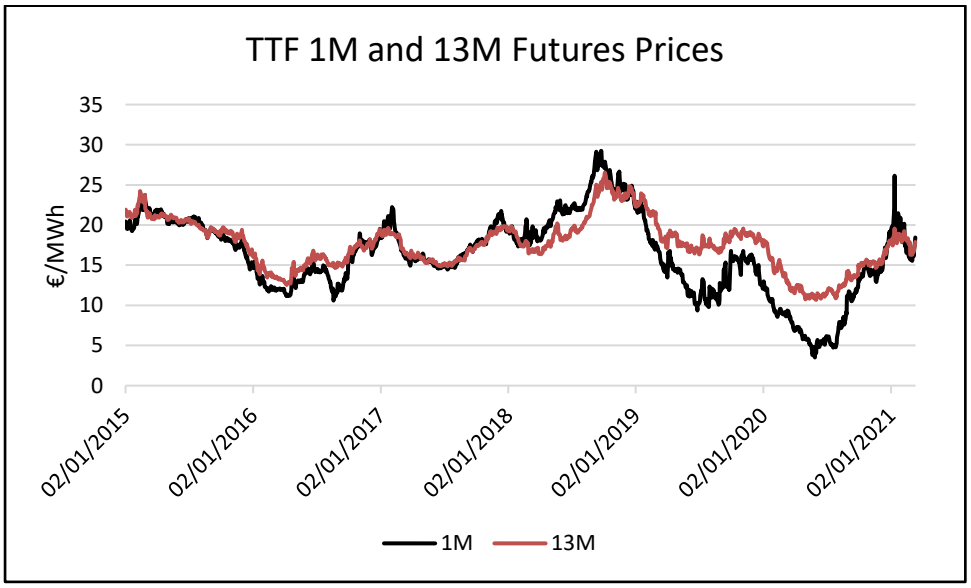
Daily prices for the one month and thirteen months Futures contract for the United Kingdom for the period 02/01/2015 - 12/03/2021.



Source: Bloomberg

Figure 2.4. Spot and forward price trajectories for TTF

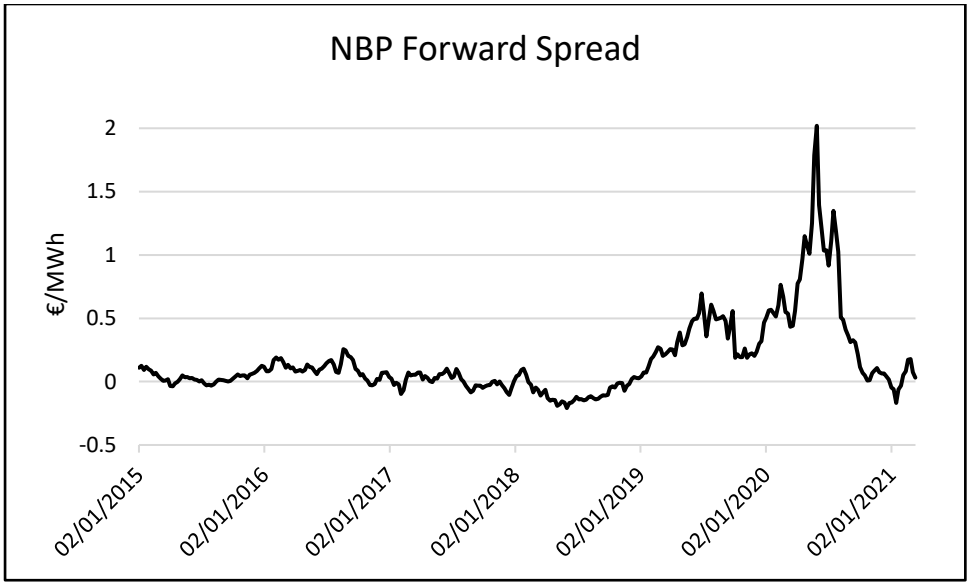
Daily prices for the one month and thirteen months Futures contract for the United Kingdom for the period 02/01/2015 - 12/03/2021.



Source: Bloomberg

Figure 2.5. NBP weekly forward spread

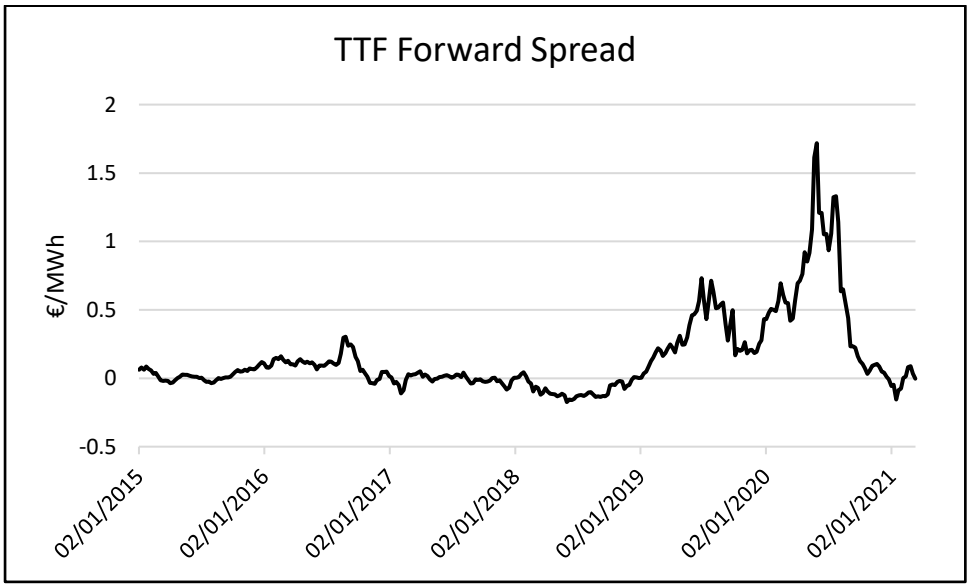
Weekly forward spread for NBP; the weekly forward spread is computed as the mean of daily forward spreads for the given calendar week for the period 02/01/2015 - 12/03/2021.



Source: Bloomberg

Figure 2.6. TTF weekly forward spread

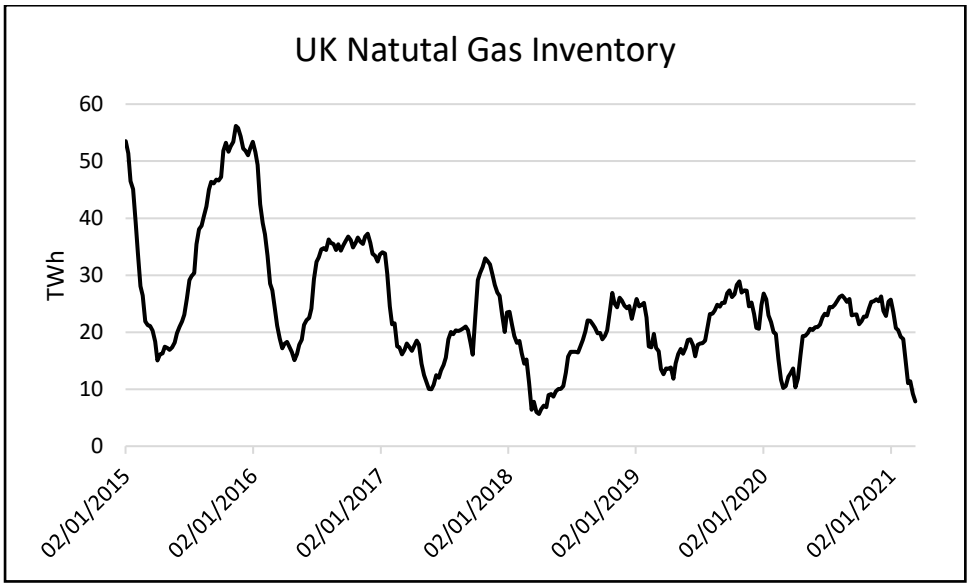
Weekly forward spreads for TTF; the weekly forward spread is computed as the mean of daily forward spreads for the given calendar week for the period 02/01/2015 - 12/03/2021.



Source: Bloomberg

Figure 2.7. United Kingdom natural gas inventory volumes

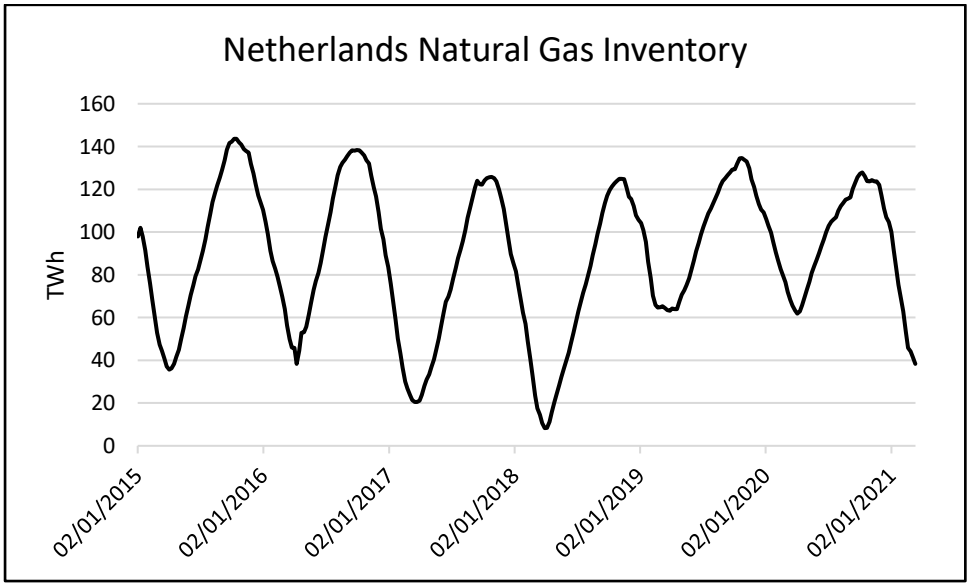
Historical weekly natural gas inventory volumes for the United Kingdom for the period 02/01/2015 - 12/03/2021 reported in TWh; the weekly inventory volumes are computed as the mean of daily inventory volumes for the given calendar week.



Source: Bloomberg

Figure 2.8. Netherlands natural gas inventory volumes

Historical weekly natural gas inventory volumes for the Netherlands for the period 02/01/2015 - 12/03/2021 reported in TWh; the weekly inventory volumes are computed as the mean of daily inventory volumes for the given calendar week.



Source: Bloomberg

Inventory data for both countries exhibit seasonality as expected. Natural gas is considered a seasonal commodity, where prices fluctuate according to weather changes with higher winter gas prices and lower summer gas prices. Accordingly, the levels in natural gas storage facilities increase during the summer months and decrease during the winter months when the demand for natural gas increases. To de-seasonalise inventory data, we use the fit of sine/cosine functions method

$$I_t = a_0 + c(t) + \gamma_1 cos(2\pi t/52) + \gamma_2 sin(2\pi t/52) + \gamma_3 cos(2\pi t/26) + \varepsilon_t \quad [8]$$

where, I_t is the weekly logarithmic inventory volume, t is the time in years, and $\gamma_1 cos(2\pi t/52)$, $\gamma_2 sin(2\pi t/52)$, $\gamma_3 cos(2\pi t/26)$ are the three sine/cosine terms. We then obtain the following expression for the de-seasonalised inventory

$$\widetilde{I_t} = I_t - I_S \quad [9]$$

where, $\widetilde{I_t}$ is the de-seasonalised inventory, I_t is the original inventory, and I_S is the estimated inventory seasonality as exhibited in Equation (8).

Table 2.12 presents the results of the inventory seasonality estimation for the United Kingdom and the Netherlands. For the Dutch inventory data, we do not include the trend in the seasonality estimation as its coefficient is not significant; we do include it in the British inventory seasonality estimation as the trend's coefficient is significant at the 1% level. In both cases, the coefficients of the seasonal components are significant at the 1% level and we reject the joint hypothesis that the coefficients of γ_1, γ_2 and γ_3 are zero. As expected, we conclude that inventory data exhibit seasonality. The trigonometric fit of inventory data for the

two countries is presented in Figure 2.9 for the United Kingdom and in Figure 2.10 for the Netherlands.

Table 2.12. Inventory seasonality estimation for the United Kingdom and the Netherlands

Seasonality regression results on weekly logarithmic inventory volumes for the United Kingdom and the Netherlands; P-Values are presented in parentheses for each coefficient.

Coefficients	UK	Netherlands
$\boldsymbol{a_0}$: Constant	3.427189 (PV:0.0000)	4.381823 (PV:0.0000)
$\boldsymbol{c(t)}$: Trend	-0.002042 (PV:0.0000)	N/A
$\boldsymbol{\gamma_1}$: Seasonal term	0.193287 (PV:0.0000)	0.078166 (PV:0.0010)
$\boldsymbol{\gamma_2}$: Seasonal term	-0.396395 (PV:0.0000)	-0.592174 (PV:0.0000)
$\boldsymbol{\gamma_3}$: Seasonal term	0.137019 (PV:0.0000)	0.162697 (PV:0.0000)

Figure 2.9. United Kingdom natural gas inventory and trigonometric fit

Weekly average logarithmic inventory volumes and trigonometric fit for the United Kingdom for the period 02/01/2015 - 12/03/2021.

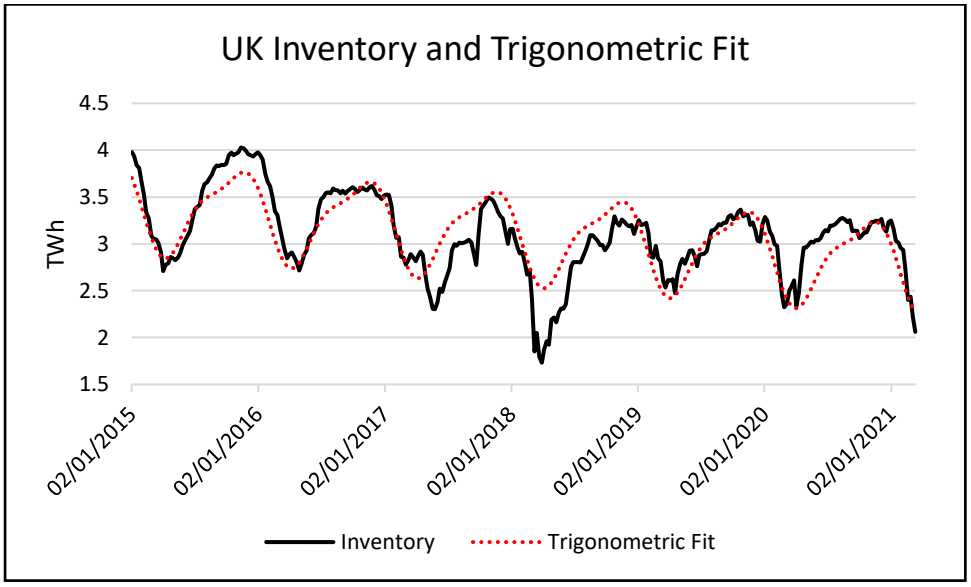
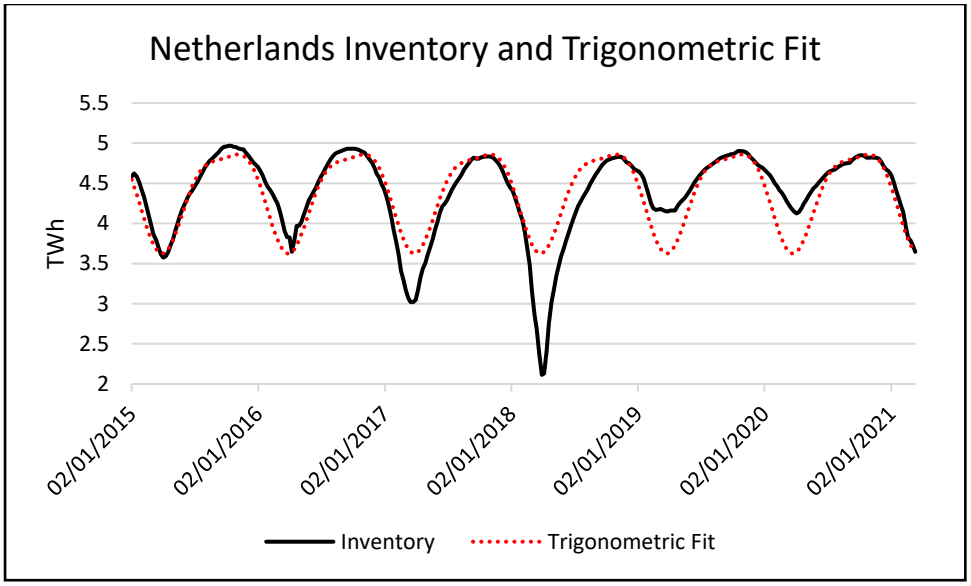


Figure 2.10. Netherlands natural gas inventory and trigonometric fit

Weekly average logarithmic inventory volumes and trigonometric fit for the Netherlands for the period 02/01/2015 - 12/03/2021.



4.4. Forward spread - inventory regression analysis

We first examine whether de-seasonalised inventories as well as their respective forward spreads in the two European countries have unit roots, by performing the Augmented Dickey Fuller test; the results are presented in Table 2.13. We conclude that inventories for both countries are $I(0)$ stationary processes, at either the 1%, 5% or 10% level. The UK forward spread has a unit root and stationarity is achieved after differencing one time, while the Netherlands forward spread is an $I(0)$ stationary process at the 10% level. Hence, a regression analysis with two lagged values of the forward spread for both countries is the appropriate way forward to investigate their relationship.

Table 2.13. ADF test results for the British and Dutch inventories and forward spreads

Augmented Dickey Fuller unit root test for the British and Dutch de-seasonalised inventory volumes and forward spreads; the lag length is based on the Schwarz Information Criterion (SIC).

Country	T-Statistic	P -Value
UK inventory (Level)	-3.731400	0.0041
UK forward spread (Level)	-2.352036	0.1565
UK forward spread (First Difference)	-14.00467	0.0000
Netherlands inventory (Level)	-3.081665	0.0290
Netherlands forward spread (Level)	-2.806773	0.0584
Netherlands forward spread (First Difference)	-4.890392	0.0000

To identify the relationship between forward spread and inventory, we regress the forward spread at week t ($Forward\ Spread_t$) on the de-seasonalised inventory at week $t-1$ ($\tilde{I}_{t-1}$) and on two lagged values of the forward spread, namely $Forward\ Spread_{t-1}$ and $Forward\ Spread_{t-2}$

$$Forward\ Spread_t = a_0 + a_1\tilde{I}_{t-1} + a_2 Forward\ Spread_{t-1} + a_3 Forward\ Spread_{t-2} + \varepsilon_t \quad [10]$$

Our results, presented in Table 2.14, show a positive relationship between the slope of the forward curve and inventory for both the United Kingdom and the Netherlands, with statistically significant coefficients at the 5% level for the Netherlands and at the 10% level for the UK. Furthermore, we find a positive relationship between the slope of the forward curve and its first lagged value, as well as a negative relationship between the slope of the forward curve and its second lagged value. Lastly, in the case of the Netherlands the R^2 is equal to 94.34% with an inventory coefficient value of 0.035, while in the UK the R^2 is equal to 93.73% with an inventory coefficient value of 0.038.

Table 2.14. Forward spread - inventory regression results

Forward spread and inventory regression results for the UK and the Netherlands; The standard errors have been computed using Newey-West estimator with a data dependent truncation parameter equal to 5.

Coefficients	UK	Netherlands
$\boldsymbol{a_0}$	0.008858 (PV:0.0551)	0.007247 (PV:0.0262)
$\boldsymbol{a_1}$	0.038220 (PV:0.0891)	0.035831 (PV:0.0161)
$\boldsymbol{a_2}$	1.173058 (PV:0.0000)	1.121914 (PV:0.0000)
$\boldsymbol{a_3}$	-0.229933 (PV:0.0019)	-0.172266 (PV:0.0301)
$\boldsymbol{R^2}$	0.937324	0.943408

5. Conclusion

In this Chapter we investigated the Western European gas market integration by analysing co-movements of both spot and forward gas prices of the major European natural gas indexes. Our results show an increased market integration in the spot and forward market, at a regional level, where we identify the important role played by the Dutch TTF. Additionally, we investigated the relationship between the inventory and the slope of the natural gas forward curve in the United Kingdom and the Netherlands, where we find a positive relationship in both European gas markets.

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Appendix

Figure 2.11. Spot price series impulse response over 52 weeks

Impulse response combined graphs for the five spot price series, where LGPL, LNBP, LNCG, LPEGN and LTTF represent the logarithmic values for GPL, NBP, NCG, PEGN and TTF respectively.

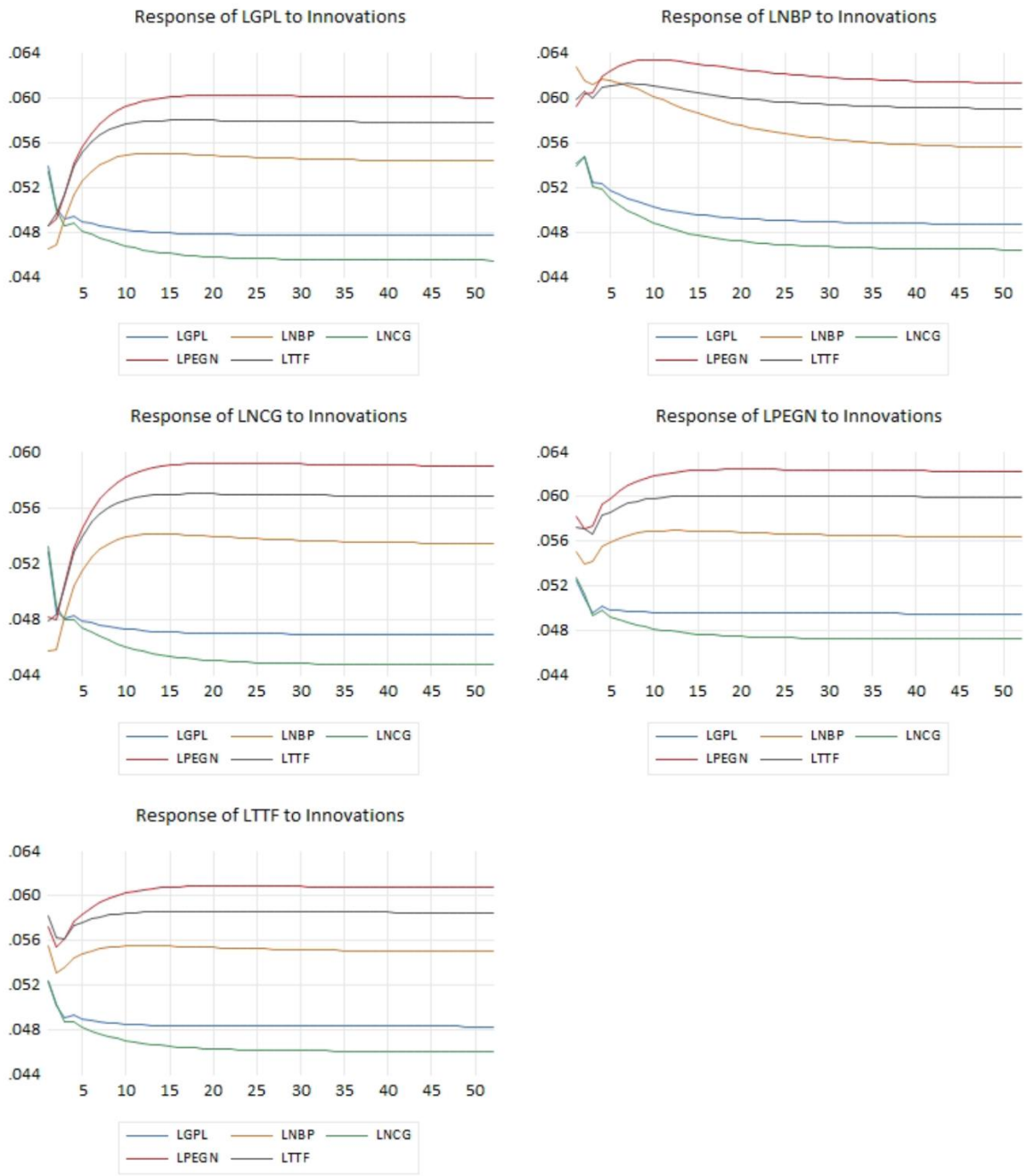


Figure 2.12. Forward price series impulse response over 52 weeks

Impulse response combined graphs for the three forward price series, where LGPL, LNBP and LTTF represent the logarithmic values for GPL, NBP and TTF respectively.

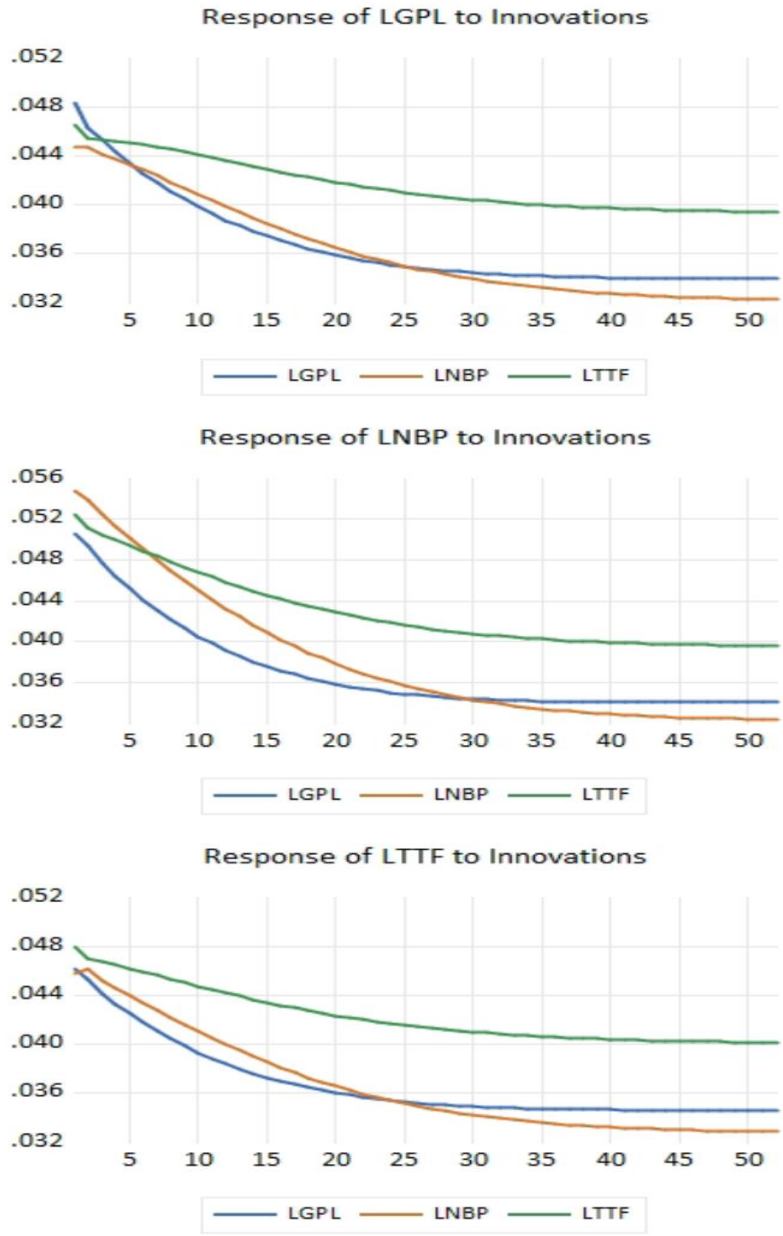


Figure 2.13. Spot price series variance decomposition for 52 weeks

Variance decomposition combined graphs for the five spot price series, where LGPL, LNBP, LNCG, LPEGN and LTTF represent the logarithmic values for GPL, NBP, NCG, PEGN and TTF respectively.

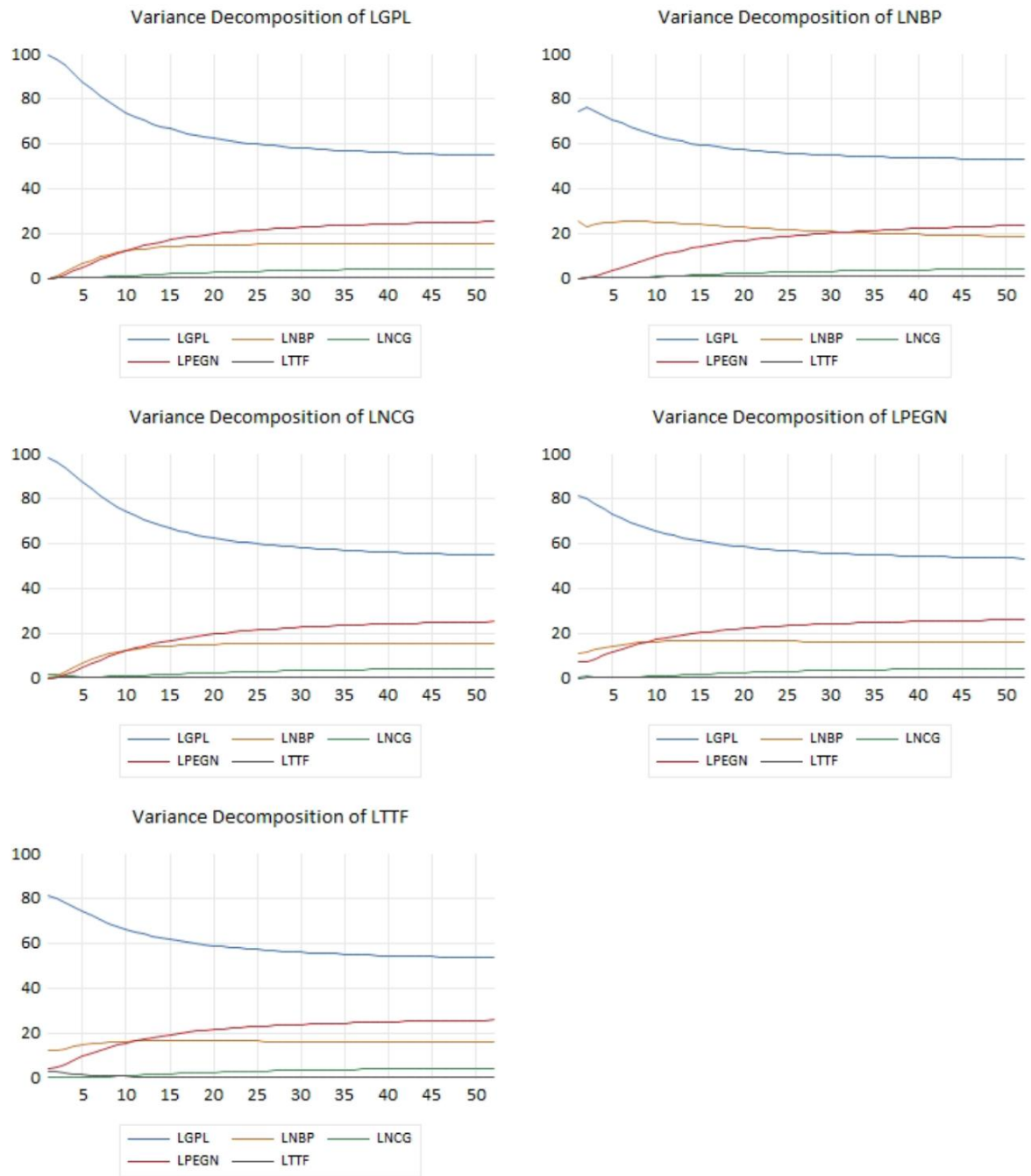


Figure 2.14. Forward price series variance decomposition

Variance decomposition combined graphs for the three forward price series, where LGPL, LNBP and LTTF represent the logarithmic values for GPL, NBP and TTF respectively

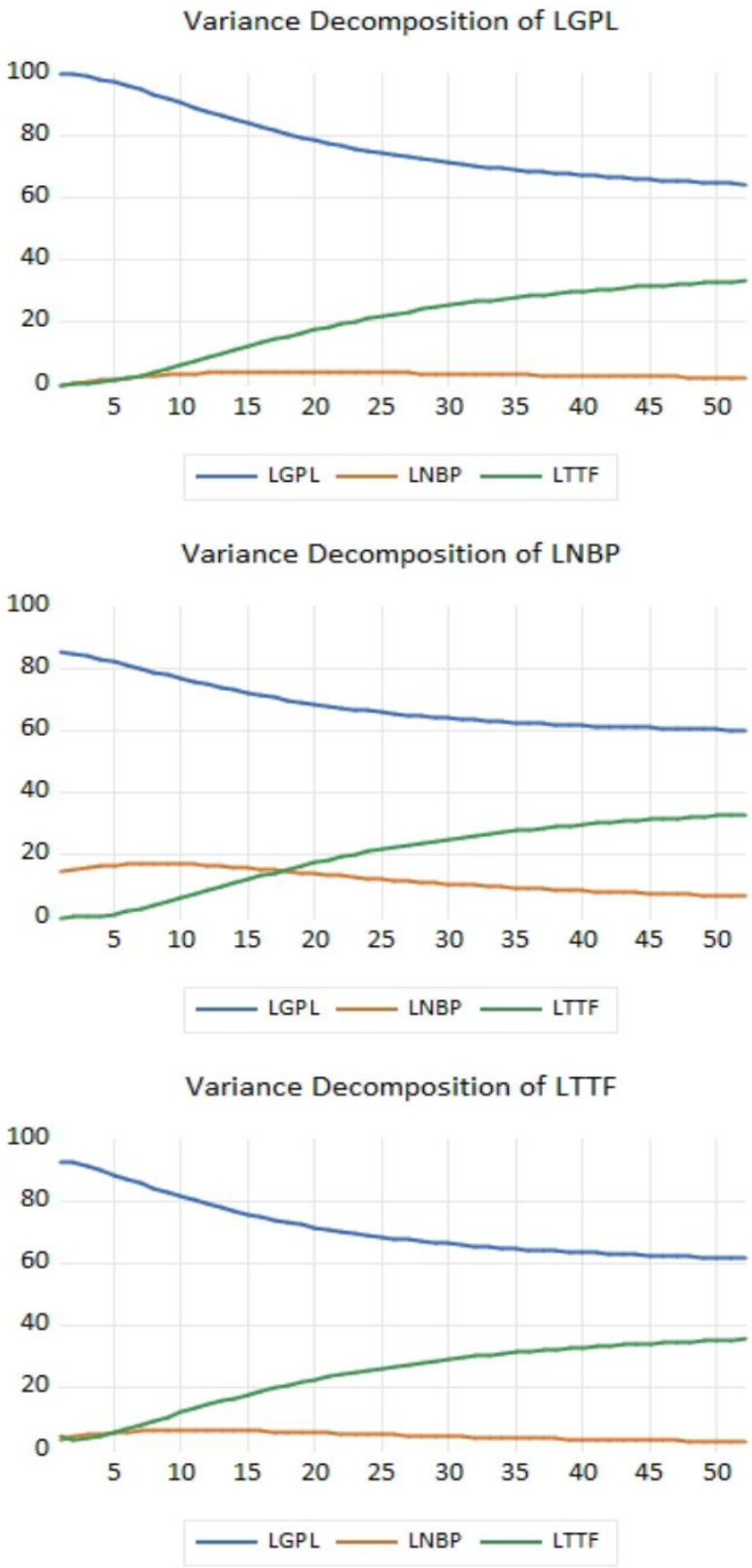


Table 2.15. VECM for regional spot prices for the period 02/04/2010 - 12/03/2015

Vector error correction model estimation results for the five spot price series in which TTF is chosen as a base; t-statistics are presented in [ ].

Cointegrating Equation	**Equation 1**	**Equation 2**	**Equation 3**	**Equation 4**	
GPL	1.000000	0.000000	0.000000	0.000000	
NBP	0.000000	1.000000	0.000000	0.000000	
NCG	0.000000	0.000000	1.000000	0.000000	
PEGN	0.000000	0.000000	0.000000	1.000000	
TTF	-0.98849 [-38.1645]	-1.440411 [-16.6862]	-1.032592 [-33.5022]	-1.084044 [-44.6970]	
C	-0.032073	1.386702	0.104867	0.24784	
Error Correction	**D(GPL)**	**D(NBP)**	**D(NCG)**	**D(PEGN)**	**D(TTF)**
Cointegrating Equation 1	-0.235208 [-0.67874]	-0.247456 [-0.54383]	0.031136 [0.09197]	-0.163248 [-0.41773]	-0.032541 [-0.08154]
Cointegrating Equation 2	0.105797 [1.40659]	-0.027952 [-0.28302]	0.131835 [1.79405]	0.135444 [1.59678]	0.104053 [1.20118]
Cointegrating Equation 3	-0.254381 [-0.71940]	0.08457 [0.18214]	-0.511312 [-1.48006]	0.022484 [0.05638]	-0.098079 [-0.24084]
Cointegrating Equation 4	0.023213 [0.10334]	0.504672 [1.71096]	0.070955 [0.32330]	-0.054285 [-0.21428]	0.208952 [0.80765]
D(GPL(-1))	0.091317 [0.18517]	0.45632 [0.70469]	0.007312 [0.01518]	0.352116 [0.63313]	0.387366 [0.68202]
D(NBP(-1))	-0.156001 [-1.15599]	-0.469215 [-2.64796]	-0.145682 [-1.10495]	-0.322019 [-2.11592]	-0.283475 [-1.82391]
D(NCG(-1))	-0.037824 [-0.07466]	-0.180824 [-0.27181]	0.054471 [0.11005]	-0.171519 [-0.30019]	-0.178349 [-0.30565]
D(PEGN(-1))	-0.047495 [-0.19454]	-0.601844 [-1.87740]	-0.060643 [-0.25424]	-0.841843 [-3.05760]	-0.531776 [-1.89125]
D(TTF(-1))	0.013963 [0.05102]	0.880117 [2.44913]	0.019183 [0.07174]	1.022952 [3.31439]	0.646522 [2.05118]
C	0.00246 [1.22532]	0.002041 [0.77414]	0.002438 [1.24310]	0.00198 [0.87474]	0.001954 [0.84496]
Log Likelihood	3713.496				

Table 2.16. VECM for regional spot prices for the period 12/03/2015 - 12/03/2021

Vector error correction model estimation results for the five spot price series in which TTF is chosen as a base; t-statistics are presented in [ ].

Cointegrating Equation	**Equation 1**	**Equation 2**	**Equation 3**	**Equation 4**	
GPL	1.000000	0.000000	0.000000	0.000000	
NBP	0.000000	1.000000	0.000000	0.000000	
NCG	0.000000	0.000000	1.000000	0.000000	
PEGN	0.000000	0.000000	0.000000	1.000000	
TTF	-0.989092 [-118.686]	-1.057739 [-41.5235]	-0.976032 [-137.750]	-1.021938 [-164.484]	
C	-0.033610	0.142075	-0.079496	0.057354	
Error Correction	**D(GPL)**	**D(NBP)**	**D(NCG)**	**D(PEGN)**	**D(TTF)**
Cointegrating Equation 1	0.058994 [0.15468]	0.302035 [0.69999]	0.242056 [0.64140]	0.202016 [0.49675]	0.302751 [0.74737]
Cointegrating Equation 2	-0.04883 [-0.41626]	-0.192682 [-1.45185]	-0.05995 [-0.51648]	-0.022951 [-0.18348]	-0.028704 [-0.23038]
Cointegrating Equation 3	-1.014218 [-2.48905]	-1.202296 [-2.60807]	-1.224422 [-3.03684]	-1.068911 [-2.46017]	-1.07171 [-2.47630]
Cointegrating Equation 4	0.472587 [1.31746]	0.920492 [2.26820]	0.463608 [1.30616]	0.328994 [0.86013]	0.686984 [1.80313]
D(GPL(-1))	-1.473231 [-2.93915]	-1.389904 [-2.45099]	-1.217883 [-2.45553]	-1.426416 [-2.66882]	-1.268732 [-2.38311]
D(NBP(-1))	-0.048179 [-0.26738]	-0.148867 [-0.73026]	0.017281 [0.09692]	-0.031989 [-0.16649]	-0.02495 [-0.13037]
D(NCG(-1))	0.746217 [1.43237]	0.431172 [0.73155]	0.464798 [0.90166]	0.765699 [1.37838]	0.498989 [0.90178]
D(PEGN(-1))	0.045232 [0.10157]	0.479245 [0.95124]	0.031363 [0.07118]	-0.026397 [-0.05559]	0.308333 [0.65188]
D(TTF(-1))	0.648811 [1.73018]	0.567729 [1.33820]	0.599504 [1.61567]	0.625575 [1.56449]	0.379628 [0.95313]
C	-0.000634 [-0.17007]	-0.000628 [-0.14883]	-0.000697 [-0.18879]	-0.000807 [-0.20290]	-0.000699 [-0.17640]
Log Likelihood	4298.616				

Table 2.17. VECM for regional forward prices for the period 02/04/2010 - 12/03/2015

Vector error correction model estimation results for the three forward price series in which TTF is chosen as a base; t-statistics are presented in [ ].

Cointegrating Equation	**Equation 1**	**Equation 2**	
GPL	1.000000	0.000000	
NBP	0.000000	1.000000	
TTF	-1.38264 [-15.1454]	-0.666745 [-7.42128]	
C	1.222928	-1.056929	
Error Correction	**D(GPL)**	**D(NBP)**	**D(TTF)**
Cointegrating Equation 1	-0.189073 [-3.19722]	-0.257961 [-4.14823]	-0.114954 [-2.09879]
Cointegrating Equation 2	-0.248142 [-4.22734]	-0.364586 [-5.90654]	-0.233021 [-4.28611]
D(GPL(-1))	0.06893 [0.52153]	0.300902 [2.16503]	0.207576 [1.69571]
D(NBP(-1))	0.091419 [0.62769]	-0.090079 [-0.58816]	0.169276 [1.25488]
D(TTF(-1))	-0.145234 [-0.72454]	-0.244527 [-1.16007]	-0.378135 [-2.03677]
C	0.00183 [0.83688]	0.002034 [0.88455]	0.001935 [0.95536]
Log Likelihood	1935.839		

Table 2.18. VECM for regional forward prices for the period 12/03/2015 - 12/03/2021

Vector error correction model estimation results for the three forward price series in which TTF is chosen as a base; t-statistics are presented in [ ].

Cointegrating Equation	**Equation 1**	**Equation 2**	
GPL	1.000000	0.000000	
NBP	0.000000	1.000000	
TTF	-1.002623 [-126.414]	-1.044116 [-29.5330]	
C	0.001631	0.099886	
Error Correction	**D(GPL)**	**D(NBP)**	**D(TTF)**
Cointegrating Equation 1	-0.558804 [-1.99597]	-0.35682 [-1.10743]	-0.316554 [-1.12669]
Cointegrating Equation 2	-0.010664 [-0.12742]	-0.069097 [-0.71738]	0.017956 [0.21378]
D(GPL(-1))	0.276693 [0.77944]	0.637858 [1.56128]	0.533407 [1.49728]
D(NBP(-1))	0.508647 [2.66059]	0.490174 [2.22784]	0.49728 [2.59192]
D(TTF(-1))	-0.877115 [-2.01347]	-1.190365 [-2.37433]	-1.107425 [-2.53316]
C	-0.000495 [-0.15370]	-0.000609 [-0.16423]	-0.000597 [-0.18473]
Log Likelihood	2344.872		

Chapter 3. The LNG spot market and valuation of the rerouting option

1. Introduction

World natural gas markets experienced remarkable changes between 2009 and 2019. On the demand side, natural gas is more and more perceived as a replacement for oil and coal in the mid to long term because it produces fewer emissions. Natural gas also plays a key role in the energy mix for power generation, in particular because flexible Combined Cycle Gas Turbines (CCGTs) are necessary to complement renewable sources of electricity, such as solar and wind, as a result of their intermittent nature. On the supply side, two elements have deeply transformed the natural gas market: the increase of natural gas production, specifically as a consequence of the large production of shale gas coming from the United States, and the expansion of unprecedented scale of the LNG industry as of 2009 (see, for instance, Corbeau and Ledesma 2016; Flower 2016), with a large number of small LNG tankers being built and allowing gas suppliers to rapidly serve regions where spot prices are momentarily high. The growth of the fleet was motivated by recent US exports and the Fukushima nuclear reactor disaster in 2011, which forced Japan, a major economy, to rapidly turn to the production of electricity using natural gas.

In parallel, the emergence of an LNG market took place in Asia around Japan, Taiwan and South Korea, while Singapore became the center of LNG derivatives trading. This region crucially depends on LNG imports, as it produces very little natural gas of its own. As a result, there has been a remarkable increase in LNG trading worldwide in recent years. Accordingly, global LNG trading set a record in 2018, reaching 316.5 million tonnes and marking an increase of 9.8% year on year from 2017 (International Gas Union 2019).

Traditionally LNG has been traded on long-term oil-indexed LNG contracts, necessary for providing security of supply to buyers and financial security to producers. Recently,

however, these contracts have been in decline, owing to small LNG tankers ready to supply LNG at any given point with short notice, creating a real market for LNG and, hence, a "desindexation" to oil. These contracts also became much less desirable when crude oil prices collapsed from US$120 per barrel in January 2014 to less than US$40 in January 2016. The same phenomenon of "desindexation" to oil prices had happened in European natural gas markets by 2009.

In the old contracts, importers typically agreed to the rules of the suppliers; options were rarely present, in particular the ability to divert cargo from its original destination (Carriere 2018). The new contracts are signed by buyers interested in the volatility of spot prices and all contract features that allow one to benefit from this. Accordingly, we will exhibit both the price and the change in the price of the rerouting option in the case of a higher volatility of LNG prices.

The rest of the Chapter is organized as follows. Section 2 describes the current structure of the LNG market and presents the relevant literature. Section 3 presents the methodology for the rerouting option pricing. Section 4 discusses the data used in the analysis, particularly the model that describes the spot price dynamics as well as the various transportation costs. Section 5 displays the option valuation and its vega/sensitivity to the volatility. Section 6 concludes.

2. Global LNG market overview

Jensen (2004) investigates the development of a global LNG market and correctly forecasts that flexible, short-term contracts will continue to rapidly increase in number and total volume. Hartley (2015) develops a model of the costs and benefits of an optimal long-term LNG contract, which is defined as one that gives the largest combined expected net present value to the trading parties. Increased spot market liquidity is analysed in terms of

how it affects such optimal contracts. The study concludes that the amount of LNG traded in long-term contracts is likely to further decline and that contracts will offer much greater volume and destination flexibility in future. Shi et al (2016) examine the impact of a change in East Asia's pricing benchmark on the regional and global gas markets. They find that both price benchmark change and contract flexibility improvements will create an overall benefit worldwide, and for East Asia importers in particular. Carriere (2018) observes that Japan is moving away from crude-oil-based pricing toward a more diverse LNG price structure, while Japanese buyers no longer accept uncompetitive destination restrictions in their supply contracts.

In relation to our study, Rodriguez (2008) introduces a real option model for the valuation of destination flexibility in long-term LNG supplies, which he evaluates "on average" over a twenty-year period. Besides choosing a different model for the spot price dynamics, our study recognizes the specific durations of a tanker's voyage to reach two different points in the world as well as a clear maturity for the option attached to a given cargo.

In recent years, the number of traded flexible contracts has grown progressively. Accordingly, in 2018, short-term LNG trade reached 99 million tonnes, an increase of 14.5 million tonnes year on year, and accounted for 31% of the total gross LNG trade. This substantial expansion can be attributed to an increasingly flexible LNG supply from Russia and North America (IGU 2019). As a result of this significant increase in short term LNG trading, in 2016, S&P Global Platts launched the Platts Gulf Coast Marker (GCM) index, reflecting the daily export value of LNG traded Free on Board (FOB) from the US Gulf Coast (S&P Global Platts).

In addition, Cheniere Energy, the second largest supplier of LNG worldwide, sells 20% of its production in flexible contracts. For example, in March 2018, a US LNG cargo ship departed from Cove Point and headed to Asia but was resold and diverted to the United

Kingdom to meet the country's gas demand after Europe was hit of extreme cold weather (Mills 2018). Ledesma and Fulwood (2019) analyze the current short-term LNG trading setting, particularly the "Cheniere model", and discuss which LNG models could underpin the next wave of LNG liquefaction capacity. They also investigate whether market participants (aggregators, portfolio companies and intermediaries) have the financial and commercial capacity to support such new models, and they announce that a fully functioning spot-traded LNG market is rapidly developing.

It is clear that the arrival of new, very large players, both exporters and importers (such as the United States and China), has increased the trading activity in Platt's JKM in the last few years; in turn, the liquidity and transparency of Platt's JKM has created a rise in spot LNG trading.

2.1. Major LNG exporting countries

For the last decade, Qatar has been the world's largest LNG exporter, accounting for 24.9% of global LNG in 2018. However, if volumes remain stable, Qatar's market share is forecasted to decrease as other countries, particularly Australia and the United States, continually invest in increasing their LNG production through new projects and infrastructure that will become fully operational over the coming years (International Gas Union 2019).

Australia, the second largest exporter of LNG, retained a market share of 21.7% of global LNG exports in 2018, and delivers most of its LNG to Japan and China. Australia has seven operating LNG terminals. The North West Shelf Venture, an investment in excess of AU$33.5 billion has been operating since 1989 and produces 16.3 million tonnes per annum of LNG. Darwin LNG started production in 2006 and has a capacity of around 3.7 million tonnes per annum. Pluto was commissioned in 2012 and has one production train with a capacity of 4.7 million tonnes per annum. Queensland Qurtis LNG, operated by Shell, began

producing LNG in 2014 and has two trains with a combined capacity of 8.5 million tonnes per annum. Gladstone LNG and Australia Pacific LNG have been online since 2015. The Gorgon project, based on Barrow Island, is one of the world's largest natural gas projects, with a production capacity of around 2.6 million cubic feet of natural gas and 15.6 million metric tonnes of LNG. The first LNG cargo left Gorgon in March 2016. Wheatstone has been operating since 2017 and has a combined capacity of 8.9 million metric tonnes per annum from two trains (Australian Petroleum Production and Exploration Association).

In 2018, Malaysia was the third largest supplier with a market share of 7.7%. From January through June 2019, US net Natural gas exports averaged 4.1 billion cubic feet per day, more than double the average net exports of 2 billion cubic feet over the whole of 2018 (according to a US Energy Information Administration (EIA) report of October 2019). Two LNG exporting terminals have been operating in the United States since 2016: the Sabine Pass in Louisiana and Cove Point in Maryland. Four more projects came online in 2019: Corpus Christi LNG in Texas; Cameron LNG in Louisiana; Elba Island LNG in Georgia; and Freeport LNG in Texas (US Energy Information Administration 2019). Nigeria was in fifth place in 2018, with a market share of 6.5%; it is likely to be surpassed by Russia as production from Yamal LNG increases (IGU 2019).

2.2. Major LNG importing countries

The Asia-Pacific basin is the largest importing region of global LNG. In 2018, Japan remained the largest importing country worldwide, with a market share of 25.4% of global LNG to fuel its vibrant economy; this was in absence of significant renewables that would have allowed the full replacement of the Fukushima nuclear plant. China, the second largest importing country, had a market share of 16.7% by the end of 2018; this was the result of an environmental policy change from coal to gas, as some major cities had passed the threshold

of acceptable pollution. Other large consuming countries are South Korea, India, Spain and Turkey (IGU 2019).

European LNG imports expanded for the fourth consecutive year in 2018, reaching a growth of 7.3% year on year. Increased LNG imports in Europe are due to a number of reasons, such as decline of domestic production of natural gas (Netherlands, United Kingdom), the increase of electricity production in gas-fired plants, lower French nuclear generation and weak hydrogen generation. Germany, a major economy, has totally moved away from nuclear electricity and wishes to respect the Paris Accord in terms of coal emissions. Africa and the Middle East remain the leaders in European LNG supply, although imports from the United States grew at a higher proportion in 2018 and this trend is expected to continue (IGU 2019).

3. The rerouting option

Optionalities are numerous in the world of energy, the context in which the important notion of "*real options*" was introduced (see Dixit and Pyndick 1994). They also exist in the world of shipping, where 'time charters contracts with purchase options' are often signed between ship owners and charterers. In this Chapter, we are interested in the rerouting option, often included in short to medium term contracts. Rodriguez (2008) looked at long term contracts, analyzing a 'destination option' with no specific maturity and averaged over a period of 20 years.

Instead, we analyse a specific cargo's route and the option that gives the buyer the right to get the LNG delivered at a point B rather than a point A targeted at departure; the option is exercised at some intermediary point C, also specified at date 0, when the tanker departs and the contract is signed between the supplier/charterer and the buyer of LNG. Hence, the maturity of the option is the date T_1, at which the point C will be reached. The additional

transportation costs are paid by the party who is “long” in the option. The buyer of the option is typically a natural gas company or a hedge fund that will buy LNG from a supplier and then re-sell the LNG to the local market where the delivery takes place.

We consider the case of LNG coming from the United States, where the original destination is Germany (point A). We suppose that point C is identical or very close to the following: point A, namely in Germany’s territorial waters; the point at which the tanker either continues into the harbour in Germany or is diverted to Japan (point B); and the time when the option is exercised. The decision to exercise the option will be based on the comparison between the spot price in Germany at the date T_1 (the date of arrival of the tanker) and a forward price that can be locked in at that moment (T_1) for delivery in Japan at date T. Note that the payoff of the option will not take place at the date when it is fully known, but at date T, when LNG is delivered in Japan against the payment of the forward price contracted at date T_1. This is why the value of the option at date 0 will be discounted from T to 0. Its payoff at date T is equal to

$$C(T) = max(0, f_J^T(T_1) - S_G(T_1) - ATC) \qquad [1]$$

where, $\mathrm{C(T)}$ is the option price at date T, $f_J^T(T_1)$ is the forward price in Japan observed at date T_1 for LNG delivery at date T, $S_G(T_1)$ is the spot price in Germany for LNG delivery at date T_1, ATC is the additional transportation cost when rerouting the vessel at date T_1 from Germany to deliver LNG to Japan at date T, T is two months (2/12), and T_1 is one month (1/12).

4. Data description and spot price dynamics

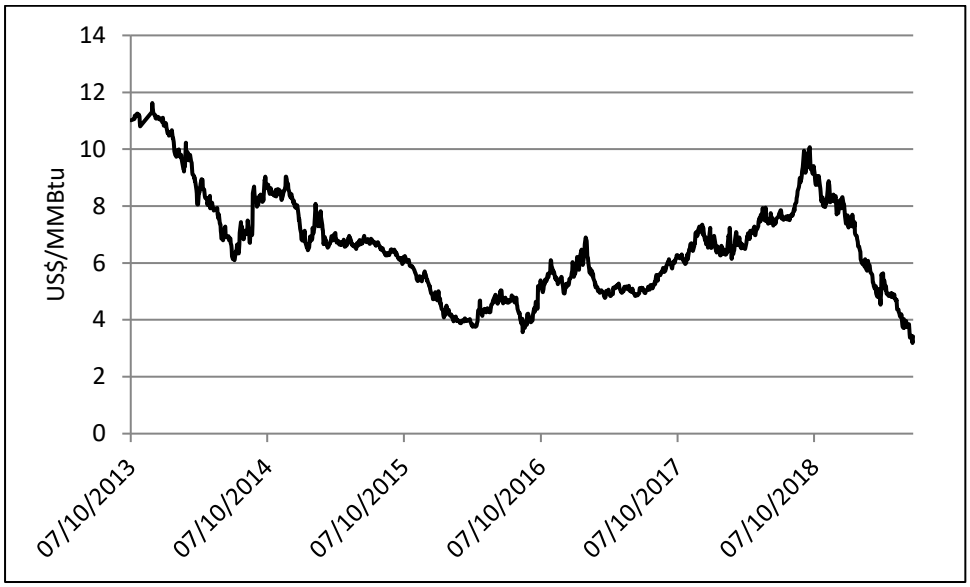
For our analysis we use spot prices from the German Gaspool (GPL) index and from the Japan Korean Marker (JKM, published by Platts) index, provided by the ICE Endex and the New York Mercantile Exchange, respectively, and accessed through Bloomberg.

We choose to use prices from the GPL index for LNG delivery in Germany as Germany is the largest gas consuming country in Europe, with its first LNG terminal on the way in Brunsbuttel. Once the terminal is fully functional, Germany will gain access to the global LNG market and is poised to become one of the major European LNG importers. In addition, we choose the Platts JKM index to represent the LNG price in Japan, since the JKM index is the LNG benchmark price assessment that reflects the spot market value of cargoes delivered into Japan, South Korea, China and Taiwan (S&P Global Platts).

For the spot price, we use the first nearby Futures contract, namely the one-month Futures contract. JKM trades in US$/MMBtu, while GPL trades in €/MWh; thus, GPL prices have been converted to US$/MMBtu at each date of analysis. Spot prices for each index are plotted in Figure 3.1 and Figure 3.2.

Figure 3.1. GPL index daily spot price trajectory in US$/MMBtu

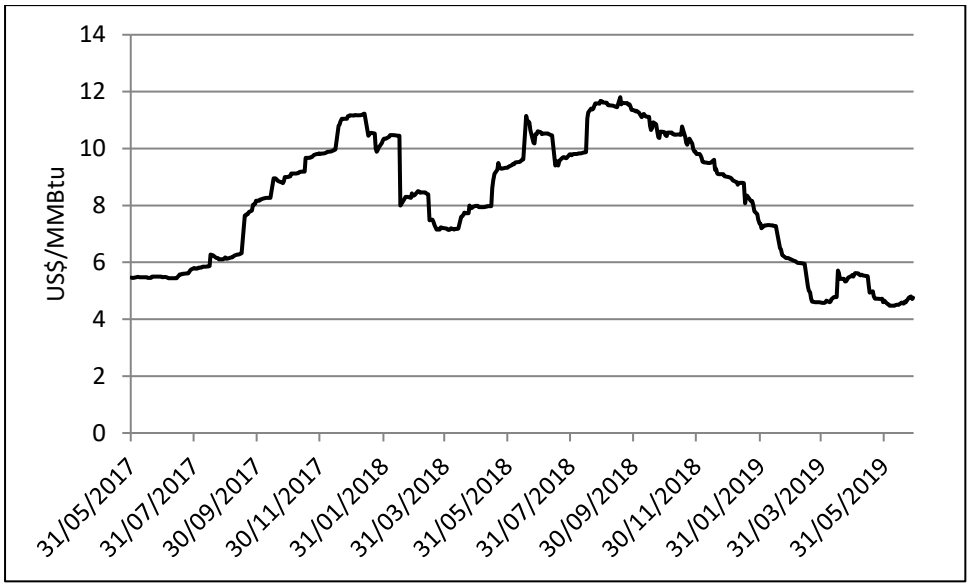
Daily prices presented in US$/MMBtu for the German GPL index for the period 07/10/2013 - 28/06/2019.



Source: Bloomberg

Figure 3.2. JKM index daily spot price trajectory in US$/MMBtu

Daily prices presented in US$/MMBtu for the Asian JKM index for the period 31/05/2017 - 28/06/2019.



Source: Bloomberg

4.1. Spot price model

We consider the price trajectories displayed above by the GPL and JKM indexes to suggest a mean-reverting process, a choice that is supported by the economics of the market. In order to ensure positivity of prices, we define $X_t = lnS_t$, and choose for (X_t) an Orstein-Uhlenbeck process driven under the pricing measure Q by the following equations

$$dX_t^G = \kappa_G(a_G - X_t^G)dt + \sigma_G dW_t^1 \quad [2]$$

$$dX_t^J = \kappa_J\left(a_J - X_t^J\right)dt + \sigma_J dW_t^2 \quad [3]$$

$$dW_t^1 . dW_t^2 = \rho dt \quad [4]$$

where, X_t^G and X_t^J are the respective log prices for Germany and Japan, a_G and a_J are the respective levels of mean reversion for Germany and Japan, κ_G and κ_J are the respective speeds of mean reversion for Germany and Japan, and W_t^1 and W_t^2 are correlated Q-Brownian motions.

Since $X(T) = lnS(T)$, the spot price at date T is defined as

$$lnS(T) = lnS(0)e^{-kT} + a\left(1 - e^{-kT}\right) + \sigma\sqrt{\frac{1-e^{-2kT}}{2k}}W(T) \quad [5]$$

Finally, the futures price $lnF^T(0)$ is the Q - expectation of the spot price at date T and satisfies

$$lnF^T(0) = lnS(0)e^{-kT} + a\left(1 - e^{-kT}\right) + \frac{\sigma^2}{4k}\left(1 - e^{-2kT}\right) \quad [6]$$

4.2. Model parameter estimation

We estimate the three unknown parameters a, k and σ through the nonlinear least squares method using five different maturity Futures contracts: the three-months ahead, six-months ahead, nine-months ahead, twelve-months ahead and eighteen-months ahead Futures contracts.

The nonlinear least squares estimator, presented in Equation (7), minimizes the sum of squared differences between the data set of historical values for each of the five different maturity Futures contracts, and the futures price maturing at each of the five maturity contracts derived from the mean-reverting model (see Equation (6)):

$$Arg\ Min\ \left\{\sum_{i=1}^{5}\left[lnF_{Market}^{T_i}(0) - lnF_{Model}^{T_i}(0)\right]^2\right\} \qquad [7]$$

where

$$lnF_{model}^{T_1}(0) = lnS(0)e^{-k3/12} + a\left(1 - e^{-k3/12}\right) + \frac{\sigma^2}{4k}\left(1 - e^{-2k3/12}\right)$$

$$lnF_{model}^{T_2}(0) = lnS(0)e^{-k6/12} + a\left(1 - e^{-k6/12}\right) + \frac{\sigma^2}{4k}\left(1 - e^{-2k6/12}\right)$$

$$lnF_{model}^{T_3}(0) = lnS(0)e^{-k9/12} + a\left(1 - e^{-k9/12}\right) + \frac{\sigma^2}{4k}\left(1 - e^{-2k9/12}\right)$$

$$lnF_{model}^{T_4}(0) = lnS(0)e^{-k12/12} + a\left(1 - e^{-k12/12}\right) + \frac{\sigma^2}{4k}\left(1 - e^{-2k12/12}\right)$$

$$lnF_{model}^{T_5}(0) = lnS(0)e^{-k18/12} + a\left(1 - e^{-k18/12}\right) + \frac{\sigma^2}{4k}\left(1 - e^{-2k18/12}\right)$$

$lnS(0)$ is the data set of historical spot prices obtained at date 0; $F_{market}^{T_1}(0)$, $F_{market}^{T_2}(0)$, $F_{market}^{T_3}(0)$, $F_{market}^{T_4}(0)$ and $F_{market}^{T_5}(0)$ are the data sets for the historical prices obtained at date 0 for the five different maturity Futures contracts; T_1 = 3 months, T_2 = 6 months, T_3 = 9 months, T_4 = 12 months and T_5 = 18 months.

The period of analysis used to estimate the parameters for the two indexes is not the same. This is due to different operational start dates as well as different availability of data across the various maturity Futures contracts. For the GPL index the period of analysis is 31/10/2013 – 28/06/2019 and for the JKM index the period of analysis is 31/05/2017 – 28/06/2019.

Table 3.1 shows the results of the parameter estimation. Both indexes exhibit a high volatility which is not unexpected since natural gas prices, excluding electricity prices, are known to have the highest volatility among commodities (Geman 2005).

Table 3.1. Parameter estimation results

Nonlinear Least Squares estimation results for the 3 parameters using monthly historical data from 5 different maturity contracts.

Parameters	JKM	GPL
α	1.6464	0.7671
κ	1.3791	0.2995
σ	1.2809	0.9434

4.3. LNG transportation costs

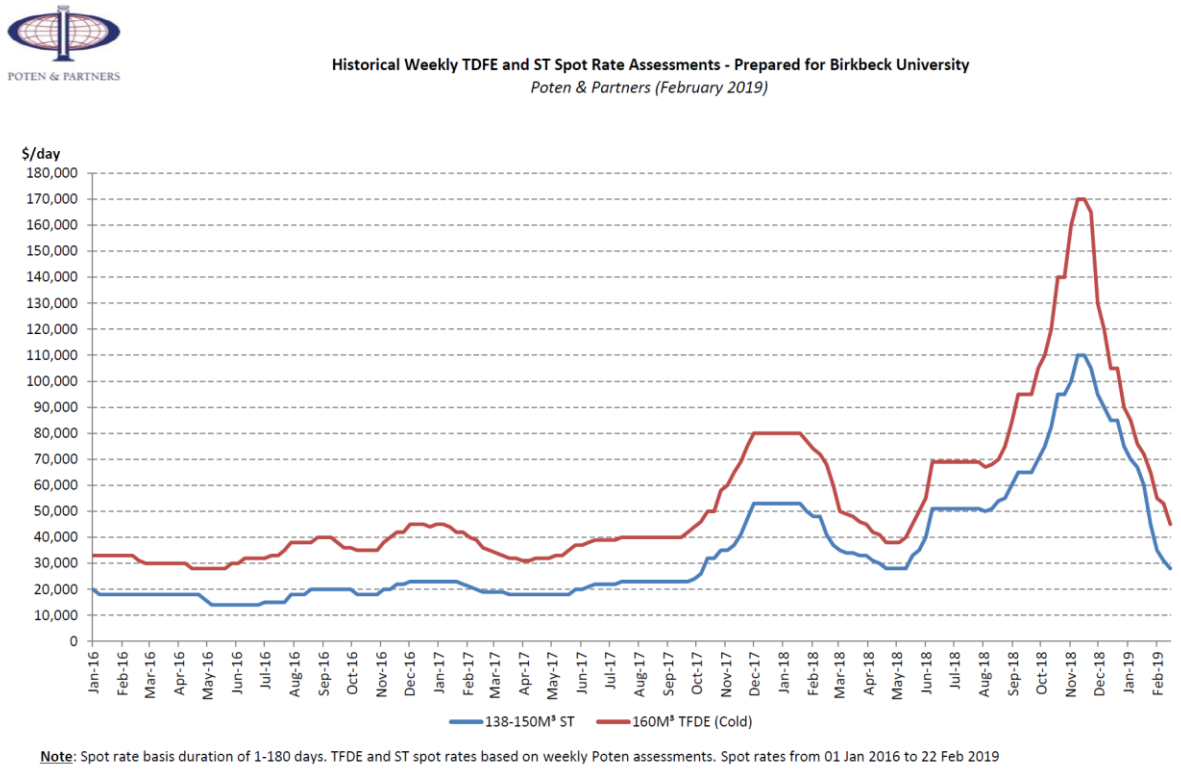
The LNG transportation costs are an important component of the valuation of the rerouting option. Therefore, before turning to the pricing of the option, we first identify an estimation methodology for the additional transportation cost incurred by delivering LNG to the alternative destination. We adopt the approach proposed by Rogers (2018), as this captures its key elements.

The transportation cost of LNG includes many components. The most important one is the daily charter rate of hiring an LNG vessel. In the early 2010s, short-term LNG charter rates increased dramatically because of the growth in Asian LNG demand following the Fukushima disaster. Moreover, the LNG vessel market is divided into two types of vessels: Steam Turbine (ST) and Dual Fuel Diesel Electric (DFDE). ST vessels burn LNG boil-off and fuel oil to generate steam and in turn use turbines to generate propulsive drive. DFDE vessels use LNG boil-off in a diesel cycle engine which transmits energy to the ship's propellers. Since the early 2000s, DFDE vessels have been the preferred choice because they are 50% fuel efficient; ST vessels are only 28% efficient. Interestingly, DFDE carriers achieve an average speed of 19 knots without the need to burn fuel oil, whereas ST carriers achieve an average speed of 14 knots (Rogers 2018). Consequently, we decide to estimate the cost of delivering LNG using DFDE charter rates.

Figure 3.3 shows the weekly cargo charter rates for both DFDE and ST provided by Poten & Partners for the period 01/01/2016 - 22/02/2019. During 2016, and until the summer of 2017, DFDE cargo charter rates were fluctuating around US$50,000 per day. In November 2018, however, prices increased substantially to US$170,000 per day and subsequently decreased to US$50,000 per day in February 2019. Thus, in our study, we assume a US$50,000 daily charter rate for a DFDE carrier.

Figure 3.3. Historical weekly cargo spot charter rates in US$/day

Weekly cargo spot charter rates for the period 01/01/2016 - 22/02/2019 in US$/day provided by Poten & Partners.



Source: Poten & Partners

Table 3.2 displays the breakdown of the various LNG transportation costs. These are (1) the charter cost, (2) the fuel cost, (3) the canal fees (depending on the route), (4) the ports cost for loading and unloading the LNG, (5) the broker fees and (6) the insurance fees. To obtain the transportation cost in US$/MMBtu, we add the aforementioned six components and divide this by the amount of LNG delivered at destination.

Table 3.3 presents the assumptions needed to obtain an estimation of transportation costs as well as a further deconstruction of the key components in the estimation methodology, in the spirit of Rogers (2018).

Table 3.2. Key components of the LNG transportation cost

Presentation of the key components of the LNG transportation costs.

LNG Transportation Cost Key Components	
1	Charter Cost
2	Fuel Cost
3	Canal Fee
4	Ports Cost
5	Broker/Agent Fees
6	Insurance Fees
7	Size of LNG delivered at destination

Source: Rogers (2018)

Table 3.3. Breakdown of key components

Breakdown of key components and assumptions used in the estimation of the LNG transportation cost for a return journey.

Key Components Breakdown	Assumptions
Charter Cost	Number of days for the entire journey multiplied by the daily charter rate
Fuel Cost	Number of days for the entire journey multiplied by the Opportunity cost of LNG boil off
Opportunity Cost Of LNG Boil Off	Daily LNG boil off which is 0.101318% of cargo size multiplied by the spot price at destination (US$/MMBtu)
Suez Canal Cost	US$400,000
Panama Canal Cost	0.2 US$/MMBtu multiplied by the size of delivered LNG at destination
Ports Cost	US$100,000 per day. Time spent at ports is 3 days for the entire journey. Outbound port, destination port and return port.
Broker/Agent Fees	2% of the total charter cost
Insurance Fees	US$2,600 per day
Size Of LNG Delivered At Destination	Initial loading which is 98% minus the reserved heel for returned journey which is 4% of the initial loading minus the boil off for the entire journey
Vessel Type	DFDE
Vessel Size	160,000 cubic meters of LNG
Lng Cubic Meters To Mmbtu	23.12
Route And Number Of Days Of Journey	https://sea-distances.org/
Average Carrier Speed	19 knots

Source: Rogers (2018)

In our study, the departure point for the LNG cargo is the Sabine Pass LNG terminal in Louisiana, US, operated by Cheniere Energy. The two arrival points for the LNG cargo are the Sodegaura terminal, the largest importing terminal in Japan operated by TEPCO and Tokyo Gas, and the Brunsbuttel site, where the first German LNG terminal is under construction.

Table 3.4 presents the breakdown and the final transportation cost in US$/MMBtu for a return journey for the two points of arrival. The US-Japan route has an additional fee for the Panama Canal, whereas the other route has no such extra charge. We also observe that the transportation cost of LNG when the recipient is Japan compared to Germany is much higher. The US-Japan route costs US$1.20/MMBtu, whereas the US-Germany route costs US$0.58/MMBtu.

Table 3.4. LNG transportation cost estimation

LNG transportation cost for a return journey for the two routes.

Components	US-JAPAN	US-GERMANY
Charter Cost	US$2,170,175	US$1,279,386
Fuel Cost	US$704,909	US$283,739
Canal Fee	US$666,361	0
Ports Cost	US$300,000	US$300,000
Broker/Agent Fees	US$43,404	US$25,588
Insurance Fees	US$112,849	US$66,528
LNG Volume delivered at destination	US$3,331,805	US$3,397,243
Total Cost $/MMBtu	US$1.20/MMBtu	US$0.58/MMBtu

The rerouting option is a spread option involving the additional transportation cost incurred if the cargo is redirected to Japan. Specifically, this one is the transportation cost for a journey from Germany to Japan, plus the difference in transportation costs between Japan and Germany, back to the supplier's terminal. The additional transportation cost (ATC) is defined in Equation (8), and the results are presented in Table 3.5. We find that the additional transportation cost is US$0.98/MMBtu.

$$Additional\ Tranposrtation\ Cost(ATC) = TC^{Germany-Japan} + TC^{Japan-USA} - TC^{Germany-USA} \quad [8]$$

where, $TC^{Germany-Japan}$ is the transportation cost from Germany to Japan (single journey), $TC^{Japan-USA}$ is the transportation cost from Japan back to the supplier's terminal (single journey), and $TC^{Germany-USA}$ is the transportation cost from Germany back to the supplier's terminal (single journey).

Table 3.5. Additional LNG transportation cost (ATC)

Results for the additional LNG transportation cost incurred from cargo rerouting.

Route	US$/MMBtu
$TC^{Germany-Japan}$	+ 0.67
$TC^{Japan-USA}$	+ 0.60
$TC^{Germany-USA}$	- 0.29
ATC	0.98

5. Valuation of the rerouting option

We identify the rerouting option as a spread option, defined in Equation (1), for which only the Kirk approximation gives some kind of explicit approximation in the case of a geometric Brownian motion assumption for the two variables at stake. In our case, we recognise mean-reverting processes in the LNG spot and forward prices; hence, from all perspectives, a Monte Carlo approach is the right way to proceed to compute the option price as the Q-expectation at date 0 of the payoff at date T. Note that the discount should be factored from date T to date 0, since the option is only cashed at date T, which is the maturity of the forward contract sold at date T_1 when reaching Germany:

$$C(0) = e^{-rT} E_Q\left[max\left(0, f_J^T(T_1) - S_G(T_1) - ATC\right) / F_0\right] \qquad [9]$$

It is important to observe that this is the added value granted at date 0 by the destination optionality; its payoff will take place at date T_1. The spot price of LNG in Germany at date T_1 is

$$lnS_G(T_1) = lnS_G(0)e^{-k_G T_1} + a_G\left(1 - e^{-k_G T_1}\right) + \sigma_G \sqrt{\frac{1 - e^{-2k_G T_1}}{2k_G}} W_1(T_1) \qquad [10]$$

The expectation at date 0 of the forward price in Japan at date T_1 for LNG delivery at date T is derived from the law of iterated expectations:

$$E\left[f_J^T(T_1) / F_0\right] = E\left[E\left[S_J(T) / F_{T_1}\right] / F_0\right] = E\left[S_J(T) / F_0\right] \qquad [11]$$

where

$$lnS_J(T) = lnS_J(0)e^{-k_J T} + a_J\left(1 - e^{-k_J T}\right) + \sigma_J \sqrt{\frac{1 - e^{-2k_J T}}{2k_J}} W_2(T) \qquad [12]$$

will be the Monte Carlo-simulated quantity.

Next, we exponentiate Equations (11) and (12):

$$S_G(T_1) = \exp\left\{lnS_G(0)e^{-k_G T_1} + a_G\left(1 - e^{-k_G T_1}\right) + \sigma_G\sqrt{\frac{1 - e^{-2k_G T_1}}{2k_G}}W_1(T_1)\right\} \quad [13]$$

$$S_J(T) = exp\left\{lnS_J(0)e^{-k_J T} + a_J\left(1 - e^{-k_J T}\right) + \sigma_J\sqrt{\frac{1 - e^{-2k_J T}}{2k_J}}W_2(T)\right\} \quad [14]$$

In order to perform a Monte Carlo valuation of the option, we introduce a new Brownian motion W_3. This is defined as

$$W_3 = \rho W_1 + \sqrt{1 - \rho^2} * W_2 \quad [15]$$

according to the Cholesky decomposition. We compute Pearson's correlation between the two spot prices for the first three months and identify that the correlation coefficient is approximately 0.5. Lastly, we simulate price values driven by Equations (13) and (14) and approximate the rerouting option's price at date 0:

$$C(0) = e^{-rT}\sum_1^n \frac{\left(Max(0, S_J(T) - S_G(T_1) - ATC\right)}{n} \quad [16]$$

Here, r is the interested rate, assumed to be 3%, and n is the number of simulations, set to 10,000.

5.1. Results

The option price we obtain with the values of the parameters discussed in Section 4.2 is US$0.856/MMBtu (see Table 3.6). The buyer of an LNG cargo delivered from the United States to either Germany or Japan has two strategies available. The first strategy is to buy the LNG from the US supplier at date 0 (US$2.31/MMBtu) and sell a forward contract in Japan (US$4.75/MMBtu) leading to a P&L at date T of US$1.24/MMBtu (accounting for the LNG transportation cost). The second strategy is to enter a forward contract delivery to Germany with a rerouting option attached. The rerouting option represents the additional profit the buyer will acquire in *average* across voyages. In this case, the P&L of the strategy will amount to US$1.39/MMBtu – for the forward contract destination Germany (US$0.53/MMBtu) plus the rerouting option - which is higher than the P&L of the carry trade delivery to Japan: an additional gain of 12%.

Table 3.6. Rerouting option price and P&L strategies 1 and 2

The rerouting option's price is presented as well as the P&L of the 2 strategies.

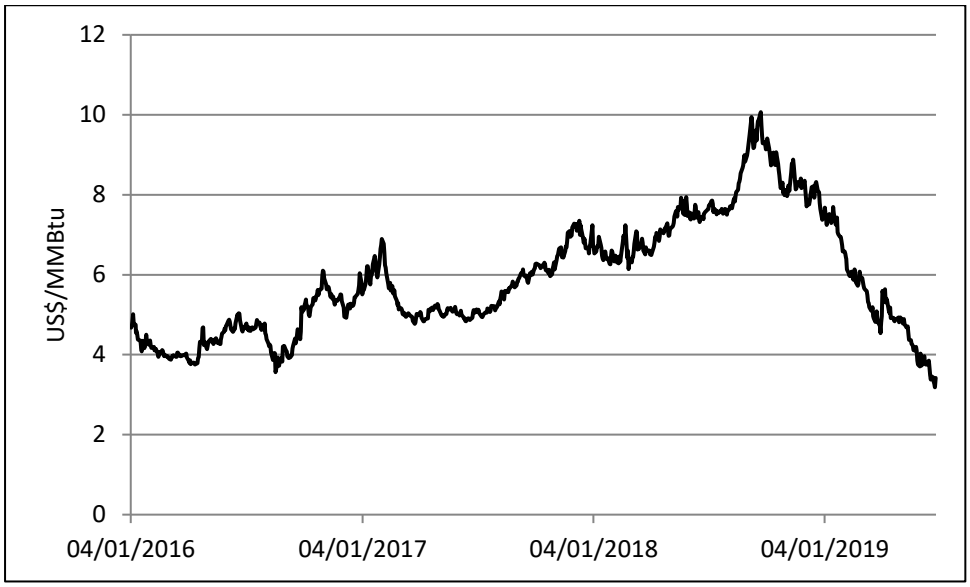
	US$/MMBtu
Rerouting Option Price	0.856
P&L Strategy 1 - Carry Trade delivery Japan	1.24
P&L Strategy 2 - Carry Trade delivery Germany + Rerouting option	1.39

The rerouting option being added to a forward contract destination of Germany as opposed to the pure forward destination of Japan will be particularly valuable when the LNG tanker reaches Germany during cold winters or during periods when, for example, the natural gas pipeline from Russia gets stopped by operational or political issues, creating spikes in German spot prices: see Figure 3.4 for the historical daily gas prices in Germany from January

2016 until June 2019 and the spike observed in the second half of 2018, leading to a very high P&L obtained through the option.

Figure 3.4. GPL index daily spot prices for the period 04/01/2016 – 28/06/2019

Daily prices presented in US$/MMBtu for the German GPL for the latest period 2016 - 2019.



Source: Bloomberg

Lastly, we test the option's price sensitivity in terms of the volatility. We compute the option price when the volatility σ_J is increased by 20%, 30% and 50%, successively, and then compare the new option prices with the original option price. Our results, presented in Table 3.7, show that a higher volatility affects the option's payoff positively: increases of 16%, 25% and 44% result from volatility increases of 20%, 30% and 50%, respectively.

Table 3.7. Option price sensitivity to the volatility

Results of the rerouting option's price in the case where the volatility $of\ the\ alternative\ destination\ \sigma_J$ is increased by 20%, 30% and 50%.

	Option Price (US$/MMBtu)	% Change
C(0)	0.856	-
C(0) σ_J +20%	0.996	16%
C(0) σ_J +30%	1.07	25%
C(0) σ_J +50%	1.23	44%

6. Conclusion

New flexible short-term LNG contracts and the subsequent emergence of the rerouting optionality are transforming the LNG market, while LNG has become a commodity in its own right. In this Chapter, we described the rerouting option granted to the buyer at departure of the tanker in a specific choice of countries and proposed a valuation methodology that extends the founding option pricing models due to both the payoff and the mean-reversion chosen for the spot prices. The profitability behind this optionality being embedded in a purchase contract - as well as its sensitivity to the transportation costs, price volatility and spikes - is also exhibited.

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Chapter 4. New developments in the UK electricity market: Valuation of capacity options and power CfDs

1. Introduction

The Paris agreement, that took place in 2015 at the Paris climate conference (COP21), is the first legally binding climate change agreement that aims to limit the global average temperature increase below 2° C before the end of this century, with an additional effort of limiting the temperature rise even further, at 1.5^{0} C. Approximately 190 countries are currently participating in the Paris agreement, in which all parties are required to report on their efforts by regularly submitting data on their country's emissions reductions and implementation strategies, whilst every five years a global review will take place to assess the joint progress in meeting the agreed targets (United Nations Climate Change).

As a result, countries around the world are transforming their electricity markets in order to reduce their greenhouse emissions. Clean renewable sources of electricity, such as hydro, biofuels and waste, solar, wind, geothermal and tidal have attracted significant interest and investments in recent years, while their share in the global energy mix has increased substantially. Specifically, in 2019, the share of global renewable electricity generation reached 27%, which is the highest level ever recorded. Renewables had a 6% rate of generation growth, which is the highest growth rate among all other electricity sources. Solar PV and wind, each accounted for one third of global renewable electricity generation growth. Hydro accounted for 23% and bioenergy represented the rest of global renewables share (IEA Renewable Power 2020).

A particularly popular renewable technology is offshore wind. According to the International Energy Agency, the global offshore wind market is set to expand by 13% per year, exceeding 20 GWh of additions per year by 2030, with a required capital spending of

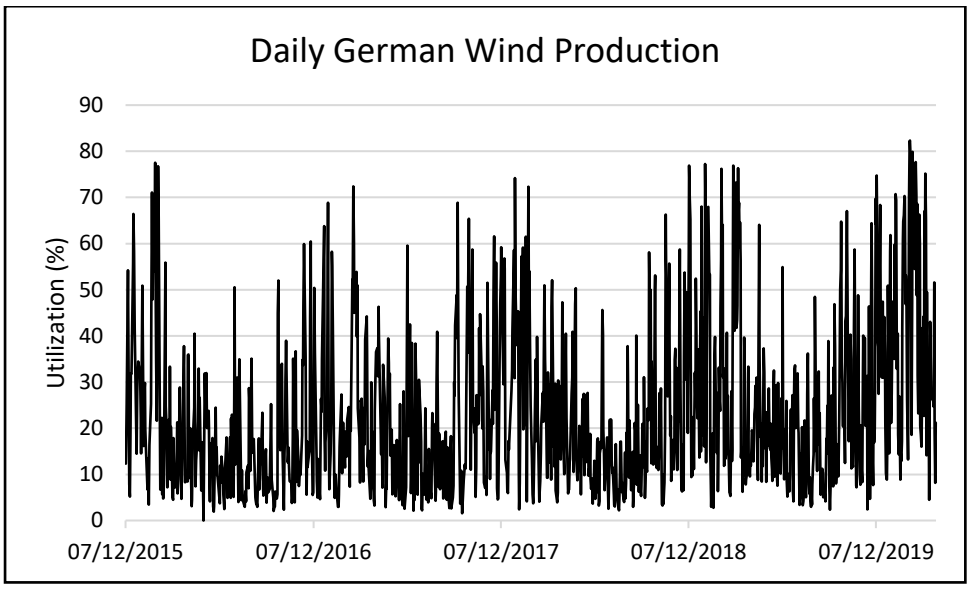
US$840 billion over the next two decades - almost the same as natural gas-fired or coal-fired capacity. In the next five years, around one-hundred-fifty new offshore wind projects are scheduled to operate worldwide, with Europe pioneering wind technology development, which is led by the United Kingdom, Germany, and Denmark. The United Kingdom and Germany have the largest wind capacity in operation, Denmark produced 15% of its electricity from wind in 2018, whilst China entered the offshore wind market by adding the highest capacity of offshore wind globally in that year. Offshore wind deployment has seen a deep reduction in costs, indicating that the technology is rapidly maturing. In 2018, the average upfront cost to build a 1 GWh offshore wind project, including transmission, was over US$4 billion; however, this cost is set to drop by more than 40% over the next decade. This overall decline is driven by a 60% reduction in the cost of turbines, their foundations, and installation. For offshore wind to be employed at scale, there needs to be sufficient policies in place to encourage investment in such projects. In fact, several European countries including the United Kingdom, Germany, the Netherlands, and Denmark have deployed relevant regulations to support offshore wind; China, the United States, Korea, Japan, Chinese Taipei, and Vietnam have also put policies in place (IEA Offshore Wind Outlook 2019).

At the same time, new financial hedging products are emerging, such as proxy revenue swaps and wind Futures. A proxy revenue swap is a bilateral financial contract where one counterparty, usually an insurance company, provides a hedge against both price volatility and production instability, which are caused by meteorological factors. The proxy revenue swap, is a new financial instrument, launched in 2016 by Allianz Risk Transfer, in which the project generator receives fixed payments from the hedge provider that are equivalent to the projected revenues for a given time period, known as proxy revenue. If the generator’s actual revenue for a given period exceeds the proxy revenue, the generator pays the insurance company the difference (IEA World Energy Investment 2019).

In 2015, NASDAQ launched the German Wind Power Index Future. NASDAQ's wind Futures are a way for producers and other stakeholders to hedge the production of German wind power; these Futures are based on the NAREX WIDE index, which is the underlying index used to settle on the relative German wind power utilization. The NASDAQ Wind Germany index, presented in Figure 4.1, is a specific synthetic index that calculates the German wind power production (NASDAQ).

Figure 4.1. NASDAQ renewable index wind Germany: NAREX WIDE

Daily German wind power production for the period 07/12/2015 - 01/04/2020.



Source: NASDAQ

In this Chapter, we examine in the case of the United Kingdom, the new developments related to its electricity market, that aim to attract investment at scale for new renewables projects at a low cost to the consumer. More specifically, we discuss the structure of the Contracts for Difference (CfD) scheme and present their valuation for different delivery years, in the case where an offshore wind generator participates in the scheme. Additionally, we examine the Great Britain Capacity Market scheme and propose to represent it through a series of daily European call options.

The rest of the Chapter is organized as follows. Section 2 describes the new developments in the UK Electricity market. Section 3 presents the structure and valuation methodology for the Contracts for Difference Scheme. Section 4 displays the Great Britain Capacity Market structure where we propose a new valuation methodology. Section 5 addresses the CfD and capacity option valuation. Section 6 concludes.

2. New developments in the UK electricity market

The United Kingdom is one of the pioneer countries in decarbonising its electricity market, with its approach used as a model for the Paris Agreement. In 2020, the United Kingdom's energy-related CO2 emissions decreased to their lowest levels since 1888, while the government committed to close all remaining coal-fired power stations by 2025. The government will also decommission the oldest nuclear reactors by 2025 and further six reactors by 2030. Natural gas and renewables are replacing the share of oil and coal in electricity generation. Specifically, in 2019, renewables had a share of 56% in the United Kingdom's energy mix, while natural gas had a share of 41% (IEA UK Review 2019; IEA Monthly Electricity Statistics Report 2021).

In 2019, the United Kingdom set a new target of reducing all greenhouse emissions to net zero by 2050, while the government is already implementing the necessary changes in order to achieve its emission goals. The United Kingdom's government goal is to attract new investment in low-carbon technologies at scale, while at the same time ensuring diversity and security in the energy mix in a cost-effective way. In 2013, the United Kingdom implemented the Electricity Market Reform (EMR); a series of interventions that will help manage the transition to a decarbonised electricity market through incentivised investment in low-carbon power, affordable to consumers. These interventions include the Great Britain Capacity Market (GB CM), Contracts for Difference (CfDs) for low-carbon electricity, a carbon price floor

(CPF) of £18.08 per tonne of carbon dioxide, and an emission performance standard (EPS) of 450 g/tCO2 (IEA United Kingdom 2019 Review).

The CfD scheme, which operates through competitive auctions, has attracted significant attention and participation from both generators and investors, since the scheme provides price certainty to its participants, and has led to a substantial investment in new renewables projects. CPFs emphasized the value of carbon in the power sector and were able to drive the coal to gas switching, while the EPS restricted any possible investment in new coal power plants. The Great Britain Capacity Market, which operates through auctions, supports the security of electricity supply in the UK (IEA United Kingdom 2019 Review).

3. Contracts for difference (CfD) scheme

The Contracts for Difference (CfD) scheme is the United Kingdom's government main tool to attract substantial investments in new low carbon electricity generation projects, that will in turn secure a diverse electricity generation mix. At the same time, the scheme protects generators from volatile wholesale electricity prices as well as consumers from higher utility bills.

After entering a CfD contract, generators exchange daily payments with the UK government for the electricity they produce over a period of fifteen years. The payments are calculated as the difference between a set strike price and an indexed reference price. When the strike price is above the reference price, generators receive a payment of the price difference (funded through the CfD Supplier Obligation Levy); when the strike price is below the reference price, generators pay back the price difference (returned to suppliers via reconciliation of the levy) (BEIS Contracts for Difference Scheme; Low Carbon Contracts Company). The cost of the CfD scheme is passed onto consumers via a levy on energy bills.

This is nothing but a swap where generators are receivers of the fixed price (or a fixed-price Power Purchase Agreement).

The scheme is protected from political interference and ensures generators will always receive a reward for the electricity they produce. As a result, new low-carbon projects that are part of the CfD scheme are very attractive to investors since they are a low-risk investment with stable returns. Over the years, the scheme has attracted a wide range of international capital (including banks, utilities, and sovereign wealth funds), which in turn led to an increased lending competition that resulted in a lower cost of capital and a reduced cost to the consumer (Low Carbon Contracts Company).

There have been three auctions to date. The first auction took place in 2015, the second in 2017, the third in 2019 and the fourth will take place in 2021; future auctions will take place every two years until 2030. Generators competing for a contract are separated into two groups: the intermittent technologies group and the baseload technologies group. Intermittent technologies are less established technologies such as offshore wind, remote island wind, wave, tidal stream, advanced conversion technologies (ACT), anaerobic digestion (AD), dedicated biomass with CHP, and geothermal. Baseload technologies are established technologies such as onshore wind, solar photovoltaic (PV), energy from waste with combined heat and power (CHP), hydro, coal-to-biomass conversions, landfill gas, and sewage gas. Prior to the auction date, the government sets an administrative strike price for each technology, known as the reserve price, that reflects the technology generation cost and is expressed in £/MWh. The final strike price is set during the auction through competitive bidding, with the constraint that it cannot be higher than the administrative strike price. The indexed reference price for intermittent technologies is the day ahead hourly electricity price in the United Kingdom, while for baseload technologies the reference prices is the season ahead electricity price in the United Kingdom (BEIS Contracts for Difference for low carbon electricity generation: Consultation on proposed amendments to the scheme 2020).

So far, the scheme has been successful in attracting new investment in both clean and cost-effective projects. More specifically, 16 GWh of new renewable electricity capacity have been awarded through CfDs, including 13 GWh of offshore wind capacity, while the average strike price has decreased by 67% from the first auction to the last. At the same time, the cost of building offshore wind turbines has been reduced by around 30% from previous auctions, while the delivery performance of CfD projects is on track, with 96% of the capacity estimated to be delivered on time, enhancing the confidence in investing in projects associated with a CfD (BEIS Contracts for Difference for low carbon electricity generation: Consultation on proposed amendments to the scheme 2020; Low Carbon Contracts Company).

Keay and Robinson (2017) analyse the way the United Kingdom and Spain have been responding to the challenges of this new era of electricity markets decarbonisation. They identify that in terms of cost reduction, the United Kingdom's approach, which incorporates the CfD scheme, has been reasonably good so far.

Welisch and Poudineh (2019) investigate the Contracts for Difference (CfDs) auctions in the United Kingdom and identify that the scheme has been successful in achieving low bids for low carbon technologies, especially for offshore wind power. They suggest that by holding annual scheduled auctions, the information on technology cost reductions can be better incorporated into the bids, lowering investor uncertainty and in turn having a positive effect on support costs.

3.1. Valuation methodology for CfDs

The Contracts for Difference scheme currently operating in the United Kingdom, are contracts between a generator of low-carbon electricity and the United Kingdom's government, in which the two parties will exchange daily cashflows over a period of fifteen

years. The floating leg is the price of electricity and the fixed leg is a strike price predefined for each delivery year (in contrast to ordinary financial swaps where the value of the fixed leg is unchanged for the duration of the swap).

We consider the case of an offshore wind generator, for whom the underlying electricity price is the daily average of the hourly day-ahead electricity prices in the United Kingdom, and the strike price is the final strike price set at the auction organised for each delivery year. The CfD is a strip of forward contracts maturing daily or a swap with a strike annually reset. Hence, the value of a CfD at date zero is

$$V_{swap}(0) = \sum_{j=1}^{q} B(0, T_i)[Strike\ Price - F^{t_j}(0)] \qquad [1]$$

where, $j = 1, 2, \dots, q$ are the daily cashflow exchanges for 15 years, $B(0, T_i)$ is the discount factor represented by zero-coupon bond prices in the UK maturing in each corresponding year $T_i = 1, 2, \dots, 15$, and $F^{t_j}(0)$ are the forward prices for maturities $t_1, t_2, \dots, t_q$.

We can note that in contrast to standard swaps, the value of a CfD at date 0 is not necessarily equal to zero, but instead reflects the government incentive and the auction effect.

4. Great Britain Capacity Market scheme

The Great Britain Capacity Market is an incentivised scheme designed to procure electricity capacity at the lowest cost to the consumer. The required capacity for each delivery year is determined by the Secretary of State, informed by an analysis undertaken by the system operator (National Grid) through its Electricity Capacity report. In 2018, the electricity market government regulator in the United Kingdom (Ofgem) introduced a new regulatory framework addressed to the system operator (National Grid), which incorporates an incentive

for accurate demand forecasting; this action was taken in order to avoid over-procurement, which translates to additional cost to the consumer.

The Great Britain Capacity Market scheme operates through auctions, where two auctions take place for each delivery year; a delivery year runs from October 1st until September 30th. In particular, the first auction is held four years ahead (T-4) of the delivery year, to allow enough time to build any new capacity needed - around 95% of the targeted capacity is procured at the first auction. The second auction (T-1) is held a year before delivery, to allow for any adjustments. Fourteen auctions took place to date for nine delivery years. The first delivery year under the Great Britain Capacity Market scheme was the year 2016/17, where only one auction was held, initiating the scheme, followed by two auctions for each delivery year, namely for the years: 2017/18, 2018/19, 2019/2020, 2020/21, and 2021/22. For future delivery years, namely 2022/23, 2023/24 and 2024/25, the first auction (T-4) already took place. The next auction will take place in 2022 and it will be the T-1 auction for the delivery year 2022/2023.

For each auction, a price cap is set in advance which is then reduced during the auction in each bidding round, at a set decrement, until a clearing price is reached. The auction price clears when the remaining capacity in the auction is less than the required capacity, meaning that the targeted capacity has been secured. After the auction price clears, the auction system will check if there has been an exact match between the supplied capacity from generators and the demanded capacity from the United Kingdom's government. If there has not been an exact match, the auction system will assess if over-procuring or under-procuring capacity, would be most economically beneficial for the consumer. In this case, the clearing price and procured capacity will be determined through the Net Welfare Algorithm (NWA), that compares the nearest points of supply on either side of the demand curve to determine which point is most beneficial for the consumer (NG ESO 2020).

All technologies are eligible to participate in the Great Britain Capacity Market scheme. Successful generators sign a Capacity Market Agreement committing to provide electricity when required and in return they receive a monthly payment, which is equivalent to the clearing price set during the auction. There are three types of agreements: one year for existing projects, three years for generation in need of refurbishment, and fifteen years for building new generation plants. There have not been any stress events to date; however, stress events may take place in the mid-2020s, when all the coal power stations will close. A stress event happens when there is insufficient electricity capacity to meet demand. National Grid ESO will notify Capacity Providers four hours ahead of a stress event, in which case Capacity Providers are required to deliver electricity against their Auction Acquired Capacity Obligation (AACO); failure to do so can lead to a financial penalty. Generators participating in the Great Britain Capacity Market scheme can still trade in the Great Britain wholesale electricity market daily; the scheme's intention is to provide additional revenue to participators in exchange for capacity reserve in times when demand surpasses supply. Capacity payments made by ESC (Electricity Settlements Company; a private limited company, owned by the Secretary of State for BEIS, that oversees the settlement of the Capacity Market) under capacity agreements are funded by the Capacity Market Supplier Charge and are passed onto consumers via a levy on energy bills. Additionally, the operational costs of ESC are funded through the Capacity Market Settlement Cost Levy (Low Carbon Contracts Company).

In 2018, the United Kingdom's government suspended the Great Britain Capacity Market scheme following a ruling from the European Union's General Court, which triggered a standstill period for the scheme that lasted for almost a year. The dispute was raised by Tempus energy, a demand side operator, arguing that the demand-side-response technology was treated unfairly under the scheme, compared to other technologies. In particular, Tempus Energy claimed that the scheme favoured fossil fuel technologies over clean technologies, for the reason that the demand-side-response technology was only eligible to bid for one-year agreements; in contrast, new build generation of other technologies were eligible to bid for

fifteen-year agreements, meaning they would receive financial support for a longer period of time.

Following the dispute, the European Commission began a formal investigation in 2018, in which they did not find any evidence that the scheme supported one technology over another and identified that the scheme complied with EU state rules. The Great Britain Capacity Market scheme was therefore reinstated in 2019.

Around the same time, the United Kingdom's department for Business, Energy and Industrial Strategy (BEIS) published a five-year review report (see BEIS Capacity Market five-year review report 2019) for the Great Britain Capacity Market scheme, to assess its performance. To complete the five-year review report, the United Kingdom's government published a call for evidence (CFE), in August 2018, inviting the views of market participants on the performance of the Great Britain Capacity Market scheme.

Following the call for evidence and the five-year review report, the United Kingdom's government identified three areas of the Great Britain Capacity Market scheme in need of improvement: (1) futureproofing and maintaining technology neutrality, (2) simplification of the scheme, and (3) procuring the right amount of capacity to ensure the scheme's cost-effectiveness. Among other actions, the United Kingdom's government is examining other types of Capacity Mechanisms currently implemented in France, Italy, New England, Pennsylvania-New Jersey & Maryland, Ireland and Poland, to support future improvements. The institutional framework of the Great Britain Capacity Market will also be revised with the goal to reduce complexity, barriers to entry and regulation in order to give participants further certainty.

The government will also revisit the auction design. Currently, there is a single auction design in place, where all capacity types are auctioned simultaneously. This type of design

has been effective so far, however, with the expectation that the proportion of new build capacity will increase in the coming years, this auction design may not be suitable, since new and existing power generation have different financial needs. The United Kingdom's government will review and decide whether a split auction design - where different capacity types are auctioned separately (e.g., new build and existing capacity) - will be more suitable in the future.

Roques (2019) analyses the different types of capacity mechanism approaches across European countries. He identifies the different drivers of national reforms, maps the key issues associated with the coordination of capacity mechanisms across countries, and explores alternative approaches to allow for explicit cross-border participation in capacity mechanisms.

According to Roques (2019), there are four different types of capacity mechanisms in Europe. The first type is the Capacity Payments, which have been in place for several years and are currently implemented in Spain, Ireland, Greece, and Italy. The payments are set by the regulator and can be fixed or variable. The second type is the Strategic Reserves of power plants, which are contracted by the system operator. Selected generators do not participate in the electricity market unless there is a capacity shortage. This type of capacity mechanism is implemented in Sweden and Finland and as an interim solution in Belgium and Germany. The third type is the Capacity Market which is what is currently implemented in the United Kingdom, with Poland following the same centralised approach. France follows a decentralised approach for capacity, where each supplier has an obligation to meet the anticipated electricity use of its customer portfolio augmented by a predefined security margin. The fourth type of capacity mechanism are Reliability Options, which are being implemented in Italy and in Ireland.

Andreis et al (2020) analyse Reliability Options under different electricity price regimes and propose a quantitative evaluation framework. Reliability Options are capacity

remuneration mechanisms, aimed at enhancing security of supply in electricity markets. They are similar to Contracts for Differences and are intended to attract and secure capacity in the electricity market. Under this type of capacity mechanism, generators sell Reliability Options to the system operator in exchange for a premium, and in turn commit to provide power capacity in the market. Generators pay back the System Operator the extra revenues they obtain when electricity prices are higher than a predetermined strike price (meaning a revenue cap).

Fabra (2018) builds a model that captures the key drivers of investment and pricing incentives in electricity markets and concludes that bundling capacity payments with financial obligations further mitigates market power, as long as strike prices are set sufficiently close to marginal costs.

4.1. Proposed valuation methodology for the Great Britain Capacity Market

We propose a simple - but novel to our knowledge - valuation methodology for the Great Britain Capacity Market, by representing a capacity option as a series of daily European call options for one year. The contract is between the electricity generator (seller) and the system operator (buyer). If a stress event occurs, the system operator will exercise the option on that very day and the electricity generator will have to provide the agreed capacity at a price K, predetermined at the beginning of the year. The value of the capacity option at date 0 is the sum of these daily options, namely

$$C(0) = B(0, T_j) E_Q\left[max\left(0, S\left(T_j\right) - K\right)\right] \qquad [2]$$

where, $\mathrm{C}(0)$ is the option price at date 0, $S\left(T_j\right)$ is the spot price at date T_j, K is the strike price, T_j is the maturity of the daily options $T_1, T_2, \ldots, T_j = 1/365, 2/365, \ldots, 365/365$, and $B(0, T_j)$ is

the discount factor represented by daily UK zero-coupon bond prices for one year obtained at date 0.

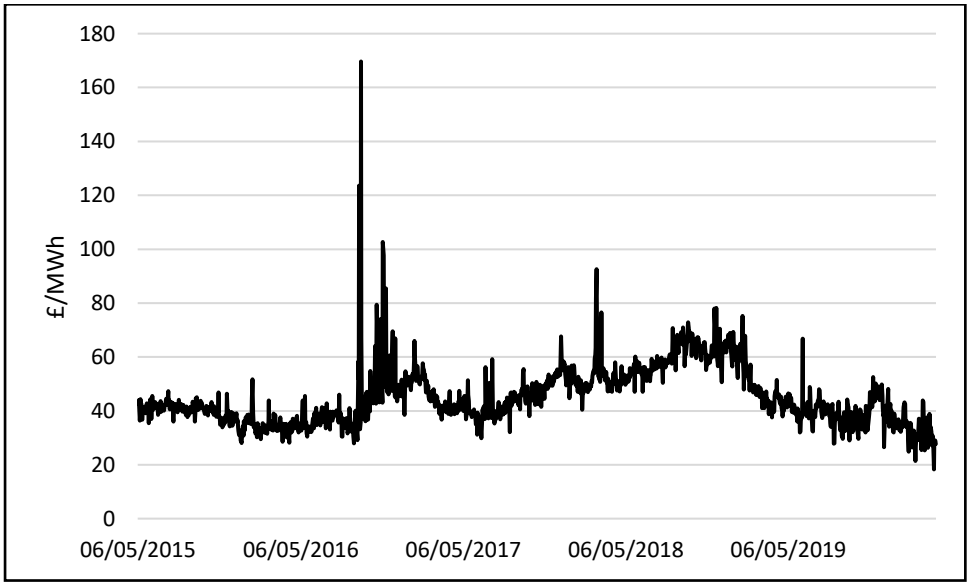
5. CfDs and capacity option valuation

5.1. Data description

For the spot price, we use the daily average of the hourly day ahead electricity prices in the United Kingdom, provided by Nordpool, which we access through Bloomberg. Figure 4.2 presents the daily spot electricity prices for the period 06/05/2015 - 01/04/2020. We observe that prices mean revert to an average long run mean level for most of the time period, except for rare price spike occurrences. Despite the large magnitude of these extreme events, price spikes are short lived; when a jump occurs, prices quickly drop back to the average price level where they continue to mean revert.

Figure 4.2. UK daily average of the hourly day ahead electricity prices

Daily average of the hourly day ahead electricity prices in the United Kingdom for the period 06/05/2015 - 01/04/2020, presented in £/MWh.



Source: Bloomberg

Table 4.1 presents the descriptive statistics for log-spot prices as well as for spot log-returns. The annualised volatility of log-returns is substantially large, at 204%, however, this is not surprising since electricity markets are known to be among the most volatile markets. Additionally, we observe a positive skewness and excess kurtosis, with a coefficient above 3, which indicates leptokurtosis in the price series and the presence of spikes. Lastly, the assumption of normality, based on the Jarque-Bera test, is rejected.

Table 4.1. Descriptive statistics for spot log-prices and spot log-returns

The table presents the descriptive statistics for the logarithmic spot prices and logarithmic returns for the period 06/05/2015 - 01/04/2020.

	Logarithmic Level	Logarithmic Returns
Mean	3.779	-0.0002
Median	3.746	-0.0036
Maximum	5.133	1.5546
Minimum	2.905	-1.2779
Standard Deviation	0.220	0.1075
Skewness	0.449	1.1888
Kurtosis	3.886	48.2753
Jarque-Bera	118.822	153306.5

5.2. Model for the spot price dynamics

We therefore choose to describe the spot price dynamics of the UK electricity market using a mean-reverting jump diffusion model with seasonality to capture the main features of electricity prices namely, seasonality, mean reversion and spikes, in accordance with the literature.

Merton (1976) proposed a jump diffusion model in the case when the underlying stock returns are generated by a mixture of both continuous and jump processes. Clewlow and Strickland (2000) extend Merton's model to account for mean-reversion and jumps. Geman and Roncoroni (2006) introduce a class of discontinuous processes with mean reversion and a jump reversion component to represent the sharp upward moves which are followed by downward moves of the same magnitude. Nomikos and Andriosopoulos (2012) consider two types of models for the electricity spot price, a mean reverting model and a spike model with mean reversion that incorporates two different speeds of mean reversion; one for the fast mean reverting behaviour of prices after a jump occurs and another for the diffuse part of the model. They also extend these models to incorporate time-varying volatility, modelled as a GARCH and an EGARCH process. In our study, the log spot price process, $lnS(t)$, under the pricing measure Q is written as

$$lnS(t) = f(t) + X(t) \qquad [3]$$

The first term, $f(t)$, is a known deterministic function of time representing the price seasonality, and is described by

$$f(t) = \gamma \cos\left(\delta + \frac{2\pi t}{365}\right) \qquad [4]$$

where, the effect of the cosine term is a periodic path displaying one maximum per year.

The stochastic term of the spot price, X_t, is a mean-reverting jump diffusion process, whose dynamics under the pricing measure are described by

$$dX(t) = \alpha\big(\mu - X(t)\big)dt + \sigma dW(t) + \kappa dq(t) \qquad [5]$$

where, α is the speed of mean reversion, μ is the level of mean reversion, σ is the price volatility, $W(t)$ is a Q-Brownian motion, κ is the proportional jump size and $dq(t)$ is a Poisson process. It is assumed that the mean-reverting process and the jump process are independent. The spot price at date T is described by

$$lnS(T) = f(T) + (lnS(T-t) - f(T-t))e^{-\alpha(T-t)} + \mu\big(1 - e^{-\alpha(T-t)}\big) + \sigma\sqrt{\frac{1-e^{-2\alpha(T-t)}}{2\alpha}}W(T-t) + J\big(\mu_j, \sigma_j\big)I_{(u_T<\Phi(T-t)} \qquad [6]$$

where, $J \sim N\big(\mu_j, \sigma_j\big)$, Φ is the jump frequency and u_T is a uniform (0,1) random variable. The indicator function $I_{(u_T<\Phi(T-t)}$ takes the value of 1 if the condition is true, which is when a jump occurs, and 0 otherwise, in which case the spot price is described by the mean-reverting process. When a jump occurs, its size is equal to the mean jump size $\bar{\kappa}$ plus a normally distributed random variable with standard deviation σ_j.

5.3. Model calibration

We estimate the parameters of the MRJD model as follows: firstly, we estimate the parameters of the deterministic seasonal function $f(t)$. We then consider the parameter estimation of the jump component using de-seasonalised prices and remove the identified jumps from the price series. Lastly, we estimate the parameters of the mean-reverting process from the filtered series, which contains de-seasonalised prices without jumps.

The parameters of the deterministic function $f(t)$ are estimated through Non-Linear Least Squares, using the logarithms of daily observations for the period 06/05/2015 - 01/04/2020, see Table 4.2. We remove seasonality from the daily series to obtain the de-seasonalised dataset.

We then turn to the estimation of the jump parameters Φ, $\bar{\kappa}$ and σ_j. We follow the methodology proposed by Clewlow and Strickland (2000), namely the Recursive Filter algorithm, where a jump is any log-return larger than three times the sample standard deviation. The algorithm is implemented as follows: firstly, we compute the sample standard deviation of log-returns. Any log-return larger than three times the sample standard deviation is considered a jump. Then, the identified jumps are removed from the data series and their respective log price is replaced by the average of the previous and the next log-price (see Nomikos and Andriosopoulos (2012)). We then move on to the second iteration where we compute the sample standard deviation of the filtered series, identify new jumps, and remove them from the price series. We repeat the process until no more jumps are identified. Finally, we estimate the jump frequency Φ (where $\Phi = \text{number of jump returns / time period of data}$), the average jump size of returns $\bar{\kappa}$ and the standard deviation of jump returns σ_j, see Table 4.2.

The three parameters of the mean reversion process, μ, α and σ are estimated via linear regression using the filtered dataset (price series without jumps)

$$Y(t) = a_1 + a_2 Y(t-1) + \varepsilon(t) \qquad [7]$$

where, $a_1 = \mu(1 - e^{-a\Delta t})$ and $a_2 = e^{-a\Delta t}$. From the estimates of a_1 and a_2 we obtain the annual estimates for a, μ and σ as follows

$$a = -\frac{\ln(a_2)}{\Delta t} \quad [8]$$

$$\mu = \frac{a_1}{(1-a_2)} \quad [9]$$

$$\sigma = \sigma_{\varepsilon(t)}\sqrt{\frac{2a}{(1-e^{-2a\Delta t})}} \quad [10]$$

The parameter estimation results, presented in Table 4.2, indicate a strong speed of mean reversion and a large volatility of 120%. However, the estimated volatility from the filtered series is substantially lower compared to the volatility of the unfiltered price series implied by the descriptive statistics. The estimated jump parameters suggest a daily jump frequency of 0.04, with a 40% daily standard deviation of jump returns.

Table 4.2. MRJD parameter estimation results

Seasonality estimates are obtained through non-linear least squares optimization; Daily jump parameters are obtained through the Recursive Filter algorithm; Annual estimates of the mean reversion level μ, mean reversion rate α and volatility σ are obtained through linear regression applied on the filtered series (de-seasonalised log spot prices without jumps).

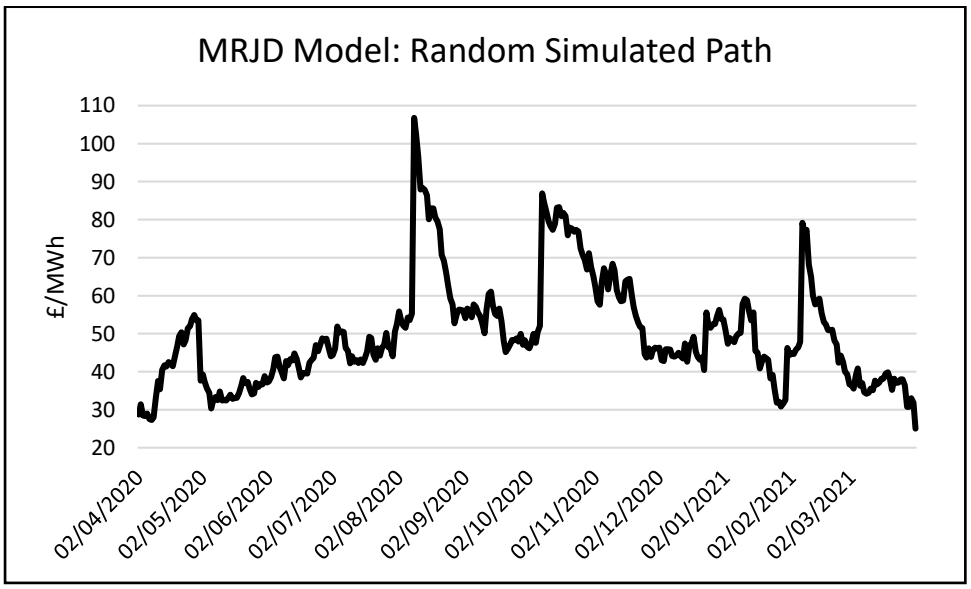
Seasonality Parameters		Jump Parameters		Mean-Reversion Parameters	
γ	0.2183	Φ_{Daily}	0.0458	μ	3.76
δ	3.2967	$\bar{\kappa}_{Daily}$	0.0596	α	13.85
		$\sigma_{j_{Daily}}$	0.4010	σ	1.20

Furthermore, we plot a random simulated spot price trajectory projection for one year implied by the estimated MRJD model, see Figure 4.3. The model captures the electricity features well, prices are mean reverting around a long run mean and the model appropriately simulates spikes at random times and at the correct frequency. We also notice that when a

jump occurs, prices return to their average mean level at a slower pace because the force of mean reversion is not high enough for the MRJD model (see Clewlow and Strickland (2000) where they simulate a price path using the MRJD model and the level of mean reversion is set to 2000). Despite this known drawback, the MRJD model suffices for our computational purposes.

Figure 4.3. Random simulated path of the MRJD model with seasonality

UK electricity spot price simulation for one year based on the estimation of the MRJD model with seasonality



5.4. Contracts for difference (CfD) valuation

We compute the value of the CfD at date 0 as defined in Equation (1). For the valuation of the CfD we use a mean reverting model with seasonality instead of the MRJD since jumps are short lived and do not have an effect on forward prices. The expression of the forward price is derived from the mean-reverting model as the expectation of the spot price at date t_j

$$F^{t_j}(0) = exp\left\{f(t_j) + \left(lnS(0) - f(0)\right)e^{-\alpha t_j} + \mu(1 - e^{-\alpha t_j}) + \frac{\sigma^2}{4\alpha}\left(1 - e^{-2\alpha t_j}\right)\right\} \qquad [11]$$

The seasonality coefficients are estimated using Equation (4) and are the same as the MRJD model. The speed of mean reversion a, the long run level of mean reversion μ and the volatility σ are estimated using Equation (7), which is applied on the unfiltered series (de-seasonalised log spot prices with jumps). The three parameters are obtained from Equations (8), (9) and (10), see Table 4.3 for the parameter estimation results. We note that both the speed of mean reversion and volatility are higher in the MR model estimation compared to the MRJD model estimation. This is expected since the linear regression is applied on the unfiltered data, meaning that the daily log spot price series includes jumps, which in turn leads to higher volatility and a stronger speed of mean reversion.

Table 4.3. Mean Reversion parameter estimation results

Seasonality estimates are obtained through non-linear least squares optimization; Annual estimates of the mean reversion level μ, mean reversion rate α and volatility σ are obtained through linear regression applied on the unfiltered series (de-seasonalised log spot prices with jumps).

Seasonality Parameters		Mean-Reversion Parameters	
γ	0.2183	μ	3.77
δ	3.2967	α	39.92
		σ	2.11

The value of the CfD at date 0 is defined as the discounted sum of the differences of the two legs

$$V_{swap}(0) = \sum_{j=1}^{q} B(0,T_i)\left[Strike\ Price - \ exp\left\{f(t_j) + \left(lnS(0) - f(0)\right)e^{-\alpha t_j} + \mu(1 - e^{-\alpha t_j}) + \frac{\sigma^2}{4\alpha}(1 - e^{-2\alpha t_j})\right\}\right] \quad [12]$$

The discount factor $B(0,T_i)$ is represented by the zero-coupon bond prices in the United Kingdom, known as gilt strips. The UK zero-coupon bond prices, presented in Table 4.4, are obtained from Tradeweb at date 0 and have yearly maturities.

Table 4.4. UK zero-coupon bond prices

Zero coupon bond prices in the United Kingdom maturing yearly, obtained at date zero (01/04/2020).

Maturity Year	Price
2021	99.909
2022	99.78
2023	99.66
2024	99.52
2025	99.35
2026	99.12
2027	98.80
2028	98.35
2029	97.74
2030	96.96
2031	96.02
2032	94.94
2033	93.78
2034	92.55
2035	91.29
2036	90.03
2037	88.80
2038	87.60
2039	86.46

Source: Tradeweb (https://reports.tradeweb.com/account/login/)

For each delivery year, offshore wind generators were assigned a specific strike price during the auction rounds. So far, generators have been awarded CfD contracts for six different delivery years: 2017/18, 2018/19, 2021/22, 2022/23, 2023/24 and 2024/25, see Table 4.5.

Our results, also presented in Table 4.5, confirm the government's incentives towards wind generators, given that the CfD value for each delivery year is not zero (the strike price should be set at £45.1 for the CfD to have a zero value at date zero). Additionally, we identify a remarkable decrease in the auction's strike prices over the various delivery years, a 67% drop from the first auction round (£119.89) to the third (£39.65), resulting from increased competition over the years in the auction rounds.

Table 4.5. CfD clearing auction strike prices and valuation results

Final strike prices for offshore wind generators which were set during the auctions for six different delivery years and their respective CfD valuation at date 0 based on the MR model.

Delivery Year	Strike Price £/MWh	CfD Value
2017/18	119.89	404,335
2018/19	114.39	373,020
2021/22	74.75	156,870
2022/23	57.5	65,044
2023/24	39.65	-28,506
2024/25	41.611	-18,125

The positive outcome of lower strike prices, is that generators receive reduced payments throughout their contract, resulting in an increased benefit for the consumer since the cost of the CfD scheme is passed on to consumers via a levy on energy bills. However, lower strike prices also indicate that the CfD scheme is no longer an incentive towards low-carbon generators but instead becomes a "support place" for generators to secure financing for their projects. This outcome could possibly result in a decline of interest from generators in entering the CfD scheme; even if generators were successful during the auction round and

awarded a CfD, they might choose not to sign the contract and instead deliver their produced electricity through merchant routes and hedge through the financial instruments that have existed for the last twenty years in electricity markets. Whilst the merchant route may still provide the desired outcome of new renewable generation deployment, it also means that consumers may not benefit from repayments when the reference price is higher than the strike price, which in turn means the government's target of a cost-effective deployment of low-carbon electricity will not be met (BEIS 2020).

5.5. Capacity option valuation

We compute the capacity option through a series of 365 daily European call options for one year, as defined in Equation (2). We choose the Monte Carlo method to price the strip of European call options as the Q-expectation at date 0, of the payoff at date T_j. We simulate 10,000 spot price trajectories using Equation (6) in its exponentiated form, for each different maturity of the 365 European options. We then approximate the value of each of the 365 European call options at date 0

$$C(0) = B(0, T_j) \sum_1^n \frac{\left(Max(0, S(T_j) - K\right)}{n} \qquad [13]$$

Here $B(0, T_j)$, is the discount factor represented by daily UK zero-coupon bond prices for one year; these are estimated through fixed increments interpolation from the UK zero-coupon bond price maturing in one year, obtained at date 0. The number of simulations, n, is set to 10,000.

The Monte Carlo valuation of the strip of daily European call options is implemented as follows: at each time step T_j, where $j = 1, 2, \ldots, 365$, we first compute the price of the option and then we average the simulated values of $S(T_j)$. At the next time step T_{j+1}, the average of

the simulated values $S(T_j)$ of the previous time step is used to compute the price of the option at date T_{j+1}. We repeat this process until we price the 365 daily European call options. The sum of the prices of the daily options will be the price of the capacity option.

We set the strike price, K, at three different price levels: 10%, 30% and 50% above the previous year's average spot electricity price, see Table 4.6. We then compute the prices of the 365 daily European call options for each strike price level.

Table 4.6. Capacity option strike price levels

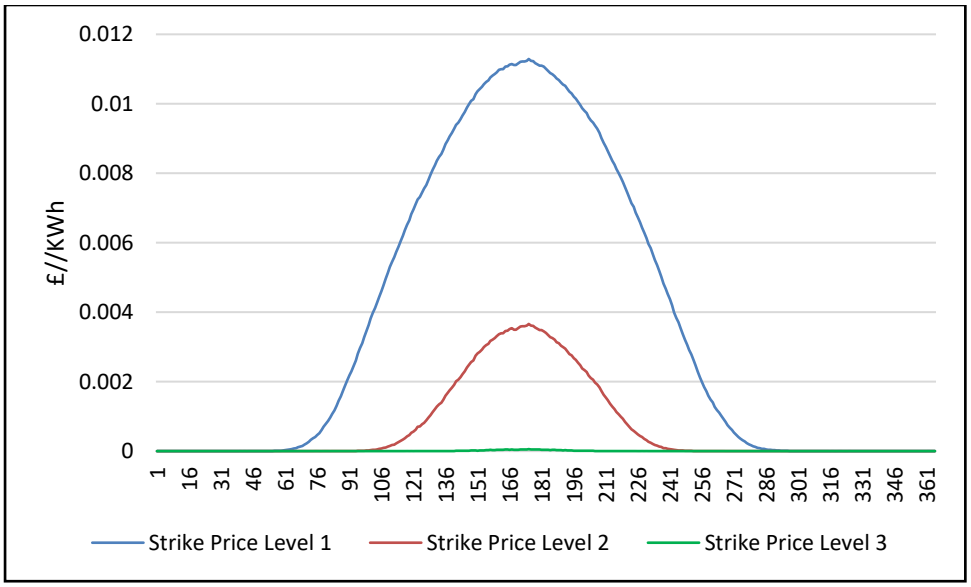
The strike price is set at three price levels: 10%, 30% and 50% above the previous year's average spot price which was £38.48/MWh.

	Strike Price Level	Strike Price £/MWh
Price Level 1	Strike +10%	£42.33
Price Level 2	Strike +30%	£50.02
Price Level 3	Strike +50%	£57.72

The results are presented in Figure 4.4, where the price of the 365 call options at the different strike price levels are displayed. We notice the seasonality effect on the prices of the daily European call options, while the value of the daily payoffs decreases with the increase of the strike price level, as expected. When the strike price is set at 10% above the previous year's average price, the daily payoffs reach a maximum value of around £0.011/KWh, then decrease to around £0.004/KWh when the strike price level is 30% above the previous year's average price, and finally the daily payoffs reach a maximum value of nearly zero, at £0.0001/KWh when the strike price is 50% above the previous year's average price.

Figure 4.4. Capacity option: daily prices for strike price level 1, 2 and 3

Daily payoffs of the 365 call options, presented in £/KWh when the strike price K is set at a level 10%, 30% and 50% above the previous year's average price.



Currently, the Great Britain Capacity Market scheme operates through competitive bidding at auctions, where successful generators will receive a monthly payment based on the clearing auction price. There have been fourteen auctions to date for nine delivery years: 2016/17, 2017/18, 2018/19, 2019/20, 2020/21, 2021/22, 2022/23, 2023/24 and 2024/25. The clearing auction prices for the different delivery years are presented in Table 4.7.

Under our proposed valuation methodology, the capacity option's price for the three strike price levels, which is the sum of the 365 daily European call options, is: £1.32/KWh for strike price level 1, £0.25/KWh for strike price level 2, and £0.002/KWh for strike price level 3.

The capacity option's price for strike price levels 2 and 3, is lower compared to the previous auction rounds held for the Great Britain Capacity Market. The capacity option's price for strike price level 1, is lower compared to most previous auction rounds, except for the 2019/20 T-1 auction and 2020/21 T-1 auction, where the price cleared at £0.77/KWh/Year and £1/KWh/Year, respectively. Lower prices for the Great Britain Capacity Market have a positive

outcome for the consumer, since generators will receive a lower monthly payment from the government, resulting in lower energy bills for consumers. At the same time the government ensures that supply will always meet demand, by exercising the option if a stress event occurs to cover any supply shortages.

Table 4.7. Great Britain Capacity Market clearing auction prices

Clearing auction prices for each delivery year presented in £/KWh.

Delivery Year	Auction Type	Clearing Price £/KWh/Year
2016/17	Transitional Capacity Auction	£27.50
2017/18	Early Capacity Auction	£6.95
2017/18	Transitional Capacity Auction	£45.00
2018/19	T-4 Auction	£19.40
2018/19	T-1 Auction	£6.00
2019/20	T-4 Auction	£18.00
2019/20	T-1 Auction	£0.77
2020/21	T-4 Auction	£22.50
2020/21	T-1 Auction	£1.00
2021/22	T-4 Auction	£8.40
2021/22	T-1 Auction	£45.00
2022/23	T-4 Auction	£6.44
2023/24	T-4 Auction	£15.97
2024/25	T-4 Auction	£18.00

Source: EMR Delivery Body, National Grid ESO

URL: https://www.emrdeliverybody.com/CM/Auction-Results-1.aspx

6. Conclusion

In this Chapter, we examined the new developments in the United Kingdom's electricity market and analysed in particular the Contracts for Difference scheme and the Great Britain Capacity Market scheme. We used a swap approach for the Contracts for Differences, a scheme which illuminates the government's incentives towards low carbon electricity generators. We recognized in the Great Britain Capacity Market, a series of European call options at different strike prices, reflecting the auction winning bids.

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Chapter 5. Conclusion

1. Final remarks

This thesis focuses on natural gas, Liquefied Natural Gas, and electricity markets, where the main significant changes that took place in recent years are addressed. We examine the European gas market, propose a valuation methodology in the LNG market, and analyse the new developments in the United Kingdom's electricity market, where we particularly focus on two government incentive schemes.

2. Main contributions

In Chapter 2, our contributions include the examination of the European gas market integration, over the recent period, as well as the revisit of the Theory of Storage in European natural gas markets. Our results confirm an increased market integration, both in the spot as well as in the forward market. We find that the British NBP no longer predicts the prices of the other European gas indexes, whereas the Dutch TTF predicts the prices of all European gas indexes in the Continent. We also recognize the validity of the Theory of Storage in the British and Dutch gas market.

In Chapter 3, we contribute to the literature by providing a valuation methodology for the rerouting option, which is an optionality attached to the new flexible short-term LNG contracts and exhibit that the buyer's P&L increases when a rerouting option is embedded in the purchasing contract. Lastly, we test the option's price sensitivity to the volatility in which we identify that a higher volatility has a positive effect on the rerouting option's price.

In Chapter 4, we address the new developments in the United Kingdom's electricity market and focus on two government incentivised schemes, namely the Contracts for

Difference scheme and the Great Britain Capacity Market scheme. We contribute to the literature by providing valuation methodologies for the two schemes. We demonstrate the government's incentive in the case of the Contracts for Difference scheme and propose to represent the Great Britain Capacity Market as a series of daily European call options for one year. Under our proposed methodology, the capacity option's price is lower than most of the previous auction rounds held for the Great Britain Capacity Market, which is beneficial for the consumer.

3. Ideas for future research

There are several interesting ideas for future research. The European market integration as well the Theory of Storage can be revisited in the future to include additional European gas indexes, as they develop in the years to come and become liquid enough to be included in the analysis. Additionally, it would be interesting to monitor the development of the Dutch TTF, in terms of a price setting hub in Europe as well as a European gas benchmark and investigate whether the British natural gas market will remain integrated with the rest of Continental Europe.

With the introduction of LNG freight Futures recently, one can incorporate them in the pricing of the rerouting option, addressed in Chapter 3, to better understand the role of transportation costs in cargo redirection. It will also be interesting to investigate the role of LNG in a global level and identify whether LNG is bringing the prices of different regions across the world closer together.

Renewables will continue to attract interest and investment in the future as the world moves to low carbon electricity markets. New financial products are already emerging to hedge the risk of renewables, because of their intermittent nature. Government policies and

incentivised schemes as well as new financial products related to renewables can be revisited in the future to identify and propose new valuation methodologies.