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Energy Markets and the Financial Environment

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Energy Markets and the Financial Environment

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Energy Markets and the Financial Environment

PhD thesis

to obtain the degree of PhD at the
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on the authority of the
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and in accordance with
the decision by the College of Deans.

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by

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List of Abbreviations, Acronyms, Initials, and Symbols

bbl	Barrel of oil
GHG	Greenhouse Gas
boe	Barrels of Oil Equivalent
bbl/d	Barrels per Calendar Day
Bcf	Billion Cubic Feet
Bcfe	Billion Cubic Feet of gas Equivalent
BS&W	Bottom Sediments of Water
Btu	British thermal unit
CO ₂	Carbon Dioxide
CPI	Consumer Price Index
Brent	Crude Oil from North Sea, Forties, Ekofisk, Oseberg, Brent, and Troll fields
cu. ft	Cubic Feet
DOE	Department Of Energy
IEA	International Energy Agency
kV	Kilovolt
KVA	Kilovolt-Ampere
KW	Kilowatt
KWh	Kilowatt-Hour
LOOP	Law Of One Price
MVA	Megavolt-Amperes
MW	Megawatts
MMbbl	Million barrels
MMboe	Million Barrels of Oil Equivalent
MMBtu	Million British Thermal Units
MMcf	Million Cubic Feet
MMcf/d	Million Cubic Feet per Day
Mtoe	Million tonnes of oil equivalent
Mbbl	Thousand Barrels
mboe	Thousand Barrels of Oil Equivalent
Mboe/d	Thousand Barrels of Oil Equivalent per Day
Mbbl/d	Thousand Barrels per Day
Mcf	Thousand Cubic Feet (of gas)
NTC	Net Transfer Capacity
OPEC	Organization of the Petroleum Exporting Countries

Toe	Tonnes of oil equivalent
Tcf	Trillion Cubic Feet
WTI	West Texas Intermediate

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Chapter 1

Introduction

1.Introduction

Energy is an indispensable component of the modern economy—and of life itself. Driving our cars, heating our homes, and charging our batteries all depend on energy availability. Energy is linked to economic growth (Chien-Chiang Lee, 2005; Narayan & Smyth, 2008) and has become a necessity (Belke et al., 2011). Uninterrupted and efficient availability of energy is crucial for economic expansion and prosperity. Historically, energy shocks have proven to disrupt economic activity and lead to periods of slow growth or recession (Hamilton, 1983; Mork et al., 1994). Energy is predominantly being derived by fossil fuels which usage contributes to climate change. Scientific evidence is overwhelmingly increasing that climate changes presents significant global risks and action should be taken (Stern, 2007). An ever-important challenge and dominant question in recent policy efforts and academic research and debate is what the best path would be to achieve both market efficiency and sustainability. Energy is a necessary input for industrial production as well as for consumers' everyday needs and amenities and thus has been in the forefront of the academic interest for decades. At the same time the fossil fuel nature of the vast sources of energy has weighted in climate change and accelerated the associated risks and costs. The needs of energy are increasing with economic growth and the mismatch between fossil energy resource supply and fossil energy resource demand are increasing the impact on climate and economies. Trade of energy resources is well globalized, however, restricted by geographic locations, storage and transmission limitations, transportation costs and changing supply and demand conditions. This thesis tackles some of the questions related to energy assets prices and markets, and policies' impact related to reducing carbon dioxide emissions. In particular, the issue of measuring market liquidity, the role of convenience yields in oil market spreads, the impact of interconnection on electricity prices, and the contribution of renewable and nuclear energy sources to fighting the climate crisis.

Prices of energy assets depend not only on their costs of extraction and transformation but also on the geographic segmentation of supply and demand, trade rules, speed and cost of trade, and market efficiency. Pricing accommodates the efficient allocation of resources that contribute to economic growth. Energy and financial markets help the discovery of prices and provide rapid estimates according to new information and changing conditions. With the use of market mechanisms and the liberalization of trade, economies have grown faster and energy consumption has increased. However, economic growth and increasing energy consumption has put a huge burden on the environment: The global temperature is increasing, and man-made carbon emissions are considered to be a significant factor. Both governments and institutions are making an effort to implement policies to reduce carbon emissions. For both researchers and policy makers, market efficiency and liquidity, the convergence of energy prices across geographical areas, and the combination of economic growth with an

environmentally sustainable present and future are themes of everyday life and determinants of the future of individual consumers and societies.

Pricing of energy assets depends on the underlying demand and supply conditions in the location in which trade takes place. Because physical assets are involved, there can be price imbalances which can be subject to arbitrage or due to friction costs. Two main energy assets, crude oil and electricity, have very distinct pricing and trade conditions. Crude oil is a raw substance that is used as an input to derive final products; it is traded across the world. Electricity is a final product for consumption that is expensive to store and trade across regions. Each energy asset has its own particular characteristics that are close to either the production or consumption parts of the value chain. Very recently during the Covid-19 pandemic crisis and the corresponding lockdowns enforced by government across the world, we have experienced an unprecedented energy demand shock. In the short term that affected predominantly global oil markets, which even reached negative price for one day in the US, as demand for fuel plummeted. In the longer term this can have important repercussions for carbon based products as well as energy demand in general. In the aftermath of the first wave of Covid-19 many of the largest energy companies announced their plans for a partial shift to renewable energy as well as their commitment to achieve carbon neutrality in the next 20-40 years.

Crude oil has evolved from being a production factor of local benefit to being the most-traded global commodity; its strategic importance has raised tensions among countries. During volatile periods (most recently, 2009 and 2014) crude oil prices moved up and down by more than 50% within a few months (see Figure 1.1). Such price volatility increases both economic and geopolitical risks. The more volatile and uncertain the price of crude oil, the worse for the economy. When consumers and firms face more difficulties to forecast their expenses with certainty, they may limit their risks by reducing their economic activity. This reduction of confidence decreases potential growth. As crude oil has become a crucial input for industries and consumers, financial markets have adapted to its drivers; they have accommodated its trade through exchanges to increase communication and efficiency, allowing products to trade freely and find their way to the highest bidders. During the last 15 years the global oil landscape has changed with the boom in shale oil production. Supply and demand dynamics as well as trade routes have shifted. US has more than doubled its oil production within 10 years and OPEC has responded by changing its policy of how to impact the global oil the market.

Although we would expect the price of a global commodity to be the same across locations, we observe this is not always true. Two of the most traded crude oil products, Brent and West Texas Intermediate (WTI), experienced a long period of divergence with a very volatile price spread. This volatility is significant for a number of reasons. First, it challenges the long-term relationship that academics and practitioners have established over the past four decades. Second, it shows that markets and the global economy may be more sensitive to changes in fundamental factors than previously

thought. Third, it affects pricing across the value chain of energy, given that the two products are used as a benchmark. Fourth, it decreases the confidence of investors who thought these scenarios were unlikely.

Together, these factors motivate us to be interested in knowing more about how to explain the differences in prices between two geographically segregated markets of a similar product. In contrast to crude oil, electricity is the most direct form of energy used continuously across the world. Currently, Europe is undergoing a process of improving the mechanisms of electricity market integration. Market integration is important not only for efficiency and direct economic benefits but also for reducing the risk of energy dependency (Figure 1.2). Beginning with the European Parliament's 96/92/EC Directive and later with its 2003/54/EC and 2009/72/EC Directives, European countries enhanced their regulatory frameworks to liberalize their national markets and create an internal electricity market. Given the benefits of full market integration, the scarcity of literature on the topic poses a challenge. Many countries in Europe have created power exchanges to improve their internal markets and boost competition across borders. The main elements of trading are liquidity and availability. Liquidity and volume of trading in these exchange hubs is gradually increasing. Moreover, transmission capacity across borders is limited, because electricity is an asset that cannot be stored economically, and every exchange trade corresponds to a physical delivery. There must be enough transmission capacity to accommodate potential supply and demand between countries.

Figure 1.1: Oil price spreads and volatility

Notes: This figure plots the spot prices of Brent and WTI, and their spread in \$/barrel, indicated in the left-hand axes. It also plots the volatility of Brent and WTI in % indicated in the right-hand axes. We are limiting the chart to the period we are focusing in Chapter 3. We use the US Energy Information Administration (EIA) as a source for the Brent and WTI prices published in their website: <https://www.eia.gov/petroleum/data.php#prices>

Figure 1.2: European energy dependency

Notes: In this figure we plot the European Union and Euro area countries energy imports and dependency as a percentage as published by Eurostat. We use all available data which start at 1990. Both axes represent the 2 groups where columns are left hand side and lines right hand side.

Although pricing, trade, and market structure are crucial for efficient allocation of resources and economic growth, there is growing awareness of the consequences of increasing energy consumption using carbon-based fuels. Carbon dioxide emissions, which have tripled over the past decades (see Figure 1.3), account for the largest amount of global aggregate greenhouse emissions. These emissions are mostly an effect of consuming fossil fuels. Energy consumption is the foremost driver of both carbon dioxide emissions and economic growth. By using numerous methodologies and perspectives, researchers have investigated the relationships between energy and economic development and the links between energy and carbon dioxide emissions. Although there may be an inevitable cost of reducing energy consumption, especially in the short term, there are also alternative ways of reducing carbon emissions. Both nuclear generation and renewable power generation diversify the energy mix and mitigate carbon dioxide emissions. In an effort to coordinate actions across governments, the first global action to limit and reserve global warming took place in Paris in 2015 with the 21st Conference of Parties of the United Nations Framework Convention on Climate Change (UNFCCC) Agreement. Most² United Nations members signed the agreement, and countries committed to achieving specific targets.

By understanding the potential impact of using renewable and nuclear energy on carbon emissions, researchers can inform governments about how to operationalize their carbon emissions targets by applying appropriate mixes of energy sources. They also can compare the costs and benefits of energy transitions according to various scenarios.

² 175 of 197 countries ratified as of April 2018.

Figure 1.3: Energy consumption and carbon dioxide emissions

Source: *BP Statistical Review 2017*

In the beginning of the introduction we discussed the importance of energy pricing for the global economy as well as the impact of fossil fuels as energy source on CO₂ emissions and climate change risks. Energy prices affect the global economic environment and a better understanding of their interrelationships and their respective markets is contributing in the academic knowledge and potential consequent policy initiatives. This thesis consists of four research pieces on some of the most important elements of energy markets and contributes across topics. Chapter 2 analyzes the impact of liquidity in energy stocks and proposes a new methodological approach to examining liquidity measures and interrelationships. Chapter 3 investigates market fundamental factors in the determination of Brent–WTI crude oil price spreads, by linking common drivers of convenience yields and price spreads such as inventories, price volatility, and interest rates. Chapter 4 analyzes the effect of changes in net transfer capacities (maximum cross-border power that can be transmitted between two countries) on the integration of European electricity markets. Chapter 5 investigates the relationships between carbon dioxide (CO₂) emissions, nuclear energy generation, renewable energy generation, and GDP growth, using a panel of 61 countries. Chapter 6 concludes.

Chapter 2 studies the interrelationships of liquidity and oil prices with the financial market, and with energy stocks in particular. Liquidity of energy markets is an important prerequisite of efficient markets. Governments and global institutions are increasing their efforts to strengthen confidence in markets by dealing with crises periods (such as 2008), fostering trade, and boosting the economy. Although liquidity has been in the spotlight for the past two decades, liquidity in the energy sector is still at an early stage of analysis. There is no widely accepted definition of liquidity. At high levels,

liquidity is thought to ease and speed trade. However, the measurement of ease and speed of trade is not straightforward; liquidity measures used by academics and practitioners capture only parts, or different dimensions, of liquidity. For instance, turnover—the gross amount of trade that occurs at a particular point of time—is an intuitive measure of liquidity. It is a necessary aspect of liquidity, but it does not necessarily imply a low cost of trade. Another measure of liquidity is the cost of immediate buy and sell of an asset, including compensation of the intermediary who participates in the trade. We investigate the interrelationships among various dimensions of liquidity, model them in a structure that is appealing theoretically, and compare them to previous literature.

To investigate liquidity in energy stocks, we focus on *bid-ask spread*, defined as the difference between the price at which an asset can be bought and sold at the same time. The main idea of our model is that in a competitive intermediaries' market, some liquidity measures precede others. We use a vector autoregression (VAR) to account for the highly correlated patterns of liquidity, and we propose a causality pattern from trading activity to price impact and from both to spread. We also add oil prices as an important determinant of energy stocks. To test our hypotheses, we use a structural VAR in which we allow the market maker to observe the information on trading activity and price impact simultaneously. This implies that although turnover depends on previous values of all liquidity measures, it does not do so simultaneously—whereas bid-ask spread depends on both previous and contemporaneous values of all liquidity measures.

In our main specification, we find that lagged values of all liquidity measures are important for explaining each other. This is an important outcome, because it verifies our theoretical assumptions and confirms previous literature. Moreover, the contemporaneous values of turnover, price impact, and oil price all significantly affect spread. Our main hypothesis is that dealers observe current trends and adapt their spread quotes accordingly. When we separate our sample into sub-periods, we find that varying characteristics apply during varying periods. Trading activity is a far more important determinant of price spreads during turbulent times (e.g., January 2008–August 2009) compared with “normal” periods. The impact in such periods is five times greater; trading during credit and illiquid times is much riskier for intermediaries, and they demand higher spreads as compensation.

Chapter 2 makes three main contributions. First, it examines liquidity of the energy sector and links theoretical and empirical findings in literature to a diverse data set. Second, it proposes a new intermediary perspective to explain the interrelationships of various aspects of liquidity in which market makers receive information and manage their risks accordingly. Third, it investigates sub-groups and sub-periods that offer interesting insights about intermediaries' behavior.

Since the publication of our study in 2013,³ there have been some significant developments in both energy and financial markets. After years of oil price volatility, prices had been stabilizing for a long period; they were at high levels from 2011 to 2014, which allowed producers (especially US producers) to use technical innovations and industrialize shale production to increase oil production. From 2014 to 2015, there was a dramatic drop in oil prices caused by excess production, significant changes in the oil industry and geopolitical shifts in which the Organization of Petroleum Exporting Countries (OPEC) and Russia came closer in their budget needs for higher oil prices. The purpose of this chapter is to contribute to knowledge and market understanding by linking studies of this issue that have evolved separately. It is positive that a diverse audience of researchers within both liquidity-related literature (Panayi et al., 2015; Sabet & Heaney, 2015) and financial markets and industry literature (Ammar and Eling, 2015; Zheng & Su, 2017) have noticed and appreciated the topic. There is also continued interest in the effects of oil prices on stocks and firm performance (Teixeira et al., 2017; Waheed et al., 2017) as well as liquidity, volatility, and market interrelationships (Cunado et al., 2015; Ratti & Vespignani, 2015)

In Chapter 3, we discuss and analyze the aforementioned significant changes in the oil markets; we study energy market fundamentals as determinants of the Brent–WTI crude oil price spread. During the late 2000s, oil prices reached unprecedented levels; US \$100 dollars per barrel was quite common. These high prices were matched by excessive uncertainty and volatility; high prices triggered production from new and less-utilized areas and fostered new techniques to reach hydrocarbons that previously were regarded as not economical. Ultra-deep offshore wells were built and unconventional projects worth billions of dollars were initiated. These developments disturbed prices and changed decades-long oil-trade flows. One remarkable change was that the prices of two of the main benchmarks for pricing crude oil diverged to an unprecedented degree. For decades, there had been a minimal price spread between Brent and WTI; however, the sharp increase in prices, new production, and the consequent trade and pricing impacts caused two commodities of very similar substance to be divergently priced. Although such divergence seems to violate the *law of one price* (LOOP), whereby the same product/commodity has the same price across markets adjusted for transportation costs if there are no barriers to trade, it persisted for a long period.

In Chapter 3, we investigate the underlying reasons that may help explain the Brent–WTI spread, using storage theory insights and testing the hypothesis that fundamental factors that affect convenience yields also may influence price spreads. The term *convenience yield* refers to the price for the benefit of physically holding the asset rather than making a future promise of delivery and the possibility of making use of the asset the moment it is wanted. When future contract prices of a

³ Konstantinos Sklavos, Lammertjan Dam, and Bert Scholtens. (2013). The liquidity of energy stocks. *Energy Economics*, 38:168–175.

commodity are below the expected future spot prices, convenience yields are larger than the costs of carry and the market is considered to be in *backwardation*. If it is the other way round, the market is in *contango*. The larger the backwardation, the more significant the yield implied for the convenience of physically holding the commodity. Therefore, there may be a certain preference for having oil in storage tanks against a future promise of delivery of the same quantity. Global investors are able to trade Brent and WTI contracts in large volumes within a liquid market. However, the actual physical delivery of the commodity from one continent to another takes weeks. The costs involved also depend on factors such as availability of transportation means, regional demand, and supply forces. Although build-up of inventories would pay off investors who trade between the two markets, uncertainty, volatility, and costs may inhibit them from taking the risk. The difference between *spot prices* and *futures prices*—which can be interpreted as the compensation for the risk of not withholding the commodity—is the underlying convenience yield after storage costs have been taken into account.

During the early 2000s in the US, shale oil development started to take place and by the end of the decade technological advancements and investments in the sector led to the shale oil revolution. While shale oil extraction is old, a combination of technology improvements and high oil prices created an environment that shale oil extraction thrived and transformed the US and global oil industry. Growth of shale oil production has been explosive and has placed US in a position targeting energy independence. US field oil production increased from about 5 million barrels per day during 2007 to about 12.2 million barrels per day during 2019.

We find some differences and some similarities between convenience yields of Brent and WTI crude oil. Inventories affect WTI convenience yields over horizons of three or more months, but they do not affect Brent convenience yields, because Brent has more flexible logistics with tankers that quickly connect the fields in North Sea to the global marketplace. Volatility affects both Brent and WTI across all horizons, with an increasing rate for longer horizons. Interest rates are insignificant over horizons of less than three months.

Price spreads between Brent and WTI crude can be explained by differences in their inventories and volatility. When US inventories increase relative to those of the UK and Norway, the price spread between Brent and WTI increases. Moreover, the larger the volatility of Brent compared to WTI, the larger the price spread, in terms of spot prices and the short term. However, when we account for differences in futures prices for one- or two-month horizons, we find the Brent–WTI spread generally is no longer related to fundamental factors; for future price spreads of three months or longer, fundamentals seem to explain price spreads, implying that short-term futures prices are taking into account fundamentals and this fades away over time.

In the past 20 years, many member countries of the European Union (EU) have created power exchanges to improve both internal markets and the welfare of European citizens. In Chapter 4, we

study electricity price integration and the role that net transfer capacities play. Twenty years ago, the electricity sector was a highly vertically integrated industry in which regulators defined the prices. This typical model depended on an evaluation of generation costs and a non-competitive market. It was often built by public organizations because of the failure of the market to finance such projects. The benefits were stable electricity prices at the cost of reduced competition. Since then, many countries, and most importantly the European market, have promoted deregulation and competition in both the generation and supply industries.

The shift from vertical national monopolies in the power markets to more competitive structures has been envisioned as a crucial element of European market integration. To foster this shift, EU countries have agreed to take a more liberalized approach to the production, networking, and wholesale or retail distribution of electric power. There are different perspectives on how to assess and implement liberalization in the energy market. Domanico (2007) provides a detailed overview of regulatory results, internal market concentration, and risks that may arise from the liberalization process. Green et al. (2006) analyze benchmarks for five areas (market design, market power, regulation, EU enlargement, and sustainability) relevant to progress in EU electricity-sector liberalization. A significant driver for this alteration is that prices are no longer defined by a regulator but are based on the supply and demand characteristics of the market. This structure creates more efficiency by enabling competition but also it has created at times large volatility of prices. The non-storable nature of electricity causes a high chance of supply and demand imbalances and results in price volatility. Demand in the short term is inelastic, implying that only elastic supply can buffer and reduce the probability of extreme price spikes. Transmission limitations may be a significant factor of an inelastic supply: The larger the pool of the market and the better the interconnections, the more elastic the supply of electricity. In this context, the motivation and will to create a single electricity market in Europe is two-fold: the first is to reduce the average price for the consumer, and the second is to allocate electricity more efficiently, with less price shock. In this regard, Creti et al. (2010) calls for more empirical studies of market integration. With regard to price integration, researchers are not in full agreement. Zachmann (2008) uses principal component analysis to reject full integration for the period of 2002 to 2006, whereas Lindstrom and Regland (2012) use six European electricity prices to model the nature of the prices; they find that bilateral dependencies vary from independent to strongly dependent. Price differences in two markets without restrictions of trade or technical limitation ought to converge to the transportation costs after account for transactional and tax costs.

Starting from this basic principle, we build our model such that price differences may be affected by transmission capacity limitations. When the price between two markets is large, participants are forced to seek electricity from the less expensive market, which creates demand for electricity from the high-priced to the low-priced market. However, if this demand is extremely large, there may be a limitation on the quantity that can be transferred at each point of time. We use prices of seven power

exchanges, representing 11 European countries and including all large economies. For our model, we collect data on net transfer capacities from the European Network of Transmission System Operators for Electricity (ENTSOE) and a number of demand and supply variables. Our model is an empirical evaluation of whether cross-border capacities of electricity transmission affect electricity price differences among countries in Europe. We find that transmission constraints do affect electricity prices among European power markets, with the implication that transmission-capacity restrictions do not allow price convergence to the LOOP. These findings are in line with theoretical studies (Borenstein et al., 2000; Younes & Ilic, 1999) and previous findings (Abrell & Weigt, 2012; Gugler et al., 2016; Mulder & Scholtens, 2013).

Chapter 4 contributes to literature in two ways. First, to our knowledge, our study is the first to directly model net transfer capacities across European countries as a determinant of electricity price disequilibrium. Second, to examine the transmission capacity effect on price differences, we construct a database for transfer capacities between seven exchanges involving 11 countries in Europe. These countries represent the majority of economic activity in Europe. We combine two databases and hand-correct missing values. Our results argue in support of undertaking larger initiatives in infrastructure investment to achieve higher market integration.

The benefits of a fully integrated market are significant. In a report to the European Commission, Booz & Co. et al. (2013) estimate these benefits can be in the range of €12.5 billion to €40 billion per year. In line with studies that recommend better use of existing grid infrastructures (Meeus et al., 2005), we find that expanding infrastructure can reduce price differences; although investments are necessary, existing regulations cannot adequately coordinate cross-border transmission investments. Balancing of concerns aggregates supply and demand not only at one period of time but also second by second at each location of the network (Verhaegen et al., 2006). In this study, we do not investigate market structure and coupling considerations; we leave it to future researchers to examine how market design, in combination with capacity constraints, can improve efficiency and integrate regional and national electricity markets.

As worldwide energy consumption has increased to satisfy the needs of the modern lifestyles of more and more people, carbon dioxide emissions also have increased. In Chapter 5, we investigate the roles of renewable and nuclear power in reducing CO₂ emissions. The reason behind the dramatic surge in anthropogenic greenhouse gas emissions is that during the last century the world used conventional fossil fuels as the driving force for energy production. Coal, oil, and natural gas are still the main sources of energy on the planet. However, conventional fuels are becoming sparser, more expensive, and dirtier. Whereas decarbonization of global energy production has many implications (such as energy security and competition), in the years to come the most prevalent and urgent action will be the reduction of global emissions. The increasing of the temperature as the result of burning

fossil fuels worsens both environmental and human health, directly and indirectly (see Haines et al., 2006). Climate change also has economic costs: Tol (2002) estimates the cost to be up to 3% of global GDP for a 1°C degree rise in temperature, including both positive and negative impacts (i.e., some countries may benefit). The target of countries and institutions is to mitigate carbon emissions. Sims et al. (2003) broadly categorizes such mitigations as: (1) more efficient fossil fuel conversion, (2) more use of low-carbon fossil fuels, (3) decarbonization of fossil fuels, (4) increase in the use of renewables, and (5) increase in the use of nuclear power.

A number of countries have or are planning to set up policies to decrease the impact of fossil fuels by incorporating alternative energy sources, predominantly renewable energy. In Chapter 5, we investigate the claim that use of nuclear and renewable energy reduces carbon emissions. The claim implies perfect substitution of technologies, in which technologies low in carbon emissions simply replace technologies high in these emissions—that is, fossil fuels. However, more nuclear or renewable production does not necessarily imply fewer carbon emissions if total energy consumption increases; there may be imperfect substitution (Berndt & Wood, 1979). To disentangle the effects attributable to energy mix and those attributable to increasing (or decreasing) energy consumption, we use a scaling approach such that the dependent variable is a measure of carbon intensity. This helps us disentangle two different effects that may push the absolute level of carbon emissions in different directions. This is not typical of related literature, which tends to use energy consumption as just one explanatory variable of carbon emissions. With this measure, we introduce a new conceptual approach to analyzing the mitigation of carbon emissions. By identifying the separate effects of nuclear and renewable consumption on carbon emissions via carbon intensity, we arrive at more informed analysis and assessment of whether a country's increase or decrease in energy consumption and carbon emissions is the result of nuclear and/or renewable energy use.

There is extensive literature on the interrelationships between carbon emissions, economic development, energy use, renewable power, and nuclear power (Apergis & Payne, 2010; Niu et al., 2011; Wolde-Rufael & Menyah, 2010). In Chapter 5, we analyze these from an energy-usage constituent's point of view and scale both the variables with the energy unit. This transforms into a new model in which carbon emissions depend on the proportion of nuclear and renewable energy in the energy mix, isolating energy use growth from the energy mix effect. With this structure, we find that both renewable and nuclear power reduce carbon emissions. Studies have disputed both effects, or found one or the other to be more effective; for example, Apergis et al (2010) finds a significant negative link between carbon emissions and nuclear power and a significantly positive link between carbon emissions and renewable power. However, we find that CO₂ emissions per energy unit are reduced when we add either renewables or nuclear power to the energy mix, and the results are robust under all specifications and controls.

We argue that the reason for this clear result is the disentangling of the effects of carbon intensity and energy intensity of an economy. Our results do *not* imply that countries that increase their renewable and nuclear energy decrease their aggregate CO₂ emissions, because they may increase their primary energy output overall. However, given that they reduce their carbon emissions per energy unit, we feel it is an interesting result and tool in the discussion. Two questions arise: Can we reduce energy use in total (i.e., conserve energy)? Can we reduce carbon emissions per energy unit (i.e., improve the energy mix)? These are, after all, two different things. In Chapter 5, we provide a new conceptual model to investigate the impact of renewable and nuclear power on carbon emissions and better identify the policies to be pursued. We also test the second question and find that renewable and nuclear power reduce carbon emissions to a similar degree. On average, a 1% increase of renewables in the energy mix has a similar effect on reducing CO₂ emissions as a 1% increase in nuclear power. Notably, we find this result for a sample of 61 countries, including the largest economies in the world (both nuclear and non-nuclear), even though previous studies have found contradictory results with regard to the effectiveness of either energy source in reducing carbon emissions.

This thesis focuses on four challenging questions in the energy sector and financial markets. It consists of four essays that investigate energy prices, markets, and carbon impact of the energy mix. More specifically it deals with the questions:

- 1) How can we measure liquidity, what changes during periods of illiquidity, and what is the role of oil price?
- 2) Do fundamental factors related to convenience yields affect the Brent–WTI crude oil spot- price spread?
- 3) Will electricity prices in Europe move closer with increases in cross-border transmission capacity?
- 4) How do renewable and nuclear power generation contribute to mitigating CO₂ emissions?

In the remainder of this thesis, these questions will be addressed.

Chapter 2

The Liquidity of Energy Stocks⁴

⁴ This Chapter is published as Sklavos, K., Dam, L., and Scholtens, B. (2013). The liquidity of energy stocks. *Energy Economics*, 38, 168-175.

2. The Liquidity of Energy Stocks

2.1 Introduction⁵

Liquidity is an important feature of energy markets. For example, Woo (2001) argues that the lack of liquidity played a major role in the black-outs and price spikes in California's electricity market in 2000-2001. Deng and Oren (2006) suggest that liquidity of energy markets is a precondition for increasing energy efficiency. In this study we focus on stock market liquidity in the energy sector. Energy constitutes a fundamental part of economic development, environmental sustainability and becomes increasingly expensive and scarce (Hamilton, 2008; IEA, 2010). In addition, there is increasing interest in trading liquidity (ease and speed of trading assets). While liquidity has received relatively strong attention the last two decades (Amihud et al., 2005), liquidity in the energy sector is still at an early stage. However, institutions and governments want to foster trade and boost confidence in global markets by avoiding or appropriately dealing with crises periods such as the liquidity crises of 2008 and 2011. A precondition for proper management, development and allocation of resources is an efficient capital market. A key element of efficient capital markets is the existence of liquidity. Both the prominence of energy assets in economic development and of liquidity in financial markets render it important to develop an understanding of what drives liquidity of energy stocks and how it varies over time.

While liquidity increasingly is being regarded as a key feature of markets, there is little agreement on how it can be measured (Sarr and Lybec, 2002). Liquidity is usually defined as the ease and speed of trade, the volume or quantity of trading units per period, or the impact trading has on prices and the cost of trading (Huberman and Halka, 2001; Goyenko et al. 2009). Each of these measures reveals different elements of liquidity. From the market maker's perspective, the spread (cost of

⁵ Since the publication of our study in 2013, there have been some significant developments in both energy and financial markets. After years of oil price volatility, prices had been stabilizing for a long period; they were at high levels from 2011 to 2014, which allowed producers (especially US producers) to use technical innovations and industrialize shale production to increase oil production. From 2014 to 2015, there was a dramatic drop in oil prices caused by excess production, significant changes in the oil industry and geopolitical shifts in which the Organization of Petroleum Exporting Countries (OPEC) and Russia came closer in their budget needs for higher oil prices. The purpose of this chapter is to contribute to knowledge and market understanding by linking studies of this issue that have evolved separately. It is positive that a diverse audience of researchers within both liquidity-related literature (Panayi et al., 2015; Sabet & Heaney, 2015) and financial markets and industry literature (Ammar and Eling, 2015; Zheng & Su, 2017) have noticed and appreciated the topic. There is also continued interest in the effects of oil prices on stocks and firm performance (Teixeira et al., 2017; Waheed et al., 2017) as well as liquidity, volatility, and market interrelationships (Cunado et al., 2015; Ratti & Vespignani, 2015)

immediacy for investors) is the compensation for the realization of a transaction. Thus, the reward for the market maker is the cost for the trader. Intermediaries balance demand and supply and serve a market clearing role. They can also hold inventories to help clear markets (Easley and O'Hara, 1987 & 1992). Liquidity providers may face costly supply and demand shocks. Thanks to clearing resulting from their services, markets can reach equilibrium faster and less costly than through direct exchange. As such, intermediaries exist due to the lower costs they create (Freixas and Rochet, 1997).

Energy liquidity has received little attention in the literature so far. Several studies deal with the impact of oil shocks on the economy or asset markets (Hamilton, 1983; Jones and Kaul, 1996). Others are interested in the volatility of oil and gas markets (Pindyck, 2003) or the risk factors characterizing oil and gas stocks (Sadorsky, 2001; Scholtens and Wang, 2008; Scholtens and Yurtsever, 2012). In addition, other studies suggest that commodity price variability affects macroeconomic variables (Hammoudeh and Yuan, 2008), especially oil after the 1973 crisis (Regnier 2007). Furthermore, this variability seems to exhibit a high degree of persistence (Ng and Ruge-Murcia, 2000). Chambers and Bailey (1996) assign this persistence to production shocks that are serially correlated. Fleming and Ostdiek (1999) find that spot volatility increases after the introduction of crude oil futures and they also suggest an inverse relationship between spot market volatility and oil futures.

To come to grips with liquidity in energy markets we focus on the bid-ask spread, defined as the difference between the price we can buy and sell an asset at the same time. In principle, the bid-ask spread can reflect both the level of competition between intermediaries and the relative liquidity of the asset. There are strong reasons to believe that a relatively liquid market results in a competitive environment for the intermediaries. Demsetz (1968) categorizes the main drivers as a) rivalry for the specialist's job, b) competing markets, c) individual investors submitting limit orders, d) floor traders who may bypass the specialist by crossing buy and sell orders themselves, and e) other specialists. If we assume that there are competitive conditions in the market for intermediaries then the bid ask spread would be characterized only by the risk (asymmetric information) and the cost (inventory or waiting costs) the intermediary bears by interfering with the transaction. Since we assume a competitive environment between the intermediaries, an implicit assumption in our study is that the observed spread should coincide with the costs of the participants (marginal costs equal marginal revenues) and that there are no oligopolistic profits. This allows us to test our model directly without having to account for potential profits from a dominant position of the intermediary.

In this study, we are particularly interested in the characteristics and interdependencies between different liquidity measures in the energy industry. Our focus on the energy industry is motivated by the strong relationship between the energy sector and economic growth (Stern, 1993; Yu and Hwang, 1984). We want to find out how liquidity behaves with energy companies, how different liquidity measures interact and what we can conclude regarding the role of market makers. We will also include

oil prices as a potential determinant of the liquidity of energy stocks. For example, Sadorsky (2001) finds that oil price is a significant risk factor for Canadian oil and gas stocks' returns. Henriques and Sadorsky (2008) find that oil prices affect stock prices of alternative energy companies as well. We will use the oil and gas sector of the NYSE, measure its liquidity proxies, and model them as a system of equations. We use companies that are related to oil and that includes producers, refiners, distributors of oil and gas and services companies in these sectors. The modelling of the liquidity measures enables us to understand how intermediaries value their risks and, consequently, price their services. We will distinguish between low and high traded firms and focus on differences in their liquidity characteristics. Finally, we compare our findings with empirical and theoretical market microstructure studies. The main idea behind our model is that when there is a competitive intermediaries market, some liquidity measures may precede others. Spread of a stock price is considered as the compensation for trading this stock for the intermediaries. Its pricing determination (how large the Spread will be) may be affected by their risks to be involved in this transaction. As financial intermediaries they will weight their costs (risks) and benefits (Spread). The higher their perceived risks the higher the Spreads they demand. Hence we argue that other liquidity measures (Turnover and Price Impact) are risks for the intermediaries and they should affect the Spread determination. On the other hand, the changes in Spread should be less relevant for determining Turnover and Price Impact due to the magnitude of the volatility of returns compared to the Spread. While Spread may change some decimal percentage points daily, this may be a small portion of whole percentage differences in prices (a typical trader would be less interested in transacting due to a small Spread difference affecting the buy and sell than an intermediary to whom these positions induce high potential losses and gains (uncertainty)). More specifically, we assume that since the spread is determined according to the costs of the intermediaries, it depends on the contemporaneous trading activity and price impact. We use a Vector Auto-Regression to capture the highly correlated patterns of liquidity, and propose causality from trading activity to price impact and from both of them to spread. We add oil prices to find out whether they affect the relationship between the liquidity variables, considering Oil as a macroeconomic factor which is particularly important for energy stocks. We find this causality pattern to be significant. Oil prices also contemporaneously affect two of the three liquidity measures, namely turnover and spread. Another finding of our analysis is that trading activity as measured by turnover is important and more traded stocks are less sensitive to changes in liquidity.

The structure of the remainder of this paper is as follows. In the second section we discuss liquidity and liquidity measures. Section three goes into the methodology and introduces the models we will use to come to grips with the dynamics of liquidity. The data are presented in section 4. We report and discuss our results in section five. Section six concludes.

2.2 Literature Review

We want to investigate the dynamics of different liquidity measures for energy stocks. Especially tradable assets are persistent and periods of low and high return volatility appear to be clustered. This has been examined extensively with autoregressive models, such as GARCH, i.e. Generalized Autoregressive Conditional Heteroskedasticity (Engle, 1982; Bollerslev, 1986). These models are used for the analysis of energy markets as well. For example, Ewing et al. (2002) use a multivariate GARCH to investigate the volatility transmission in the oil and gas markets. Hammoudeh and Yuan (2008) examine metal price volatilities in the presence of oil shocks using three variations of GARCH models. Sanin and Violante (2009) and Chevallier (2009) use these models to examine the relationship between carbon futures and macroeconomic conditions. Other studies focus on the empirical connection between volatility and liquidity. Hasbrouck and Seppi (2001) find important cross-firm factors in returns, order flows and market liquidity (see also Chordia et al., 2000; Domowitz et al., 2005). Furthermore, volatility and liquidity both appear to have time-varying properties. For volatility this property is more widely accepted but some researchers suggest that it also characterizes liquidity. For example, Chordia et. al. (2000) find an asymmetric response of bid-ask spreads to market movements: Spreads increase sharply in bearish markets and decrease marginally in bullish markets. This pattern is similar to that of volatility and its asymmetric response to shocks. Also many studies have discussed a commonality pattern along liquidity measures, returns and volatility (Amihud & Mendelson 1986; Chordia et al., 2005; Roll et al. 2007). Roll et al. (2007) use a Granger causality framework and find bilateral causality between liquidity measures and the futures-cash basis. Korajczyk and Sadka (2008) use a latent factor model and find commonality across assets and across measures of liquidity. In our study, we will first examine the clustering behavior of the individual liquidity measures in order to justify the use of a Vector Autoregressive model. This enables us to model each of the series appropriately. This can result in new insights in the underlying reasons of firm behavior.

Furthermore, the role of commodity prices in the energy sector is very important. Oil price shocks can lead to increases in wages and general price levels as well as to real output drops (Burbidge and Harrison, 1984). Especially crude oil prices affect global trade and the international economy. The two largest markets in which crude oil contracts are traded are the NYMEX (New York Mercantile Exchange) and the IPE (International Petroleum Exchange). Since our focus is on the NYSE and due to the links of the exchanges (NYSE and NYMEX) we will use changes in the West Texas Intermediate (WTI) index as a proxy for the supply shocks in the energy sector. Until now, oil price changes have not been regarded as a relevant factor for the determination of liquidity. Thus, to the best of our knowledge, we are the first to investigate whether oil prices may have an impact on liquidity in general and on the risk perception of the liquidity providers in particular.

In addition, there is an extensive market microstructure literature about the determinants of spreads in financial markets. The literature provides inventory cost and asymmetric information models. The first takes into consideration the sub-optimal portfolio of the market maker directly after a trade; the second focuses on potential losses from traders with superior information. In this respect, Garman (1976) assumes that the market is characterized by a flow of orders to buy and sell and the spread is the compensation for the risk taken. An interesting extension is how price setting changes when the inventory position does change (Amihud and Mendelson, 1980). Hasbrouck and Sofianos (1993) investigate dealer behavior in more detail accounting for asymmetric information. According to Stoll (1978), the total cost of immediacy is the sum of the costs of holding, ordering and information. Stoll emphasizes the holding costs, the price risk and opportunity cost of holding securities, which are referred to as inventory costs. Dealers (dealers, market makers and financial intermediaries are used interchangeably in the text) act as principals and they trade from their account when investors can not immediately match their orders or wishes. If the market maker is viewed as any other individual investor holding a portfolio and having similar preferences, then offering immediacy will result in differences between their actual portfolio and the optimal one. The dealer undertakes excess risk or moves to a risk/return trade-off that differs from her preferences (the dealer is risk averse).

There is no widely accepted definition of liquidity. While intuitively it can be said that it is determined by the ease and speed of trade, operationally every measure captures different aspects of it. Traditionally, the commonly used measures are the quantity of trade or turnover and the cost of trade as expressed by the bid and ask quotes. The first is considered to be necessary for the existence of the trade itself. This fundamental dimension has been typically expressed either in terms of volume (quantity or currency units) or in relative terms comparing the trading activity to the available quantity (turnover). The second is regarded as the cost of an immediate buy and sell transaction of the same asset. It includes only the compensation of the intermediary for accommodating the transaction. This dimension of liquidity is more directly visible to the counterparty and it is not only affected by the trading volume, but it can affect trading activity as well.

2.3 Methodology

In this section we will first define the liquidity measures used in our analysis, and then describe the methods used for main hypotheses. The first liquidity measure, Turnover, is constructed by calculating a stock specific measure of turnover, defined as:

$$T_{ti} = \frac{\text{Trading Volume}_{ti}}{\text{Total Value}_{ti}} \quad (2.1)$$

where T_{ti} is Turnover of firm i at time t . $\text{Trading Volume}_{ti}$ is the value of all trading actions for firm i during the period t , and Total Value_{ti} is the capitalization of firm i at time t . Next we aggregate the individual measures to get an energy sector measure of liquidity:

$$T_t = \sum_{i=1}^j w_i T_{ti} \quad (2.1a)$$

where T_t is the energy sector Turnover at time t , w_i is the (capitalization) weight of firm i compared to the rest of the sector, $\sum_{i=1}^j w_i = 1$, and T_{ti} as defined in (1). The second measure is the Bid-Ask spread. Again, we calculate a stock specific measure first:

$$S_{ti} = \frac{\text{ask}_{ti} - \text{bid}_{ti}}{\text{price}_{ti}} \quad (2.2)$$

where S_{ti} is the proportional quoted spread (Spread for the rest of the text) for firm i at time t , ask_{ti} is the ask price of firm i quoted at the close of market, bid_{ti} is the bid price of firm i offered at close of market, and price_{ti} is the closing price of the day t for firm i . Next we aggregate the individual bid-ask spreads to obtain another liquidity measure for the energy sector as a whole

$$S_t = \sum_{i=1}^j w_i S_{ti} \quad (2.2a)$$

where S_t is the energy sector Spread at time t , w_i is the (capitalization) weight of firm i compared to the rest of the sector, $\sum_{i=1}^j w_i = 1$, and S_{ti} as defined in (2).

Equation (2.2a) suggests that the proportional quoted spread is defined as the difference between bid and ask prices over the closing price. The ask price is the lowest price for which a seller is willing to exchange her asset and the bid price is the highest price a buyer is willing to pay for purchasing that asset.

Spread and Turnover do not fully reflect every aspect of liquidity. While the quoted spread is the current price at which trades can take place, in practice sudden excess demand or supply of an asset may change both turnover of trade and prices as well as their quoted differences. In order to account for this aspect of liquidity, academics have used the concept of price impact of a trade, as described by the change of the price compared to the amount of trade. Amihud (2002) suggests a price impact measure where illiquidity is accounted for in nominal terms. The difference with our equation (2.3) below is that Amihud suggests the use of the trading volume in the denominator, while we use Turnover which is a percentage (see Florackis et al., 2011). Our third measure is:

$$I_{ti} = \frac{|returns_{ti}|}{T_{ti}} \quad (2.3)$$

where I_{ti} is the price impact of trading for firm i at time t (Price Impact for the rest of the text), $|returns_{ti}|$ is the absolute difference of the price of firm i between period t and $t-1$, divided by the price at period $t-1$, and T_{ti} is the one period Turnover of firm i as defined in (1). Again we aggregate individual measures to obtain a measure at the energy sector level:

$$I_t = \sum_{i=1}^j w_i I_{ti} \quad (2.3a)$$

where I_t is the energy sector Price Impact at time t , w_i is the (capitalization) weight of firm i compared to the rest of the sector, $\sum_{i=1}^j w_i = 1$, I_t as defined in (3).

Our study contributes to the literature in three ways. First, it examines liquidity in the energy sector. Second, it departs from a financial intermediation perspective, where market makers are central. Third, we compare our results with other theoretical and empirical studies on liquidity. In order to achieve this, we structure our paper as follows. First, we analyze the interdependencies of the liquidity

measures, that is, which are the most significant factors determining liquidity and to what extents can a vector autoregression (VAR) explain variation in liquidity. Second, we investigate potential differences in the behavior of these liquidity proxies for different groups of stocks. Here, we will particularly focus on the patterns of frequently and less frequently traded stocks. Third, a VAR framework and its impulse response function will provide us with information about the speed of adjustment to new information. Fourth, we adopt an intermediary perspective, and assume that the market maker decides about the spread according to her risks and costs.

Since liquidity proxies move together through time and affect each other, we will employ a vector autoregression (VAR) to analyze the interdependencies as a system. VAR modeling has been used before in the energy literature (see Stern, 1993). But as far as we are aware of, we are the first to look into the autoregressive behavior in energy liquidity context.. VAR is applied to different groups of energy stocks in order to examine several hypotheses from the market microstructure theory, such as when we may observe stronger clustering of liquidity, or whether more traded stocks are less sensitive to changes. We use Turnover as a straightforward measure of trading activity. More traded stocks have by definition higher Turnover. Using trading activity as the driving force in the characteristics of liquidity is also in line with our suggestion for an intermediaries' perspective, and the structure our fundamental model is built.

As we discussed in the introduction, our theoretical perspective is based on the financial intermediation theory and how market makers perceive changes as costly or risky (Garman, 1976; Amihud and Mendelson, 1980) and the focus is on the determination of the spread. Glosten and Harris (1988), and Stoll (1989) confirm empirically the significance of adverse selection costs as a large part of the bid-ask Spread. We model Turnover, Price Impact and Spread simultaneously. In order to estimate a SVAR model, we need to impose some restrictions, otherwise the system of equations is not identified. As explained earlier we adopt a financial intermediaries' perspective. The spread of quoted stock prices is the compensation for actively participate in the trade and its price discovery. Financial intermediaries weighting their costs (risks) and benefits (Spread) decide on the necessary compensation. This implies that spread is determined by its involved risks. This tradeoff of risk and return for the intermediaries, here translates to Spread (their compensation or return) and Turnover and Price Impact (their risks when involved in trading).

We therefore assume a contemporaneous causality direction from Turnover to Price Impact and from both Turnover and Price Impact to Spread. Thus, while current values of Turnover and Price Impact do play a role in determining Spread (from the intermediary's point of view), the Spread itself affects Turnover and Price Impact only with some lag in time. As such, we imply that the amount of trading of a stock in each period is not determined by that period's Spread but rather by the Spread of previous periods. In contrast, the amount of stocks traded in a particular period does affect the current

Spread, as we hypothesize that market dealers will react and adjust their compensation according to their risks. The same is the case with the Price Impact, which is not affected by current values of Spread but depends on current levels of Turnover. This implies that the trading volume will affect prices and returns during the current period. System (I) below summarizes our Structural VAR model,

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 & 0 & 0 & \alpha_{10} \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 & \beta_8 & 0 & \beta_{10} \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 & \gamma_8 & \gamma_9 & \gamma_{10} \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \\ T_t & T_t & T_t \\ I_t & I_t & I_t \\ O_t & O_t & O_t \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate). The coefficients α_8 , α_9 and β_8 are set to zero, to reflect the causality assumptions, which identify the system. Including the crude oil price index in (I) gives us information on whether intermediaries consider oil prices as a factor affecting their daily evaluation of the risks involved in holding and clearing the markets in energy stocks. Regarding system (I), we expect some specific patterns and relationships between the variables. Previous studies find commonality and clustering in the liquidity measures (Chordia et al. 2000; Domowitz et al. 2005; Hasbrouck and Seppi, 2001) or give a theoretical reason for clustering (Vayanos, 2004). From these findings, we expect all measures to be positively related to their lagged values due to persistence. Second, contemporaneous increases in Turnover and Price Impact, signaling more risk for the market maker, should cause an increase in the Spread. This is in line with our assumption of the competitive financial intermediaries' market, together with theoretical models explaining Spread as a result of asymmetric information (Copeland and Galai, 1983; Glosten and Milgrom, 1985) and inventory costs (Stoll, 1978; Amihud and Mendelson, 1980). Finally, we hypothesize that the oil index may have a negative effect on the contemporaneous liquidity indices due to uncertainty caused by oil returns. In fact, Hammoudeh et al. (2004) find that oil futures prices explain movements in oil sector stock indices.

2.4 Data

We use daily NYSE time series of energy industry stocks. The bid and ask prices and volumes are collected from Datastream for the time period between April 2006 and April 2011 for Oil & Gas Producers and Oil Equipment & Services. We collect WTI oil prices for the same period. Stocks being listed after April 2006 and hence having missing observations for the full period are not taken into account. To avoid potential spurious influences from extreme prices, stocks with a price outside the \$2 and \$1000 range are excluded. Other anomalous records such as negative bid ask spreads or proportional quoted spread $> 30\%$ are deleted. As such, we are left with 130 stocks. There are 66 firms belonging to Oil & Gas Producers and 64 firms in Oil Equipment & Services. In total, we have 1,255 observations. We create the value weighted aggregate Spread of the NYSE stocks as explained in the Background section. In the same way, we create the weighted proxies for Turnover and Price Impact. Next, we rank the stocks according to their Turnover ratio and create deciles. We will especially investigate the 2nd and 9th decile to capture any differences in highly and poorly traded stocks. We do not want to use the first and tenth deciles because then the conclusions might be affected by extreme observations. Furthermore, we also look into the two largest firms, namely Exxon and Chevron (their size about 80 and 30 times the average of the rest of group and together they represent about 40% of the market capitalization of the energy industry).

Table 2.1 shows the summary statistics of the data sample. We see that for the full sample roughly 1% (0.97% Mean Turnover) of the outstanding shares are exchanging hands on a daily basis. We create 10 deciles according to trading activity and the most traded firms are in the top decile. We focus on the 2nd and 9th to avoid extreme outliers while still comparing very different groups. The difference in Turnover between these two sub-groups is extremely large (2.26% vs. 0.28%). Another interesting feature of our sample is that the two largest firms, Exxon and Chevron, are not among the relatively most traded stocks but are closer to the less traded stocks. Regarding the Price Impact, we observe that more traded stocks are less sensitive to changes in trading volume, which is what we would expect: a higher relative trading volume implies ‘deep’ markets and therefore changes in trading activity will cause less concern to the counterparties. A one percentage change in Turnover results in 1.15% change in returns for the 2nd decile and in 4.75% change for stock returns in the 9th decile. Table 2.1 also reveals that the Spread ‘behaves’ as expected as it is higher for less traded stocks. Stocks in the 9th decile have more than four times the cost of buying and selling as that of stocks in the 2nd decile (0.576% and 0.134% respectively). Stocks that belong to the Oil & Gas Producers have smaller Turnover than those in Oil Equipment & Services, 0.85% and 1.3% respectively. In contrast, the proportional Spread of Producers is lower than that of Services, 0.117% and 0.149% respectively. This is somewhat counterintuitive since we would expect more traded stocks to have also lower Spread.

Table 2.1: Summary statistics

	Mean	Mean	Mean
	Turnover (T_t)	Price Impact (I_t)	Spread (S_t)
Full sample	0.97%	2.21	0.125%
2 nd decile	2.26%	1.15	0.134%
9 th decile	0.28%	4.75	0.576%
Exxon	0.52%	2.34	0.106%
Chevron	0.55%	2.36	0.101%
Oil & Gas Producers	0.85%	2.23	0.117%
Oil Equipment & Services	1.3%	2.19	0.149%

The Table reports time series means for the different series used in this study. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average of all stocks in the group. The same procedure has been followed for all liquidity measures. Mean Turnover and Mean Spread are reported as percentages. The second row reports the mean average liquidity proxies for the whole 130 stocks during the period April 2006 and April 2011. Third and fourth rows report the averages for the 2nd and 9th decile, each groups includes 13 stocks according to their ranking in terms their Turnover ratio of the sample, respectively. We use the 2nd and 9th decile to avoid extreme values, stocks that are highly traded or not traded at all. However the groups differ substantially, as it can also be indicated from the Mean Turnover values (almost tenfold for Mean Turnover). Oil & Gas Producers as indicated by Datastream, include 66 firms and Oil Equipment & Services 64 firms.

2.5 Results

2.5.1. Persistence and VAR specification

Before using a VAR specification, we first check whether our variables are indeed autocorrelated. To do so, we first independently estimate a simple AR(1) model separately for each of the three liquidity measures. The autoregressive coefficients are reported in Table 2.2 and the stationarity tests are reported in the Appendix 2.A.1. We find that all coefficients are highly significant. The difference for high and low traded stocks is relatively small for Turnover (0.98 versus 0.97). However, for Price Impact and Spread we observe a different situation: Less traded stocks have a higher coefficient in their Price Impact series, while for Spread the opposite is the case. The second can be partly explained if less traded stocks are also affected by different factors than just the previous values of Spread. For instance, in our intermediaries' framework, this suggests that more traded stocks (2nd decile) are considered to be less risky or costly to trade for market makers. Less traded stocks (9th decile) are perceived as being more risky when traded and hence depend less on their autoregressive value.

Table 2.2: Autoregressive coefficients

	Turnover	Price Impact	Spread
	(T_t)	(I_t)	(S_t)
Full sample	0.98	0.79	0.82
2 nd decile	0.98	0.81	0.84
9 th decile	0.97	0.87	0.62

This Table reports the autoregressive coefficients of the three liquidity measures (Turnover, Price Impact and Spread) for the oil and gas sector. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each of the three liquidity proxies. The second row reports the autoregressive coefficients (AR(1)) for the whole 130 stocks during the period April 2006 and April 2011. Third and fourth rows report the autoregressive coefficients (AR(1)) for the 2nd and 9th decile (each group includes 13 stocks according to their ranking in terms their Turnover ratio of the sample respectively. Deciles have been created according to Turnover ratio, 1st decile contains the 10% relatively most traded stocks.

Table 2.3: VAR specification of liquidity measures

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.1801*** (7.78)	0.5356*** (17.85)	0.2237*** (7.54)	0.0205*** (4.47)	-0.0026 (-0.58)	0.1619** (2.53)	-0.046 (-0.71)	0.59
I_t	1.6649*** (11.47)	-0.06 (-0.32)	0.0234 (0.12)	-0.04 (-1.39)	0.0854*** (2.98)	2.8288*** (7.06)	1.0539*** (2.58)	0.12
S_t	-0.029*** (-2.71)	0.0325** (2.28)	0.0375*** (2.66)	0.0069*** (3.19)	0.0012 (0.58)	0.3734*** (12.3)	0.1741*** (5.63)	0.42

In this table we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for all the stocks (130 stocks) in the oil and gas sector in NYSE for the full data sample. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each of the three liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

In Table 2.3 we report the results of a VAR(2) specification for the three liquidity proxies. The VAR-framework allows for interactions among the variables and we are able to evaluate the effect of lagged values on the liquidity proxies. We are particularly interested in the reaction of the market maker (as proxied by the Spread) to changes in Turnover and Price Impact. In general, it appears that Turnover (T_t) and Spread (S_t) can be described better on the basis of this framework than Price Impact (I_t). The

VAR(2) explains 59% and 42% respectively of their variation, while for Price Impact this is only 12%. Turnover and Spread are characterized by their lagged values and by the first lag of Price Impact. This suggests that current Turnover depends on yesterday's and the day before Turnover as well as on yesterday's Price Impact and Spread. Spread depends on Spread and Turnover of the previous two days, and on the Price Impact of the previous day. We always witness positive relationships between the liquidity proxies. This also suggests that an increase in Turnover may signal informed trading and force the market maker to increase Spreads (Glosten and Milgrom, 1985). Similarly, the lower (higher) the depth of the market (Price Impact of Turnover), the larger (smaller) the Spread.

In Appendix 2.A.2, we report the results of a VAR(2) specification for the 2nd and 9th decile⁶, for Exxon and Chevron, and for producer and services firms. Comparing the interdependencies of the variables in these different series, we observe an interesting pattern. On the one hand, as we can see in Panels I and II, the Spread of the more traded stocks (2nd decile) in general is responding more than those in the 9th decile to changes of the lagged values in general. This also is what we would expect from theory; more actively traded stocks incorporate information so an increase in Turnover would imply informed trading (Kyle, 1985). This increase in Turnover would also include liquidity traders but if the informed fraction is higher, then the market maker is not compensated enough and demands higher Spread. This is in line with Easley and O'Hara (1987, 1992), Kyle (1985) and Glosten and Milgrom (1985). However, looking at Panel II, we observe that for less traded stocks a sudden increase in Turnover does not seem to signal new information. This suggests that either these stocks are not actively traded and thus informed traders are harder to be recognized, or that for the stocks with low Turnover an increase itself would be of importance only if it impacts on their prices (higher coefficients of lagged Price Impact than for the equivalent coefficients of more traded stocks). This can be justified by the fact that the coefficient of Price Impact in determining Spread on Panel II for the less traded stocks is almost double that of more traded stocks in Panel I. Another explanation could be that since less traded stocks have spreads more than four times the size of those of more traded stocks, a very high Spread covers for part of the risks while for more traded stocks with lower spreads intermediaries have to monitor movements more intensively. The characteristics of Exxon and Chevron (Panel III and IV) are closer to those of the full sample in the case of Turnover. If we take into account that almost half of the weights of the full sample are these two stocks we can see a very distinct behavior of these two firms compared to the others. Panels V and VI in Appendix 2.A.2 give the results of VAR for Producers and Services in the energy sector respectively. In line with our results regarding the full sample, we observe a moderate performance for the Price Impact. There is a clear difference regarding the Spread of the two groups: Stocks listed in the Oil Equipment and Services group seem to depend more on lagged values of liquidity than those in Oil & Gas Producers. This is the case even though the first lag of Turnover is significant for the Producers and insignificant for the Services. This suggests that the variation for the

⁶ We have performed this analysis also for the 1st and 5th Quintiles finding similar results

Services group is mainly sourcing from the highly autocorrelated Spread rather than from information from other liquidity variables.

Appendix 2.A.3 shows the impulse-response functions of the liquidity measures. The impulse-responses show how long it takes for new information to be reflected in the prices. We simultaneously model Turnover, Price Impact and Spread, so it is possible to follow the expected values at each point of time t . The expected change in the variables depends on which variable of the VAR system we decide to shock. For the full sample (Panel I in Appendix 2.A.3), we observe that in most of the cases values respond quickly and shocks are incorporated within two observations (days) except in the case of a shock in Turnover to Turnover itself. As discussed in the Literature & Background section, microstructure models give various suggestions regarding the relationships that should direct different liquidity measures. Nevertheless, what we would expect is that stocks more intensively traded respond faster when new information arrives (Holden and Subrahmanyam 1992). However, for Turnover we observe virtually no difference between the groups, but we can detect differences between the subgroups Price Impact and Spread. Comparing the graph of the highly traded stocks with that of the low traded stocks (Panels II and III) we observe a slightly different pattern of the responses of Spread. For the highly traded stocks, Spread seems to respond to shocks from Price Impact and Spread even after three or four observations. Spread of less traded stocks surprisingly responds faster (as a response to a shock in Spread) than that of more traded stocks. Responses of Spread to Turnover for the less traded stocks show a somewhat different pattern. This can also be seen in the results of the VAR where the first lag of Turnover is insignificant for describing Spread whereas the second lag is significant.

2.5.2. Spread and its interrelationships with Turnover and Price Impact

In this section, we investigate the main model (i.e. system I) of our study. As we described in the methodology section, the specification of system (I) is structured to imply a causality pattern from Turnover and Price Impact to Spread. The fundamental intuition of this SVAR model is that Spread efficiently reflects the costs of market makers and also that market makers are able to determine their bid and ask prices after they observe some variables. Assuming that Spread is affected by lagged values of Turnover and Price Impact gives the typical structure of a vector autoregression. We can test our hypothesis when we allow that the market maker observes Turnover and Price Impact simultaneously. If the contemporaneous coefficients are significant then this supports the implied assumption that spreads are determined also by current values of Turnover and Price Impact. The estimation results are in Table 2.4.

Table 2.4 shows several interesting properties of the liquidity of energy stocks. First, the model seems to have a good fit and explains 52% of the variation of the Spread. As regards the Turnover, R^2 is 60% and for Price Impact it is 14%. Second, lagged values of all series are important in characterizing each other. While there are some insignificant coefficients, such as the second lag of Turnover in explaining the behavior of Price Impact or Spread, there is no value that is insignificant for all three dependent variables. Thus, it seems we have arrived at an appropriate specification of the system. A very important result is that the contemporaneous values of Turnover, Price Impact and Oil price all significantly affect Spread. This confirms our hypothesis about dealers observing current trends and adapting their quoted spreads accordingly. Both Turnover and Price Impact at time t are significant in determining Spread at time t , with the expected positive sign. Higher Turnover signals informed trading according to market microstructure models. This should force market makers to increase their quoted prices due to increased risk exposure. Similarly, a higher Price Impact of the trading activity implies a more risky environment for the market makers and this would also cause the spreads to increase. The Price Impact and Turnover at time $t-2$ are insignificant in determining Spread. This suggests that the contemporary values of Turnover and Price Impact already capture the variation of their lagged values (due to their highly persistent nature). This can be also seen from the fact that contemporaneous values of Turnover and Price Impact are positive while their lagged values are reduced compared to the VAR(2) case. Thus, our model is an improvement with respect to the symmetric VAR(2) case. Furthermore, the oil returns significantly affect Turnover and Spread. Both coefficients are significantly negative (-0.75 and -0.27 for the Turnover and Spread equation respectively), suggesting that an increase in oil returns causes a reduction of the traded value as well as of the Spread set by market makers. It seems that while rising oil prices lower the immediate cost of trading, they also diminish market depth, which might discourage further trade. However, it could also suggest that higher prices may indeed discourage trade, but at the same time increased prices favor the energy firms and their future prospects and, as such, indirectly reduces the spreads. Oil price returns do not seem to affect Price Impact, at least not more than the indirect effect they have on current Turnover (which also determines Price Impact).

This model treats the whole period having a constant behavior through time. One could argue that while liquidity is important, it may have different characteristics in different periods. In order to have better idea on the specifics in distinct periods we perform a sub-period analysis⁷. We split our sample period in three parts according to the size and volatility of liquidity at these. Two periods, April 2006-December 2007 and August 2009-2011, can be characterized as ‘normal’ periods. The period in between, January 2008-August 2009, is an illiquid period stigmatized by the credit and liquidity crisis.

⁷ We would like to thank an anonymous referee for this suggestion

We apply our main model, system (I) for these three periods and present the results in the Appendix 2.A.4. We observe a range of interesting results. First, the differences in magnitude of the Turnover coefficient in the spread equation between the periods is striking. Current Turnover during January 2008-August 2009 affects positively (0.297) the Spread at more than four-fold impact than the equivalent of the first and the third period (0.05 and 0.06 respectively). This indicates that trading activity is much more risky for the intermediaries during illiquid (turbulent) times than for normal. This result strengthens our hypothesis for a financial intermediaries' perspective for the determination of spread. Similarly, the current Price Impact affects more strongly the Spread during Period 2 than the two normal periods. In addition, for the Price Impact equation current Turnover coefficient is larger for Period 2 (1.06) than Period 1 (0.57) and Period 3 (0.44 and insignificant).

To wrap up, we tested whether causality in liquidity measures runs from Turnover to Price Impact and from both of them to Spread. Contemporary values of Turnover and Price Impact explain a large part of the Spread. Oil returns are a significant factor in explaining two of Turnover and Spread.

Table 2.4: Results for the system of equations (I)

	Turnover _{<i>t</i>} (<i>T_t</i>)	Price Impact _{<i>t</i>} (<i>I_t</i>)	Spread _{<i>t</i>} (<i>S_t</i>)
Constant	0.1867*** (8.12)	1.5147*** (10.26)	-0.0743*** (-6.93)
Turnover _{<i>t-1</i>}	0.5397*** (18.14)	-0.5015** (-2.39)	-0.0535*** (-3.66)
Turnover _{<i>t-2</i>}	0.2134*** (7.23)	-0.1572 (-0.83)	-0.0033 (-0.25)
Price Impact _{<i>t-1</i>}	0.0199*** (4.40)	-0.0567** (-1.98)	0.0038* (1.90)
Price Impact _{<i>t-2</i>}	-0.0025 (-0.55)	0.0875*** (3.09)	0.0008 (0.44)
Spread _{<i>t-1</i>}	0.1525** (2.40)	2.6986*** (6.79)	0.3139*** (11.12)
Spread _{<i>t-2</i>}	-0.0320 (-0.49)	1.0877*** (2.69)	0.1763*** (6.23)
Turnover _{<i>t</i>}		0.8218*** (4.65)	0.1648*** (13.25)
Price Impact _{<i>t</i>}			0.0103*** (5.26)
Oil index _{<i>t</i>}	-0.7512*** (-4.00)	0.2357 (0.19)	-0.2747*** (-3.33)
R ²	0.6025	0.1398	0.5212

In this table we report the coefficients for the system of equations (I) of Turnover, Price Impact and Spread as described by their lagged values, current values and an oil price index for the 130 stocks in the NYSE energy sector. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each one of the three liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

2.6 Conclusions

We investigate the effect of oil prices on liquidity and the interactions of different liquidity measures, namely Turnover, Price Impact, and Spread. We use energy stocks to examine the hypothesis that Spread depends on Turnover and Price Impact contemporaneously, on top of their previous values, and on the WTI. We find that the liquidity measures are highly persistent and that they cluster. We also find that the intensity with which stocks are traded is important for describing the interrelationships of different liquidity time series. We investigate different groups of energy stocks: heavily and sparsely traded, producers and service companies, and the two largest energy firms (Chevron and Exxon). All groups and stocks examined exhibit a high degree of liquidity clustering. The degree of persistence of Price Impact is lower for stocks that trade more, which contrasts with the more general findings of Foster and Viswanathan (1990). We also find that Spread responds to Turnover changes after one day for the highly traded stocks while it takes two days to respond for less traded stocks. Furthermore, the highly traded stocks seem to respond faster to new information. As such, we are able to confirm the intuition of Easley and O'Hara (1992) that higher trading activity implies a higher fraction of informed traders. We find that the services stocks are more persistent than producer stocks as regards their Spread.

Oil prices significantly affect liquidity in the energy sector. An increase in oil returns results in a reduction of the traded volume of energy stocks as well as in a lower spread. Contemporary values of Turnover and Price Impact are significant in describing Spread. Market makers observe the trends of the market and adapt their pricing decisions regarding spreads. Our findings show that trading activity, its impact on energy stock prices, and oil prices influence the (price) decision for a perceived fair price of spread on these traded stocks. These results are consistent for the energy stocks of NYSE for the period examined. However, the causality pattern we are proposing is quite general and may be applied in larger groups of stocks-assets. A limitation of our approach is that we exclude potential influences that spreads might have on trading activity and price impact in turn. For instance, we could argue that a lower spread would induce more trading. The reason we did not analyze it that way is because the relative importance of changes in liquidity should be much more important for intermediaries exposed to such risks than for an average investor or portfolio manager. The magnitude of spread is very small compared to returns themselves to actually influence a portfolio rebalancing. Even during 2008, when the proportional quoted spread jumped to values of more than 0.5% for some days, the absolute returns on these days were 10-20 times larger. Here an interesting aspect could be to find out how volatility intervenes in these relationships. In this study we investigate companies in the NYSE that have a direct link to oil, and this includes either companies involved in producing, processing, and distributing oil and gas or companies offering services on these sectors. We do not include companies in the renewable sector which continuously have an increasing share impact, and which could be an interesting expansion

of the study. Comparison across sectors in the energy industry as well as in differences sectors, assets, and frequencies can offer valuable insights.

Beyond the contribution in academic literature by providing a new framework in modelling causality in stock market liquidity, our results can be useful for all participants in the US energy industry. Oil companies, Producers or Servicers that are traded in the NYSE, current or future investors in the sector, and traders interested in understanding more on how the liquidity measures of energy stocks are interrelating. This may be of even more interest for financial intermediaries. Their cost/risk exposure in buying and selling stocks makes them more interested in the characteristics of liquidity.

2.7 Appendix

Appendix 2.A.1

Unit Root Tests

	Turnover	Price Impact	Spread
	(T_t)	(I_t)	(S_t)
DF statistic	-6.91	-4.76	-3.75
p-value	0.00	0.00	0.03

The test is applied on the levels of the full sample series (we found similar results for all the groups used in this paper) used in the analysis part. We observe that all three liquidity measures are stationary. The regression model can be written as:

$$\Delta Y_t = \delta + \beta Y_{t-1} + \gamma t + \sum a_i \Delta Y_{t-i} + u_t$$

The null hypothesis is that β is zero which if it cannot be rejected indicates the existence of a unit root and non stationarity of the series.

Appendix 2.A.2: VAR specification of liquidity measures for subgroups**Panel I: 2nd decile**

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.4365*** (8.19)	0.5701*** (20.22)	0.1872*** (6.59)	0.0938*** (4.47)	0.0027 (0.13)	-0.0231 (-0.19)	0.0332 (0.28)	0.54
I_t	0.6386*** (8.65)	-0.382 (-0.97)	-0.0009 (-0.02)	0.0224 (0.77)	0.2003*** (6.89)	0.9600*** (5.92)	0.8360*** (5.11)	0.19
S_t	-0.0156 (-1.16)	0.0272*** (3.84)	0.0025 (0.36)	0.0129** (2.45)	0.0220*** (4.17)	0.2904*** (9.88)	0.2236*** (7.55)	0.36

In this table we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for the 2nd decile (13 stocks) in the oil and gas sector in NYSE. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each of the three liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10%, 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

Panel II: 9th decile

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.0375*** (6.20)	0.5543*** (19.96)	0.1912*** (6.87)	0.0040*** (4.49)	0.0024*** (2.78)	0.0051 (1.53)	-0.001 (-0.31)	0.61
I_t	1.4312*** (7.38)	2.8228*** (3.18)	2.6876*** (3.01)	0.1501*** (5.27)	0.1231*** (4.35)	0.5173*** (4.80)	0.3300*** (3.05)	0.25
S_t	-0.1896*** (-3.72)	0.3444 (1.47)	1.049*** (4.47)	0.0228*** (3.05)	0.0271*** (3.64)	0.1264*** (4.46)	0.1206*** (4.24)	0.22

In this table we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for the 9th decile (13 stocks) in the oil and gas sector in NYSE. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each of the liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

Panel III: Exxon

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.1002*** (7.52)	0.5043** * (17.23)	0.3000** * (10.41)	0.0052* * (2.25)	- (-2.78)	0.0628** (1.98)	-0.0272 (-1.17)	0.5 9
I_t	2.1300*** (13.12)	-0.1528 (-0.42)	-0.6402* (-1.82)	0.0484 (1.71)	0.0978*** (3.47)	1.8829** * (4.89)	0.7775* * (2.00)	0.0 4
S_t	-0.0350*** (-2.72)	0.1069** * (3.79)	0.0687** (2.47)	0.0052* * (2.32)	0.0025 (1.15)	0.1814** * (5.96)	0.1126* ** (3.67)	0.2 0

In this table we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for Exxon. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each of the liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

Panel IV: Chevron

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.1086*** (8.08)	0.5068*** (17.66)	0.2781*** (9.91)	0.0065*** (2.74)	-0.0052** (-2.21)	0.0895*** (3.40)	-0.0236 (-0.89)	0.58
I_t	1.9951*** (12.34)	0.2286 (0.06)	0.1265 (0.37)	-0.0374 (-1.30)	0.0704** (2.46)	1.3586*** (4.29)	0.6059* (1.90)	0.03
S_t	-0.0595*** (-3.93)	0.0868*** (2.68)	0.1109*** (3.50)	0.0084*** (3.13)	0.0046* (1.75)	0.1598*** (5.40)	0.0482 (1.61)	0.15

In this table we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for Chevron. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each one of the three liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

Panel V: Producers group

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.1576*** (7.92)	0.5310*** (17.85)	0.2460*** (8.40)	0.0151*** (4.11)	-0.0069** (-1.89)	0.1548*** (3.02)	-0.0329 (-0.63)	0.61
I_t	1.7336*** (11.19)	-0.0540 (-0.23)	-0.0153 (-0.06)	-0.0211 (-0.73)	0.0819*** (2.86)	2.6419*** (6.62)	0.9160** (2.25)	0.09
S_t	-0.0364*** (-3.09)	0.0468*** (2.66)	0.0456*** (2.63)	0.0064*** (2.94)	0.0011 (0.55)	0.3255*** (10.74)	0.1671*** (5.41)	0.37

In this panel we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for the group of Producers of the sample. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each one of the three liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

Panel VI: Services group

	C	T_{t-1}	T_{t-2}	I_{t-1}	I_{t-2}	S_{t-1}	S_{t-2}	R^2
T_t	0.2530*** (7.41)	0.5338*** (18.05)	0.1933*** (6.52)	0.0304*** (3.90)	0.0088 (1.14)	0.1709 (1.36)	-0.0497 (-0.38)	0.52
I_t	1.4411*** (11.71)	-0.3337*** (-3.13)	0.1784* (1.66)	0.0050 (0.17)	0.1494*** (5.36)	3.2489*** (7.21)	0.8902* (1.93)	0.16
S_t	-0.0093 (-1.14)	0.0002 (0.03)	0.0298*** (4.23)	0.0066*** (3.56)	0.0032* (1.74)	0.5415*** (18.21)	0.1084*** (3.56)	0.53

In this panel we report the coefficients of the VAR(2) specification for the three liquidity measures (Turnover, Price Impact and Spread) for the group of Services of the sample. There are 1255 observations (April 2006-April 2011) for each series. Each observation has been calculated as the capitalization weighted average for each one of the three liquidity proxies. In parentheses () we report the coefficients' t-statistics, and *, **, *** indicate significance at 10% 5%, and 1% respectively. The VAR(2) used can be described by the below equation, where T_t is the Turnover at time t as is defined in equation (2.1a), I_t is the Price Impact at time t as is defined in equation (2.3a), S_t is the Spread at time t as is defined in equation (2.2a) and O_t is the return of the crude oil price index (West Texas Intermediate):

$$\begin{bmatrix} T_t \\ I_t \\ S_t \end{bmatrix} = \begin{bmatrix} \alpha_1 & \alpha_2 & \alpha_3 & \alpha_4 & \alpha_5 & \alpha_6 & \alpha_7 \\ \beta_1 & \beta_2 & \beta_3 & \beta_4 & \beta_5 & \beta_6 & \beta_7 \\ \gamma_1 & \gamma_2 & \gamma_3 & \gamma_4 & \gamma_5 & \gamma_6 & \gamma_7 \end{bmatrix} \begin{bmatrix} c & c & c \\ T_{t-1} & T_{t-1} & T_{t-1} \\ T_{t-2} & T_{t-2} & T_{t-2} \\ I_{t-1} & I_{t-1} & I_{t-1} \\ I_{t-2} & I_{t-2} & I_{t-2} \\ S_{t-1} & S_{t-1} & S_{t-1} \\ S_{t-2} & S_{t-2} & S_{t-2} \end{bmatrix} + \begin{bmatrix} \varepsilon_{1t} \\ \varepsilon_{2t} \\ \varepsilon_{3t} \end{bmatrix} \quad (I)$$

Appendix 2.A.3

Impulse Response Functions

Panel I: Impulse Responses (in days) of liquidity measures for returning to long term equilibrium for the full sample (all 130 stocks). The period is from April 2006 to April 2011 and it includes 1255 daily observations. Lines in red signify the ranges for 1.96 standard deviations above and below forecast providing a 90% confidence interval.

Panel II: Impulse Responses (in days) of liquidity measures for returning to long term equilibrium for the 2nd decile (13 stocks). The period is from April 2006 to April 2011 and it includes 1255 daily observations. Lines in red signify the ranges for 1.96 standard deviations above and below forecast providing a 90% confidence interval.

Response to Cholesky One S.D. Innovations ± 2 S.E.

Panel III: Impulse Responses (in days) of liquidity measures for returning to long term equilibrium for the 9th decile (13 stocks). The period is from April 2006 to April 2011 and it includes 1255 daily observations. Lines in red signify the ranges for 1.96 standard deviations above and below forecast providing a 90% confidence interval.

Appendix 2.A.4Sub-period Analysis

Period 1: April 2006-December 2007

	Turnover _{<i>t</i>}	Price Impact _{<i>t</i>}	Spread _{<i>t</i>}
	(T _{<i>t</i>})	(I _{<i>t</i>})	(S _{<i>t</i>})
Constant	0.3500*** (7.60)	2.1153 *** (6.52)	0.0064 (0.54)
Turnover _{<i>t-1</i>}	0.5240*** (10.83)	-0.7499** (-2.08)	-0.0161 (-1.28)
Turnover _{<i>t-2</i>}	0.0864* (1.76)	-0.5626* (-1.73)	0.0028 (0.24)
Price Impact _{<i>t-1</i>}	0.0269*** (3.73)	-0.0504 (-1.04)	0.0035** (1.90)
Price Impact _{<i>t-2</i>}	-0.0168** (-2.31)	0.0384 (0.80)	0.0022 (1.31)
Spread _{<i>t-1</i>}	-0.1249 (-0.62)	4.0162*** (2.99)	0.2484*** (5.26)
Spread _{<i>t-2</i>}	-0.1480 (-0.72)	3.4941*** (2.59)	0.2099*** (4.43)
Turnover _{<i>t</i>}		0.5685* (1.79)	0.0477*** (4.30)
Price Impact _{<i>t</i>}			0.0036** (2.12)
Oil index _{<i>t</i>}	-0.6149 (-1.49)	3.7750 (1.38)	0.0473 (0.49)
R ²	0.34	0.07	0.25

Period 2: January 2008-August 2009

	Turnover _{<i>t</i>}	Price Impact _{<i>t</i>}	Spread _{<i>t</i>}
	(T _{<i>t</i>})	(I _{<i>t</i>})	(S _{<i>t</i>})
Constant	0.2720*** (5.38)	1.3946 *** (4.03)	-0.1689*** (-5.35)
Turnover _{<i>t-1</i>}	0.5010*** (9.15)	-0.3137 (0.79)	-0.0754** (-2.12)
Turnover _{<i>t-2</i>}	0.1891*** (3.55)	-0.1954 (-0.54)	0.0032 (0.10)
Price Impact _{<i>t-1</i>}	0.0257*** (4.40)	-0.0919* (-1.81)	0.0017 (0.38)
Price Impact _{<i>t-2</i>}	0.0028 (0.36)	0.0946* (1.88)	-0.0032 (-0.70)
Spread _{<i>t-1</i>}	0.1448* (1.75)	2.1248*** (3.87)	0.2225*** (4.44)
Spread _{<i>t-2</i>}	-0.0666 (-0.78)	0.6621 (1.18)	0.1168** (2.32)
Turnover _{<i>t</i>}		1.0668*** (3.25)	0.2967*** (9.98)
Price Impact _{<i>t</i>}			0.0148*** (3.34)
Oil index _{<i>t</i>}	-0.97835*** (-3.80)	-1.632 (-0.94)	-0.2208 (-1.41)
R ²	0.57	0.17	0.51

Period 3: August 2009 – April 2011

	Turnover _{<i>t</i>}	Price Impact _{<i>t</i>}	Spread _{<i>t</i>}
	(T _{<i>t</i>})	(I _{<i>t</i>})	(S _{<i>t</i>})
Constant	0.2014*** (4.91)	1.4500*** (6.35)	0.0162*** (2.66)
Turnover _{<i>t-1</i>}	0.5447*** (10.22)	-0.4836 (-1.50)	-0.0302*** (-3.68)
Turnover _{<i>t-2</i>}	0.2662*** (5.00)	0.2093 (0.71)	-0.0159** (-2.11)
Price Impact _{<i>t-1</i>}	-0.0051 (-0.56)	-0.0791 (-1.61)	0.0002 (0.13)
Price Impact _{<i>t-2</i>}	0.0028 (0.31)	0.0352 (0.72)	-0.0006 (-0.50)
Spread _{<i>t-1</i>}	-0.2774 (-0.80)	3.9613** (2.10)	0.3355*** (6.97)
Spread _{<i>t-2</i>}	-0.1056 (-0.30)	0.0321 (0.02)	0.2617 *** (5.45)
Turnover _{<i>t</i>}		0.4408 (1.64)	0.0644*** (9.44)
Price Impact _{<i>t</i>}			0.0004 (0.29)
Oil index _{<i>t</i>}	-0.1932 (-0.45)	6.313*** (2.69)	-0.1287** (-2.15)
R ²	0.55	0.05	0.40

Chapter 3

**Market Fundamentals as Determinants of the Brent–
WTI Crude Oil Price Spread**

3. Market Fundamentals as Determinants of the Brent–WTI Crude Oil Price Spread

3.1 Introduction

In the past decade, oil prices reached unprecedented levels; prices of more than US \$100 per barrel were not uncommon. At the same time, there was substantial uncertainty and huge volatility in oil markets, which created interest in investment consequences (Diaz et al., 2016; Elder & Serletis, 2010) and stock market repercussions (Phan et al., 2016; Soucek & Todorova, 2013). Increased volatility also motivated research that uses advanced forecasting techniques (Azevedo & Campos, 2016; Ding & Meade, 2010; Dunis et al., 2010) and analysis on the impact of new technologies such as shale oil extraction (Stocker et al., 2018). Notably and remarkably, the two major oil markets, Brent and West Texas Intermediate (WTI) crude oil, began to diverge beginning in 2011. Figure 3.1 shows the spot prices and spot price spreads of Brent and WTI crude 2006 to 2017. This period included very high and very low prices as well as high and low volatility of prices. In this study, we consider the fundamental drivers of convenience yields that affect crude oil price spreads.

Figure 3.1: Monthly spot prices of WTI and Brent crude in US\$/barrel, their volatility, and price spread

Notes: in this figure we use our dataset under investigation from 2006 to 2017 and plotting Brent and WTI prices and their spread over time. Source of the data is the US Energy Information Administration (EIA).

For decades, crude oil price spreads were minimal; they were perceived to obey the *law of one price* (LOOP), which is that large price differences quickly weaken as the result of arbitrage opportunities in the market. However, this long-run relationship between Brent and WTI crude prices

started to diverge in 2011. During 2015–2019 the spread between the two crude oil indexes came closer together, however, most recently in 2020 we are experiencing increasing divergence. During the beginning of 2020, the world has experienced an unprecedented pandemic, COVID-19, and demand for oil reduced substantially because of governments' containment measures. In general, market frictions, transportation, and trading costs induce different prices for the same good, but arbitrage opportunities imply that this spread remains within particular boundaries (Samuelson, 1964). Brent and WTI crude are similar but not identical products that are traded in two different locations. We are concerned with two questions about their differing prices. The first is whether they are explained by their differing product properties; although both are classified as “sweet” crude oils, WTI has a lower sulfur content (0.24% versus 0.37% for Brent) and an easier refining process, both of which should give WTI the price advantage (see Figure 2 with historical prices). The second question is whether the locations and logistics associated with production areas and delivery points justify a bandwidth or threshold large enough to explain the price difference. We note that WTI's delivery point is in Cushing, Oklahoma, whereas Brent pricing includes transactions of physical trades in fields⁸ between the UK and Norway.

These two issues could be either complementary or competitive, depending on the direction of the physical flows and the price spreads. If buyers seek one of the crude oils more than the other, even though there are transportation costs involved, the oils would be competitive pricing forces, but if the more sought-after crude also were logistically more proximate, they would complement each other. Milonas and Henker (2001) find that in near-term months (up to three) convenience yields positively affect price spreads, whereas for longer horizons, the quality of the products dictates their price differentials.

The term *convenience yield* refers loosely to the price for the benefit of physically holding an asset instead of a making a future promise of delivery and the possibility of making use of the asset the moment it is wanted (Kaldor, 1939). During periods in which contract prices of a commodity are below the expected future spot prices, convenience yields are larger than the costs of carry, and the market is considered to be in *backwardation*. If it is the other way around, the market is in *contango*. The larger the backwardation, the more significant the yield implied for the convenience of withholding the commodity.

Keynes's concept of normal backwardation suggests it is not abnormal for commodities to have an inverse forward curve (downward sloping for longer maturities). For an extractive commodity such as crude oil, backwardation seems to be the most common pattern, because holding field production can be seen as a real option in which producers choose when to sell the product. In periods of no backwardation, producers have the incentive to not exercise this option, that is, to withhold the

⁸ Forties, Ekofisk, Oseberg, Brent, and Troll fields.

commodity. According to Pindyck (2001), this real option feature of crude oil production suggests that volatility of spot prices may be related positively to convenience yield. Markets move between backwardation and contango depending on supply and demand characteristics of the commodity, the storage market for the commodity, and the risk premiums associated with trading or holding the commodity at different points in time.

Figure 3.2: Monthly Brent and WTI spot prices spread in US\$/barrel

Notes: in this figure we use a long history of data to plot Brent and WTI price over time to enable the discrepancy between the previous years price spread and the change after 2011. Source of the data is the US Energy Information Administration (EIA).

A number of authors have addressed the Brent–WTI spot price differential; Liao et al. (2014) and Fattouh (2010) find that global oil markets are globalized and integrated, whereas Bentzen (2007) finds an influence from OPEC oil prices on Brent and WTI. Researchers also have examined the relationship between convenience yields and fundamental factors (Almansour, 2016; Fama & French, 1988). In this paper, we are interested in the impact of fundamental factors that affect crude oil convenience yields on spot price differentials. Fundamental drivers may include a wide array of elements related to economy, politics, geography, technology among others. In this study we are motivated by the common drivers between convenience yields and spot price differences and we use as fundamental the factors that have been defined impactful in explaining convenience yields. We discuss these and the relevant literature in the following. These fundamental factors are inventories, interest rates and volatility, and we investigate whether convenience-yield-affecting factors also drive oil price spreads. The *theory of storage* (Kaldor, 1939) suggests that level of inventories is related to convenience yields. The larger the storage capacity of an imperishable commodity, the more flexibility the producer has to store the production for future sales if pricing conditions are more favorable. Although investors

can trade Brent and WTI crude contracts quickly, in large volumes, and in liquid markets, the actual physical delivery of the product from one continent to another takes weeks.

In addition to this delay, both the availability of transport and regional demand and supply patterns affect costs (Alizadeh & Nomikos, 2004). If convenience yields and spot prices between two markets differ, we can imagine several scenarios. First, it could be that the products are quite different⁹ and therefore not real substitutes. However, this conjecture does not seem to apply for Brent and WTI crude, because they experienced small price spreads (average of US -\$1.38/barrel) for decades and, as previously discussed, there should be a small price advantage for WTI because of its refining properties (Milonas & Henker, 2001). This is confirmed by historical data that shows the average price spread from 1987 to 2010 was US -\$1.38/barrel, implying that WTI was more expensive than Brent most of the time.

An important development in the global oil market in the 21st century is the increasing extraction of oil from shale formations in the US during the last decade. Technological advancements that utilized previously known techniques such as fracking and directional drilling allowed the economic development of tight oil field. These ‘unconventional’ methods thrived since the early 2000s and currently they provide a large part of US oil production. US field oil production increased from about 5 million barrels per day during 2007 to about 12.2 million barrels per day during 2019. This has been a shift that has changed the global market and brought US closer to energy independence. Previously dominant OPEC has changed a decades-old policy and more aggressively attempted to manipulate the market and a previously market-watcher Russia has cooperated with OPEC to control the global oil market¹⁰.

Second, the inventory levels of the two markets can be different; larger inventories imply a more efficient buffer of demand and supply shocks. The supply dynamics in the two regions around the pricing mechanism differ. The North Sea has produced more than half of its reserves, with most large fields declining to the decommissioning phase; however, it still produces around three million barrels per day, with Norway owning the larger part. Cushing, Oklahoma is surrounded by many of the producing states in the US. Most notably, the Permian basin (Texas and New Mexico, producing about four million barrels per day) has contributed to increasing US crude oil production in the last 10 years, with the rise of “unconventionals” (shale oil). In the North Sea, there is a generally declining trend (with the exception of the 2015 to 2016 period, in which production increased), whereas in the US, there is a resurrection of the shale oil and gas extraction industries. Figure 3.3 plots the production of UK and Norway and the PADDs 2 and 3 in the US.

⁹ WTI contains slightly less sulfur than Brent and hence is ‘sweeter’

¹⁰ This coordination has been named OPEC+

Figure 3.3: Monthly crude oil production in North Sea(UK & Norway) and WTI sourcing areas (PADD 2 & PADD 3; in thousand barrels/day)

Notes: in this figure we plot the production of crude oil in two key areas of interest, UK & Norway, and PADD 2 & PADD 3 in the US PADDs 2 and 3 in the US are providing the Cushing hub with WTI barrels, and Brent consists of five UK and Norwegian fields in the North Sea discussed previously. We use all the data available which for oil production in UK and Norway is since 2002. Sources for the UK and Norway production is the Joint Organisations Data Initiative (JODI) and for the US production data is the US Energy Information Administration (EIA).

Despite their production-cycle differences, the supply dynamics of the two substitute products in spatially different markets may not be of crucial importance in the long run. This relates to the fact that when there is a substantial difference in the price of an identical product, the build-up of inventories pays off to investors. In the short run, however, it seems logical to assume that inventory levels in the two markets may indeed affect prices, spreads, and convenience yields because of the time and costs involved in transporting the commodity. Ye et al. (2005, 2006) propose an inventory–price relationship and their short-term model shows sound forecasting results when applied to WTI.

Third, because volatility may influence convenience yields, different intensities of the two markets' volatility partly may explain increasing convenience yields and growing spot price differences. If convenience yields are regarded as call options (Heinkel et al., 1990; Milonas & Thomadakis, 1997), more volatility in oil prices would imply higher convenience yields. We capture volatility of each crude oil price index independently with a GARCH specification.

Although the importance of oil in the global economy is broadly recognized, there is much less consensus on how oil prices are explained. Historically, oil prices have moved from contango to backwardation and vice versa, with researchers unable to establish the mechanism through which this occurs. To explain oil shocks, Hamilton (2009) and Kilian (2009) suggest a perspective based on demand (global commodities and crude oil specific) and supply characteristics. Similarly, Smith (2009) suggests that oil prices are subject to the laws of demand and supply, even though market fundamentals also have a dominant impact. Kaldor (1939) pioneered another approach to describing oil pricing, that

is, the theory of storage, for which Working (1948) and Brennan (1958) provided further analysis. This fundamental theory elaborates on commodity-specific characteristics and links the spot price of a commodity to the expected future price on the basis of inventories and convenience yields. Fama and French (1988) showed the implications of the theory; although relative convenience yields decline with increases in storage, they do so at a reducing rate. The authors empirically tested a number of commodities and found evidence of the exception of precious metals; precious-metal inventory costs are low, which causes a near-zero convenience yield. Gibson and Schwartz (1990) claimed their futures pricing model was consistent with the theory of storage.

Gorton et al. (2013) use a data set of 31 commodities to find that convenience yields have a decreasing relationship with inventories, as predicted by the theory of storage. Almansour (2016) uses a regime-switching model and finds one regime with high volatility and high convenience yield and another with low volatility and low convenience yield. Previously, Brennan (1958) specified the equation between futures prices, spot prices, and storage costs according to Kaldor's theory of storage; Fama and French (1988) used this calculation to empirically test insights on a data set of metal commodities. (We explain this in more detail in Section 3.2, with reference to Equation [3.1].)

Given information on spot prices, futures prices, and inventory levels, it is possible to extract the implied convenience yield. The convenience yield corrects for potential differences between spot and futures prices that differ from storage costs. Differences in spot and futures prices also depend on the interest rates of the markets involved, because interest rates partly determine carrying costs. Therefore, we also use interest rates as a fundamental convenience-yield-affecting factor, and by extension, spot price differences. In the oil market, this translates to value added to the holder of the commodity and the “convenience” that may occur in holding the asset (oil) in cases of sharp demand shocks and temporary shortages. The occurrence of convenience yields can be particularly important in global oil markets. Given that the supply-and-demand sources of crude oil may be different locations, there are transportation and time frictions as well as costs. Because of this natural fragmentation, oil indexes in markets located far apart may not always follow the same price. Convenience yields is the implied value given by prices for the benefit of physically withholding the commodity; therefore, the fundamental drivers (most importantly, inventories) also may affect the divergence/convergence of crude oil market indexes. In particular, the higher the convenience yield, the more likely prices will differ in spatially separated markets. This is because large convenience yields imply a market that values holding of a commodity, even when there are alternative sources or substitutes.

By using fundamental factors that determine convenience yields, we examine whether these factors also drive the price spreads between Brent and WTI. We consider the theory of storage (Kaldor, 1939) to be a fundamental analytical point of view, and we build on the specifications of Brennan (1958) and Fama and French (1987), as used by Fama and French (1988), to derive convenience yields in the

crude oil market. By accounting for inventory levels, interest rates, and volatility as fundamental factors that affect convenience yields and price spreads, we control for different model specifications. Accordingly, our study aims to extend literature by proposing a link between fundamental convenience-yield-affecting factors and spot price differences in the oil market. It also aims to provide detailed information on convenience yields, spot prices, and futures prices of crude oil and discuss the fundamentals that may have led to an increasing price spread between Brent and WTI.

The remainder of the paper is structured as follows: In Section 2, we explain the methodology of our approach. In Section 3, we discuss our data and the descriptive statistics. In Section 4, we present and discuss our results, and we conclude in Section 5.

3.2 Methodology

We depart from a general model for the relationship between futures prices, spot prices, interest rates, storage costs, and convenience yields as provided by Fama and French (1987):

$$F_{t,T} - S_t = S_t R_{t,T} + W_{t,T} - CY_{t,T}, \quad (3.1)$$

where $F_{t,T}$ is the futures price at time t , for a delivery at time T ; S_t is the spot price at time t ; $R_{t,T}$ is the interest rate for the time period between t and T ; $W_{t,T}$ is the storage costs for the period between t and T ; and $CY_{t,T}$ is the convenience yield from holding the commodity the period between t and T .

Commodity prices and spreads may be affected by real interest rates, storage costs, and convenience yields. Equation (3.1) shows that these are interrelated. Supply and demand dynamics and their elasticities affect price changes, with inventory levels acting as a stabilizing mechanism. Accordingly, inventories are an important determinant of convenience yields, because abundance implies less benefit from withholding more physical commodities. Although inventory levels do not appear in Equation (3.1), they indirectly play a role through convenience yields. The full conceptual model of Brennan (1958) is:

$$E(S_{t+1}) - S_t = w_t(L_t) + \pi_t(L_t) - cy_t(L_t), \quad (3.2)$$

where w_t is the marginal storage cost; π_t is the marginal risk premium on inventory; cy_t is the marginal convenience yield; and L_t is the inventory level at time t . The higher the inventory levels, the less likely a convenience yield is present for the particular commodity. When inventories are running low, demand shocks may affect prices significantly, and the convenience yield tends to be higher. Others have used the theory of storage to explain the variability of futures and spot prices (Fama & French, 1988) and compared alternative theories such as expected risk premiums (Fama & French, 1987). Gorton et al.

(2013) found that convenience yields and inventories have a negative non-linear relationship, and Almansour (2016) separated the relationship into two regimes.

Given that the highest frequency of storage data is on a monthly basis, we use monthly prices and volatility to match availability-of-storage data. Because we have multiple futures contracts, we are able to estimate multiple convenience yields for our two types of crude oil (Brent and WTI). There is no publicly available data or exchanges that price oil storage; therefore, we cannot observe directly the cost of physical storage for Brent and WTI crude oil. However, as Equation (3.2) signifies, storage costs may be affected by inventory levels; as inventory levels vary, their effects on convenience yields and marginal storage costs may vary too. Because storage costs increase the basis (the difference between futures price and spot price) and convenience yields reduce it, the two move in opposite directions. High storage costs imply higher futures prices, whereas large convenience yields imply the opposite.

Empirically, we cannot decompose directly the magnitude of the change caused by storage costs and convenience yields. Rogers et al. (2005) suggest that storage is a fixed cost for crude oil; they find that WTI storage costs for the period 1989 to 2004 were 22% of the spot price per annum, on average. With regard to our variable of interest, which is the Brent–WTI price spread, as long as tanker-chartering costs¹¹ do not differ significantly between the US and the UK markets, most of the variation should be proxying differences in the convenience yields. When calculating the convenience yield, we do not attempt to subtract the storage costs.¹² In support, Alizadeh and Nomikos (2004) find no evidence that freight costs are related to physical crude oil (Brent and WTI) price differences.

We rewrite Equation (3.1) by re-arranging to make the convenience yield a dependent variable and excluding storage costs, we calculate (net) convenience yields by:

$$CY_{t,T} = S_t - F_{t,T}e^{-R(t-T)}, \quad (3.3)$$

where $CY_{t,T}$ is the convenience yield from holding the commodity the period between t and T ; $F_{t,T}$ is the futures price at time t for a delivery at time T ; and S_t is the spot price at time t .

Equation (3.3) defines the net convenience yields for every period and every commodity. Convenience yield theory (Brennan, 1958; Kaldor, 1939; Working, 1948) was developed to explain backwardation (when forward prices are higher than expected future spot prices) in commodity markets. Physically holding the consumption asset, compared to the promise of future delivery, may provide this

¹¹ Marginal storage cost should be close to the cost of chartering very large crude carriers (VLCCs), because traders use them for hedged contango trade (storing crude that has to be delivered in the future). Tanker chartering is a global market and prices similarly affect different locations' storage costs for crude oil.

¹² As such, $CY_{t,T}$ in Equations (1) and (3) is not the same; it differs by a fixed number, that is, storage costs. Equation (3) calculates the net convenience yield, which is the convenience yield after subtracting storage costs.

convenience. The scarcer the commodity, the higher the convenience; the commodity's scarcity in the short run is determined by the storage levels. On the one hand, with high storage levels, refineries and industries that need the commodity as an operational input will consider it less risky to not hold the physical asset they will need in the near future. On the other hand, when stocks are running lower, the possibility that they will lack input will increase their risk of being vulnerable to supply shocks. According to Heinkel et al. (1990) and Milonas and Thomadakis (1997), the convenience yield is a call option on a respective commodity; because holding the physical asset actually provides an option the futures contract does not have, the difference between futures and spot prices after including all other costs is the convenience yield—and therefore the value—of this option.

Another factor that contributes to higher convenience yields may be the volatility of the spot price of crude oil. When stock is low, prices may be higher because of scarcity. Accordingly, the volatility of a crude oil index, together with the oil inventories in respective geographical areas, informs us of the potential convenience the commodity may offer to the physical holder (see also Ye et al. 2005, 2006).

Convenience yields are measured in US dollars per barrel. A relative measure of convenience yield compared with spot price may provide more intuitive results. Whereas dollars per barrel inform us about level of convenience, a percentage over the current price provides perspective on the relative significance of the yield. Gibson and Schwartz (1990) and Fama and French (1988) also refer to the relative convenience yield.

Therefore, we calculate *cash convenience yields*, which are convenience yields over the spot price for the same month, multiplied by a hundred to be expressed in percentages:

$$\text{Cash \% } CY_{t,T} = \frac{CY_{t,T}}{S_t} * 100, \quad (3.4)$$

where $\text{Cash \% } CY_{t,T}$ is convenience yield from holding the commodity the period between t and T , measured as a percentage of the spot price; $CY_{t,T}$ is the convenience yield from holding the commodity for the period between t and T ; and S_t is the spot price at time t .

As previously discussed, according to the theory of storage, inventories are a fundamental determinant of convenience yields, because they act as a buffer against supply and demand imbalances. Many authors have used specifications regressions in which convenience yields depend on inventories. Heaney (2006) models convenience yields as a function of current and lagged changes in inventory levels, of the form $CY_t = a + \sum_{k=0}^K \beta_k \Delta \ln(S_{t-k})$, where $\Delta \ln(S_{t-k})$ is the change in the natural logarithm of stock levels. Heaney also incorporates an interest-rate-adjusted version in his analysis. Omura and West (2014) and Milonas and Henker (2001) maintain that convenience yields depend directly on inventories. Buyuksahin et al. (2013) directly link crude oil price spreads with interest rate

and inventory levels. According to the findings of Gibson and Schwartz (1990) and Milonas and Thomadakis (1997), convenience yields have an option-like nature; therefore, they increase with volatility. Sevi (2015) finds that volatility and jumps are important in modeling convenience yields for WTI during the 2001 to 2010 period. In this study, we use inventories, interest rates, and volatility to develop a greater understanding of their relationships with convenience yields and determine their role in regional crude-oil price differences.

Based on the previous and intending to identify the potential impact of fundamental factors we use a regression model for both Brent and WTI crude of the following form:

$$\text{Cash \% } CY_{t,T}^i = \alpha_1 \Delta I_t^i + \alpha_2 \Delta R_t^i + \alpha_3 \text{Vol}R_t^i, \quad (3.5)$$

where $\text{Cash \% } CY_{t,T}^i$ is the relative convenience yield from holding the respective crude oil i for the period between t and T ; ΔI_t^i is the percentage changes on inventory levels of crude oil in market i at time t ; ΔR_t^i is the change in market i base interest rate at time t ; and $\text{Vol}R_t^i$ is the volatility of crude oil i spot price returns on a monthly basis, measured by a GARCH specification. We expect that for different time horizons and different products, the importance of each fundamental factor will differ. Something noteworthy here is that volatility is not directly observed but is constructed and modelled before being utilized as an explanatory factor of relative convenience yields. We believe the additional noise is not problematic as the sample size is large enough and volatility of oil spot prices has been modelled independently on a typical GARCH manner. We stress our results over different periods and convenience yield maturity specifications.

In Section 3.1, we discussed the reasons that we expect distinct behavior of convenience yields and oil prices in the short run. For short horizons, demand and supply shocks may distort spot prices, and these distortions are larger when fundamentals—such as inventory levels functioning as shock absorbers—are lower. Similarly, convenience yields of shorter horizons may show different characteristics and sensitivities to fundamentals than longer horizons. We use a number of longer horizons and present their results so as to be able to verify short and long term dynamics and that results are not due to a certain horizon's idiosyncrasies.

Equation (3.5) implies a relationship between fundamentals and convenience yields. Based on the theory of storage and previous findings (Gorton et al., 2013; Heaney, 2006) we expect convenience yields to have a negative relationship with changes in inventory levels; larger inventory levels of a commodity should decrease the “convenience” of withholding a commodity and therefore reduce the convenience yield. Interest rates and volatility are less straightforward. According to Gibson and Schwartz (1990), Milonas and Thomadakis (1997), and Pindyck (2001), volatility should increase convenience yields, because higher volatility increases the value of an option. However, Chiarella et al. (2016) suggest that the positive relationship between convenience yields and volatility holds under

normal market conditions. In periods of sharp contraction as the result of economic conditions, we may observe a negative relationship. With regard to interest rates, there are two opposite forces at play; one increases convenience yields with opportunity costs, and the other decreases convenience yields with the time value of money.

After testing our basic assumptions with regard to the determinants of convenience yields, we focus on the fundamental reasons for a spread in spot prices between the two crude types of crude oil. Because the convenience yield signifies willingness to hold a physical commodity, it may shed some light on the actual divergence between crude oil prices in different locations. The reasons for physically withholding a commodity—instead of holding a promise of delivery in the future—may be identical to the reasons for a large spread between the spot price of two commodities, that is, the distance between the two markets reduces flexibility and arbitrage opportunities in the short term. According to Milonas and Henker (2001), the entire procedure of loading, shipping, and unloading could make crude available at a minimum of one-and-a-half months to a maximum of two to three months. Alizadeh and Nomikos (2004) estimate that it can take three to five weeks to load Brent crude in the Sulom Voe terminal, transport it, and unload it in the US. In addition, it takes time to deliver the cargo to Cushing, WTI's delivery point. These time constraints define convenience yield, because an alternative source of crude oil is not immediately available, making prices more sensitive to changes in demand and supply conditions. Accordingly, price volatility and storage conditions may play a significant role in determining crude oil spreads. Therefore, the fundamental factors that drive the spread are the same as those that determine the convenience yields of each crude oil type.

The main idea of our paper is that the fundamental forces that affect convenience yields explain the spread between Brent and WTI spot prices. We hypothesize that spreads in prices can be explained by differences in convenience yields; therefore, the factors that explain convenience yields also may explain price spreads. If markets are frictionless, such that trading can take place quickly and without cost, potential price differences should disappear instantly through arbitrage opportunities. However, crude oil markets experience both transport costs and delays in actual delivery from one place to another. This spatial fragmentation magnifies the importance of fundamentals, causing both convenience yields and spot prices. We extend this basic specification by including the difference of futures contracts prices as an explanatory variable of the Brent–WTI spot price spread. This is defined as the percentage change of the price difference between a futures contract of Brent for delivery at time T with the futures contract of WTI for the same month delivery:

$$dFut_{t,T} = \frac{F_{t,T}^{Brent} - F_{t,T}^{WTI}}{\frac{F_{t,T}^{Brent} + F_{t,T}^{WTI}}{2}}, \quad (3.6)$$

where $F_{t,T}^{Brent}$ is the price of a Brent crude oil futures contract at time t for delivery at time T , and $F_{t,T}^{WTI}$ is the price of a WTI crude oil futures contract at time t for delivery at time T . On the basis of Equation (3.3), the difference in spot prices can be represented by the following identity:

$$\frac{S_{t,T}^{Brent} - S_{t,T}^{WTI}}{\frac{S_{t,T}^{Brent} + S_{t,T}^{WTI}}{2}} = cash\%CY_{t,T}^{Brent} - cash\%CY_{t,T}^{WTI} - dFut_{t,T}. \quad (3.7)$$

Given that we hypothesize that convenience yields can be modeled as in Equation (3.5), we substitute this equation in the above expression, taking into account different maturities, to arrive at the following reduced form that we estimate as:

$$\frac{S_{t,T}^{Brent} - S_{t,T}^{WTI}}{\frac{S_{t,T}^{Brent} + S_{t,T}^{WTI}}{2}} = \beta_0 + \beta_1 dI_{t,T} + \beta_2 dR_{t,T} + \beta_3 VolR_{[Brent-WTI]} + \beta_4 dFut_{t,T}, \quad (3.8)$$

where $dFut_{t,T}$ is the difference of Brent and WTI prices of futures contracts at time t for delivery at time T as defined in Equation (3.6).

3.3 Data

We use daily values of the spot and futures prices of Brent and WTI crude oil. Brent is a leading global benchmark for the Atlantic Basin crude oils. The Intercontinental Exchange (ICE) is the market operator for Brent crude oil contracts, and WTI is the midcontinent US benchmark; related contracts are traded at the Chicago Mercantile Exchange (CME). From these prices, we construct the convenience yields, in line with Brennan (1986) and Milonas and Henker (2001). The convenience yield $CY_{t,T}$ is the difference at time t between the spot price of the crude oil and the futures price for maturity time T at time t , $F_{t,T}$. The futures price is discounted for carrying charges. This extraction of the convenience yield implies that we are left with the net convenience yield, for which the cost of storage has been included (subtracted). That is, a negative net convenience yield, as constructed by Equation (3.3), is not counterintuitive, because it implies a storage cost that is higher than the convenience yield. We collect spot and futures crude oil prices (Brent and WTI) and interest base rates for the US and the UK from Datastream.

We extract monthly ending oil stocks for the UK, Norway,¹³ and the US from the Joint Organisations Data Initiative (JODI) database for the longest period of available inventories data, June 2006 to June 2017, and use this period for all our variables. Table 3.1 presents the descriptive statistics for crude oil spot prices, volatility, and price spread.

Table 3.1: Descriptive statistics of crude oil prices, spread, volatility, and crude inventories

	Brent Spot	WTI Spot	Spread (relative)	WTI (returns volatility)	Brent (returns volatility)	UK & Norwegian Inventories	US Inventories
	Dollars per barrel (US\$/billion)					Thousands of tonnes	
			[%]	[%]	[%]		
Mean	82.05	76.71	5.34%	0.93%	0.99%	6636	143292
Median	77.11	77.43	3.62%	0.75%	0.64%	6496	141221
Maximum	132.72	134.1	27.55%	3.83%	6.23%	8644	166134
Minimum	32.18	30.66	-8.85%	0.38%	0.07%	5363	130451
Std. Dev.	26.60	23.38	7.53%	0.56%	1.10%	635	8481
Observations	133	133	133	133	133	133	133

In this table, we present descriptive statistics for spot crude oil prices, their volatility, and the inventory stocks of crude for the US, UK, and Norway. Brent and WTI Spot are the average monthly spot prices of crude oil price and Spread is their difference. They are denominated in US dollars per barrel. Brent and WTI volatility is modeled as a GARCH(1,1) from the monthly average prices, and standard deviation (Std. Dev.) is the rolling standard deviation of average monthly spot price of its crude oil of the last 12 months; it also is denominated in US dollars per barrel. The final two columns present the crude oil inventories (ending stocks) in the US, UK, and Norway from June 2006 to June 2017. Inventories are expressed in thousands of tonnes of crude oil; they are extracted from the JODI database.

The table provides a sample of 133 monthly observations and includes a variety of periods both volatile and tranquil. During 2009, Brent prices average about \$20/barrel lower than their average over the whole period. Similarly, during 2015–2017 Brent oil price averaged more than \$30/barrel less than the average price over the period. In contrast, oil prices peaked before the global financial crisis in 2008, and average about \$16/barrel higher than the full sample average, as they also did during 2014. While 2009 has been very volatile for the markets and the crude oil price, 2012 was a tranquil period. During the period we investigate exist periods with both small (2008–2010) and high (2011–2014) spreads in the spot price of Brent and WTI (Figure 1). The average spot price of Brent during these years is roughly US \$82 per barrel, whereas WTI has an average spot price of somewhat less than US \$77 per barrel. Both Brent and WTI have extreme observations, ranging from US \$30–US \$32 dollars as a minimum to US \$132–US \$134 as a maximum. Brent is somewhat more volatile than WTI. The spread of their spot prices is positive (Brent spot price–WTI spot price), implying that on average, Brent experienced

¹³ As per Section 3.1, we include Norway, because Brent pricing is dominated by three Norwegian and two large UK fields.

a higher price in the period under review, more than 5% of the average price of the two crudes. This occurred particularly from 2011 to 2014, when Brent was much more expensive than WTI. The spread reached a maximum of almost 28% and the minimum was close to -9% (WTI was more expensive than Brent). The relative spread during these 11 years was quite volatile, with a standard deviation of more than 7.5% on a monthly basis. The last two columns of Table 3.1 show the end-of-month oil inventories of the UK, Norway, and the US. The US held, on average, more than 20 times the stocks in crude oil as inventory compared to the UK and Norway combined.

Tables 3.2 and 3.3 present the convenience yields for Brent and WTI, calculated for different time horizons. As previously discussed, convenience yield theory explains the empirical finding with regard to backwardation in commodity futures markets. The benefit of holding the physical asset may exceed the cost of storage and the time value of money. When this is the case, we should observe positive net convenient yields. Because of the fragmentation of the market and the duration of possible delivery between the two markets, we would expect a decline in the values of convenience yields over longer horizons. Table 3.2 presents the descriptive statistics for the convenience yields of WTI over an increasing horizon from one to 24 months. Table 3.3 provides the descriptive statistics for Brent convenience yields for the same horizons. We note that the two crudes have some common features, as well as some distinct features.

Figure 3.4: Volatility of spot price returns for Brent and WTI crude

Notes: This figure plots volatility of spot price returns for Brent and WTI, for the period June 2006 to June 2017. We take into account persistence to model volatility and find a GARCH(1,1) to be the best-fitting model for both Brent and WTI.

First, both experience decreasing convenience yields when moving from the one-month horizon to the seven-month horizon. Whereas WTI convenience yields continue to decline until the nine-month horizon, Brent convenience yields start increasing again at the eight-month horizon. The decreasing convenience yield can be explained by the lesser importance of withholding the physical asset over a longer period of time. In addition, storage costs increase with the horizon, causing a negative net convenience yield. Because we do not have data on storage costs, we are limited only to observing when they are larger, as indicated by the gross convenience yield. The convenience yields of the two types of crude differ in size: For WTI, a horizon of one month is US \$-0.42 per barrel, whereas for Brent it is more negative (US \$-0.99 per barrel). Given that a smaller convenience yield implies a market that is less sensitive to demand conditions, in this case WTI is “tighter” for the one-month horizon. The same holds for horizons up to 11 months. For horizons of less than a year, Brent generally shows more negative net convenience yields, signifying that in this market convenience yield is less impactful than storage costs, and the time value of money and storage costs counter the benefits from holding the commodity. For horizons of one year or longer the opposite is the case: Brent convenience yields range from US \$0.28 to US \$-1.51 per barrel, whereas for WTI, they range from US \$-0.42 to US \$-1.32 per barrel.

The Appendix, Tables 3.A and 3.B, show the cash convenience yields as defined in Equation (3.4) for the same time horizons as their dollar equivalents. These convenience yields are expressed as a percentage of the respective spot prices at the time. This specification corrects for potential biases from the spot price differences between Brent and WTI. Cash convenience yields show both similarities and disparities with their convenience-yield equivalents; WTI cash convenience yields steadily increase from -0.81% to -3.47% at a lower rate as horizons lengthen, with a peak between 18 and 24 months. Brent cash convenience yields also increase overall with horizons, peaking at 12 months. However, they are smaller than WTI cash convenience yields across all horizons, with averages ranging from -1.53% to -4.12%.

Table 3.2: Descriptive statistics of WTI crude oil convenience yields for 2006–2017

WTI CY (US\$/billion)	Mean	Median	Maximum	Minimum	St. Dev.	Observations
1 month	-0.42	-0.09	1.23	-6.80	1.17	133
2 months	-0.69	-0.38	1.80	-7.07	1.38	133
3 months	-0.87	-0.60	4.18	-7.84	1.88	133
4 months	-1.01	-0.80	3.40	-8.32	2.09	133
5 months	-1.13	-0.94	4.09	-8.75	2.32	133
6 months	-1.21	-1.10	4.73	-9.14	2.56	133
7 months	-1.27	-1.24	5.33	-9.49	2.81	133
8 months	-1.31	-1.39	5.88	-9.82	3.05	133
9 months	-1.32	-1.41	6.41	-10.13	3.27	133
10 months	-1.18	-1.43	11.76	-10.42	3.70	133
11 months	-1.20	-1.44	10.16	-10.71	3.87	133
12 months	-1.21	-1.51	9.16	-11.05	4.05	133
18 months	-1.10	-1.61	11.77	-13.51	5.16	133
24 months	-0.81	-1.34	14.80	-15.43	6.21	133

This table includes descriptive statistics of the convenience yields of WTI crude oil for 2006 to 2017 on a monthly basis and for horizons ranging from one to 24 months. The convenience yields are defined as the difference between the average spot price of WTI crude oil and the discounted average futures price of the respective horizon. We constructed them according to Equation (3.2): $CY_{t,T} = S_t - F_{t,T}e^{-R(t-T)}$. The sample consists of 133 monthly observations from June 2006 to June 2017. We take horizons from one month to two years and report them in dollars per barrel (US\$/billion).

Table 3.3: Descriptive statistics of Brent crude oil convenience yields for 2006–2017

Brent CY (US\$/billion)	Mean	Median	Maximum	Minimum	St. Dev.	Observations
1 month	-0.99	-0.84	2.97	-13.10	1.88	133
2 months	-1.11	-1.26	4.54	-12.68	2.19	133
3 months	-1.26	-1.67	5.37	-12.21	2.58	133
4 months	-1.38	-1.96	5.90	-11.64	3.00	133
5 months	-1.45	-2.12	6.31	-10.97	3.41	133
6 months	-1.50	-2.53	6.60	-11.37	3.82	133
7 months	-1.51	-2.70	6.84	-12.46	4.23	133
8 months	-1.50	-2.88	7.08	-13.41	4.62	133
9 months	-1.46	-2.71	7.75	-14.25	5.01	133
10 months	-1.41	-2.61	8.55	-14.96	5.38	133
11 months	-1.34	-2.58	9.34	-15.59	5.74	133
12 months	-1.26	-2.50	10.13	-16.23	6.10	133
18 months	-0.56	-1.73	14.40	-19.79	8.11	133
24 months	0.28	-0.65	18.03	-22.39	9.88	133

This table includes the descriptive statistics of the convenience yields of Brent crude oil for 2006 to 2017 on a monthly basis and for horizons ranging from 1 to 24 months. The convenience yields are defined as the difference between the average spot price of Brent crude oil and the discounted average futures price of the respective horizon. We constructed them according to Equation (3.2): $CY_{t,T} = S_t - F_{t,T}e^{-R(t-T)}$. The sample consists of 133 monthly observations from June 2006 to June 2017. We take horizons from one month to two years and report them in dollars per barrel (US\$/B)

3.4 Results

Crude oil prices have been very volatile during the last decade. At the same time, two major trading hubs that affect global crude oil prices experienced divergent prices for long periods and unprecedented price spreads. Using a convenience yield point of view, we investigate the impact of fundamental determinants of the crude oil market on the spot price differential of Brent and WTI crude oil. Tables 3.4 and 3.5 present Equation (3.5) results for horizons of one to 24 months for WTI and Brent respectively; WTI cash convenience yields depend on US inventory percentage changes, US interest rate changes, and volatility of WTI spot price returns. US inventories have a negative effect on WTI cash convenience yields across horizons. For horizons longer than two months, the impact is significant and increases over time. Between the three-month horizon and the 24-month horizon, the coefficient more than doubles.

The larger the stocks of crude oil in the US market, the less likely the crude oil price is to show sensitivity to demand and supply shocks. Equation (3.2) in Section 3.2 describes the convenience yield conceptual model. As inventory levels increase, the risk of not being able to access the physical commodity in the short term reduces, which in turn reduces the value of withholding the asset compared to an expectation of a future delivery. Our results confirm this for most US horizons: Although most horizons support the expectation of the theory of storage—that larger inventories reduce the “convenience” of holding crude oil—results show this is not the case for the first two months. For periods up to two months, the sign of the impact is negative, although the explanatory power is small, especially for the one-month horizon. The significant impact of US inventories indicates that the convenience of holding crude oil does not reduce, at least not for a period up to 24 months. Using data on 21 commodities, Symeonidis et al. (2012) find similar results on the relationship between convenience yield and inventories for horizons of two, six, and 10 months. They also find an increasing magnitude of the coefficient and significance over longer horizons (from two months to 10 months); however, in our sample, the two-month horizon coefficient is insignificant. Our findings with regard to inventories are similar to Gorton et al. (2013), who find a negative relationship between convenience yields and inventories for the period 1971 to 2010.

With the interest rate variable, we control for any macroeconomic-related effects to convenience yields. If interest rates do not change, inventories and volatility impact are captured more directly. For the WTI case in Table 3.4, we observe that for short-term horizons, changes in interest rates are insignificant. For a three-month horizon and longer there is a significantly negative relationship. Interest rates weigh in the carrying costs and in turn in the convenience yield. Moreover, US interest rates have a generally decreasing coefficient in determining convenience yields—from -0.8 for the one-month horizon to -12.1 for 24 months. Two conflicting forces drive this coefficient: On one hand, an increasing interest rate implies a higher opportunity cost and therefore less incentive to hold

the physical asset. On the other hand, a higher interest rate decreases the value of the futures prices and therefore increases the convenience yield. When we observe a negative sign, the force of the first power is larger.

Table 3.4: Relationship between WTI cash convenience yields and fundamental factors

	US Inventories (% change)	US Interest Rate (change)	WTI Volatility (returns)	Spot Constant	Adjusted R ²
WTI CASH CY 1	-6,842 [0.69]	-0.798 [0.42]	-0.646** [0.05]	-0.175 [0.61]	0.04
WTI CASH CY 2	-28,42 [0.13]	-1.794 [0.10]	-1.945*** [0.00]	0.522 [0.17]	0.22
WTI CASH CY 3	-69.29** [0.03]	-4.639** [0.01]	-3.028*** [0.00]	1.057* [0.09]	0.24
WTI CASH CY 4	-76.28** [0.02]	-5.389*** [0.01]	-3.786*** [0.00]	1.461** [0.03]	0.30
WTI CASH CY 5	-82.56** [0.02]	-6.007*** [0.00]	-4.459*** [0.00]	1.829** [0.01]	0.34
WTI CASH CY 6	-88.23** [0.02]	-6.560*** [0.00]	-5.089*** [0.00]	2.207*** [0.00]	0.37
WTI CASH CY 9	-105.24** [0.01]	-7.958*** [0.00]	-6.732*** [0.00]	3.322*** [0.00]	0.43
WTI CASH CY 12	-122.92** [0.01]	-9.343*** [0.00]	-8.275*** [0.00]	4.695*** [0.00]	0.47
WTI CASH CY 18	-141.14** [0.01]	-10.837*** [0.00]	-10.64*** [0.00]	6.669*** [0.00]	0.50
WTI CASH CY 24	-157.82** [0.02]	-12.077*** [0.00]	-12.67*** [0.00]	8.619*** [0.00]	0.51

In this table, we present the results of regressing WTI cash convenience yields as estimated by Equations (3.3) and (3.4): $CASH\ CY_{t,T} = S_t - F_{t,T}e^{-R(T-t)}$ on fundamental factors affecting the convenience yields. The relationship is described by Equation (3.5): $Cash\ \% CY_{t,T}^i = \alpha_1 \Delta I_t^i + \alpha_2 \Delta R_t^i + \alpha_3 VolR_t^i$, where $Cash\ \% CY_{t,T}^i$ is the relative convenience yield from holding the respective crude oil; i is the period between t and T ; ΔI_t^i is the percentage changes of inventory levels of crude oil in market i at time t ; ΔR_t^i is the change in market i base interest rate at time t ; $VolR_t^i$ is the volatility of crude oil i spot price returns on a monthly basis as measured by a GARCH specification; p -values are presented in brackets ([]); and *, **, *** signify significance at 10%, 5%, and 1% respectively.

Volatility of spot WTI prices has a negative effect on convenience yields. According to previous theoretical work and empirical findings (Milonas and Thomadakis, 1997; Pindyck, 2001), we would expect a positive effect of increasing volatility, because it would make holding the commodity more appealing and thereby increase the value of the convenience yield. This is based on a view of convenience yield as having option contract features. However, according to Chiarella et al. (2016), the positive relationship is true only in normal market conditions (when the futures curve is inverted) for backwardation in crude oil. The opposite holds during downturns and low convenience yields. In our

sample, two significant downturns (2009 and 2014–2015) stand out in the sample period, and the market is not “normal” more than half the time. Table 3.4 reports that volatility significantly and negatively affects convenience yields for all horizons. Our results indicate that the option feature (at least with regard to volatility) of convenience yield is not confirmed for the period of our sample. The explanatory power of the regression increases over time, with volatility having the most impact. We present the results of the regressions for a number of horizons to allow comparability and consistency.

Table 3.5 provides the results of all regressions defined in Equation (3.5), for horizons from one to 24 months in the case of Brent. For the one-month horizon, we regress the cash convenience yield as defined in Equation (3.4), over changes in inventories, changes in interest rates, and volatility of spot price returns. Here, inventories have a positive coefficient, in contrast to our WTI finding, and to our expectation according to our discussion in Section 3.2. Even though coefficients vary from 0.45 to 5.48, regressions for all horizons produce non-significant results for inventories’ effect on Brent convenience yields. It seems that the Brent market is not sensitive to changes in inventories in the UK and Norway. Despite much smaller inventories in these two countries compared to the US, Brent convenience yields are not significantly affected by changes in inventories. This could be the result of the international impact and exposure of Brent; it serves as a benchmark for oil pricing for many global transactions and contracts. The result supports the view that Brent crude is a truly international index. Its pricing may be the result of global oil demand and supply characteristics, whereas WTI is a large but somewhat segregated market—also because of export restrictions on crude oil and petroleum products in the US (Nerurkar, 2012). Rate changes in the UK have a significant and positive effect on Brent convenience yields for horizons longer than four months; as previously discussed, there are two conflicting forces that drive the impact of interest rates on convenience yields. In the Brent case, it seems that the value decrease of futures prices (and thus the increase of convenience yields) caused by higher interest rates is higher than the decrease caused by opportunity costs. Brent convenience yields are negatively affected by Brent volatility. Similar to WTI spot return volatility, Brent spot return volatility significantly affects cash convenience yields for all horizons between one month and 24 months. Coefficients start at -0.7 for the one-month horizon regression with the highest at -8.7 for the 24-month horizon. As we expected from the one-month horizon results, Brent convenience yields are less affected by volatility for all longer horizons. With regard to the results for WTI in Table 3.4, we note they contrast with the findings of Gibson and Swartz (1990) and Milonas and Thomadakis (1997). As with WTI, the abnormal market conditions that Brent crude experienced for the largest part of the sample explain the negative impact of volatility in cash convenience yields (Chiarella, 2016).

To explore the relationship between convenience yields and price spreads, as well as the fundamental drivers of the spreads, we use Equation (3.8) to regress the monthly relative spot price spread on four variables. In line with this equation, we regress the relative spot spread on the differences of all fundamental factors that explain convenience yields and on the relative price spread of futures

prices for one-, two-, three-, six-, 12-, and 24-month horizons (see Section 3.2). In Table 3.6, for comparison and robustness reasons, we present results for specifications under various futures contracts horizons. When we account for fundamental factors, we find that changes in inventories and volatility of the spread significantly affect spread. Changes in inventories positively affect spread, implying that the higher US inventories compared with combined UK and Norway inventories, the larger the spread between the Brent spot price and the WTI spot price.

Table 3.5: Relationship between Brent cash convenience yields and fundamental factors

	UK & Norway Inventories (% change)	UK Interest Rate (change)	Brent Volatility (returns)	Spot Constant	Adjusted R ²
Brent CASH CY 1	0.447 [0.83]	0.499 [0.86]	-0.712*** [0.00]	-0.806*** [0.00]	0.11
Brent CASH CY 2	0.578 [0.81]	3.632 [0.27]	-1.387*** [0.00]	-0.505* [0.10]	0.31
Brent CASH CY 3	0.858 [0.77]	6.201 [0.11]	-2.012*** [0.00]	-0.288 [0.81]	0.41
Brent CASH CY 4	1.215 [0.72]	7.813* [0.09]	-2.567*** [0.00]	-0.0851 [0.84]	0.46
Brent CASH CY 5	1.526 [0.69]	8.869* [0.09]	-3.087*** [0.00]	0.120 [0.80]	0.48
Brent CASH CY 6	1.822 [0.67]	9.821* [0.09]	-3.555*** [0.00]	0.336 [0.53]	0.49
Brent CASH CY 9	2.723 [0.63]	12.831* [0.09]	-4.747*** [0.00]	1.089 [0.12]	0.50
Brent CASH CY 12	3.621 [0.59]	15.686* [0.09]	-5.702*** [0.00]	1.878** [0.03]	0.50
Brent CASH CY 18	4.716 [0.60]	21.502* [0.08]	-7.358*** [0.00]	3.726*** [0.00]	0.49
Brent CASH CY 24	5.475 [0.61]	27.388* [0.06]	-8.660*** [0.00]	5.564*** [0.00]	0.49

In this table, we present the results of regressing Brent cash convenience yields as estimated by Equations (3.3) and (3.4): $CASH\ CY_{t,T} = S_t - F_{t,T}e^{-R(T-t)}$ on fundamental factors affecting convenience yields. The relationship is described by Equation (3.5): $Cash\ \%CY_{t,T}^{Brent} = \alpha_1 \Delta I_t^{UK} + \alpha_2 \Delta R_t^{UK} + \alpha_3 VolR_t^{Brent}$, where $Cash\ \%CY_{t,T}^{Brent}$ is the relative convenience yield from holding WTI crude oil the period between t and T ; ΔI_t^{US} is the percentage changes of inventory levels of crude oil in the US at time t ; ΔR_t^{US} is the change in US base interest rate at time t ; $VolR_t^{Brent}$ is the volatility of WTI crude oil spot price returns on a monthly basis as measured by a GARCH specification; p -values are presented in brackets ([]); and *, **, *** signify significance at 10%, 5%, and 1% respectively.

Table 3.6: Relationship between crude oil price spread¹⁴ and fundamental factor spreads

	Spread	Spread	Spread	Spread	Spread	Spread	Spread
Δ Inventories = [US Inventories] - [UK & NO Inventories]	0.769*** [0.00]	0.002 [0.98]	0.005 [0.97]	0.288* [0.06]	0.267 [0.11]	0.358* [0.08]	0.533** [0.02]
Δ Interest Rate = [UK Interest Rate] - [US Interest rate]	-0.022 [0.47]	0.016 [0.16]	0.025 [0.16]	0.028 [0.21]	0.038 [0.12]	0.036 [0.23]	0.009 [0.79]
Volatility of Spread = [Brent - WTI Volatility]	4.829*** [0.00]	-0.150 [0.68]	-0.127 [0.75]	1.142** [0.02]	1.999*** [0.00]	3.611*** [0.00]	4.654** [0.00]
Constant	-1.395*** [0.00]	-0.009 [0.96]	-0.016 [0.51]	-0.528* [0.06]	-0.496 [0.10]	-0.660* [0.07]	-0.972** [0.02]
dFut1		1.054*** [0.00]					
dFut2			1.124*** [0.00]				
dFut3				0.874*** [0.00]			
dFut6					0.846*** [0.00]		
dFut12						0.570*** [0.00]	
dFut24							0.239** [0.03]
Adjusted R-Squared	0.55	0.87	0.85	0.76	0.72	0.61	0.55

In this table, p -values are presented in brackets ([]), and *, **,***, signify significance at 10%, 5%, and 1% respectively. The table presents the results of regressing spot price spreads of WTI and Brent on the spreads of fundamental factors used to characterize convenience yields in Equation (3.4) and also on the futures prices differences for various maturities. Equation (3.7) describes the model in which we set $dFut_{t,T}$ at either 0 for Equation (3.5) or for different maturities of futures prices: $[S_t^{Brent} - S_t^{WTI}] / [\frac{S_t^{Brent} + S_t^{WTI}}{2}] = \beta_0 Constant + \beta_1 dI_{t,T} + \beta_2 dR_{t,T} [R_t^{UK} - R_t^{USA}] + \beta_3 V_{[Brent-WTI]} + \beta_4 dFut_{t,T}$, where $dFut_{t,T} = \frac{F_{Brent} - F_{WTI}}{\frac{F_{Brent} + F_{WTI}}{2}}$, $dI_{t,T} = \frac{I_{UK\&NO} - I_{US}}{[\frac{I_{UK\&NO} + I_{US}}{2}]}$, $dR_{t,T} = \frac{R_{UK} - R_{US}}{[\frac{R_{UK} + R_{US}}{2}]}$.

We use inventories of the UK and Norway to include stocks on all physical areas in which trading takes place and include its pricing in the Brent calculation. However, when we use UK-only inventories, we find the same results with slightly different coefficients (signs and significance are alike). These results are presented in the Appendix.

As we expected, the sign is positive. When the US market experiences more inventory, this causes more favorable conditions for buying the commodity, because it is more widely available and therefore less expensive than Brent, reflecting a larger spread in favor of the Brent crude spot price. In

¹⁴ We note that in this table, spread is measured by relative spot spread as defined in Equations (3.7) and (3.8).

contrast, higher inventories in the UK and Norway markets may reduce the price of Brent and consequently the Brent–WTI spread. In Table 3.6, we report the results of Equation (3.8) with inventories for both the UK and Norway, given that fields from both countries are included in Brent pricing. In the Appendix (Table 3.E), we report the results for Equation (3.8), finding similar results. At first glance, our results do not confirm findings of Buyuksahin et al. (2013) with regard to US inventories; those authors find that when they account for their sub-sample of public information, US inventories marginally and significantly affect spread only in one of their specifications. When they include information known to traders only (positions and volumes), and some financials (including liquidity and financial stress proxy) variables, US inventories turn insignificant.

Another reason for our findings may be that they do not include any inventory proxy for the Brent market, implying that only the US inventory market exists. The direction of the sign is the same as in our results, that is, higher US stocks (relative to UK and Norway levels) lead to larger spreads. In line with our results, Milonas and Henker (2001) find there is a negative impact of US inventories on WTI convenience yields (significant for horizons of two, three, and four months but not for five and six months) and that convenience yields directly affect spread. The effect of the difference between interest rates in the US and UK on the spread turns out to be insignificantly negative. Table 3.6 suggests that the higher the UK interest rate compared to the US rate, the smaller the spot price spread; however, it is insignificant for all specifications. Also in line with Equation (3.8), volatility of relative spread positively and significantly affects relative spread. This suggests that higher volatility of prices differences between WTI and Brent is higher, and more uncertainty in the market indicates higher relative spread.

Table 3.6 also reports results for regressions of Equation (3.8), including differences in futures prices ($dFut$) under different horizons. Futures price differences significantly and positively affect spot spread with close to one-to-one relationships for horizons of one and two months, with the coefficient gradually reducing to 0.24 for the 24-month contracts. Including the differences of contract prices one month ahead in Equation (3.8) makes the previously significant factors of inventories and volatility insignificant. However, signs remain the same, and the explanatory power increases substantially from 55% to 87%. An explanation for the increasing explanatory power and the insignificance of the fundamental factors is that the correlation between the spot relative spread and one-month futures relative spread is very high because of time proximity and one-month futures price differences attract all variability. Moving to longer than two-month horizons, inventories and volatility become significant.

To investigate further, we ran Equation (3.8) with futures-price differences ($dFut$) as the dependent variable. Table 3.7 presents the results. For spreads in one-month futures prices, the results are almost the same as the spot price spread with regard to volatility and inventories. Interest rate differences are now significant, increasing the overall explanatory power to 64%. With longer horizons,

as we move toward 12 and 24 months, fundamental factors become less relevant (as indicated by a falling explanatory power, 39% for 24 months).

During 2011, a significant shift in crude oil price spread began. To examine potential differences in our results between periods, we estimate Equation (3.5) for two sub-periods, before and after January 2011. The first period includes 55 months from June 2006 to December 2009, and the second includes 77 months between January 2010 and June 2017. This separation and robustness check can provide insights about how fundamental factors may change their influence over time. In the Appendix, we present the results for these equations for both WTI and Brent convenience yields (Tables 3.F and 3.G respectively), which we use as a robustness check for our results. All signs remain the same between the two periods; however, magnitude—and sometimes significance—vary. Volatility remains an important effect on convenience yields, with generally increasing impacts over longer horizons; it is statistically significant for all horizon periods expected from one-month convenience yields from 2006 to 2010. Similar to our findings for the entire period, we find that for both periods, the Brent convenience yield is less affected by volatility than the WTI convenience yield is. The main difference between the two periods is that WTI inventories seem to be less relevant from 2006 to 2010 than from 2011 to 2017. During the second period in which spread increased in favor of Brent, WTI inventories had an increasingly greater impact on WTI pricing.

Table 3.7: Relationship between futures crude oil price spread and fundamental factor spreads

	dFut1	dFut2	dFut3	dFut6	dFut12	dFut24
Δ Inventories = [US Inventories] - [UK - NO Inventories]	0.728*** [0.00]	0.681*** [0.00]	0.550*** [0.00]	0.593*** [0.00]	0.721*** [0.00]	0.986*** [0.00]
Δ Interest Rate = [UK. Interest Rate] - [US Interest rate]	-0.043* [0.09]	-0.042* [0.07]	-0.057** [0.02]	-0.072*** [0.00]	-0.102*** [0.00]	-0.130*** [0.00]
Volatility of Spread = [Brent - WTI Volatility]	4.726*** [0.00]	4.411*** [0.00]	4.220*** [0.00]	3.346*** [0.00]	2.136*** [0.00]	0.732** [0.05]
Constant	-1.315*** [0.00]	-1.227*** [0.00]	-0.992*** [0.00]	-1.063*** [0.00]	-1.289*** [0.00]	-1.770*** [0.00]
Adjusted R- Squared	0.64	0.65	0.60	0.56	0.47	0.39

In this table, p -values are presented in brackets ([]), and *, **, *** signify significance at 10%, 5%, and 1% respectively. The table presents the results of regressing spot price spreads of Brent and WTI on the spreads of fundamental factors used to characterize convenience yields in Equation (3.4) and also on the futures price differences for various maturities. This is equivalent to Equation (3.8) but uses futures price differences as the dependent variable: $dFut_{t,T} = \beta_0 Constant + \beta_1 dI_{t,T} + \beta_2 dR_{t,T} [R_t^{UK} - R_t^{USA}] + \beta_3 V_{[Brent-WTI]}$, where $dFut_{t,T} = \frac{F_{Brent} - F_{WTI}}{F_{Brent} + F_{WTI}}$, $dI_{t,T} = \frac{I_{UK} - I_{US}}{I_{UK} + I_{US}}$, $dR_{t,T} = \frac{R_{UK} - R_{US}}{R_{UK} + R_{US}}$.

3.5 Conclusion

This paper confirms a link between fundamental factors that affect convenience yields in the oil markets, namely inventories, interest rates and volatility, and the spot price spread between two of the globe's most important crude oil indexes. Each of these fundamental factors may themselves be impacted by several politico-economic environment developments, as well as dimensions such as geography and technology. The latter for example took place in the US where the combination of technological innovations, hydraulic fracturing and horizontal drilling, led to the shale oil boom and a dramatic increase of crude oil production during the last decade. Another example is the Organization of the Petroleum Exporting Countries (OPEC) and their decisions to restrict output when this is deemed beneficial to its members influencing crude oil price and volatility. Using a theoretical framework for commodity markets (Brennan, 1958; Fama & French, 1988) we find that convenience yields of holding Brent and WTI crude oil are affected by volatility of spot price returns, and by changes in US Cushing inventories but not regional Brent inventories. This indicates both market-structure differences and geographical differences between the two indexes. Brent crude has more flexible logistics, with tankers loading crude bound for a global marketplace; this is reflected by the insignificance of changes in regional (UK and Norway) inventories. This is important from both a research point of view—because it proves there are different dynamics between two similar products that ostensibly are governed by the LOOP—and from a financial and business point of view—because it disrupts decades-long patterns of trade and creates opportunities and threats.

Further, the inverse relationship between WTI convenience yields and inventories not only confirms the long-established theory of storage (Kaldor, 1939; Working, 1949) but also recent research (Byun, 2017). Several researchers (Buyuksahin et al., 2013; Chen et al., 2015) have been interested in the spread between Brent and WTI crude. We focus on a relatively turbulent period in which crude oil prices rapidly rose and rapidly fell, and in which the major crude oil types, Brent, and WTI, showed substantial price divergence. This was unprecedented; it took the markets and the global economy by surprise.

We show that the Brent–WTI price spread can be modeled with fundamental factors that determine convenience yields and establish that volatility and inventories significantly affect spread. Overall, we highlight two findings. First, we establish that inventories negatively affect WTI convenience yields for horizons longer than two months but do not negatively affect Brent convenience yields for all horizons between one and 24 months. Thus, the WTI market seems to be described more accurately by the classic theory of storage. Second, price spreads between Brent and WTI are affected by differences in inventories and volatility in accordance with theory. We examined two of the global indexes from 2006 to 2017; access to data before 2006 is limited, as is information about the behavior of other indexes (Dubai crude, OPEC basket, Tapis crude, Bonny light) typically used for pricing

contracts. In particular, because of differences in results between Brent and WTI with regard to convenience yields and inventories, investigation of more crude oil prices, over longer horizons, could shed more light.

Another limitation of our study is frequency of data; we use monthly data points, even though oil markets are highly traded and significant amounts of information are priced daily. Data on public availability of crude oil inventories is released on a monthly basis, and therefore, given that inventories are a key part of our model, we are limited by frequency. With new methods of collecting information (satellites, cameras, sensors, big data) future researchers may be able to examine these relationships in a more data-rich and frequent manner.

To our knowledge this is the first study to investigate the fundamental factors underlying convenience yields to help explain the Brent WTI crude oil price spread. As such it contributes in two ways. First, it tests empirically a fundamental-factors framework derived by theory in convenience yields' literature. Second, by utilizing fundamental factors such as inventories, interest rates, and inventories as explanatory factors it provides insights and evidence to help explain price differences in a landmark oil price spread index.

3.6 Appendix

Table 3.A: Descriptive statistics of WTI crude oil cash convenience yields for 2006–2017

$cashCY_{t,T}^{WTI}$ (%)	Mean	Median	Maximum	Minimum	St. Dev.	Observations
1 month	-0.81	-0.12	1.19	-10.34	2.04	133
2 months	-1.35	-0.47	2.25	-11.50	2.51	133
3 months	-1.89	-0.68	4.38	-26.06	4.15	133
4 months	-2.20	-0.92	4.26	-27.65	4.55	133
5 months	-2.47	-1.14	5.12	-29.07	4.96	133
6 months	-2.69	-1.35	5.92	-30.36	5.35	133
7 months	-2.87	-1.58	6.67	-31.54	5.73	133
8 months	-3.01	-1.68	7.36	-32.64	6.09	133
9 months	-3.13	-1.81	8.02	-33.66	6.45	133
10 months	-3.02	-1.82	15.41	-34.61	7.01	133
11 months	-3.13	-1.89	13.32	-35.57	7.29	133
12 months	-3.22	-1.88	12.01	-36.42	7.58	133
18 months	-3.47	-2.18	13.07	-40.95	9.27	133
24 months	-3.44	-1.87	15.94	-44.58	10.82	133

This table includes descriptive statistics of the cash convenience yields of WTI crude oil for 2006 to 2017 on a monthly basis and for horizons ranging from one month to 24 months. Convenience yields are defined as the difference between the average spot price in Brent crude oil and the discounted average futures price of the respective horizon. We constructed them according to Equation (3.2): $CY_{t,T} = S_t - F_{t,T}e^{-R(t-T)}$. Cash convenience yields are defined according to Equation (3.4): $Cash \% CY_{t,T} = \frac{CY_{t,T}}{S_t} * 100$. The sample consists of 133 monthly observations from June 2006 to June 2017. We take horizons from one month to two years and report them in dollars per barrel (US\$/billion).

Table 3.B: Descriptive statistics of Brent crude oil cash convenience yields for 2006–2017

$cashCY_{t,T}^{Brent}$ (%)	Mean	Median	Maximum	Minimum	St. Dev.	Observations
1 month	-1.53	-1.07	2.63	-12.18	2.23	133
2 months	-1.97	-1.83	4.02	-12.9	2.98	133
3 months	-2.42	-2.42	4.75	-17.94	3.83	133
4 months	-2.81	-2.91	5.23	-21.99	4.65	133
5 months	-3.14	-3.09	5.59	-25.44	5.41	133
6 months	-3.41	-3.21	5.85	-28.47	6.14	133
7 months	-3.62	-3.32	6.60	-31.19	6.83	133
8 months	-3.78	-3.63	7.51	-33.56	7.48	133
9 months	-3.90	-3.83	8.34	-35.66	8.09	133
10 months	-3.99	-3.90	9.25	-37.44	8.68	133
11 months	-4.07	-3.82	10.11	-39.04	9.24	133
12 months	-4.12	-3.71	10.95	-40.63	9.78	133
18 months	-4.03	-2.59	15.58	-49.55	12.77	133
24 months	-3.62	-1.04	19.51	-56.04	15.24	133

This table includes descriptive statistics of the cash convenience yields of Brent crude oil for 2006 to 2017 on a monthly basis and for horizons ranging from one month to 24 months. The convenience yields are defined as the difference between the average spot price of Brent crude oil and the discounted average futures price of the respective horizon. We constructed them according to Equation (3.2): $CY_{t,T} = S_t - F_{t,T}e^{-R(t-T)}$. Cash convenience yields are defined by Equation (3.4): $Cash \% CY_{t,T} = \frac{CY_{t,T}}{S_t} * 100$. The sample consists of 133 monthly observations spanning from June 2006 to June 2017. We take horizons from one month to two years and report them in dollars per barrel (US\$/billion)

Table 3.C: Unit root tests

Variable	Statistic	Unit Root Test
<i>Spread_relative_t</i>	Augmented Dickey Fuller	-4.128*** [0.001]
	Phillips Perron	-3.886*** [0.002]
<i>d_rate_t</i>	Augmented Dickey Fuller	-3.607*** [0.006]
	Phillips Perron	-3.705*** [0.004]
<i>d_stocks_t</i>	Augmented Dickey Fuller	-4.366*** [0.000]
	Phillips Perron	-3.911*** [0.002]
<i>Cash CY WTI 1</i>	Augmented Dickey Fuller	-11.500*** [0.000]
	Phillips Perron	-11.914*** [0.000]
<i>Cash CY WTI 2</i>	Augmented Dickey Fuller	-8.723*** [0.000]
	Phillips Perron	-9.212*** [0.000]
<i>Cash CY WTI 3</i>	Augmented Dickey Fuller	-6.575*** [0.000]
	Phillips Perron	-6.646*** [0.000]
<i>Cash CY WTI 4</i>	Augmented Dickey Fuller	-5.992*** [0.000]
	Phillips Perron	-6.013*** [0.000]
<i>Cash CY WTI 5</i>	Augmented Dickey Fuller	-5.637*** [0.000]
	Phillips Perron	-5.635*** [0.000]
<i>Cash CY WTI 6</i>	Augmented Dickey Fuller	-5.273*** [0.000]
	Phillips Perron	-5.243*** [0.000]
<i>Cash CY WTI 7</i>	Augmented Dickey Fuller	-4.978*** [0.000]
	Phillips Perron	-4.927*** [0.000]
<i>Cash CY WTI 8</i>	Augmented Dickey Fuller	-4.749*** [0.000]
	Phillips Perron	-4.684*** [0.000]
<i>Cash CY WTI 9</i>	Augmented Dickey Fuller	-4.552*** [0.000]
	Phillips Perron	-4.478*** [0.000]
<i>Cash CY WTI 12</i>	Augmented Dickey Fuller	-4.334*** [0.000]
	Phillips Perron	-4.234*** [0.001]
<i>Cash CY WTI 24</i>	Augmented Dickey Fuller	-3.266** [0.016]
	Phillips Perron	-3.250** [0.017]

Table 3.C: Unit root tests
(continued)

Variable	Statistic	Unit Root Test
<i>Cash CY Brent 1</i>	Augmented Dickey Fuller	-9.145*** [0.000]
	Phillips Perron	-9.356*** [0.000]
<i>Cash CY Brent 2</i>	Augmented Dickey Fuller	-6.584*** [0.000]
	Phillips Perron	-6.739*** [0.000]
<i>Cash CY Brent 3</i>	Augmented Dickey Fuller	-5.195*** [0.000]
	Phillips Perron	-5.145*** [0.000]
<i>Cash CY Brent 4</i>	Augmented Dickey Fuller	-4.424*** [0.000]
	Phillips Perron	-4.280*** [0.000]
<i>Cash CY Brent 5</i>	Augmented Dickey Fuller	-3.942*** [0.002]
	Phillips Perron	-3.775*** [0.003]
<i>Cash CY Brent 6</i>	Augmented Dickey Fuller	-3.611*** [0.006]
	Phillips Perron	-3.453*** [0.009]
<i>Cash CY Brent 7</i>	Augmented Dickey Fuller	-3.376** [0.012]
	Phillips Perron	-3.242** [0.017]
<i>Cash CY Brent 8</i>	Augmented Dickey Fuller	-3.198** [0.020]
	Phillips Perron	-3.094** [0.027]
<i>Cash CY Brent 9</i>	Augmented Dickey Fuller	-3.058** [0.029]
	Phillips Perron	-2.985** [0.036]
<i>Cash CY Brent 12</i>	Augmented Dickey Fuller	-2.849* [0.052]
	Phillips Perron	-2.833* [0.054]
<i>Cash CY Brent 24</i>	Augmented Dickey Fuller	-2.770* [0.063]
	Phillips Perron	-2.780* [0.061]
D_Fut1	Augmented Dickey Fuller	-2.708* [0.073]
	Phillips Perron	-2.594* [0.094]
D_Fut2	Augmented Dickey Fuller	-2.765* [0.068]
	Phillips Perron	-2.618* [0.081]

Table 3.C: Unit root tests**(continued)**

Variable	Statistic	Unit Root Test
D_Fut3	Augmented Dickey Fuller	-2.889** [0.047]
	Phillips Perron	-2.884** [0.047]
D_Fut4	Augmented Dickey Fuller	-2.855* [0.051]
	Phillips Perron	-2.896** [0.046]
D_Fut5	Augmented Dickey Fuller	-2.859* [0.050]
	Phillips Perron	-2.932** [0.042]
D_Fut6	Augmented Dickey Fuller	-2.876** [0.048]
	Phillips Perron	-2.967** [0.038]
D_Fut7	Augmented Dickey Fuller	-2.906** [0.045]
	Phillips Perron	-3.015** [0.034]
D_Fut8	Augmented Dickey Fuller	-2.931** [0.042]
	Phillips Perron	-3.053** [0.030]
D_Fut9	Augmented Dickey Fuller	-2.953** [0.040]
	Phillips Perron	-3.095** [0.027]
D_Fut12	Augmented Dickey Fuller	-3.454*** [0.009]
	Phillips Perron	-3.527*** [0.007]
D_Fut24	Augmented Dickey Fuller	-3.055** [0.030]
	Phillips Perron	-3.283** [0.015]
US Inventories (% change)	Augmented Dickey Fuller	-7.652*** [0.000]
	Phillips Perron	-7.497*** [0.000]
UK NO Inventories (% change)	Augmented Dickey Fuller	-17.624*** [0.000]
	Phillips Perron	-25.982*** [0.000]
US rate (change)	Augmented Dickey Fuller	-8.221*** [0.000]
	Phillips Perron	-8.207*** [0.000]
UK rate (change)	Augmented Dickey Fuller	-5.166*** [0.000]
	Phillips Perron	-5.241** [0.000]
Volatility Brent (GARCH 1,1)	Augmented Dickey Fuller	-3.402** [0.010]
	Phillips Perron	-3.658*** [0.005]

**Table 3.C: Unit root tests
(continued)**

Variable	Statistic	Unit Root Test
Volatility WTI (GARCH 1,1)	Augmented Dickey Fuller	-3.335** [0.013]
	Phillips Perron	-3.381** [0.012]

Table 3.D: Descriptive statistics of the average futures price spread (dFut) of Brent and WTI for 2006–2017

dFut [Futures Prices relative Spread] (%)	Mean	Median	Maximum	Minimum	St. Dev.	Skewness	Kurtosis	Observations
1 month	6.09	5.06	24.96	-4.48	6.90	0.78	2.88	132
2 months	6.02	4.78	23.21	-3.55	6.40	0.78	2.82	132
3 months	5.99	5.19	22.55	-12.4	6.49	0.50	3.13	132
4 months	6.10	5.34	22.08	-11.3	6.19	0.45	3.02	132
5 months	6.17	5.47	21.94	-10.2	5.95	0.43	2.95	132
6 months	6.25	5.52	21.51	-9.13	5.75	0.40	2.86	132
7 months	6.30	5.60	21.19	-8.20	5.60	0.38	2.81	132
8 months	6.33	5.51	20.77	-7.33	5.46	0.36	2.74	132
9 months	6.36	5.65	20.53	-6.47	5.34	0.36	2.71	132
10 months	6.58	5.93	20.72	-5.64	5.42	0.37	2.71	132
11 months	6.56	6.00	19.87	-4.96	5.31	0.34	2.61	132
12 months	6.54	6.01	19.53	-4.33	5.24	0.32	2.57	132
18 months	6.29	5.51	18.21	-4.23	5.13	0.37	2.60	132
24 months	6.00	5.32	19.13	-4.72	5.29	0.49	2.77	132

This table provides descriptive statistics of the average relative spread of futures prices of Brent and WTI for 2006 to 2017 on a monthly basis and for horizons ranging from one month to 24 months. The futures price spread is calculated by Equation (3.6): $dFut_{t,T} =$

$$\frac{F_{t,T}^{Brent} - F_{t,T}^{WTI}}{\frac{F_{t,T}^{Brent} + F_{t,T}^{WTI}}{2}}$$

The futures average monthly price spread is calculated as the relative spread between the average monthly future price of Brent and the average monthly futures price of WTI. The same has been applied for futures of one month to 24 months.

Table 3.E: Relationship between crude oil price spread¹⁵ and fundamental factor spreads (UK inventories)

	Spread	Spread	Spread	Spread	Spread	Spread	Spread
Δ Inventories = [US Inventories] - [UK Inventories]	0.734* [0.07]	-0.077 [0.76]	-0.083 [0.58]	-0.131 [0.44]	-0.198 [0.31]	-0.233 [0.28]	-0.102 [0.69]
Δ Interest Rate = [UK Interest Rate] - [US Interest rate]	-0.076*** [0.00]	0.001 [0.93]	0.009 [0.22]	0.008 [0.32]	0.003 [0.73]	-0.001 [0.95]	-0.011 [0.33]
Volatility of Spread = [Brent - WTI Volatility]	2.805*** [0.00]	0.800** [0.02]	-0.385 [0.12]	-0.520* [0.06]	-0.555* [0.09]	-0.507 [0.16]	-0.273 [0.52]
Constant	1.202** [0.05]	-0.102 [0.78]	-0.148 [0.51]	-0.215 [0.38]	-0.304 [0.29]	-0.354 [0.27]	-0.157 [0.67]
dFut1		0.898*** [0.00]					
dFut2			1.246*** [0.00]				
dFut3				1.309*** [0.00]			
dFut6					1.453*** [0.00]		
dFut12						1.734*** [0.00]	
dFut24							2.119*** [0.00]
R Squared	0.51	0.84	0.94	0.92	0.90	0.88	0.83

In this table, p -values are presented in brackets ([]), and *, **,***, signify significance at 10%, 5%, and 1% respectively. The table presents the results of regressing spot price spreads of Brent and WTI on the spreads of fundamental factors used to characterize convenience yields in Equation (3.4) and also on the futures prices differences for various maturities. Equation (3.7) describes the model where we set $dFut_{t,T}$ at either 0 for Equation (3.5) or for different maturities of the futures prices: $[S_t^{Brent} - S_t^{WTI}] / [\frac{S_t^{Brent} + S_t^{WTI}}{2}] = \beta_0 Constant + \beta_1 [I_t^{US} - I_t^{UK}] + \beta_2 [R_t^{UK} - R_t^{USA}] + \beta_3 [V_t^{Brent} - V_t^{WTI}] + \beta_4 dFut_{t,T}$,

where $dFut_{t,T} = \frac{F_{Brent} - F_{WTI}}{\frac{F_{Brent} + F_{WTI}}{2}}$.

¹⁵ We note that in this table, spread is effectively measured by relative spot spread as defined in Equations (3.7) and (8).

Table 3.F: Relationship between WTI convenience yields and fundamental factors

	US Inventories (% change)	US Interest Rate (change)	WTI Spot Volatility (returns)	Constant	Adjusted R ²
WTI CASH CY 1 [2006-2010]	16.93 [0.59]	-0.529 [0.76]	-0.362 [0.42]	-0.163 [0.77]	0.01
[2011-2017]	-11.22 [0.57]	0.094 [0.94]	-1.740*** [0.00]	0.490 [0.31]	0.12
WTI CASH CY 2 [2006-2010]	-8.235 [0.81]	-2.359 [0.24]	-1.776*** [0.00]	0.702 [0.25]	0.18
[2011-2017]	-30.68 [0.16]	-0.346 [0.79]	-2.971*** [0.00]	1.053* [0.05]	0.30
WTI CASH CY 3 [2006-2010]	-24.56 [0.53]	-3.657 [0.10]	-2.810*** [0.00]	1.336* [0.05]	0.34
[2011-2017]	-81.53* [0.07]	-3.816 [0.16]	-4.206*** [0.00]	1.683 [0.13]	0.22
WTI CASH CY 4 [2006-2010]	-38.31 [0.37]	-4.554* [0.06]	-3.650*** [0.00]	1.876** [0.02]	0.43
[2011-2017]	-84.79* [0.07]	-4.514 [0.11]	-4.820*** [0.00]	1.922* [0.10]	0.25
WTI CASH CY 5 [2006-2010]	-47.70 [0.31]	-5.237* [0.05]	-4.382*** [0.00]	2.365*** [0.01]	0.49
[2011-2017]	-88.82* [0.07]	-5.062* [0.09]	-5.426*** [0.00]	2.184* [0.07]	0.30
WTI CASH CY 6 [2006-2010]	-56.92 [0.26]	-5.762** [0.05]	-5.031*** [0.00]	2.829*** [0.00]	0.52
[2011-2017]	-91.66* [0.07]	-5.565* [0.07]	-6.062*** [0.00]	2.515** [0.05]	0.30
WTI CASH CY 9 [2006-2010]	-78.63 [0.19]	-6.803* [0.05]	-6.680*** [0.00]	4.142*** [0.00]	0.57
[2011-2017]	-103.02* [0.07]	-6.923** [0.05]	-7.812*** [0.00]	3.584** [0.01]	0.35
WTI CASH CY 12 [2006-2010]	-108.47 [0.14]	-7.553* [0.07]	-8.309*** [0.00]	6.000*** [0.00]	0.59
[2011-2017]	-108.30* [0.09]	-8.246** [0.03]	-9.426*** [0.00]	4.730*** [0.00]	0.38
WTI CASH CY 18 [2006-2010]	-129.14 [0.14]	-7.934 [0.11]	-10.628*** [0.00]	8.238*** [0.00]	0.62
[2011-2017]	-119.72 [0.11]	-9.963** [0.03]	-12.032*** [0.00]	6.707*** [0.00]	0.41
WTI CASH CY 24 [2006-2010]	-146.30 [0.17]	-7.907 [0.19]	-12.642*** [0.00]	10.529*** [0.00]	0.62
[2011-2017]	-130.08 [0.12]	-11.477** [0.02]	-14.272*** [0.00]	8.609*** [0.00]	0.43

We examine two sub-periods within our sample, 2006 to 2010 and 2011 to 2017; 2011 was the year the spread started deviating from its historical average. In this table, we present the results of regressing WTI cash convenience yields as estimated by Equations (3.3) to (3.4): $CASH\ CY_{t,T} = S_t - F_{t,T} e^{-R(T-t)}$ on fundamental factors affecting the convenience yields. The relationship is described by Equation (3.5): $Cash\ \% CY_{t,T}^{WTI} = \alpha_1 \Delta I_t^{US} + \alpha_2 \Delta R_t^{US} + \alpha_3 VolR_t^{WTI}$, where $Cash\ \% CY_{t,T}^{WTI}$ is the relative convenience yield from holding WTI crude oil; the period between t and T , ΔI_t^{US} is the percentage changes of inventory levels of crude oil in the US at time t ; ΔR_t^{US} is the change in US base interest rate at time t ; $VolR_t^{WTI}$ is the volatility of WTI crude oil spot price returns on a monthly basis as measured by a GARCH specification; p -values are presented in brackets ([]); and *, **, *** signify significance at 10%, 5%, and 1% respectively.

Table 3.G: Relationship between Brent convenience yields and fundamental factors

	UK Inventories (% change)	UK Interest Rate (change)	Brent Spot Volatility(returns)	Constant	Adjusted R ²
Brent CASH CY 1 [2006-2010]	0.817 [0.68]	-0.659 [0.83]	-0.831*** [0.00]	-0.397 [0.18]	0.31
[2011-2017]	0.235 [0.95]	2.617 [0.64]	-0.723** [0.02]	-0.908** [0.01]	0.04
Brent CASH CY 2 [2006-2010]	1.075 [0.67]	2.073 [0.60]	-1.552*** [0.00]	-0.245 [0.52]	0.57
[2011-2017]	1.319 [0.97]	4.235 [0.52]	-1.324*** [0.00]	-0.638 [0.17]	0.13
Brent CASH CY 3 [2006-2010]	1.301 [0.68]	4.734 [0.35]	-2.148*** [0.00]	-0.199 [0.68]	0.63
[2011-2017]	0.418 [0.93]	6.383 [0.40]	-1.947*** [0.00]	-0.327 [0.54]	0.21
Brent CASH CY 4 [2006-2010]	1.526 [0.70]	6.657 [0.27]	-2.649*** [0.00]	-0.134 [0.82]	0.65
[2011-2017]	0.906 [0.87]	8.361 [0.34]	-2.551*** [0.00]	-0.033 [0.96]	0.27
Brent CASH CY 5 [2006-2010]	1.755 [0.70]	8.173 [0.26]	-3.070*** [0.00]	-0.060 [0.94]	0.65
[2011-2017]	1.322 [0.83]	10.37 [0.30]	-3.135*** [0.00]	0.269 [0.70]	0.30
Brent CASH CY 6 [2006-2010]	2.004 [0.71]	9.749 [0.24]	-3.429*** [0.00]	0.027 [0.97]	0.64
[2011-2017]	1.689 [0.81]	12.40 [0.26]	-3.689*** [0.00]	0.587 [0.45]	0.33
Brent CASH CY 9 [2006-2010]	2.924 [0.68]	15.09 [0.18]	-4.285*** [0.00]	0.412 [0.70]	0.62
[2011-2017]	2.583 [0.77]	17.71 [0.20]	-5.124*** [0.00]	1.605 [0.10]	0.37
Brent CASH CY 12 [2006-2010]	3.782 [0.67]	21.09 [0.13]	-4.863*** [0.00]	0.906 [0.50]	0.59
[2011-2017]	3.518 [0.74]	22.34 [0.18]	-6.330*** [0.00]	2.596** [0.03]	0.39
Brent CASH CY 18 [2006-2010]	4.624 [0.70]	32.83* [0.08]	-5.879*** [0.00]	2.483 [0.17]	0.58
[2011-2017]	4.904 [0.72]	30.99 [0.15]	-8.416*** [0.00]	4.637*** [0.00]	0.41
Brent CASH CY 24 [2006-2010]	5.143 [0.72]	44.43* [0.05]	-6.685*** [0.00]	4.201* [0.06]	0.57
[2011-2017]	5.976 [0.71]	39.83 [0.12]	-10.13*** [0.00]	6.581*** [0.00]	0.42

We examine two sub-periods within our sample, 2006 to 2010 and 2011 to 2017; 2011 was the year the spread started deviating from its historical average. In this table, we present the results of regressing Brent cash convenience yields as estimated by Equations (3.3) to (3.4): $CASH\ CY_{t,T} = S_t - F_{t,T}e^{-R(T-t)}$ on fundamental factors affecting the convenience yields. The relationship is described by Equation (3.5): $Cash\ \% CY_{t,T}^{Brent} = \alpha_1 \Delta I_t^{UK} + \alpha_2 \Delta R_t^{UK} + \alpha_3 VolR_t^{Brent}$, where $Cash\ \% CY_{t,T}^{Brent}$ is the relative convenience yield from holding WTI crude oil the period between t and T ; ΔI_t^{US} is the percentage changes of inventory levels of crude oil in the US at time t ; ΔR_t^{US} is the change in the US base interest rate at time t ; $VolR_t^{Brent}$ is the volatility of WTI crude oil spot price returns on a monthly basis as measured by a GARCH specification; p -values are presented in brackets ([]); and *, **, *** signify significance at 10%, 5%, and 1% respectively.

Chapter 4

European Electricity Prices and Net Transfer Capacities

4. European Electricity Prices and Net Transfer Capacities

4.1 Introduction

The European Union (EU) represents an effort toward further development, economic cooperation, and stability. Market integration through elimination of barriers is one of its crucial objectives. The “Single Market Programme” and the elimination of non-tariff trade barriers are steps toward deeper market integration. From a political-economy point of view, the underlying idea is that liberalization increases competition, which in turn increases efficiency that benefits consumers. The shift from vertical national monopolies in the power markets to more competitive structures is a crucial element of European market integration. To foster this, EU countries have agreed to create a more liberalized environment for the production, networks, and wholesale or retail distribution of electric power. So far, this liberalization does not relate to market access for unconventional providers like cooperatives and local initiatives, who are being thwarted from access to networks.

The process of such liberalization has been gradual and with delays. Planning and implementation of legislation to advance the integration of the electricity markets has varied across member states and areas. According to European Commission’s report (2017) about €180 billion in investments are needed to upgrade and expand European energy networks until 2030. Based on this study (European Commission, 2017) these €180 billion in investments would lead to €40 to €70 billion annual savings by way of avoided generation costs and more competitive gas wholesale prices.

In the past 20 years, power exchanges have been created in many member states to improve the internal market and increase the welfare of European citizens. Two elements of power exchanges are crucial for the successful contribution to the creation of one internal market: liquidity and cross-border transmission capacity. Liquidity relates to the volume of trading in these exchange hubs, which has gradually improved over the years. Transmission capacity across borders is of interest because electricity is an asset that cannot be stored economically, and every exchange trade corresponds to a physical delivery.

In this chapter, we focus on transmission capacity, which is the maximum amount of power that can be sent between two locations with a transmission line. We seek to improve our understanding of the process of power market integration in the EU by investigating whether cross-border capacity of electricity influences the Single Market process. One of the classic topics of international economics is the convergence of prices to the *law of one price* (LOOP). According to this law, a common commodity (e.g., electricity) traded in different markets should have the same price. However, electricity’s asset

characteristics differ from those of most other assets; the natural fragmentation of energy markets implies large investments in infrastructure to increase the capacity for energy electricity mobility between neighboring areas. Even after efficient networks of grids and exchange hubs are established, transportation costs remain. Furthermore, electricity is a commodity that at the moment is hard to store in an economically efficient way. This lack of storability may contribute to rising and volatile prices during demand shocks.

In this paper, we examine the impact that cross-border capacities have on prices of seven exchanges that constitute the power markets of 11 EU economies: Denmark, Finland, France, Germany, Italy, the Netherlands, Norway, Portugal, Spain, Sweden, and the UK. These markets represent the largest part of the European economy; they can help us understand how cross-border transmission infrastructures and other fundamentals drive market prices of electricity. We find that with increasing cross-border capacity, prices converge which benefits the competitiveness of industries in Europe by having access at similar prices and by extension it helps consumers and the price they are paying. Our finding is useful for policy makers, because it confirms the benefits of investing in infrastructure and legislation and contributes to the academic debate about whether European electricity prices are converging.

The chapter is organized as follows: In Section 4.2, we introduce the background of European energy markets integration and relevant literature. In Section 4.3, we discuss our methodological approach. In Section 4.4, we present our data and descriptive statistics, and we discuss our results in Section 4.5.

This study is the first to directly model net transfer capacities across European countries as a determinant of electricity price disequilibrium. As such, we provide an empirical specification of how this can be tested. The contribution of cross border transmission capacity to price integration across European countries can help policy makers weigh the costs and benefits of infrastructure investments and policies' implementation.

4.2 Background

Uninterrupted and efficient availability of energy is a necessary component of economic expansion and prosperity according to the EU's policy ambition. Energy shocks historically have disrupted economic activity and led to periods of slow growth or recession. Shocks in the price of fossil fuel, which is used as input for electricity generation, have been extensively researched since Hamilton (1983) presented his thesis linking most US economic recessions after World War II to positive oil price shocks. Kilian and Park (2009) found that demand shocks in oil prices significantly negatively affect stock prices. Jimenez-Rodriguez and Sanchez (2005), using multivariate VAR analysis, showed that for many Organisation for Economic Co-Operation and Development (OECD) countries, a positive-increase price shock has a greater effect than a negative shock on gross domestic product (GDP) growth. Rotemberg and Woodford (1996) presented a theoretical explanation of why oil shocks may be of such

importance to real economic activity. Research also has focused on the effect of volatility of energy prices—not just the prices themselves—on economic activity (Ferderer, 1996).

Global energy shocks may have an unequal effect on economies, given that energy-producing countries are likely to satisfy the needs of their own consumption first, before exporting their surplus energy to energy-deficit economies. The EU as a whole is an energy-deficit entity;¹⁶ it imports almost 70% of its gas and 90% of its oil (European Commission 2015). This is considered a threat and an important security issue for the European Commission (Energy 2020). According to Yergin (2006), diversification of energy resources is key to energy security.

Until the 1990s, the electricity market was still a highly regulated sector in most member countries. Distinct characteristics of the industry, such as high sunk costs, vertical integration, and non-storability of electricity were the norm. The first legislative step was the European Parliament's 96/92/EC Directive establishing common rules in generation, transmission, and distribution of electricity countries ought to adopt in order to create an electricity internal market. This intention to unbundle the market was further sought with the 2003/54/EC Directive, which updated and enhanced the regulatory provisions of the 96/92/EC Directive. The most recent Directive in 2009/72/EC repealed Directive 2003/54/EC. National legislation following EU directives intensified the process of an integrated liberalized market. However, the process of regulation harmonization has been slow for most EU countries. National parliaments often implement EU directives as the result of EU pressure, and delays and objections are common. Directive 2009/72/EC specifically states:

However, at present, there are obstacles to the sale of electricity on equal terms and without discrimination or disadvantages in the Community. In particular, non-discriminatory network access and an equally effective level of regulatory supervision in each Member State do not yet exist.

While Directive 2009/72/EC recognizes the significant contribution of Directive 2003/54/EC towards the creation of an internal electricity market, also concludes that EU is not reaching its target of a common energy policy as quickly or thoroughly as initially planned.

One of the EU's foremost priorities for the next decades, according to European Commission¹⁷, is the establishment of a competitive energy-sector environment, not only to increase effectiveness, boost trade, and efficiently allocate resources but also to partly alleviate the security-threatening energy deficit. By increasing internal competition in Europe and allowing determination of prices by market conditions within Europe, the EU is seeking to increase effectiveness. To do so, it has decided on regulation to motivate the integration of energy markets within Europe; it has encouraged increased energy cooperation and integration.

¹⁶ See graph 4.A in the Appendix to this chapter

¹⁷ https://ec.europa.eu/commission/priorities/energy-union-and-climate_en

This effort to create a pan-European energy market with interconnected infrastructure has given rise to new energy exchanges and new cooperation among energy exchanges and promoted an intensive process of integration of the electricity sector (Jamasb & Pollitt, 2005). Moreover, European countries with higher proportions of energy production from renewable sources may have lower exposure to fossil-fuel prices (Green et al., 2006). Despite Europe's energy-integration efforts, the market is still fragmented. The European electricity market is not yet a single market, even though some cross-border hubs and exchanges are moving the market in that direction.

A number of researchers have addressed the regulatory issues of whether and how the European power market can be integrated; several empirical studies have investigated whether this has happened. Domanico (2007) provides an overview of regulatory results, internal market concentration, and the risks that may arise from the liberalization process. Green et al. (2006) analyze benchmarks for five areas (market design, market power, regulation, EU enlargement, and sustainability) relevant to progress in the EU's electricity-sector liberalization. Creti et al. (2010) calls for more empirical studies on market integration and points at the modest integration of the Italian case. Bunn and Gianfreda (2010) suggest that although market integration has increased over time in five European power markets, there is inefficiency in forward and spot price convergence. Fiorio and Florio (2013) investigate corporate ownership and suggest it is linked to lower electricity prices in Western Europe.

Not all researchers agree on price integration. Zachmann (2008) uses principal component analysis to reject full integration for the period 2002 to 2006, whereas Lindstrom and Regland (2012) use six European electricity prices to model the nature of the prices; they find that bilateral dependencies vary from independent to strongly dependent. Ferkingstad et al. (2011) find that Nordic and German prices are interlinked. When considering spot prices for nine European markets, Menezes and Houllier (2016) find that electricity markets are not increasingly integrated. Cross-border transmission capacity has been investigated in theoretical studies (Cardell et al., 1997; Hobbs et al., 2000; Parisio & Bosco, 2008), however, to our knowledge no empirical study has directly estimated the effect of cross border capacity to price integration. The question of price integration and convergence (Bunn and Gianfreda, 2007; Zachmann, 2005) has been researched in a variety of ways and with varying outcomes. Also, empirical studies have focused on the relationship of electricity consumption and output (Ang, 2007; Lean & Smyth, 2010; Payne, 2009) as well as renewable power effect on electricity prices in individual countries (Mulder and Scholtens, 2013) and regions (Mauritzen, 2013).

Graph 4.1 shows the map of cross border interconnections in Europe as depicted by the European Network of Transmission System Operators (ENTSO-E). Given the lack of direct investigation of the cross-border capacity effect in price convergence and the disparity of findings and suggestions with regard to European-market integration, in the following section we apply a methodology and perspective to examine how cross-border transfer capacities contribute to electricity price integration. In this chapter, we aim to empirically test whether additional cross border capacity has contributed to electricity price convergence in Europe.

4.3 Methodology

A uniform and generalized concept in economics is the prevalence of one price for the same asset in an efficient market. In Chapter 3 we discussed this concept in relation to oil prices and benchmarks at two different locations. This should hold true for all commodities and assets excluding any type of market frictions. However, electricity is a physical commodity with particular characteristics that may imply incomplete price convergence. Although electricity must be continuously available, it is substantially expensive to store in large volumes and thus impractical. This makes it an inflexible asset.

Electricity also presents physical and logistical problems; efficient transmission systems are required to trade electricity between countries and within countries. This requires very large and costly infrastructure investments when the electricity system is highly centralized. Whereas the storability challenge is hard to address, solving the infrastructure problem depends on the costs and benefits these projects offer. The political consensus in the EU and that of the incumbents is that the markets should be as integrated as possible to increase competition and efficiency. This implies that over the years there was, and continues to be, some convergence of prices—perhaps not to a single price, but to a competitive price spread that would not diverge too much for too long. Convergence may depend not only on efficient transmission systems across borders, but also on common drivers of electricity prices, such as natural gas or oil prices. In any case, prices should not diverge further than a proscribed range over long periods of time and given an efficient transmission system. If we would express the LOOP concept in a simple framework of prices at different period t at a number of locations j then it could imply:

$$p_t^1 = p_t^2 = \dots = p_t^j, \quad (4.1)$$

where p_t^1 is the price of an asset at location 1 at period t , and p_t^j is the price of an asset at location j at period t . This implies that prices in different markets of the same product have the same price. If there are no frictions or trading/transporting costs, this asset's Equation (4.1) should be true for every time period. However, as previously mentioned, electricity is a distinct type of commodity. Even if we assume an efficient transmission network and exchange market, there may be costs involved in transferring electricity from one location to another. For instance, if the price of electricity in Germany at time t is €40/megawatt (MWh) hour, and the transmission cost of electricity from Germany to Netherlands is “ c ,” we would expect the price of electricity in the Netherlands would not be more than (€40+ c)/MWh. More formally, the LOOP extension when we experience physical movement and transmission costs would be:

$$p_t^i \leq p_t^j + Costs_t^{ji}, \quad (4.2)$$

where $Costs_t^{ji}$ is the transmission cost from location j to location i. On the one hand, Inequality (2) explains that price at location i cannot be larger than the price at location j and the cost of transmitting electricity from j to i. On the other hand, this also should be true for the price of electricity at location j, giving us Inequality (4.3):

$$p_t^j \leq p_t^i + Costs_t^{ij}. \quad (4.3)$$

Inequalities (4.2) and (4.3) restrict the range of prices for electricity in different markets by their transmission costs. Price differences between markets can be smaller or equal to, but not larger than, their transmission cost. However, these inequalities imply a capacity for accommodating electricity transmissions. If the electricity price in one market increases, the market would force a demand for regional, cheaper electricity. Although freedom of trade and legislation allow for such demand, there may be a limitation in the possible volume of trade. This results from the nature of electricity and the infrastructure available at a point in time. With regard to Inequalities (4.2) and (4.3), we add that if cross-border capacities allow the complete satisfaction of the demand for electricity, the inequalities are true.

This leads to the main questions of our study, which are: Do electricity-transfer capacities play a role in price determination in different markets in Europe? Does increasing the infrastructure across borders would reduce price differences? We seek to understand whether price differences are caused by operational frictions such as bottlenecks and lack of infrastructure or by other pricing issues. When actual capacity of transmitting electricity across borders is binding to the desired quantity, prices may deviate from Inequalities (4.2) and (4.3). To this extent, transfer capacities of electricity may well explain a part of the price differences experiences in European countries; this could transform inequality (4.3) in equality conditional to a large enough transfer capacity between two markets. Cunningham et al. (2002) provide a detailed analysis of potential consequences of binding transmission constraints on electricity price differences. Borenstein et al. (1999) model how an increasing transmission capacity between two regions can enhance competition and reduce prices.

An empirical way to test the question of whether transfer capacities determine price differences is to use transmission capacity as an explanatory variable in the equation and add a random component:

$$p_t^i = a_1 p_t^j + a_2 NTC_t^{ji} + \varepsilon_{it}; \quad (4.4)$$

$$p_t^j = \beta_1 p_t^i + \beta_2 NTC_t^{ij} + \varepsilon_{jt}, \quad (4.5)$$

where NTC_t^{ji} is the net transfer capacity from market j to market i at time t, and NTC_t^{ij} is the net transfer capacity from market i to market j. Although there are costs involved for network users, there is no fixed price per size of the transaction; rather, there is a combination of first connection costs and

utilization rates. We do not observe the implied costs of the participants and thus are captured by the error term.

Theoretical research has focused on the importance of cross-border electricity trade (Parisio & Bosco, 2008) to price integration and the strategic market power interactions of limited electrical networks (Cardell et al., 1997; Hobbs et al., 2000). Electricity is a naturally fragmented asset; it does not allow the LOOP to apply unless there is both free trade and the infrastructure to facilitate trade. Despite the EU's efforts to create a single market, there are still infrastructure limitations to electricity trade. These limitations can be binding or non-binding, depending on bilateral price differences and demand in electricity between two neighboring countries and power exchanges.

Abrell and Weigt (2012) consider the transportation limitation caused by grid boundaries in their model of price interactions. In our study, these physical barriers are our main variable to explain the bilateral price differences between electricity prices. To be able to include all markets, we model price differences as the dependent variable and transfer capacities of both directions as the explanatory variables. This reveals a complication, which is that transfer capacities are not always bilaterally equal. Cross-border capacities may differ depending on the directionality between markets i and j . For instance, during the winter of 2010/2011, the net transfer capacity from France to Spain was 1300MW, and the equivalent net transfer capacity from Spain to France was 500MW. This complicates the sensitivity of the transmission effect on price differences. Accordingly, we use two different variables as dimensions to capture capacities across borders. Using the minimum of the two capacities ($\min[NTC_t^{ij}, NTC_t^{ji}]$) and the difference ($[NTC_t^{ij} - NTC_t^{ji}]$) as distinct variables, we are able to determine the effect of bilateral capacities of the first, and the unidirectional effect of the second, through the sign and extent of the second coefficient. If the two directional capacities match, the minimum is the only effect. However, when they differ, the second variable—which is defined as their difference—accounts for:

$$\frac{p_t^i - p_t^j}{\frac{p_t^i + p_t^j}{2}} = \gamma_1 \min[NTC_t^{ij}, NTC_t^{ji}] + \gamma_2 [NTC_t^{ij} - NTC_t^{ji}] + \gamma_3 x_t^{ij} + \varepsilon_t, \quad (4.6)$$

where $\min[NTC_t^{ij}, NTC_t^{ji}]$ is the minimum between NTC_t^{ij} and NTC_t^{ji} , and x_t^{ij} is a vector of parameters that may contribute to the transferring costs from location i to j .

Equation (4.6) introduces the main model of our study. First, we examine differences in prices between markets; this separates our perspective from most previous empirical work. Most work has examined cointegration of prices (De Vany & Walls, 1999; Ferkingstad et al., 2011) or GARCH-type modeling frameworks (Escribano et al., 2011; Giafredda & Grossi, 2012). By using relative differences of price—which are stationary—we are able to investigate in a linear-regression manner while modeling transmission-capacity limitations that are by nature bilateral.

If we compare Equation (4.6) with Equations (4.4) and (4.5), we observe that except for subtracting them and separating the transfer capacities to their minimum and their differences, we also added the vector x_t^{ij} . This vector incorporates all determinants of electricity's direct and indirect transferring costs and fundamental factors across borders. In a similar framework, but by time-varying transmission costs, Zachmann (2005) finds convergence in most bilateral markets, without using transfer capacities as an explanatory variable.

An important factor that may influence prices between two markets is the demand parameters of each. When cross-border capacity is limitless, the price of the smaller market converges within the range of Inequalities (4.2) and (4.3). However, with limited capacity, electricity demand may affect price differences. We expect large, high-electricity-consuming countries to be less affected by price changes in neighboring, small electricity markets. Therefore, price differences decline, with more demand in less expensive markets and even more when markets are the smaller. Bunn and Giafrenda (2010) argue that the larger the interconnector capacity and the market size of the importer, the higher the integration.

Similarly, we use interconnector capacities to describe the price differences across markets; several factors describe the sizes of these markets. Many studies show the relationship between electricity consumption and output (Ang, 2007; Lean & Smyth, 2010; Payne, 2009). To differentiate between “large” and “small” markets, we use demand data for both markets. Some countries are importers of electricity on average, whereas others are typically exporters. This may explain why there are some differences in cross-border bilateral net transfer capacities, but it also may contribute to persistent price differences. We use a variable for net imports between every two markets we examine. Taxes are factor that affects the price of the final product that the consumers pay for using the commodity and, as such, we add it to the determinants of price convergence. Another factor that may implicitly lead to larger price differences is the use of renewable energy. Renewable energy supply can be erratic compared to other sources and that can cause less available power at times in countries using them extensively and hence have a temporary impact on price differentials:

$$\frac{p_t^i - p_t^j}{\frac{p_t^i + p_t^j}{2}} = a_0 + a_1 \min[NTC_t^{ij}, NTC_t^{ji}] + a_2 [NTC_t^{ij} - NTC_t^{ji}] + a_3 IP_t^i + a_4 IP_t^j + a_5 NI_t^i + a_6 NI_t^j + a_7 T_t^i + a_8 T_t^j + a_9 R_t^i + a_{10} R_t^j + a_{11} EC_t^i + a_{12} EC_t^j + \varepsilon_t^{ij}, \quad (4.7)$$

where p_t^i is the price of electricity in location i at time t ; p_t^j is the price of electricity in location j at time t ; NTC_t^{ij} is the net transfer capacity from market i to market j at time t ; NTC_t^{ji} is the net transfer capacity from market j to market i at time t ; $\min[NTC_t^{ij}, NTC_t^{ji}]$ is the minimum between NTC_t^{ij} and NTC_t^{ji} ; IP_t^i is the industrial production of market i ; IP_t^j is the industrial production of market j ; NI_t^i is the net electricity imports of market i at time t ; NI_t^j is the net electricity imports of market j at time t ; T_t^i is the implicit energy tax at market i at time t ; T_t^j is the implicit energy tax at market j at time t ; R_t^i

is the renewables use in market i at time t ; R_t^j is the renewables use in market j at time t ; EC_t^i is the electricity consumption at market i at time t ; and EC_t^j is the electricity consumption at market j at time t .

The structure of Equation (4.7) is such that we are able to capture potentially different cross-border effects between electricity prices and how transmission capacities come into play. Equations (4.2) to (4.6) do not include a constant effect (c_{ij}) for every cross-border relationship, because we could not extract any information on the effect of net transfer capacities in such a case. Doing so would absorb all across-group action (Beck 2001).

4.4 Data and descriptive statistics

Because we are building a model with diverse variables across markets, we use a variety of data from different sources. We collect European electricity prices from Datastream; it includes prices for seven European exchanges representing markets of 11 countries: The UK, The Netherlands, France, Italy, Spain, Portugal, Germany, Norway, Denmark, Sweden, and Finland. Trading for electricity in the UK and the Netherlands takes place on the Amsterdam Power Exchange (APX), the first electricity exchange market in Continental Europe. NordPool is the trading hub for electricity in the Nordic countries (Norway, Sweden, Finland, Denmark) and is the largest market in Europe in terms of volume. Prices are provided in Norwegian Krone for NordPool; for British pounds (APX UK), we use the daily exchange rate provided by Datastream. In Germany, the main electricity exchange market is European Energy Exchange (EEX), which is the product of the merger of two German power exchanges in Leipzig and Frankfurt. In the Iberian market (Spain and Portugal), OMEL is the operator. For these markets, we have 12 years of daily data since 2001. For the Italian (GME) and French (Powernext) markets we have 10 years of data since 2004. Although trading also may occur on weekends, we have data only for the weekdays. That is, we have 3,044 spot electricity prices for APX UK, APX NL, EEX, NordPool, OMEL, and 2198 spot electricity prices for GME and Powernext. This is covering a period of more than 8 years between 2004 and 2012 for all markets and since 2001 for some of the markets.

These markets represent markets having the largest part of the economic activity of Europe. Table 4.1 presents a summary of the available electricity prices for each country and power exchange. Table 4.2 displays descriptive statistics with regard to our data sample. We use data from six exchanges, consisting of seven electricity spot prices. In general, in period studied, we observe that the most extreme prices occurred in the Netherlands (APX NL) and France (Powernext). At the same time, Italy experienced the highest average price (€73/MWh), and the Nordic area (NordPool) experienced the lowest average price (€37.17/MWh).

The volatility of prices is striking, given that electricity is a very important input for industries, with APX NL having a standard deviation of €28.86/MWh over the 12 years period. We collected the net transfer capacities from the European Network of Transmission System Operators for Electricity (ENTSOE)¹⁸. Our data observations were biannual, starting in winter of 2004/2005 and finishing in winter of 2010/2011. In 2005, the reporting technique changed to a matrix. There are many observations missing; we do not know whether there is a specific reason for this is lack of interconnection or whether there was a difference in the planning schedules of the transmission operators. To deal with this uncertainty, we used the *Statistical Yearbooks* issued by ENTSOE and Union for the Co-Ordination of Transmission of Electricity (UCTE).

From the *Statistical Yearbooks* issued by ENTSOE for 2008 to 2012 and by UCTE for 2004 to 2008, we collected data on the unavailability of international tie lines. This is presented in number of minutes that cross-border substations were unavailable on a monthly basis per year. The reasons for unavailability include maintenance, repair, new constructions, overload, false operation, failure, outside impacts, very exceptional conditions, other reasons, or unknown reasons. For instance, for the year 2004 between France and Great Britain, there were two ties among the French substation “Mandarins” (operated by RTE) and the British substation “Sellindge” (operated by National Grid). Throughout the year, the substation ties were unavailable for 5,346 minutes for the former and 6,057 minutes for the latter. For the former, most of this unavailability occurred in September (4,262 minutes) because of maintenance or repair, and for the latter, in May (5,948 minutes) because of other or unknown reasons.

Table 4.1: European electricity markets data

Exchange	Market	Data
APX NL	Netherlands	March 2001–November 2012
APX UK	UK	March 2001–November 2012
EEX	Germany	March 2001–November 2012
NordPool	Norway, Sweden, Denmark, Finland	March 2001–November 2012
OMEL	Spain, Portugal	March 2001–November 2012
Powernext	France	June 2004–November 2012
GME	Italy	June 2004–November 2012

This table gives an overview of the markets we investigated. Our sample included seven European power markets, focusing on electricity spot prices. Each market may represent trading in one or more countries (for instance, NordPool is the trading hub for four Nordic countries, Norway, Sweden, Denmark, and Finland). The last column indicates the period for which there is daily data on electricity spot prices for these exchanges.

¹⁸ <https://www.entsoe.eu/publications/market-and-rd-reports/ntc-values/ntc-matrix/>

Table 4.2: Descriptive statistics of electricity prices in the seven power exchanges

	APX NL	APX UK	EEX	NordPool	OMEL	GME	Powernext
Mean (EUR/MWh)	50.31	47.56	44.46	37.17	43.94	73.00	52.00
Median	46.71	43.92	41.88	33.63	42.30	71.79	48.05
Maximum	660.34	265.76	301.54	136.02	103.76	142.60	612.77
Minimum	7.84	16.25	3.12	7.94	3.13	24.68	12.62
Std. Dev.	28.86	23.23	19.70	14.78	14.23	14.42	24.65
Skewness	7.79	2.04	2.45	1.27	0.45	0.40	7.79
Kurtosis	134.79	10.40	20.65	5.79	3.24	3.77	144.22
Observations	3044	3044	3044	3044	3044	2198	2198

In this table, we provide some descriptive statistics on the data series we dealing with in our following analysis. The first five* exchanges (APX NL, APX UK, EEX, NordPool, OMEL) represent power markets in nine countries and have 12 years of available data since 2001. The last two markets of Italy (GME) and France (Powernext) have fewer observations (2,198), with data since 2004. The prices are in €/MWh.

*APX NL and APX UK are traded in the same exchange but relate to the markets of the Netherlands and the UK respectively.

By taking this information from the *Statistical Yearbooks* for the monthly unavailability of each cross-border substation, we were able to correct the missing values of the net transfer capacities. For example, for the same substations (Sellindge and Mandarins), we found that during 2006 the connection from Great Britain to France was unavailable for 6,544 minutes and 4,011 minutes for the first and second ties respectively. Most of this unavailability occurred in September (5,466 and 3,120 minutes respectively) of that year. These are a few hours of unavailability over an entire month, and the same is true for the whole year. They do not explain the missing value of net transfer capacity for the summer of 2006. We correct that by taking the previous value and filling in the missing value for the net transfer capacity between France and Great Britain. We follow the same procedure for all cross-border substations for the countries we examine. When there was more than one country and one power exchange involved (e.g., for the Nordic area) in the cross-border transmission system, we aggregated the transmission of all countries. More specifically, given that Denmark has two interconnectors with Germany, and Sweden has another interconnector with Germany, we added the net transfer capacity of all three.

In the following graphs, we plot the aggregate number for all net transfer capacities and their average electricity price differences involving the countries we are examining. Graph 4.2 plots the net transfer capacity for all cross-border connections in these seven markets. It ranges from 36,050 megavolts (MV) during the winter of 2004/2005 and up to 38,414MV during the winter of 2010/2011. Graph 4.4 plots the average price differences in these seven European markets for the period considered of 2004 to 2011. During the summer of 2008, we observe the largest average price difference of

€20.54/MWh, and the smallest difference during the summer of 2010 of €7.56/MWh. As a first insight, we observe a significant drop between summer of 2008 and summer of 2009 from €20.54/MWh to €8.64/MWh, and a generally reducing average price difference in electricity across Europe from 2004 to 2011.

Graph 4.2: Aggregate net transfer capacities (MV)

In this graph, we plot the semiannual aggregate net transfer capacities from the bilateral interconnectors as reported by the ENTSOE. The values are in MV. In the chart ‘W’ stands for the Winter period and ‘S’ stands for the Summer period of the corresponding years. For example, ‘S2005’ is Summer of 2005 while ‘W2005.06’ is the Winter including end of 2005 and beginning of 2006. The semiannual split is provided by ENTSOE categorizations and data provide.

Graph 4.3: Average price differences (€/MWh)

In this graph, we plot the average price differences for all markets in the study at a biannual frequency. The price differences of different pairs of countries are averaged after being expressed in absolute terms. In the chart ‘W’ stands for the Winter period and ‘S’ stands for the Summer period of the corresponding years. For example, ‘S2005’ is Summer of 2005 while ‘W2005.06’ is the Winter including end of 2005 and beginning of 2006. The semiannual split is provided by ENTSOE categorizations and data provide.

Graph 4.4: Changes in industrial production and electricity price differences in European markets

In this graph, we plot the percentage changes in industrial production and electricity average price differences. We multiplied the industrial production changes by 10 to be on a similar scale with electricity price differences. In the chart ‘W’ stands for the Winter period and ‘S’ stands for the Summer period of the corresponding years. For example, ‘S2005’ is Summer of 2005 while ‘W2005.06’ is the Winter including end of 2005 and beginning of 2006. The semiannual split is provided by ENTSOE categorizations and data provide.

In Graph 4.4, we plot the percentage changes of our demand variable of industrial production, over this period, next to percentage changes of average electricity prices. This allows us to grasp how these variables differentiate and co-move over time. We see, for example, that with the significant drop of output after the financial crisis in 2008, electricity prices differences also fell. As demand for electricity drops, grids can cover distribution more efficiently; when they are close to their limits, however, more demand may lead to imports from other markets, which—because of capacity limitations—increases price differences.

We want to find out if transfer capacity does play a crucial role in price differences in Europe. In Table 4.3, we present the average sizes of characteristics for all the markets we investigate. Net imports are expressed in billions of kilowatt hours (KWh); we observe that France is by far the largest net exporter (24 billion KWh), and Italy is the largest importer (22.49 billion KWh). During this period, both Germany (6.69 billion KWh) and Spain (3.08 billion KWh) were net exporters of electricity. The Netherlands (6.70 billion KWh), the UK (3.15 billion KWh), and the Nordic area (3.29 billion KWh) were net importers of electricity. In Table 4.3 we report the implicit tax rates on energy as they are reported by Eurostat. The implicit tax rate ranged from an average of €120/tonne of oil equivalent (toe) for Germany up to €250/toe for the UK. Renewable use was also diverse between the economies, ranging from as low as 2.3% of energy consumption in the UK to 39% in the Nordic countries. In the Appendix, Table 4.A, we present the correlations and descriptive statistics (Table 4.B) for all variables.

Table 4.3: Average net imports, taxes on energy, renewables share for each country over the sample

	France	Germany	Italy	Netherlands	Spain	UK	Nordic
Net Imports (in billions of KWh)	-24.21	-6.694	22.49	6.70	-3.086	3.15	3.29
Implicit Tax Rate (€ per toe)	187.55	119.93	153.37	203.68	182.85	252.81	204.03
Renewables share (% of final energy consumption)	8.303	10.86	10.90	7.007	3.05	2.269	38.67

In this table, we report the averages of determinant variables for the period 2004 to 2011 for all countries. Net imports are reported in billions of KWh, taxes are reported in € per tonne of oil equivalent (toe), and share of renewables in percentage of final energy consumption.

4.5 Results

In Sections 4.1 and 4.3, we elaborated on a modeling procedure that allows us to improve our understanding of electricity prices in Europe and examine the role that cross-border transmission capacities may play. Our reasoning stems from the LOOP perspective—and the fundamental reasons for deviation from that perspective. Prices for the same product should be very close to each other, given free trade agreements without barriers. Potential differences may be the result of barriers and costs associated with markets, or of logistical problems in transferring products from one market to another. Electricity is a particular type of commodity because of its non-storability, and because transferring it from one market to another is less flexible; these particularities may be essential to its price determination. On the one hand, given unlimited availability of transmission capacity between markets, and without any restrictions or frictions, prices should differ only as the result of tax and transmission costs (Equations [4.2] and [4.3]). On the other hand, when transmission capacity is limited, prices may deviate further when capacity becomes binding and cannot accommodate demand. In that case, we would observe imbalances in the two markets and segregated demand and supply characteristics.

Equation (4.7) describes the complete model, in which demand characteristics and transmission capacity representations affect differences in prices. From that perspective, we suggest

that after controlling for electricity-price fundamental parameters, cross-border transmission restrictions help explain the price differences between countries in Europe. If prices are not aligned, and the price difference is not the result of direct and indirect costs, there should be some binding transfer restriction from one market to another.

In Table 4.4, we present the results of Model (4.7) for the relationship between European electricity price differences, cross-border transmission capacities, and fundamental price parameters. The first column describes the variable; the second column provides the coefficients and significance for our main Model (7), using random effects; and the third column presents the results of fixed effects estimation. We find that net transfer capacities *do* play a role in determining electricity price differences across European countries, as shown by Table 4.4 in the second and third rows. We use two variables to capture the cross-border transmission capacity restrictions: $\min[NTC_t^{ij}, NTC_t^{ji}]$, and $[NTC_t^{ij} - NTC_t^{ji}]$. The first corresponds to the minimum net transfer capacity between the two-directional transmission lines across the borders of two countries. The second is the difference between these two net transfer capacities in markets *i* and *j*.

In Section 4.3, we discussed how transmission capacities between two countries differ depending on direction. We used these two explanatory variables to show that when the net transfer capacity is the same in both directions, the model simplifies with the exclusion of the second variable ($[NTC_t^{ij} - NTC_t^{ji}]$ equals 0) and the minimum of the two also being the maximum (because they are equal). As shown in Table 4.4, we find that for both estimations, net transfer capacities affect electricity price differences across borders. Results in Table 4.4 show that both variables are statistically significant (at the 5% level) in determining electricity price differences across borders. The minimum of the two net transfer capacities ($\min[NTC_t^{ij}, NTC_t^{ji}]$) has a negative coefficient of -0.00032. The negative relationship between the minimum of the two net transfer capacities and relative price differences implies that the larger the minimum net transfer capacity between markets *i* and *j*, the smaller their price differences. This is the result of restricted transmission capacity; it appears that prices deviate because of transferring binds. This result manifests that installed capacity is not capable of integrating cross-border markets in Europe and more bidirectional capacity is necessary to help prices come closer together.

This finding of a negative bilateral net transfer capacity and price differences confirms the suggestions of Borenstein et al. (1999) and Cunningham (2002) as well as the findings of Bunn and Giafrenda (2010) and Gugler et al. (2016). With regard to the second characteristic of transmission capacity, the difference in net transfer capacities ($NTC_t^{ij} - NTC_t^{ji}$) between the two markets has a positive coefficient of 0.00047. To give an economic practical meaning of this coefficient it would be that for every 1000MV of difference between the bilateral transmission capacity, prices diverge by about 0.5% between these two locations. This confirms the importance of transmission capacity as

discussed in Section 4.3. When transmission capacity from i region to j is larger than from j to i , demand from region i has more limited access to electricity from region j . Consequently, in times of price imbalance, region i has less ability to purchase from region j ; this causes a larger price difference. In contrast, the price gap decreases when the country with cheaper electricity transmits more electricity to the country with more expensive electricity. Both signs of $\min[NTC_t^{ij}, NTC_t^{ji}]$ and $[NTC_t^{ij} - NTC_t^{ji}]$ are in line with theory and intuition, and both are significant for European electricity markets during the period of 2004 to 2011.

We control for several parameters that may affect relative price differences, given limitations in transmission capacity. We find that industrial production at market i (IP_t^i) positively (0.00882) affects the electricity price difference between markets i and j , and industrial production at market j (IP_t^j) negatively (-0.00812) affects the electricity price difference between the markets. These coefficients of 0.0088 and -0.0081 are close to each other with about a 0.8% (0.008*100) impact in the price difference for every 1% divergence in industrial production. This implies that if one of the two connected countries grows much faster its industrial production it would impact significantly the price difference. This result has an important economic consequence which is also intuitive, divergence in underlying demand for electricity, in this case via increased industrial production, causes electricity prices to also diverge, signifying the impact of supply and demand dynamics as well as the bottlenecks of transmissions between borders. The signs of the coefficients follow the direction of the price differences, because we use relative $p_t^i - p_t^j$. On the left side of the equation, the demand characteristics of p_t^i (such as IP_t^i) increase the price spread and the demand characteristics of p_t^j (such as IP_t^j) decrease the price spread. Bunn and Giafrenda (2010) examine the cross-market interactions and find that the larger the importing market, the higher the integration of prices.

We also find that electricity-deficient countries have higher electricity prices, because of transmission limitations. Net imports of electricity at country i (NI_t^i) positively (0.05) affect the electricity price difference, and net imports of electricity at country j (NI_t^j) negatively (-0.01) affect electricity price differences; both signify electricity deficiency. The economic significance of a 0.05 coefficient for net imports implies that for every 228MW¹⁹ per hour of net imports price difference is impacted by 0.5%. Electricity's implicit tax rate does not significantly affect relative price differences when we control for fixed effects. Renewable energy use increases price differences; if two neighboring countries increase their renewables use by 1%, there is an average price divergence of 0.3% to 3%, depending on the estimation model. However, for fixed effects estimation (which provides the upper range of the potential impact, 3%), renewables use of country i is not statistically significant.

¹⁹ Is estimated in billion KWh over a period of 6 months, biannually

Our model is an empirical evaluation of whether cross-border capacities of electricity transmission affect electricity price differences among countries in Europe. To our knowledge, this is the first study to directly model net transfer capacities across European countries as a determinant of electricity price disequilibrium. We find that transmission constraints *do* affect electricity prices among European power markets. The implication of this result is that transmission capacity restrictions do not allow price convergence to the LOOP. Game theory models of transmission constraints and strategic decisions of generators have predicted a direct role in the outcome of oligopolistic competition (Younes & Ilic, 1999), because transmission limitations can isolate sub-markets economically. In our study we find that transmission capacity is important in reducing price differences between countries. Price convergence is the epitome of market integration. Electricity price convergence and market integration can significantly benefit Europe according to the European Commission and Booz & Co. et al. (2013) which estimates that these benefits can be in the range of €12.5 billion to €40 billion per year.

Table 4.4: Relationship between European electricity price differences, cross-border transmission constraints, and fundamental price parameters

	Equation (4.7) Fixed Effects	Equation (4.7) Random Effects
$\min[NTC_t^{ij}, NTC_t^{ji}]$	-0.00032** [0.01]	-0.00007** [0.02]
$[NTC_t^{ij} - NTC_t^{ji}]$	0.00047** [0.04]	0.00030*** [0.00]
IP_t^i	0.00882*** [0.00]	0.00165 [0.40]
IP_t^j	-0.00812*** [0.00]	-0.00668*** [0.01]
NI_t^i	0.05016*** [0.00]	0.02238*** [0.00]
NI_t^j	-0.00981*** [0.01]	-0.01138*** [0.00]
T_t^i	-0.00117 [0.51]	-0.00167*** [0.00]
T_t^j	-0.00155 [0.55]	0.00091* [0.06]
R_t^i	-0.01044 [0.34]	-0.00921*** [0.00]
R_t^j	0.04175*** [0.01]	0.01209*** [0.00]
EC_t^i	-0.00001 [0.70]	0.00002*** [0.00]
EC_t^j	-0.00004 [0.32]	-0.00003*** [0.23]
Constant	0.93823 [0.34]	0.71729* [0.06]
Observations	273 (= 21 groups*13 periods)	273 (= 21 groups*13 periods)
R-squared	0.22	0.63

In this table, we present the results from Model (4.7) describing the relationship between European electricity price differences, cross-border transmission constraints, and fundamental price parameters; * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level; p -values are reported in brackets ([]). The last column presents the results of Model (4.7) after adding a constant. The Appendix presents robust standard error results and reports OLS standard errors.

$$\frac{p_t^i - p_t^j}{\frac{p_t^i + p_t^j}{2}} = a_0 + a_1 \min[NTC_t^{ij}, NTC_t^{ji}] + a_2 [NTC_t^{ij} - NTC_t^{ji}] + a_3 IP_t^i + a_4 IP_t^j + a_5 NI_t^i + a_6 NI_t^j + a_7 T_t^i + a_8 T_t^j + a_9 R_t^i + a_{10} R_t^j + a_{11} EC_t^i + a_{12} EC_t^j + \varepsilon_t, \quad (7)$$

where p_t^i is the price of electricity in location i at time t ; p_t^j is the price of electricity in location j at time t ; NTC_t^{ij} is the net transfer capacity from market i to market j at time t ; NTC_t^{ji} is the net transfer capacity from market j to market i at time t ; $\min[NTC_t^{ij}, NTC_t^{ji}]$ is the minimum between NTC_t^{ij} and NTC_t^{ji} ; IP_t^i is the industrial production of market i ; IP_t^j is the industrial production of market j ; NI_t^i is the net electricity imports of market i at time t ; NI_t^j is the net electricity imports of market j at time t ; T_t^i is the implicit energy tax at market i at time t ; T_t^j is the implicit energy tax at market j at time t ; R_t^i is the renewables use in market i at time t ; R_t^j is the renewables use in market j at time t ; EC_t^i is the electricity consumption at market i at time t ; and EC_t^j is the electricity consumption at market j at time t .

This finding is in line with an earlier study by Borenstein et al. (2000), who predicted that even small investments in transmission infrastructure would significantly enhance competition and benefit consumers. According to our results, an average increase of 10% in transmission capacity could lead to a 2.5%²⁰ smaller average price difference. On average in our sample, relative price differences ranged from 4% to 17%, implying a significant reduction in price divergence. That is, during the seven-year period that we investigated, transmission capacity (bilateral minimum) increased an average of about 7%.

The Appendix, Table 4.C, reports results for Equation (4.7) when we included time dummies and OLS-errors estimation (Table 4.D). In support of our suggestions, we generally find similar results to the main specification: Net transfer capacities have a negative effect on price differences and all coefficients have the same sign. Table 4.C reports results with the specification; including time dummies, minimum bilateral cross-border transmission capacities have almost the same coefficient (-0.00033 for the fixed effects) as the main model. However, the significance of net transfer capacities differences between countries is reduced in the fixed effects estimation. Adding a time dummy attracts all time variability and reduces our ability to explore how net transfer capacity differences may affect prices. For completeness, we report the results of Equation (4.7) estimation with OLS errors (Table 4.D). Overall, theory and empirical results find common ground with regard to the crucial role of transmission capacity and the competitive and economic effects it has on European economies.

4.6 Conclusions

In this chapter, we investigate the electricity market in Europe and examine the impact that cross-border capacities have on prices of seven exchanges that constitute the power markets of 11 European economies²¹. As they represent a large part of the European economy, we can acquire knowledge about how cross-border transmission infrastructures and other fundamental drivers affect electricity prices. A significant finding is that with increasing cross-border capacity, prices converge which benefits the European economies and consumers. We also find that when the transfer capacity is not bilateral prices do not converge as demand shocks are absorbed unequally between the two regions. The expensive nature of storing electricity creates a volatile environment at times of excess demand, and this can be contained only when cross-border capacities flow bilaterally. This result stands after controlling for a number of parameters such as industrial production and renewable energy usage. Countries with electricity deficiency experience higher electricity prices since transmission capacity is limited. Supportive to that is the result that net imports of electricity improve convergence of prices. Increased imports towards the more expensive market reduces the price difference between two neighboring

²⁰ Using the fixed effects estimation coefficient

²¹ Denmark, Finland, France, Germany, Italy, the Netherlands, Norway, Portugal, Spain, Sweden, and the UK

countries. Differences in countries' sizes is captured by the industrial production and energy consumption variables, however, different modelling structures could be explored such as a weighted approach as well as potential interaction terms between country size and cross-border capacity.

We find that expansion of infrastructure can reduce price differences. Meeus et al. (2005) maintain that although much can be done with better use of existing grid infrastructure, existing regulations cannot adequately coordinate cross-border transmission investments. Electrical energy cannot be stored, and balancing supply and demand across a large geographic area is complicated. Balancing requires aggregated supply and demand not only at one period in time, but also second by second at each location of the network (Verhaegen et al, 2006). Cunningham et al. (2002) show that the combination of a non-competitive market (oligopoly) with transmission constraints can significantly increase prices in all markets. In this study, we do not investigate the market structure and coupling considerations. This is an avenue that future researchers can examine by accounting for both capacity constraints and how markets are designed to interact. Our finding is useful for policy makers, because it confirms the benefits of investing in infrastructure and legislation and contributes to the academic debate about whether European electricity prices are converging.

4.7 Appendix

Graph 4.A: Net imports (Mtoe) and import dependency (%) of European Union (28 members) and Eurozone area (19 countries)

Source: [Eurostat](#). Import dependency is the percentage of total power consumption that is imported (net imports). European Union in this metrics include United Kingdom that is not anymore a member of EU. Eurozone area includes all EU countries using Euro as their currency: Austria, Belgium, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxemburg, Malta, Netherlands, Portugal, Slovakia, Slovenia, Spain.

Table 4.A: Correlation matrix for all explanatory variables

	Min [NTC_t^{ij}, NTC_t^{ji}]	[$NTC_t^{ij} - NTC_t^{ji}$]	IP_t^i	IP_t^j	NI_t^i	NI_t^j	T_t^i	T_t^j	R_t^i	R_t^j	EC_t^i	EC_t^j
Min [NTC_t^{ij}, NTC_t^{ji}]	1											
[$NTC_t^{ij} - NTC_t^{ji}$]	0.73	1										
IP_t^i	-0.09	-0.22	1									
IP_t^j	-0.14	-0.21	0.42	1								
NI_t^i	0.09	0.13	-0.16	0.10	1							
NI_t^j	-0.49	-0.13	0.10	-0.02	-0.20	1						
T_t^i	0.15	0.13	-0.30	0.01	0.32	-0.02	1					
T_t^j	-0.29	-0.04	0.02	-0.21	0.23	0.52	-0.15	1				
R_t^i	-0.15	-0.06	0.20	-0.06	-0.05	0.01	0.14	-0.03	1			
R_t^j	0.09	-0.02	-0.22	-0.08	0.19	-0.16	0.07	-0.32	-0.14	1		
EC_t^i	0.17	-0.07	0.17	0.04	-0.46	0.00	0.26	0.05	0.37	-0.28	1	
EC_t^j	0.57	0.49	0.13	-0.30	0.06	-0.59	-0.11	-0.13	-0.02	0.07	-0.03	1

In this table, we report correlation coefficients for all pairs of explanatory variables of our main model. We have 273 observations for each variable, 21 groups of countries, and 13 periods.

Table 4.B: Descriptive statistics for all variables

Variable	Mean	Median	St. Dev.	Min.	Max.	Skew	Kurt
$\frac{p_t^i - p_t^j}{\frac{p_t^i + p_t^j}{2}}$ Relative price difference	-0.11	-0.06	0.29	-1.06	0.74	-0.09	3.18
$\min[NTC_t^{ij}, NTC_t^{ji}]$ in MV	809.7	0.00	1444	0.00	5000	1.73	4.79
$NTC_t^{ij} - NTC_t^{ji}$ differences in MV	120.35	0.00	385.11	-400	1600	2.73	10.82
IP_t^i Index, 2010 = 100	104.72	101.69	9.64	89.17	127.45	0.72	2.60
IP_t^j Index, 2010 = 100	107.29	110.05	8.80	89.17	127.45	0.03	2.08
NI_t^i in billions of KWh	2.53	2.45	7.01	-10.05	24.58	0.79	4.11
NI_t^j in billions of KWh	-2.05	-1.64	17.59	-31.67	24.58	-0.64	2.02
T_t^i € per toe	184.23	188.40	37.25	116.50	271.20	-0.31	2.99
T_t^j € per toe	188.40	190.20	41.12	116.50	271.20	0.18	2.23
R_t^i % on final energy consumption	13.89	8.35	14.29	1.30	41.18	1.07	2.39
R_t^j % on final energy consumption	9.28	9.10	7.45	1.30	41.18	2.82	12.08
EC_t^i 1,000s of toe	12147	12936	5905	4469	22741	0.19	2.11
EC_t^j 1,000s of toe	16043	14916	3606	10165	22741	0.37	2.12

In this table, p_t^i is the price of electricity in location i at time t; p_t^j is the price of electricity in location j at time t; NTC_t^{ij} is the net transfer capacity from market i to market j at time t; NTC_t^{ji} is the net transfer capacity from market j to market i at time t; $\min[NTC_t^{ij}, NTC_t^{ji}]$ is the minimum between NTC_t^{ij} and NTC_t^{ji} ; IP_t^i is the industrial production of market i; IP_t^j is the industrial production of market j; NI_t^i is the net electricity imports of market i at time t; NI_t^j is the net electricity imports of market j at time t; T_t^i is the implicit energy tax at market i at time t; T_t^j is the implicit energy tax at market j at time t; R_t^i is the renewables use in market i at time t; R_t^j is the renewables use in market j at time t; EC_t^i is the electricity consumption at market i at time t; and EC_t^j is the electricity consumption at market j at time t.

Table 4.C: Relationship between European electricity price differences, cross-border transmission constraints and fundamental price parameters (with time dummies)

	Equation (4.7) with time dummies and RE	Equation (4.7) with time dummies and FE
$\min[NTC_t^{ij}, NTC_t^{ji}]$	-0.00006** [0.02]	-0.00033** [0.01]
$[NTC_t^{ij} - NTC_t^{ji}]$	0.00027*** [0.00]	0.00042 [0.12]
IP_t^i	0.00024 [0.91]	0.00971*** [0.00]
IP_t^j	-0.01323*** [0.01]	-0.00585** [0.05]
NI_t^i	0.02169*** [0.00]	0.05087*** [0.00]
NI_t^j	-0.01154*** [0.00]	-0.01114*** [0.00]
T_t^i	-0.00167*** [0.00]	-0.00279 [0.20]
T_t^j	0.00067 [0.20]	-0.00323 [0.16]
R_t^i	-0.00891*** [0.00]	-0.02119 [0.26]
R_t^j	0.01174*** [0.00]	0.02831 [0.27]
EC_t^i	0.00002*** [0.00]	-0.00001 [0.96]
EC_t^j	-0.00003*** [0.23]	-0.00003 [0.54]
Constant	1.7015** [0.03]	1.1925 [0.30]
Summer 2005	0.0544** [0.03]	0.0498* [0.07]
Time Winter 2005–2006	0.0311 [0.60]	-0.0056 [0.92]
Time Summer 2006	0.1315*** [0.01]	0.0594 [0.31]
Time Winter 2006–2007	0.0914* [0.09]	0.0298 [0.60]
Time Summer 2007	0.0558 [0.27]	-0.0045 [0.94]
Time Winter 2007–2008	0.0714 [0.21]	-0.0023 [0.97]
Time Summer 2008	0.0720 [0.24]	0.0510 [0.46]
Time Winter 2008–2009	-0.0876 [0.12]	0.1211 [0.34]
Time Summer 2009	-0.1139 [0.13]	0.1960 [0.31]
Time Winter 2009–2010	-0.0868 [0.35]	0.1520 [0.40]
Time Summer 2010	-0.0152 [0.78]	0.1490 [0.35]
Time Winter 2010–2011	0.0342 [0.67]	0.1840 [0.34]
Observations	273 (= 21 groups*13 periods)	273 (= 21 groups*13 periods)
R-squared	0.65	0.27

In this table, we present the results of adding time dummies to Model (4.7), describing the relationship between European electricity price differences, cross-border transmission constraints, and fundamental price parameters; * indicates significance at the 10% level ** indicates significance at the 5% level, and *** indicates significance at the 1% level; p -values are reported in brackets ([]).

$$\frac{p_t^i - p_t^j}{p_t^i + p_t^j} = a_0 + a_1 \min[NTC_t^{ij}, NTC_t^{ji}] + a_2 [NTC_t^{ij} - NTC_t^{ji}] + a_3 IP_t^i + a_4 IP_t^j + a_5 NI_t^i + a_6 NI_t^j + a_7 T_t^i + a_8 T_t^j + a_9 R_t^i + a_{10} R_t^j + a_{11} EC_t^i + a_{12} EC_t^j + \sum Dummy_t + \varepsilon_t,$$

where p_t^i is the price of electricity in location i at time t ; p_t^j is the price of electricity in location j at time t ; NTC_t^{ij} is the net transfer capacity from market i to market j at time t ; NTC_t^{ji} is the net transfer capacity from market j to market i at time t ; $\min[NTC_t^{ij}, NTC_t^{ji}]$ is the minimum between NTC_t^{ij} and NTC_t^{ji} ; IP_t^i is the industrial production of market i ; IP_t^j is the industrial production of market j ; NI_t^i is the net electricity imports of market i at time t ; NI_t^j is the net electricity imports of market j at time t ; T_t^i is the implicit energy tax at market i at time t ; T_t^j is the implicit energy tax at market j at time t ; R_t^i is the renewables use in market i at time t ; R_t^j is the renewables use in market j at time t ; EC_t^i is the electricity consumption at market i at time t ; and EC_t^j is the electricity consumption at market j at time t .

Table 4.D: Relationship between European electricity price differences, cross-border transmission constraints, and fundamental price parameters

	Equation (4.7) Random Effects (OLS errors)	Equation (4.7) Fixed Effects (OLS errors)
$\min[NTC_t^{ij}, NTC_t^{ji}]$	-0.00007*** [0.00]	-0.00032** [0.01]
$[NTC_t^{ij} - NTC_t^{ji}]$	0.00030*** [0.00]	0.00047 [0.35]
IP_t^i	0.00165 [0.32]	0.00882*** [0.00]
IP_t^j	-0.00668*** [0.00]	-0.00812*** [0.00]
NI_t^i	0.02238*** [0.00]	0.05016*** [0.00]
NI_t^j	-0.01138*** [0.00]	-0.00981*** [0.01]
T_t^i	-0.00167*** [0.00]	-0.00117 [0.61]
T_t^j	0.00091** [0.01]	-0.00155 [0.53]
R_t^i	-0.00921*** [0.00]	-0.01044 [0.46]
R_t^j	0.01209*** [0.00]	0.04175** [0.01]
EC_t^i	0.00002*** [0.00]	-0.00001 [0.82]
EC_t^j	-0.00003*** [0.23]	-0.00004 [0.46]
Constant	0.71729*** [0.00]	0.93823 [0.47]
Observations	273 (= 21 groups*13 periods)	273 (= 21 groups*13 periods)
Wald Chi2(12)	445.23 (Prob. = 0.000)	
F(12,240)		15.57 (Prob. = 0.000)
R-squared	0.63	0.22

In this table, we present results from Model (7) using OLS errors and describing the relationship between European electricity price differences, cross-border transmission constraints, and fundamental price parameters; * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level; p -values are reported in brackets ([]).

$$\frac{p_t^i - p_t^j}{\frac{p_t^i + p_t^j}{2}} = a_0 + a_1 \min[NTC_t^{ij}, NTC_t^{ji}] + a_2 [NTC_t^{ij} - NTC_t^{ji}] + a_3 IP_t^i + a_4 IP_t^j + a_5 NI_t^i + a_6 NI_t^j + a_7 T_t^i + a_8 T_t^j + a_9 R_t^i + a_{10} R_t^j + a_{11} EC_t^i + a_{12} EC_t^j + \varepsilon_t, \quad (7)$$

where p_t^i is the price of electricity in location i at time t ; p_t^j is the price of electricity in location j at time t ; NTC_t^{ij} is the net transfer capacity from market i to market j at time t ; NTC_t^{ji} is the net transfer capacity from market j to market i at time t ; $\min[NTC_t^{ij}, NTC_t^{ji}]$ is the minimum between NTC_t^{ij} and NTC_t^{ji} ; IP_t^i is the industrial production of market i ; IP_t^j is the industrial production of market j ; NI_t^i is the net electricity imports of market i at time t ; NI_t^j is the net electricity imports of market j at time t ; T_t^i is the implicit energy tax at market i at time t ; T_t^j is the implicit energy tax at market j at time t ; R_t^i is the renewables use in market i at time t ; R_t^j is the renewables use in market j at time t ; EC_t^i is the electricity consumption at market i at time t ; and EC_t^j is the electricity consumption at market j at time t .

Chapter 5

**The Role of Nuclear and Renewable Energy in
Mitigating Carbon Dioxide Emissions**

5. The Role of Nuclear and Renewable Energy in Mitigating Carbon Dioxide Emissions

5.1 Introduction

The world's attention is shifting to global warming, climate change, and the role of carbon dioxide (CO₂) emissions. During the November/December 2015 Paris Climate Change Conference (COP21²²), most members of the United Nations agreed to commit to action to reduce future global emissions. After decades of controversy about the causes of climate change, its impact on the economy and quality of life, decisions were taken by most nations. Although energy poverty is still prevalent in large parts of the world (Jefferson, 2016), nations are intensifying their efforts to reduce pollution and greenhouse gas emissions to adapt to or mitigate global warming. In this chapter, we are interested in whether and to what extent renewable power and nuclear power help mitigate CO₂ emissions, and which strategy would be most effective in reducing country-level carbon emissions.

Energy generation is one of the main activities held responsible for anthropogenic CO₂ emissions. According to the findings of the Intergovernmental Panel on Climate Change (IPCC), each of the past three decades has been warmer (Fifth Assessment Report, 2014). Every decade, Greenland and Antarctic ice have experienced faster loss of ice mass, and man-made greenhouse emissions have increased rapidly since the industrial period and accelerated since the 1990s. This result is attributed mostly to population growth and economic development. If countries and institutions take no action, climate change will result in important and irreversible consequences. For the world to accomplish an average temperature of less than 2°C higher than pre-industrial levels, there must be a global effort. The Paris 2015 Agreement is the first truly global effort to limit and potentially reverse climate change. However, even though the Agreement defined certain targets, we need further analysis of how these targets will be implemented and it is already clear that the policy measures resulting from it will not achieve the objective to remain below the two degrees threshold (Lane, 2016).

The most commonly used energy sources for reduction of carbon emissions are renewable power and nuclear power. The transition to a low-carbon energy mix is costly, and many countries, due to the influence of vested industry interests have resisted it. Espen Moe (2010) explains how vested interests are impacting policy makers and their capacity to implement structural change to energy policy as well as industrial policy. One of the reasons for resistance is the link between economic growth and CO₂ emissions (Omri, 2014; Wang et al., 2016). The most polluting sources of energy, such as coal, are

²² 21st Conference of Parties

less expensive to extract and consume. Although the economic gains of cheaper and dirtier energy are concentrated in specific countries, the environmental effects spread beyond them and affect the entire planet. Because each country has little incentive to reduce CO₂ emissions while others increase them, the “tragedy of the commons” occurs. Even though doing nothing comes with a future cost, there must be common agreement that is viably and reliably enforced.

Various policies are being proposed to curb emissions, and the energy industry is incentivized to adapt its production technology. One interesting avenue that has attracted a lot of attention is the production of energy with the help of carbon-neutral energy sources, such as nuclear energy and renewable energy. The use of nuclear energy and hydro-power pre-dates the debate about climate change. Nuclear energy was a by-product of the quest for nuclear arms during World War II. The production process of nuclear power and uranium enrichment can develop into nuclear weapons and this issue is behind the current political conflict between US and Iran. Nuclear power has been an important source of energy for several countries, but it has also raised risks and disasters at the same time. An important risk is nuclear proliferation as countries could use the technology of developing nuclear power into capability of developing nuclear weapons. Similarly, there is an impactful environmental impact from uranium mining, and occasional radioactive leakages from accidents such as the latest disaster in Fukushima. Radioactive waste, a by-product of nuclear power, is also another concern for governments as there is no viable solution for its disposal. Nevertheless, with a view on CO₂ emissions both nuclear and renewable energy may play a central role in countries’ attempts to diversify energy sources and find a stable, safe, clean supply of energy (Wolde-Rufael & Menyah, 2010).

Transforming a high-carbon-energy world to a low-carbon-energy world is costly; the cost depends on the targets (of carbon intensity) to be achieved and the speed at which these targets are achieved. Therefore, there may be a trade-off between speed and extent of transition and the costs to be borne; achieving higher targets at stricter deadlines naturally also will cost more. However, doing nothing also will cost more, not only in the long run and as a weight on future generations, but also as a direct consequence of climate change and the catastrophic phenomena it brings (Stern, 2007). The impact of global warming and climate change may vary depending on the geographies and development of countries (Stern, 2007). According to Stern (2007) developing countries will be hit the hardest but also developed countries at lower latitudes are vulnerable. Costs of extreme weather events will multiply at increased temperatures and costs could reach 1% of world GDP by the middle of the century and keep rising while accounting for welfare, impact can be estimated at 5-20% (Stern, 2007). In a recent study (Auffhammer, 2018) the author reviews a number of efforts and estimations and discusses that significant assumptions have to be made and the very wide range of estimations that can be derived. Indicatively IWG (2016) and EPA (2014) provide a social cost of carbon range of about \$15-80/tCO₂, that estimate reached less than \$10/tCO₂ during President Trump administration (EPA, 2018).

A recent evaluation of the updated Dynamic Integrated Climate–Economy (DICE) model (Nordhaus, 2016) estimates that to achieve the current target of 2°C degrees of warming, the required cost of carbon emission has to be increased substantially, because policies have been delayed. Given various alternatives, policy makers, governments, and researchers are seeking to understand the effectiveness of each program. Although there is an engineering debate (Ausubel, 2007; Hadian & Madani, 2015) that presents, analyzes, and evaluates the estimations of each technology, in this study we are interested in whether countries that opt for nuclear and renewable energy are indeed able to achieve further reductions in their CO₂ emissions, compared to using neither. There also has been a debate in the literature about which carbon-free alternative is more effective in reducing CO₂ emissions, with conflicting research findings that favor either nuclear power (Apergis et al., 2010; Wolde-Rufael & Menyah, 2010) or renewable power (Panwar et al., 2011; Verbruggen, 2008).

In this chapter, we focus on whether renewable power, nuclear power, or both help mitigate CO₂ emissions. We measure carbon emissions intensity, and we model renewable power, nuclear power, and GDP energy intensity. We add to literature in two ways: First, we introduce a new conceptual structure for examining the problem of carbon emissions mitigation, and second, we use a straightforward panel data sample to test the effects of renewable power, nuclear power, and structure of the economy on CO₂ emissions. Our explanatory variable is CO₂ emissions/energy unit (Mtoe), which measures carbon intensity of an economy. We use this variable because it separates the effects of energy intensity (gross domestic product [GDP] per energy unit) and energy technology (carbon, renewables, nuclear power generation). We pose the following sub-questions: How much energy are we using? How environmentally friendly is the energy we are consuming? By answering these questions, we can use the insights on the aggregate issue of how to reduce absolute levels of CO₂ emissions most efficiently and more accurately forecast future emissions, given varying policy scenarios.

Accordingly, we investigate 61 countries (see Appendix 5.A), of which 28 are nuclear producers, for the period of 1990 to 2013²³. In Section 2, we present the background and links to literature; in Section 3, we discuss our methodological approach and data. In Section 4, we present our results, and in Section 5 we discuss our findings.

²³ We are limited in the timeframe by World Bank data availability. There is a multi-year lag in publishing the data of the World Development Indicators. Currently, during 2020, the latest update of the WDI index for carbon emissions data is including year 2014.

5.2 Background and literature

There are several ways to mitigate carbon emissions. If we categorize in a broad manner these would be (Sims et al; 2003) “i) more efficient fossil fuel conversion, ii) more use of low-carbon fossil fuels iii) decarbonisation of fossil fuels iv) increase the use of renewables, v) increase the use of nuclear power”. Another direct way of reducing CO₂ emissions is by using less energy.

The aim of our study is to complement literature and in particular compare the impact of the use of nuclear and renewable energy with regard to CO₂ emissions in connection with economic development. We examine alternative sources of energy and their CO₂ emissions effects, as related to a long tradition of literature that investigates the relationships between energy sources, CO₂ emissions, and economic growth. Wolde-Rufael and Menyah (2010) study the relationship between CO₂ emissions, renewable and nuclear energy consumption, and real GDP for the US during the period of 1960 to 2007; they find a unidirectional negative relationship from nuclear power to CO₂ emissions. They also find no causality running from renewable energy to carbon emissions. Sims et al. (2003) examine alternatives in mitigation-cost comparisons between fossil fuels, nuclear and renewable energy sources for electricity generation, and their carbon emissions. Examination of a variety of methods and technologies (decarbonization of fuels, carbon dioxide sequestration, low-carbon fossil fuels switch, renewables, and nuclear power) showed that most (with the exception of solar power and CO₂ sequestration) have the potential to reduce both generating costs and carbon emissions (Sims et al., 2003). Soytaş et al. (2007) examine carbon emissions, power consumption, and income in the US. They find that in the long run, the main cause of CO₂ emissions is energy consumption. A long-run relationship between emissions and energy consumption in a world in which the primary source of energy is carbon based would be the intuitive and expected outcome. However, the equation may become more complex when energy sources include non-carbon (nuclear, renewables) technologies and the carbon mix switches to less-carbon-intense energy.

In this study, we develop a new scaling approach that relates energy sources to units of energy rather than to the per capita or absolute values used by most studies. By relying on the per capita metric, one assumes that all countries have a similar growth path and are simply at different points on this path. This assumption is at the basis of the *environmental Kuznets curve* (EKC), which holds that countries initially increase their pollution until they reach a turning point, at which they gradually reduce their emissions, resulting in an inverted U-shaped pattern when moving from poor to rich (Grossman & Krueger, 1995). There is conflicting evidence about the existence of this curve. Some studies argue there is no robust evidence for it (Stern, 2004), whereas others find support for the assumed relationship (Narayan & Narayan, 2010). Specifically, in the case of CO₂ emissions, Galeotti et al. (2006) find the EKC model to be rather fragile; its assumption that countries have a similar growth and pollution path

may be the root cause of the conflicting evidence previously discussed with regard to the effect of renewable and nuclear power on CO₂.

A related stream of research investigates the relationships among CO₂ emissions, GDP, renewable power, and nuclear power, using a panel-error-correction methodology. Apergis et al. (2010) examine the causal relationship between CO₂ emissions, nuclear and renewable energy consumption, and economic growth for 19 countries; they find a long-run negative relationship between nuclear energy and CO₂ emissions, and the reverse relationship for renewable energy. Sadorsky (2009) finds that increases in GDP and CO₂ emissions per capita significantly increase renewable energy consumption in G7 countries.

Other studies investigate causal relationships between energy consumption and economic growth (Lee & Chang 2008; Stern 1993), between energy consumption and carbon emissions (Acaravci & Ozturk 2010; Shafiei & Salim, 2014; Soytas et al. 2007; Zhang & Cheng 2009), and long-run relationships between growth, energy consumption, and carbon emissions (Ghosh 2010; Soytas & Sari 2009; Zhang & Cheng 2009). Our study expands on literature by proposing a framework that includes carbon intensity and energy intensity aspects in the same equation. We scale carbon emissions of a country in relation to their energy consumption, using an alternative approach to address how renewable and nuclear energy usage affects emissions. Previously we discussed the contingencies of applying a per capita or absolute measure of carbon emissions. By creating a measure on per energy unit basis we disentangle two different effects, carbon intensity of energy generation and energy intensity of the economy. This is a pillar of this paper and we discuss the usefulness in detail in Section 5.3 where we explain our perspective on disentangling a complex set of economic and energy variables, which we believe adds value to literature, because it allows more geographic, economic, social, and cultural variation in differences among countries with regard to their energy mixes and usage. Although the studies previously discussed (Acaravci & Ozturk 2010; Ghosh 2010; Shafiei & Salim, 2014; Soytas et al. 2007; Soytas & Sari 2009; Zhang & Cheng 2009) that use panels of countries and time-series techniques account for these, they do not distinguish the effects of carbon intensity from the effects of energy intensity. We believe that our alternative scaling approach enables us to better differentiate the precise effects of energy policies and strategies.

In particular, we seek to investigate one of the claimed benefits of both nuclear and renewable energy, that is, that they reduce carbon emissions. This claim implies there is substitution between technologies, in which technologies low in carbon emissions –at least to some extent- may replace technologies high in carbon emissions, that is, those based on fossil fuels. However, more nuclear or renewable production does not necessarily imply fewer carbon emissions if total energy consumption increases and substitution is imperfect. This is the well-known *impact of substitution and complementarity of alternative technologies* (Berndt & Wood, 1979). By using our alternative scaling

approach, we avoid the mixture of substitution and growth of energy usage effects. By identifying the separate effects of nuclear and renewable energy consumption on carbon emissions, we arrive at a more informed analysis and assessment of whether a country's increase or decrease in energy consumption and carbon emissions relates to the use of nuclear and/or renewable energy.

We have to keep in mind that the greenhouse gases issue is a problem that results from emissions that have occurred over a long period of time. As such every year that emissions exceed the target the more difficult it becomes to achieve a certain stock of greenhouse gases in the future. Equivalently, the later the actions and implementation of reducing emissions the more costly it would be to balance these excesses. Stern (2007) estimates that welfare could be reduced at levels equivalent to 5%-20% of consumption reduction if no action is taken.

5.3 Methodology and data

From a global perspective, we are interested in aggregate levels of carbon emissions. Given that the targets are designed to decrease emissions with some milestones over the next decades, it is interesting to identify the most efficient way of achieving them. Fossil fuel use has historically increased carbon emissions; a direct way to reduce them naturally is to reduce fossil fuel consumption. However, this would imply less energy, and because energy relates to GDP growth, the result would be less economic development. If fossil fuel energy consumption could be replaced with cleaner products, or with more efficient use of fossil fuels, the targets of both sustainability and economic growth would be satisfied. As ultimate objectives, we suggest that countries would want to (1) reduce their CO₂ emissions while (2) increasing their GDPs. This could also be expressed as maximizing potential GDP while maintaining or reducing CO₂ emissions according to a threshold:

$$\max\{GDP\} \text{ subject to } CO_2 \leq \text{target}. \quad (5.1)$$

If we were to express these two objectives in a ratio, we would decrease CO₂ emissions for every economic unit of GDP, while keeping CO₂ below an absolute target. In essence, this ratio describes the emissions' intensity of a country's GDP; it could be separated into two parts, CO₂ emissions for every energy consumption unit and GDP produced by each energy consumption unit:

$$\frac{CO_2}{GDP} = \frac{CO_2}{Energy\ Consumption} * \frac{Energy\ Consumption}{GDP}. \quad (5.2)$$

Figure 5.1 shows the two constituents of a country's GDP CO₂ emissions-intensity. Ideally, economies will be able to simultaneously increase their economic output and sustain or reduce their aggregate levels of carbon emissions. Two ways to reduce the energy intensity of the economy are to conserve energy and use it more efficiently. Individuals, organizations, and policy makers may seek to

reduce the overall use of energy. For example, energy-efficient buildings or less energy-intensive consumer products reduce the amount of energy needed to achieve the same consumers' needs. Technological advances, such as cars that get more mileage from the same amount of fuel, also help increase energy efficiency. These are all ways to decrease energy consumption as a ratio to economic output.

The second constituent of Equation (5.2) is the carbon intensity of energy usage. To contribute to Objective (1), it can accommodate smaller carbon emissions for a given energy consumption. That is, even if a country did not reduce its energy use or increase its GDP, it could replace emissions-intensive energy products (coal, oil) with cleaner, or seemingly clean, energy sources (e.g., renewables, nuclear power). In Figure 5.1 we make this separation to help us construct a framework and analyze the effects of alternative energy sources.

Figure 5.1: CO₂ emissions GDP's contribution and constituents

In this study, we are interested in the effects of the second sub-part of improving the ratio of carbon emissions compared to GDP, i.e., the carbon emission intensity of energy use.

The driving forces of carbon emissions have been investigated for some time. Ehrlich and Holdren (1971) discussed the environmental impact of population growth. Expanding on their work, Verbruggen (2008) expressed carbon emissions as a function of population, affluence, energy intensity, and carbon intensity²⁴:

$$Total\ carbon\ emissions_i = Population_i * \left(\frac{Euros}{Person} \right)_i * \left(\frac{Joules}{Activity} \right)_i * \left(\frac{Activity}{Euros} \right)_i * \left(\frac{CO2\ emissions}{Joules} \right)_i \quad (5.3)$$

where i is country i and the ratios represent the average affluence, energy intensity, and carbon intensity of country i .

²⁴ The original representation by Verbruggen (2008) is: $Total\ carbon\ emissions = \sum Population * \frac{Euros}{Person} * \frac{Joules}{Activity} * \frac{Activity}{Euros} * \frac{carbon\ emissions}{Joules}$

In Section 5.1, we discussed part of the extensive literature in energy economics on the interrelationships between carbon emissions, economic development, energy usage, renewable, and nuclear power (Apergis and Payne, 2010; Omri, 2014; Wang et al., 2016; Wolde-Rufael and Menyah, 2010). Most studies use data for energy consumption, GDP levels and growth, renewables, and nuclear power to examine any long-term relationships they may have and determine direction of causality and impact of each. These studies imply that carbon emissions are a function of a number of factors such as GDP, economic growth, energy consumption, and energy mix:

$$\text{Total carbon emissions} = f \{GDP, \text{growth}, \text{energy use}, \text{nuclear power}, \text{renewables}\}. \quad (5.4)$$

To analyze this function from an energy-usage constituents' point of view, according to previously discussed literature and the structure of Equation (5.2), we scale the parameters on the left and right parts of Equation (5.4) with energy consumption. By combining the perspective of the global aggregate of carbon emissions and the separation of effective policies as shown in Equations (5.1) and (5.2), we focus on carbon emissions per energy unit:

$$\frac{CO_2}{\text{Energy Consumption}} = f \left\{ \frac{GDP}{\text{Energy Consumption}}, \frac{\text{Nuclear Power}}{\text{Energy Consumption}}, \frac{\text{Renewables}}{\text{Energy Consumption}} \right\}. \quad (5.5)$$

In Figure 5.2, we visualize the sub-categories of energy sources and examples of their relevant multiple constituents. If we were to separate energy consumption into three generic groups, these would be fossil fuels, nuclear energy, and renewables. Each involves multiple products and sub-categories; for example, renewables may include any of hydro, solar, wind, or geothermal. The most common nuclear reactor is the Pressurized Water Reactors (PWR), and VVER (Water-Water Energetic Reactors), and CANDU (Canada Deuterium Uranium) are common PWRs.

Figure 5.2: Decomposing the sub-parts of energy consumption

According to the World Bank's World Development Indicators (WDI), oil releases about 50% more CO₂ than natural gas, and coal releases about twice as much, which implies there are dirty—and dirtier—fossil fuels. The amount of CO₂ emitted depends on the technology and origin of the fuel; neither nuclear nor renewable power is completely clean. As previously discussed, we focus on the efficiency of different options of clean energy. Energy consumed is a mix of all technologies and sub-products involved, and it determines the emissions print of each country. In aggregate, CO₂ emissions are the weighted average of energy consumption for each sub-category multiplied by the carbon intensity of energy consumption:

$$CO2_{ij} = Energy\ Consumption_{ij} * Carbon\ Intensity_{ij} \quad (5.6)$$

where *i* is the type of energy, and *j* the year.

These factors will be different for each country and for each year. We seek to determine how efficient energy consumption has been, given the use of renewables and nuclear. Nuclear and renewable power use is regarded as a means to mitigate CO₂ emissions and slow down global warming. Accordingly, we are interested in the effect of nuclear and renewable power generation on carbon emissions, the interactions between these variables, and GDP changes, after controlling for other relevant factors.

However, to arrive at a complete picture of the reasons for changes in CO₂ emissions, we must consider other factors that affect the emissions. Our literature review suggests these are energy consumption, nuclear power consumption, renewable power consumption, and economic growth. The framework discussed earlier allows us to examine both nuclear and renewable power and explain their effects on carbon emissions. Our aim is to shed more light on the conflicting evidence (Narayan & Narayan, 2010; Stern, 2004) with regard to the effects of deployment of renewable and nuclear power on CO₂ emissions. In the literature, we did not encounter any other variables that affect CO₂ emissions. With regard to methodological approaches, we find that most research in the field has used non-stationary techniques to identify which actions mitigate carbon emissions most efficiently.

Although there is a plethora of research on the topic of the drivers of carbon emissions, there is little agreement on the most effective ways to reduce them without sacrificing economic growth; some studies support the use of nuclear power (Apergis et al., 2010; Menyah & Wolde-Rufael, 2013), whereas others support renewable power (Panwar et al., 2011; Verbruggen, 2008). We believe that one reason for such conflicting evidence may be that studies of the relationship between renewable and nuclear power and emissions have not controlled for the energy and carbon intensities of each economy. Accordingly, we seek to contribute to the debate by showing that the reasons for the disparity of evidence are the compounded effects of energy intensity and emissions intensity. We take a specific perspective with regard to changes in nuclear use, renewable energy use, and GDP to develop a greater

understanding of their effects on CO₂ emissions. To do so, we use a panel of data of 61 countries over a 24-year period (1990–2013).

Using Equations (5.2), (5.3), and (5.5), our generic model form is:

$$C_{it} = \alpha + \beta_1 r_{it} + \beta_2 n_{it} + x'_{it} \beta + u_{it} \quad (5.7)$$

where C_{it} are the CO₂ emissions per energy unit (Mtoe) of i country at t year, α is a constant; n_{it} is the nuclear power per energy unit (Mtoe); r_{it} is the renewable power per energy unit (Mtoe); x'_{it} is a matrix of factors influencing carbon emissions as will be explained; and β is the coefficients vector for these factors.

We use three models to investigate the interrelationships of these variables, starting with the simplest form of direct effects of nuclear power, renewable power, and GDP energy intensity on CO₂ emissions:

$$\Delta C_{it} = \alpha + \beta_1 * \Delta n_{it} + \beta_2 * \Delta r_{it} + \beta_3 * \Delta GDPint_{it} + u_{it}, \quad (5.7a)$$

where $C_{it} = \frac{ca_{it}}{e_{it}}$ are the CO₂ emissions per energy unit at country i in year t ; $n_{it} = \frac{nuclear_{it}}{e_{it}}$ is the percentage of power generated by nuclear energy by country i at time t ; $r_{it} = \frac{renewable_{it}}{e_{it}}$ is the percentage of power generated by renewables by country i at time t ; $GDPint_{it}$ is the gross domestic product per energy unit $GDPint_{it} = \frac{GDP_{it}}{e_{it}}$ (constant 2010 US\$) at country i in year t ; ca_{it} is the carbon emissions of country i at year t in metric tonnes; e_{it} is the primary energy of country i at year t in million tonnes of oil equivalent (Mtoe); $nuclear_{it}$ is the nuclear power generated in Mtoe by country i at time t ; and $renewable_{it}$ is the renewable power (solar, wind, biomass, thermal, and hydro) generated in Mtoe by country i at time t .

In the second model, we include the direct effects of these three variables with regard to carbon emissions after we control for the time trend, the nuclear effect variable, and changes in primary energy consumption. This specification allows us to separate nuclear from non-nuclear countries, detects whether there has been a trend of reduction (or increase) of CO₂ emissions over time, and reveals whether this behaves differently for the two country groups.

$$\begin{aligned} \Delta C_{it} = & \alpha + \beta_1 * \Delta n_{it} + \beta_2 * \Delta r_{it} + \beta_3 * \Delta GDPint_{it} \\ & + \beta_4 * NuclearDummy_i + \beta_5 * Nuclear.effect_{it} + \beta_6 \Delta e_{it} + \beta_7 * Time + u_{it}, \end{aligned} \quad (5.7b)$$

where $Nuclear.effect_{it}$ is a variable used to identify the potential long-term effect of nuclear power and is 0 when $n_{it} = 0$ and $Time$ otherwise; $Nuclear.effect_{it}$ is a dummy variable that takes 0 when

$n_{it} = 0$ and 1 otherwise; e_{it} is the primary energy of country i at year t in Mtoe; and $Time$ is a time trend variable that increases during the time period examined, taking the values 1 to 24, starting from 1990 (1) until 2013 (24).

Note that Equations (5.7a) and (5.7b) are based on Equations (5.2) to (5.5), where the relationships between CO₂ emissions, energy mix, and GDP energy intensity are multiplicative. To investigate potential interactions among the three main variables, the third model includes:

$$\begin{aligned} \Delta C_{it} = & \alpha + \beta_1 * \Delta n_{it} + \beta_2 * \Delta r_{it} + \beta_3 * \Delta GDPint_{it} \\ & + \beta_4 * NuclearDummy_i + \beta_5 * Nuclear.effect_{it} + \beta_6 * \Delta e_{it} + \beta_7 * Time \\ & + \beta_8 * \Delta n_{it} * \Delta r_{it} + \beta_9 * \Delta n_{it} * \Delta GDPint_{it} + \beta_{10} * \Delta r_{it} * \Delta GDPint_{it} \\ & + \beta_{11} * \Delta n_{it} * \Delta r_{it} * \Delta GDPint_{it} + u_{it}. \end{aligned} \quad (5.7c)$$

We use the *BP Statistical Review of World Energy 2017* to collect data for nuclear, renewable, and total energy use. We collect CO₂ emissions and GDP data from the World Bank's WBDI, which provide data for CO₂ emissions up to 2013. In this way, we restrict our analysis for that period. We include only countries for which we have all variables for the 24-year period (1990–2013). This leaves 61 countries: 30 that made use of nuclear power during this period and 31 that did not use nuclear power for all, or most, of the period (see Appendix, Table 5.A). These 61 countries represent about 95% of global total energy consumption. We have 1,342 observations for nuclear, renewable, primary energy, and GDP energy intensity; for carbon emissions, we have 1,323 observations.²⁵

Table 5.1, Table 5.B in the Appendix, and Figure 5.3 present some of the descriptive statistics for our data. Table 5.1 shows all variables used in this study. It shows that our explanatory variable, carbon emissions per energy unit, has a mean of 2.42 thousand metric tonnes for every Mtoe of primary energy, and over the countries it varied from 2.34 to 2.58 over 24 years. There is a decreasing trend in average carbon emissions per energy unit, with the minimum occurring during 2013. In the cross-section, the minimum was as low as 0.36 and as high as 5.08, more than a ten-fold difference, signifying the diversity of countries' emissions compared to the energy consumed. Norway is the champion of “cleanness,” with about 0.8 thousand metric tonnes of CO₂ emissions for every Mtoe of primary energy. At the other end, India emitted more than 3,000 metric tonnes of CO₂ per Mtoe, which is more than four times that of Norway. The reasons lie in both the technological development level of infrastructure in each country as well as the origins of the power source. As a practical illustration, for the same household application, for example a lamp, one hour of light implies that compared to India, Norway

²⁵ This is because of the unavailability in the World Banks' WDI of a few observations of CO₂ emissions, including 19 missing observations with regard to CO₂ emissions for Azerbaijan, Uzbekistan, Kazakhstan, Russia, Turkmenistan, Ukraine, Slovakia, Lithuania, the Czech Republic, and Germany. The years missing are 1990 and 1991 for the first nine countries and 1990 for Germany.

emitted one-quarter of CO₂. Renewable energy as a percentage of the energy mix is 10% for these countries over the span of 24 years; nuclear power is about 5%. Both increased—the average values of their differences ($\Delta r_{it}, \Delta n_{it}$) show that renewables increased faster (renewables contributed an additional 1% to the energy mix every nine years, whereas nuclear power contributed an additional 1% in 43 years).

Previously, we discussed the objective of maximizing GDP given a maximum threshold of CO₂ emissions (Equation 5.1) and separating the sub-parts of energy intensity and emissions intensity (Equation 5.2). An implication of this is the ability of countries to produce their GDP while controlling overall carbon emissions. One interesting and related metric is that of GDP per energy unit, on average the 61 countries in our sample produced about US \$5,000 for every toe of energy usage. However, this varied from less than US \$1,000 (Turkmenistan) to more than US \$10,000 (Japan) for each toe. The lower part of Figure 5.3 presents the evolution of energy-use carbon intensity (carbon emissions per energy unit) metric over time; whereas CO₂ emissions per energy unit did not change substantially (they reduced by 8%), the GDP produced by each energy unit used increased substantially, with an improvement of about 32%. This implies that although energy-mix emissions have not shown any impressive changes overall, GDP increases with less use of energy.

In the Appendix, Figure 5.A, we plot four variables (dependent variable and the three main explanatory variables in levels) for the two most extreme years, 1990 and 2013. We observe there is a clearly negative relationship between renewables and carbon emissions per energy unit for the first year (1990). Countries that use renewables intensively generally emit less CO₂. This seems to reduce somewhat for 2013. For a cluster of countries on the left side of the plot, there is no relationship between renewables and carbon emissions per energy unit, whereas for another cluster, there is somewhat of a negative relationship. Chiu and Chang (2009) use OECD panel data and methodology to test for a threshold; they suggest that a threshold of at least 8.4% of renewables in the energy mix may reduce CO₂ emissions. The scatter plot in the Appendix shows no apparent relationship for small levels of renewables, whereas it shows a negative relationship for countries with higher use of renewables. In general, countries seem to focus more on renewable energy than nuclear energy. Moreover, GDP per energy unit seems important; countries with higher GDPs per energy unit make more use of renewable and nuclear energy. The relationship between GDP and nuclear is more dispersed than between GDP and renewables, implying that adoption of a nuclear-power-generation strategy may not be as related to GDP as renewable adoption is. This means generally more wealthy countries are more willing to invest in renewable energy while nuclear energy has been adopted across countries with very different GDP profiles.

Figure 5.3: Time series global averages for energy mix and carbon/energy intensity

3a: Average % contribution to energy mix renewables and nuclear

Source: BP Statistical Review of World Energy 2017

3b: Average global energy mix

Source: BP Statistical Review of World Energy 2017

3c: CO2 emissions per energy unit and GDP per energy unit

Source: World Bank and BP Statistical Review of World Energy 2017

3d: Energy intensity and GDP for 2013

Source: World Bank and BP Statistical Review of World Energy 2017

Description: in this chart we plot the GDP per capita and GDP per energy unit for the countries in our sample for the year of 2013.

Table 5.1: Descriptive statistics for key variables, 1990–2013

Variable	Mean	Median	St. Dev.	Min.	Max.
C_{it} (Carbon emissions per energy unit) <i>Thousand metric tonnes/Mtoe</i>	2.418	2.464	0.685	0.355	5.083
ΔC_{it} (Absolute changes in carbon emissions per energy unit)	-0.012	-0.008	0.153	-1.820	1.035
n_{it} (Nuclear power per energy unit)	0.051	0.00	0.086	0	0.411
Δn_{it} (Absolute changes in nuclear power per energy unit *100)	0.023	0.00	0.932	-9.925	9.044
r_{it} (Renewable power per energy unit)	0.100	0.048	0.125	0.000	0.697
Δr_{it} (Absolute changes in renewable power per energy unit *100)	0.115	0.029	1.442	-7.093	8.063
$GDPint_{it}$ (Gross domestic product per energy unit at constant 2010 US\$)	5.799	5.217	3.625	0.356	21.752
$\Delta \% GDPint_{it}$ (Percentage changes in gross domestic product per energy unit at constant 2010 US\$)	1.399	1.118	5.097	-22.548	38.273
e_{it} (Primary energy in Mtoe)	153.19	47.184	356.76	5.366	2903.95
Δe_t (Absolute changes in primary energy)	2.984	0.776	17.385	-114.15	228.94
ca_{it} (CO ₂ emissions in metric tonnes)	397.47	111.10	1008.7	12.163	10249
$nuclear_{it}$ (Nuclear power generated in Mtoe)	9.144	0.00	26.252	0.000	192.21
$renewable_{it}$ (Renewable power (solar, wind, biomass, thermal, and hydro) generated in Mtoe)	10.853	3.038	22.57	0.000	252.38

In this table, we report descriptive statistics for all variables for the entire period used in the study: $C_{it} = \frac{ca_{it}}{e_{it}}$ are the CO₂ emissions per energy unit at country i in year t ; $n_{it} = \frac{nuclear_{it}}{e_{it}}$ is the percentage of power generated by nuclear energy by country i at time t ; $r_{it} = \frac{renewable_{it}}{e_{it}}$ is the percentage of power generated by renewables by country i at time t ; $GDPint_{it}$ is the GDP per energy unit $GDPint_{it} = \frac{GDP_{it}}{e_{it}}$ (constant 2010 US\$) at country i in year t ; ca_{it} is the carbon emissions of country i at year t in metric tonnes; e_{it} is the primary energy of country i at year t in Mtoe; $nuclear_{it}$ is the nuclear power generated in Mtoe by country i at time t ; $renewable_{it}$ is the renewable power (solar, wind, biomass, thermal, and hydro) generated in Mtoe by country i at time t .

5.4 Results

To test the importance of renewable and nuclear energy in reducing CO₂ emissions, we use Equations 5.7(a) to 5.7(c) as defined in Section 5.3. Many studies (Acaravci & Ozturk 2010; Ghosh 2010; Soytaş et al. 2007; Zhang & Cheng 2009) use time series techniques to investigate causality patterns and long-run relationships. In this paper, we take a different point of view. We consider that carbon emissions depend on the energy mix, and we separate the components of carbon emissions changes to changes in power generation technology (carbon, nuclear, renewables) and changes in energy capacity levels, thereby disentangling the effects caused by increasing energy consumption and changed energy mix to produce energy. This allows us to investigate more thoroughly how CO₂ emissions are affected by changes in the energy mix and economic development, while controlling for other factors. We investigate 61 countries (see Appendix 5.A), of which 28 use nuclear energy.

Table 5.2 presents the results for Equations 5.7a and 5.7b, including the three main variables and focusing on their direct effects on carbon emissions. We find that renewables and nuclear power have almost the same effect on CO₂ emissions: The second column of Table 5.2 shows that changes in nuclear power represent a coefficient of -2.39, whereas changes in renewables represent a coefficient of -2.44. These coefficients imply that for both nuclear and renewables, an increase of 1% in the energy mix proportion reduces carbon dioxide emissions per energy unit by 2.4%. Practically, it demonstrates that on average, assuming energy use remains the same for two years, for every 1% increase in the energy mix of either nuclear or renewables, carbon emissions will drop by 2.4% from one year to the next. The difference in their economic impact is marginal as in the simplest specification (5.7a) they differ only 0.055% and in the last (5.7b) one by 0.011%, their distance is less than 2.5% of their total impact on carbon emissions. This significantly negative association confirms findings in literature with regard to both renewable (e.g., Dogan & Seker, 2016; Shafiei & Salim, 2014) and nuclear (Baek, 2016; Menyah & Wolde-Rufael, 2010) energy. Despite the main regressors having different absolute representation in the energy mix, renewable power percentage is almost double that of nuclear power on average, they are modeled as relative changes and thus their coefficients are directly comparable regarding their marginal effect of changing either renewable or nuclear power.

We also find, in line with previous studies (e.g., Galeotti et al., 2006; Stern, 2004) that increases in GDP per energy unit lead to increases in carbon emissions. The significantly positive coefficient implies that even when economic growth does not increase absolute levels of energy consumption, it can increase CO₂ emissions. To some degree, this could be the outcome of developing countries increasing their carbon emissions faster than their energy consumption. However, the impact of the coefficient is small; a 1% rise in GDP per energy unit increases CO₂ emissions per energy unit by 0.006%. All variables, including the constant, are highly significant. A negative constant coefficient

Table 5.2: Relationship between carbon emissions, energy mix, and GDP (Models 5.7a, 5.7b) for different specifications

model	(5.7a) Fixed Effects	(5.7a) Random Effects	(5.7a+) Fixed Effects	(5.7a+) Random Effects	(5.7b) Fixed Effects	(5.7b) Random Effects
Constant	-0.019*** [0.00]	-0.018*** [0.00]	-0.021 [0.48]	-0.017*** [0.00]	-0.016 [0.59]	-0.011 [0.36]
Δn_{it}	-2.388*** [0.00]	-2.461*** [0.00]	-2.389*** [0.00]	-2.460*** [0.00]	-2.391*** [0.00]	-2.461*** [0.00]
Δr_{it}	-2.443*** [0.00]	-2.481*** [0.00]	-2.443*** [0.00]	-2.480*** [0.00]	-2.432*** [0.00]	-2.472*** [0.00]
$\Delta \%GDP_{intit}$	0.006*** [0.00]	0.006*** [0.00]	0.006*** [0.00]	0.006*** [0.00]	0.007*** [0.00]	0.006*** [0.35]
Nuclear Dummy			0.005 [0.93]	-0.006 [0.94]	0.007 [0.92]	-0.006 [0.74]
<i>Nuclear effect_{it}</i>					0.000 [0.74]	0.000 [0.74]
Δe_{it}					0.000 [0.40]	0.000 [0.51]
Time					-0.001 [0.47]	-0.001 [0.52]
R^2	0.103	0.104	0.103	0.104	0.102	0.104

In this table, we present the results of the panel regressions for Model (5.7a) and different specifications. The dependent variable is the changes of carbon emissions per energy unit used; $\Delta C_{it} = \frac{ca_{it}}{e_{it}}$ is the carbon emissions per energy capacity at country i in year t , where ca_{it} = carbon emissions of country i at year t in metric tonnes; $n_{it} = \frac{nuclear_{it}}{e_{it}}$ is the percentage of power generated by nuclear energy by country i at time t ; $r_{it} = \frac{renewable_{it}}{e_{it}}$ is the percentage of power generated by renewables by country i at time t ; $GDPint_{it}$ is the GDP per energy unit; $GDPint_{it} = \frac{GDP_{it}}{e_{it}}$ (constant 2010 US\$) at country i in year t ; ca_{it} is the carbon emissions of country i at year t in metric tonnes; e_{it} is the primary energy of country i at year t in Mtoe; $nuclear_{it}$ is the nuclear power generated in Mtoe by country i at time t ; $renewable_{it}$ is the renewable power (solar, wind, biomass, thermal, and hydro) generated in Mtoe by country i at time t ; p -values are in brackets ([]); * indicates significance at the 10% level; ** indicates significance at the 5% level; and *** indicates significance at the 1% level.

implies a reducing level of carbon dioxide emissions per energy unit over time, which is not the result of increasing renewables and nuclear power. Both random and fixed effects models yield almost identical coefficients and p values, suggesting that our results are highly robust. Our dependent variable definition differs from related studies, because we measure in relationship to energy use rather than per capita use. Thus, our results differ from previous studies, such as that of Menyah and Wolde-Rufael (2010), who find that in the US, nuclear energy use Granger-causes CO₂ emissions reduction, but renewable energy use does not. Moreover, Apergis et al. (2010), in a sample of 19 countries, find a

negative association between nuclear energy consumption and carbon emissions, and a positive association between renewable energy consumption and emissions.

We believe the construction of our variables helps explain the contradictory findings of previous studies. For example, if we used a sample of countries and years in which both energy consumption and renewable energy have increased, but energy consumption has increased faster, we would expect the per capita result that carbon emissions have increased with more renewable use. Although this would be confirmed by such a construct, it omits relevant information and may lead to the incorrect conclusion that renewables (or nuclear power) are not helping to reduce carbon emissions. Our findings for the significant impact of GDP per energy unit are in line with those of Menyah and Wolde-Rufael (2010), but they contrast with those of Soytaş et al. (2007).

In order to investigate the relationship in more detail between CO₂ emissions, renewable, and nuclear power we control for a number of factors that may also play a role. Namely, we employ a dummy variable for countries with nuclear capacity (5.7a+), primary energy usage, time adjusted dummy for nuclear use, and a time trend (5.7b). Table 5.2 shows the results for fixed and random effects for the main specifications (5.7a) and (5.7b). The nuclear dummy takes the value of 0 for countries/years that do not produce nuclear energy (with the result that the nuclear effect variable also is 0 for these observations). For countries/years with nuclear energy generation, the nuclear effect coefficient adds up to the time trend coefficient. This allows us to distinguish between the characteristics of nuclear- and non-nuclear-producing countries. Although the nuclear dummy variable is negative for random effects and positive for fixed effects, it is insignificant in both cases. Similarly, the time trend is insignificant in both fixed and random effects regressions. Because our variables are in differences, the time trend is embedded in the constant and we have no further time effects. We also do not find changes in levels of energy use significantly affect CO₂ emissions per energy unit.

When we separate the sample into two sub-groups (Table 5.3), we observe that nuclear countries differ from non-nuclear countries. For example, the effect of GDP per energy unit for non-nuclear countries is up to four times higher (0.008) than for nuclear countries (0.002). This result implies that countries without nuclear power increase their carbon emissions faster with increasing GDP. However, the absolute contribution may be small as 1% rise in GDP per energy unit increases CO₂ emissions per energy unit by 0.008%. Another striking difference is that carbon emissions changes for the nuclear countries are explained largely by changes in nuclear and renewable power. The explanatory power of the nuclear group regression is almost three times (24%) higher than that of the non-nuclear group (8%). Moreover, for the fixed effects regression, changes in energy use significantly affect non-nuclear countries but do not significantly affect nuclear countries. For this group, our results differ from those of Zhang and Cheng (2009), who find a relationship between energy consumption and carbon emissions, and those of Lean and Smyth (2010); like our results for the entire sample, the scaling and

definition of our variables differs from these studies. As we have discussed in the methodology section a fundamental contribution of this study is the isolation of the carbon intensity from the energy intensity question.

Table 5.3: Relationship between carbon emissions, energy mix, and GDP (Models 5.7a, 5.7b) for sub-groups of nuclear and non-nuclear countries

model	Nuclear Countries		Nuclear Countries		Non-Nuclear Countries		Non-Nuclear Countries	
	(5.7a) Fixed Effects	(5.7a) Random Effects	(5.7b) Fixed Effects	(5.7b) Random Effects	(5.7a) Fixed Effects	(5.7a) Random Effects	(5.7b) Fixed Effects	(5.7b) Random Effects
Constant	-0.012*** [0.00]	-0.012*** [0.00]	-0.015** [0.04]	-0.015** [0.04]	-0.020*** [0.01]	-0.019*** [0.01]	-0.005 [0.74]	-0.008 [0.58]
Δn_{it}	-2.612*** [0.00]	-2.636*** [0.00]	-2.588*** [0.00]	-2.619*** [0.00]	-	-	-	-
Δr_{it}	-2.580*** [0.00]	-2.604*** [0.00]	-2.563*** [0.00]	-2.595*** [0.00]	-2.398*** [0.00]	-2.422*** [0.00]	-2.404*** [0.00]	-2.421*** [0.00]
$\Delta \%GDPint_{it}$	0.002*** [0.00]	0.003*** [0.00]	0.003*** [0.00]	0.003*** [0.00]	0.008*** [0.00]	0.007*** [0.00]	0.007*** [0.00]	0.007*** [0.00]
Time			0.000 [0.83]	0.000 [0.77]			-0.001 [0.64]	-0.001 [0.54]
Δe_{it}			0.000 [0.18]	0.000 [0.21]			-0.006* [0.08]	-0.002 [0.36]
R^2	0.24	0.24	0.24	0.24	0.08	0.08	0.08	0.09

In this table, we present the results of the panel regressions for Equations 5.7a and 5.7b for the separate groups of countries with nuclear and without nuclear power. The dependent variable is changes in carbon emissions per energy unit used; $\Delta C_{it} = \frac{ca_{it}}{e_{it}}$ is carbon emissions per energy capacity at country i in year t where ca_{it} = carbon emissions of country i at year t in metric tonnes; $n_{it} = \frac{nuclear_{it}}{e_{it}}$ is the percentage of power generated by nuclear energy by country i at time t ; $r_{it} = \frac{renewable_{it}}{e_{it}}$ is the percentage of power generated by renewables by country i at time t ; $GDPint_{it}$ is the GDP per energy unit $GDPint_{it} = \frac{GDP_{it}}{e_{it}}$ (constant 2010 US\$) at country i in year t ; ca_{it} is the carbon emissions of country i at year t in metric tonnes; e_{it} is the primary energy of country i at year t in Mtoe; $nuclear_{it}$ is the nuclear power generated in Mtoe by country i at time t ; $renewable_{it}$ is the renewable power (solar, wind, biomass, thermal, and hydro) generated in Mtoe by country i at time t ; p -values are in brackets ([]); * indicates significance at the 10% level; ** indicates significance at the 5% level; and *** indicates significance at the 1% level.

Previous studies (Chiu, 2017; Galeotti et al., 2006) have suggested that income level may have a non-linear relationship with carbon emissions. These results stem from the *environmental Kuznets curve* (EKC) hypothesis that countries initially increase their carbon emissions, but as their income reaches a turning point, they start reducing them. To test the potentially differing effects of income, non-carbon energy used, and carbon emissions, we introduce interaction terms into our model. We introduce the terms in Equation 5.7c; Table 4 presents the results for both fixed and random effects. For robustness, we also test a number of other variables, such as time trend and changes in the levels of

energy use (as described in Equation 5.7b). We find results equivalent to our previous analysis, with both renewable and nuclear power shown to reduce carbon emissions. The three main variables continue to have the same sign and significance. The coefficients for nuclear and renewables do not change substantially, whereas the impact of GDP increases. This shows that including interaction terms and control variables has no substantial effect on the significant impact of nuclear and renewable energy use on EKC emissions. Although we do not test directly for an EKC, given the construction of our model, we do not find any of the non-linear effects that part of this literature suggests. This may be because we use stationary series for our analysis; Wagner (2014) suggests that previous studies may have found evidence of a non-linear effect because they applied typical co-integration techniques in both their unit root variables and integer powers (GDP and GDP squared). Overall, we find robust evidence that the main driving force in reducing CO₂ emissions is the use of renewable and nuclear power and that changes in the economy that lead to more energy use increase carbon emissions.

5.5 Conclusion

In this paper, we investigate the relationships between CO₂ emissions, nuclear energy generation, renewable energy generation, and GDP energy intensity. We control for a set of relevant variables and use a three-way interaction approach for the main explanatory variables. We use a panel of 61 countries for the period of 1990 to 2013. Instead of using outright levels of carbon emissions, renewable and nuclear use, and per capita income levels, according to relevant literature (Apergis & Payne, 2009; Galeotti et al., 2006; Menyah & Wolde-Rufael, 2010), we use an alternative scale. We use a metric for carbon emissions intensity and we model renewable power, nuclear power, and GDP energy intensity, allowing us to separate the effects of energy intensity of the economy and the energy technology used to generate power. To our knowledge this is the first²⁶ study to use a stationary framework modeling procedure to examine carbon emissions relationships with nuclear power generation, renewable power generation, and economic growth using a large sample.

We contribute to the literature in two ways. First, we introduce a new conceptual approach to investigate the carbon-emissions-mitigation problem in a straightforward panel data global sample. Taking the differences between the independent variables comes at the cost of not being able to determine the direct effects of the levels of the variables. However, it allows a more holistic view of a complex relationship and helps us resolve the contradicting findings of literature by using co-integration and error-correction techniques. Moreover, by using stationary modeling, we are able to examine the

²⁶ Schmalensee et al. (1998) use the logarithms of carbon emissions, energy use, and GDP normalized to population, resulting in the stationary variables they investigate. However, they forecast carbon emissions, whereas we focus on the role of nuclear and renewable consumption in carbon emissions.

Table 5.4: Relationship between carbon emissions, energy mix, and GDP (Equation 5.7c)

model	(5.7b) Fixed Effects	(5.7b) Random Effects	(5.7c) Fixed Effects	(5.7c) Random Effects
Constant	-0.016 [0.59]	-0.011 [0.36]	-0.014 [0.64]	-0.011 [0.36]
Δn_{it}	-2.391*** [0.00]	-2.461*** [0.00]	-1.950*** [0.00]	-2.113*** [0.00]
Δr_{it}	-2.432*** [0.00]	-2.472*** [0.00]	-2.381*** [0.00]	-2.407*** [0.00]
$\Delta \%GDPint_{it}$	0.007*** [0.00]	0.006*** [0.35]	0.006*** [0.00]	0.006*** [0.00]
Nuclear Dummy	0.007 [0.92]	-0.006 [0.74]	0.002 [0.98]	-0.006 [0.74]
<i>Nuclear. effect</i>_{it}	0.000 [0.74]	0.000 [0.74]	0.000 [0.80]	0.000 [0.79]
Time	-0.001 [0.47]	-0.001 [0.52]	-0.001 [0.47]	-0.001 [0.53]
Δe_{it}	0.000 [0.40]	0.000 [0.51]	0.000 [0.41]	0.000 [0.50]
$\Delta n_{it} * \Delta r_{it}$			22.75 [0.47]	19.37 [0.46]
$\Delta n_{it} * \Delta \%GDPint_{it}$			-0.944 [0.18]	-0.061 [0.32]
$\Delta r_{it} * \Delta \%GDPint_{it}$			-0.036 [0.55]	-0.047 [0.37]
$\Delta n_{it} * \Delta r_{it} * \Delta \%GDPint_{it}$			-2.788 [0.50]	-3.836 [0.33]
R^2	0.102	0.104	0.106	0.109

In this table, we present results of the panel regressions for Model (5.7c). The dependent variable is changes of carbon emissions per energy unit used; $\Delta C_{it} = \frac{ca_{it}}{e_{it}}$ is the carbon emissions per energy capacity at country i in year t where ca_{it} = carbon emissions of country i at year t in metric tonnes; $n_{it} = \frac{nuclear_{it}}{e_{it}}$ is the percentage of power generated by nuclear energy by country i at time t ; $r_{it} = \frac{renewable_{it}}{e_{it}}$ is the percentage of power generated by renewables by country i at time t ; $GDPint_{it}$ is the GDP per energy unit $GDPint_{it} = \frac{GDP_{it}}{e_{it}}$ (constant 2010 US\$) at country i in year t ; ca_{it} is the carbon emissions of country i at year t in metric tonnes; e_{it} is the primary energy of country i at year t in Mtoe; $nuclear_{it}$ is the nuclear power generated in Mtoe by country i at time t ; $renewable_{it}$ is the renewable power (solar, wind, biomass, thermal, and hydro) generated in Mtoe by country i at time t ; p -values are in brackets ([]); * indicates significance at the 10% level; ** indicates significance at the 5% level; and *** indicates significance at the 1% level.

Within this setting, we find that both nuclear and renewable energy directly and negatively affect carbon emissions. This result confirms the findings of Dogan and Seker (2016) on the renewables side and Baek (2016) on the nuclear side. On average, all countries in our sample reduced their relative carbon emissions over the investigation period, implying that society has become more aware of the issue and is trying to reduce its detrimental environmental impact. We find that renewable and nuclear power additions to the energy mix have very similar effects. This finding contrasts with those of Apergis et al. (2010) and Menyah and Wolde-Rufael (2010), who suggest that although nuclear energy use reduces carbon emissions, renewable energy use does not. We believe our finding is useful to policy makers, because it shows that to reduce emissions, it is more important to increase non-carbon power generation than to use specific renewable or nuclear technologies.

A limitation of our study is that we investigate the impact of renewables and nuclear power on countries' overall CO₂ emissions. For future research, it would be interesting to have a more detailed understanding of the exact ways of using renewables and nuclear power that maximize CO₂ reduction. For example, Liddle and Sadorsky (2017) find that using non-fossil fuels reduces CO₂ emissions in the long run, with an elasticity of -0.33 (1% increase of non-fossil fuels in the energy mix reduces by 33% carbon dioxide emissions), but increasing the non-fossil-fuel input to electricity generation is much more effective (elasticity reduces to -0.77). Their findings suggest that the ways in which additional renewable and nuclear energy are used can have significant impacts. Another interesting avenue for future research is the economic impact of reducing CO₂ emissions. Although we find energy intensity of the economy affects carbon emissions, we do not investigate the impact of carbon-emissions-reduction policies on income. Montasser et al. (2017) find that reducing CO₂ emissions does not reduce income for two countries while it may have negative effects for five countries out of twelve countries in the Middle East and North Africa. This is an interesting result for policy makers, showing the particularities of each country, because their goal is to reduce environmental impact while achieving high economic growth.

5.6 Appendix

Table 5.A: Countries included in data set

Nuclear countries	Non-Nuclear countries
Argentina	Algeria
Belgium	Australia
Brazil	Austria
Bulgaria	Azerbaijan
Canada	Bangladesh
China	Belarus
Czech Republic	Chile
Finland	Colombia
France	Denmark
Germany	Ecuador
Hungary	Egypt
India	Greece
Japan	Indonesia
Kazakhstan	Iran
Lithuania	Ireland
Mexico	Israel
Netherlands	Italy
Pakistan	Malaysia
Romania	New Zealand
Russian Federation	Norway
Slovakia	Peru
South Africa	Philippines
South Korea	Poland
Spain	Portugal
Sweden	Singapore
Switzerland	Thailand
Ukraine	Trinidad & Tobago
UK	Turkey
US	Turkmenistan
	Uzbekistan
	Venezuela
	Vietnam

Table 5.B: Descriptive statistics of carbon emissions per energy unit for all years

C_{it}	Mean	Median	St. Dev.	Maximum	Minimum
1990	2.5568	2.5962	0.6193	3.7019	0.7960
1991	2.5594	2.6100	0.6236	3.8808	0.8782
1992	2.5722	2.5274	0.6285	3.7543	0.8316
1993	2.5826	2.5746	0.6264	3.7663	0.8854
1994	2.5330	2.5291	0.5917	3.7075	0.8760
1995	2.5359	2.5318	0.6884	3.7889	0.8199
1996	2.5241	2.5283	0.6156	3.7604	0.8875
1997	2.4955	2.4787	0.5964	3.7994	0.9090
1998	2.4848	2.4834	0.6067	3.8827	0.9195
1999	2.4645	2.5144	0.5842	3.7131	0.9504
2000	2.4414	2.4207	0.5993	3.7936	0.8577
2001	2.4353	2.4695	0.5909	3.7260	0.9335
2002	2.4215	2.4421	0.5852	3.6536	0.8721
2003	2.4316	2.4577	0.5963	3.7708	0.7996
2004	2.4103	2.4607	0.6221	4.1756	0.6514
2005	2.3969	2.4302	0.6298	4.1794	0.6408
2006	2.3979	2.4194	0.6337	4.0581	0.5887
2007	2.3951	2.4051	0.6694	4.4516	0.3549
2008	2.3837	2.4231	0.6124	3.9568	0.6044
2009	2.3873	2.4037	0.6461	4.0437	0.5758
2010	2.4123	2.3798	0.6820	5.0825	0.6369
2011	2.3863	2.3629	0.6824	4.7086	0.5342
2012	2.3711	2.3769	0.6571	4.2579	0.7595
2013	2.3435	2.3631	0.6466	4.5819	0.6843

In this table, we present descriptive statistics for the levels of the dependent variable, $C_{it} = \frac{ca_{it}}{e_{it}}$, for every year of the sample.

Table 5.C: Panel unit root tests for dependent and explanatory variables

Variable	Statistic	Nuclear Countries	Non-Nuclear Countries
C_{it}	Fisher-PP Inverse	210.43***	188.34***
	Chi-squared	[0.00]	[0.00]
	Fisher-PP Inverse normal	-5.56***	-5.63***
	[0.00]	[0.00]	[0.00]
	Fisher-PP Inverse logit	-8.35***	-6.59***
	[0.00]	[0.00]	[0.00]
	Fisher-PP Modified	14.59***	10.65***
	Inv. Chi-squared	[0.00]	[0.00]
	Fisher-DF Inverse	210.43***	188.34***
	Chi-squared	[0.00]	[0.00]
	Fisher-DF Inverse normal	-5.56***	-5.63***
	[0.00]	[0.00]	[0.00]
	Fisher-DF Inverse logit	-8.35***	-6.59***
	[0.00]	[0.00]	[0.00]
	Fisher-DF Inverse Modified Inv. Chi-squared	14.59***	10.65***
	[0.00]	[0.00]	[0.00]
n_{it}	Fisher-PP Inverse	80.50**	-
	Chi-squared	[0.02]	-
	Fisher-PP Inverse normal	-0.45	-
	[0.33]	[0.33]	-
	Fisher-PP Inverse logit	-0.73	-
	[0.23]	[0.23]	-
	Fisher-PP Modified	2.32**	-
	Inv. Chi-squared	[0.01]	-
	Fisher-DF Inverse	80.50**	-
	Chi-squared	[0.02]	-
	Fisher-DF Inverse normal	-0.45	-
	[0.33]	[0.33]	-
	Fisher-DF Inverse logit	-0.73	-
	[0.23]	[0.23]	-
	Fisher-DF Inverse Modified Inv. Chi-squared	2.32**	-
	[0.01]	[0.01]	-
Δn_{it}	Fisher-PP Inverse	751.04***	
	Chi-squared	[0.00]	
	Fisher-PP Inverse normal	-23.34***	
	[0.00]	[0.00]	
	Fisher-PP Inverse logit	-39.26***	
	[0.00]	[0.00]	
	Fisher-PP Modified	65.68***	
	Inv. Chi-squared	[0.00]	
	Fisher-DF Inverse	751.04***	
	Chi-squared	[0.00]	
	Fisher-DF Inverse normal	-23.34***	
	[0.00]	[0.00]	
	Fisher-DF Inverse logit	-39.26***	
	[0.00]	[0.00]	
	Fisher-DF Inverse Modified Inv. Chi-squared	65.68***	
	[0.00]	[0.00]	

Table 5.C: Panel unit root tests for dependent and explanatory variables (continued)

Variable	Statistic	Nuclear Countries	Non-Nuclear Countries
r_{it}	Fisher-PP Inverse Chi-squared	119.75*** [0.00]	147.59*** [0.00]
	Fisher-PP Inverse normal	-2.33*** [0.01]	-2.77*** [0.00]
	Fisher-PP Inverse logit	-3.77*** [0.00]	-3.11*** [0.00]
	Fisher-PP Modified Inv. Chi-squared	6.02*** [0.00]	7.10*** [0.00]
	Fisher-DF Inverse Chi-squared	119.75*** [0.00]	147.59*** [0.00]
	Fisher-DF Inverse normal	-2.33*** [0.01]	-2.77*** [0.00]
	Fisher-DF Inverse logit	-3.77*** [0.00]	-3.11*** [0.00]
	Fisher-DF Inverse Modified Inv. Chi-squared	6.02*** [0.00]	7.10*** [0.00]
	Fisher-PP Inverse Chi-squared	550.20*** [0.00]	756.57*** [0.00]
	Fisher-PP Inverse normal	-19.04*** [0.00]	-23.08*** [0.00]
	Fisher-PP Inverse logit	-28.66*** [0.00]	-36.38*** [0.00]
	Fisher-PP Modified Inv. Chi-squared	46.70*** [0.00]	60.11*** [0.00]
	Fisher-DF Inverse Chi-squared	550.20*** [0.00]	756.57*** [0.00]
	Fisher-DF Inverse normal	-19.04*** [0.00]	-23.08*** [0.00]
	Fisher-DF Inverse logit	-28.66*** [0.00]	-36.38*** [0.00]
$\Delta\%GDPint_{it}$	Fisher-DF Inverse Modified Inv. Chi-squared	46.70*** [0.00]	60.11*** [0.00]
	Fisher-PP Inverse Chi-squared	550.20*** [0.00]	756.57*** [0.00]
	Fisher-PP Inverse normal	-19.04*** [0.00]	-23.08*** [0.00]
	Fisher-PP Inverse logit	-28.66*** [0.00]	-36.38*** [0.00]
	Fisher-PP Modified Inv. Chi-squared	46.70*** [0.00]	60.11*** [0.00]
	Fisher-DF Inverse Chi-squared	550.20*** [0.00]	756.57*** [0.00]
	Fisher-DF Inverse normal	-19.04*** [0.00]	-23.08*** [0.00]
	Fisher-DF Inverse logit	-28.66*** [0.00]	-36.38*** [0.00]
	Fisher-DF Inverse Modified Inv. Chi-squared	46.70*** [0.00]	60.11*** [0.00]
	Fisher-PP Inverse Chi-squared	597.24*** [0.00]	587.85*** [0.00]
	Fisher-PP Inverse normal	-19.71*** [0.00]	-19.27*** [0.00]
	Fisher-PP Inverse logit	-31.07*** [0.00]	-28.23*** [0.00]
	Fisher-PP Modified Inv. Chi-squared	51.14*** [0.00]	45.42*** [0.00]
	Fisher-DF Inverse Chi-squared	597.24*** [0.00]	587.85*** [0.00]
	Fisher-DF Inverse normal	-19.71*** [0.00]	-19.27*** [0.00]
	Fisher-DF Inverse logit	-31.07*** [0.00]	-28.23*** [0.00]
Δe_{it}	Fisher-DF Inverse Modified Inv. Chi-squared	51.14*** [0.00]	45.42*** [0.00]
	Fisher-PP Inverse Chi-squared	597.24*** [0.00]	587.85*** [0.00]
	Fisher-PP Inverse normal	-19.71*** [0.00]	-19.27*** [0.00]
	Fisher-PP Inverse logit	-31.07*** [0.00]	-28.23*** [0.00]
	Fisher-PP Modified Inv. Chi-squared	51.14*** [0.00]	45.42*** [0.00]
	Fisher-DF Inverse Chi-squared	597.24*** [0.00]	587.85*** [0.00]
	Fisher-DF Inverse normal	-19.71*** [0.00]	-19.27*** [0.00]
	Fisher-DF Inverse logit	-31.07*** [0.00]	-28.23*** [0.00]
	Fisher-DF Inverse Modified Inv. Chi-squared	51.14*** [0.00]	45.42*** [0.00]
	Fisher-PP Inverse Chi-squared	597.24*** [0.00]	587.85*** [0.00]
	Fisher-PP Inverse normal	-19.71*** [0.00]	-19.27*** [0.00]
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	Fisher-PP Modified Inv. Chi-squared	51.14*** [0.00]	45.42*** [0.00]
	Fisher-DF Inverse Chi-squared	597.24*** [0.00]	587.85*** [0.00]
	Fisher-DF Inverse normal	-19.71*** [0.00]	-19.27*** [0.00]
	Fisher-DF Inverse logit	-31.07*** [0.00]	-28.23*** [0.00]

Panel Tests: Fisher-PP: Philips-Peron; Fisher-DF: Dickey-Fuller; *** indicates p -value less than 1%, ** indicates p -value less than 5%, * indicates p -value less than 10% on H_0 : Panels contain unit roots.

In this table, we present the results for the unit root tests of the variables used for the two groups of data, nuclear and non-nuclear countries.

Figure 5.A: Scatter plots for years 1990 and 2013

Chapter 6

Conclusions

6. Conclusions

This thesis is the study of four topics related to some of the most important elements of energy markets. Its intention is to contribute to relevant academic debates, policy makers' discussions, and practitioners' insights. Climate change is one of the urgent crises of our times. Energy is predominantly being derived from the deployment of fossilized organic materials, which usage contributes to climate change. There is overwhelming scientific evidence that the climate crisis presents unprecedented global risks and urgent action should be taken. Energy markets have become more complex, and previously monopolistic markets such as electricity have become more competitive and adopted a market-pricing framework. At the same time, traditional global trading routes such as those of crude oil have experienced changes in their decades-long pricing realizations; forces of supply and demand do not always move prices into balance quickly. Furthermore, the world's environment has started to feel the weight of growing consumption of carbon fuels. The combination of environmentally sustainable economic growth with reduced costs of energy generation, market efficiency, and liquidity, and the convergence of energy are priorities for improving our current livelihood and securing our future.

Accordingly, this thesis focuses on four challenging questions in the energy sector and financial markets:

- 1) How can we measure liquidity, what changes during periods of illiquidity, and what is the role of oil price?
- 2) Do fundamental factors related to convenience yields affect the Brent–WTI crude oil spot- price spread?
- 3) Will electricity prices in Europe move closer with increases in cross-border transmission capacity?
- 4) How do renewable and nuclear power generation contribute to mitigating CO₂ emissions?

Liquidity of energy markets is an important prerequisite of efficient markets. Policy makers and institutions are increasingly interested in having mechanisms in place to strengthen confidence in markets and react quickly to crises such as the global financial crisis. Liquidity in energy assets has received scant attention. In Chapter 2, we focus on Question 1 by investigating the interrelationships of three liquidity measures and the effect of oil prices. Using three commonly known liquidity measures—turnover, price impact, and price spread—we propose a specific direction regarding the causality. We find that trading activity as proxied by turnover significantly and positively affects price impact contemporaneously. When turnover of trading increases, prices may be affected more intensely. Turnover and price impact both positively affect the bid-ask spread contemporaneously. Larger turnover and higher price impacts increase transacting costs, confirming the view that bid-ask spreads

reflect costs and risks to intermediaries and measure various liquidity risks. More liquidity risk (informed trading activity and price impact) results in increasing of price spreads to compensate counterparties for the risks taken in transacting.

Another finding of Chapter 2 is that trading intensity is important for describing the interrelationships of various liquidity time series. We find that the degree of persistence of price impact is lower for stocks that are traded more often; spread responds to turnover changes after one day, but it takes twice as long for less-traded stocks. By examining energy stocks, we find that oil prices affect their liquidity, and an increase in oil returns reduces turnover and spread. Our approach forces a specific causality pattern in the three liquidity measures, because we take the intermediaries' perspective, in which costs and risks are reflected by the bid-ask spread.

Our results are useful to both energy-industry participants and researchers, including oil companies, producers and servicers that are traded on the New York Stock Exchange (NYSE), current or future investors in the sector, and traders who are interested in understanding more about how the liquidity measures of energy stocks interrelate. They may be of even more interest to financial intermediaries, whose cost/risk exposures in buying and selling stocks makes them more focused on characteristics of liquidity. Future research on the topic could examine how liquidity affects other energy markets, such as electricity, crude oil, or natural gas. We believe our findings apply to literature on stock market liquidity and tests of liquidity-measure characteristics, given that we find a structural causality pattern.

In Chapter 2 we address oil market liquidity and how we measure it, what impacts illiquidity, and what is the role of oil price. Three important results are derived. One, liquidity has different dimensions and application, however, we propose a specific causality direction between turnover, price impact and price spread. Two, we build and propose a new method to explain illiquidity impact and interrelationships of liquidity aspects. Three, we find that oil prices significantly impact liquidity and an increase in oil returns results in a reduction of the traded volume of energy stocks and in a lower price spread.

In the past decade, oil markets have experienced significant changes that have disrupted the traditional models of trade and supply-and-demand balance. Prices have moved to unprecedented levels and volatility has increased sharply. One of the most striking pricing occurrences was the imbalance of the two most-traded crude oil indexes in the world. Chapter 3 examines the price spread of Brent and WTI crude oil price indexes. In the past ten years, oil prices rose to unprecedented levels for years, dropped by more than 70% in a few months, then rose again and dropped to US \$26/barrel during February of 2016. At the same time, the price spread between Brent and WTI crude oil became disconnected after years of almost identical prices. To examine the determinants of convenience yields and spot price spreads, we take a fundamental-factors perspective, investigating their role in the Brent–

WTI price spread. Fundamental drivers may include elements related to economy, politics, geography, and technology among others. In this study, we use as fundamental the factors that have been defined impactful in explaining convenience yields. The fundamental factors are inventories, interest rates and volatility, and we investigate whether convenience-yield-affecting factors also drive oil price spreads. We find that whereas UK inventories affect Brent convenience yields negatively for a two-month horizon, US market inventories affect convenience yields up to one month. Interest rates in the US affect both Brent and WTI convenience yields over long horizons. In the short term all fundamental factors (inventories, interest rates, volatility) affect the Brent–WTI price spread. Differences in interest rates and inventories significantly affect spread in our base model; however, when we include differences of futures prices for longer horizons, they are insignificant. Differences in futures prices dominate the regressions for horizons up to 24 months. Differences in volatility affect spot price spreads significantly and positively for short horizons.

In Chapter 3 we find that fundamental factors such as inventories, volatility, interest rates affect convenience yields and the Brent–WTI crude oil spot- price spread. Fundamental factors affect WTI index more than Brent as the latter is much closer to the global market by means of seaborne trade while the former is influenced by regional supply-demand and geography characteristics.

Electricity is a crucial input for almost all households. Currently, the EU undergoes a process of improving the mechanisms of electricity market integration. Market integration is important not only for efficiency and direct economic benefits, but also for reducing the risk of high dependency on energy. In Chapter 4, we investigate electricity price differences across Europe and the effect of cross-border transmission capacities. Our modeling approach restricts the causes of price differences to either transactional/trade costs or limitations in the logistical parts of trade. We find that two aspects of net transfer capacities affect electricity price differences across Europe. First, bidirectional cross-border transmission capacity negatively affects price differences; this is intuitive and translates into the need for more cross-border capacity. More investments in infrastructure will move price differences towards a single electricity market, to the benefit of the European consumer. Second, when cross-border net transfer capacities are unbalanced, one direction's capacity is larger than the other's, and price differences may increase; when transmission capacity from i region to j is larger than from j to i , the demand from region i has more limited access to electricity from region j . Consequently, in times of price imbalances, region i has less ability to purchase from region j ; this causes a larger price difference. In contrast, the price gap decreases when the country with the cheaper electricity transmits more electricity to the country with the more expensive price.

We also find that demand features, such as industrial production, affect electricity price differences. When trade capacity from one market to another is limited, demand shocks may have an impact on prices of the respective market and not transmit quickly through the network, thereby

increasing price differences. The negative relationship between the minimum of the two net transfer capacities and relative price differences implies that the larger the minimum net transfer capacity between markets i and j , the smaller their price differences. This is the result of restricted transmission capacity. We find that although expanding infrastructure can reduce price differences, much can be done with better use of the existing grid infrastructure, for example making use of smart grid technology and decentralized energy networks. Investments in new cross-border infrastructure are necessary to increase capacity, but more action in the market structure is crucial. In this study, we do not investigate the market structure and coupling considerations. This is an avenue that future researchers can incorporate into a study that considers both capacity constraints and how markets are designed to interact.

Chapter 4 finds evidence that increasing cross-border transmission capacity helps bring European electricity prices closer together. Transfer capacities should be bilateral for the benefits to be translated into market integration.

Energy is necessary to support the economic growth of countries and improve the lifestyle of large populations of the world. At the same time, energy generation is one of the activities held responsible for a substantial proportion of anthropogenic CO₂ emissions. According to the findings of the Intergovernmental Panel on Climate Change (IPCC), each of the last three decades has been warmer (IPCC, Fifth Assessment Report, 2014). This climate change is considered to have been accelerated due to the decades-long excess CO₂ emissions. The Paris-Agreement target is to sustain the increase in global average temperature to well below 2 °C above pre-industrial levels. In Chapter 5, we examine CO₂ emissions and the roles renewable and nuclear power generation may play in mitigating them. We use a panel of 61 countries for a period of 24 years (1990–2013) and find a clearly negative effect of both nuclear and renewable power on carbon emissions for all specifications used. Although there are conflicting results in the literature with regard to the relationships among carbon emissions, GDP, nuclear power, renewable power, and primary energy, we use a new framework to investigate our main question. We do not use the outright levels of carbon emissions, renewable and nuclear use, or per capita income levels that are typical of relevant literature, but instead use an alternative scaling approach. By modeling a metric for carbon emissions intensity and its relationship with renewable power, nuclear power, and GDP energy intensity, we are able to separate the effects of energy intensity of the economy and the energy technology used to generate power.

To our knowledge, this is the first study to use a stationary-framework modeling procedure to examine the relationship of carbon emissions with nuclear power generation, renewable power generation, and economic growth using a large sample. We contribute to the literature in two ways, by introducing a new conceptual structure for investigating the carbon-emissions-mitigation problem and using it in a straightforward panel data global sample. By disentangling two different effects and using

a regression methodology, we seek to add value to an important, strategic energy-policy issue, that is, how to mitigate carbon dioxide emissions.

In this context, we find that both nuclear and renewable energy directly reduce carbon emissions to a similar degree. We believe this is a useful finding for policy makers, because it shows that to reduce emissions, it is more important to increase non-carbon power generation than to focus on specific renewable or nuclear power technologies. Future researchers can use our findings to conduct more detailed investigation of how to apply renewable and nuclear power to reduce CO₂ emissions most effectively. An interesting aspect for policy makers is how much it will cost to mitigate carbon emissions. Although we find that energy intensity of the economy affects carbon emissions, we do not investigate the impact that policies to reduce carbon emissions have on income. However, such policies are highly important, because both economic growth and environmental impact are high-priority goals.

Chapter 5 finds that either renewable or nuclear energy helps reduce CO₂ emissions in a similar manner. This is a significant result as literature has indicated one of the two being more impactful. We achieve this insight by using a panel of 61 countries and separating the impact of energy conservation from the impact of the energy mix on CO₂ emissions.

All in all, this thesis has addressed four important topics for energy markets. In the second chapter we propose new insights in measuring liquidity and show how liquidity interrelationships change in turbulent times. We also find that oil price returns affect liquidity measures. These are useful for market participants as well as provide an alternative perspective in the liquidity research debate. In the third chapter we relate fundamental factors to the price difference between Brent and WTI, the two most liquid crude oil price indexes. We find that all fundamental factors, inventories, interest rates and volatility affect the Brent–WTI price spread. We also find that when investigating the effect of the futures prices' spread in contemporaneous Brent-WTI spread, fundamental factors can still help explain changes for shorter horizons and less for longer horizons. Chapter four deals with a crucial element of European integration which is the energy market and more particularly, the electricity market. A unique contribution of this study is the direct use of net transfer capacities across borders in Europe to help explain electricity price differences. We find that increasing cross border capacities bilaterally contributes significantly in electricity prices integration. In chapter five we investigate the contribution of renewable and nuclear power generation to mitigating CO₂ emissions. This study contributes in the literature by introducing a new structure to investigate the CO₂ emissions mitigation issue. It also provides evidence that renewable and nuclear power generation reduce CO₂ emissions in a highly similar way and addresses the underlying reasons of contradicting findings in the relevant literature.

Samenvatting (summary in Dutch)

Dit proefschrift onderzoekt vier energiemarktthema's. Door het onderzoeken van sommige van de meest uitdagende vraagstukken in de energie- en financiële markten willen we een bijdrage leveren aan academische debatten, overwegingen van beleidsmakers en inzichten uit de praktijk. De opwarming van de aarde en de gevolgen van een decennialang stijgend verbruik van fossiele brandstoffen heeft geleid tot het wereldwijd geaccepteerde Akkoord van Parijs om de uitstoot van broeikasgassen te beperken. Een duurzame economische groei vormt de prioriteit als het gaat om het welzijn van huidige en toekomstige generaties. Het huidige internationale energiesysteem wordt beïnvloed door nieuwe, meer klimaatbewuste wetgeving, en de olie-industrie is daar niet immuun voor. De traditionele ruwe olie handelsroutes zijn verschoven, waardoor verstoringen in markten ontstaan, die niet altijd weer snel in balans raken. Onlangs hebben de COVID-19 pandemie en de wereldwijde lockdowns een kloof in de vraag naar olie gecreëerd wat een groot deel van de industrie heeft doen dichtslibben. De marktstructuur, de liquiditeit en het beleid zijn van invloed op zowel de financiële als de energiemarkten, wat nieuwe uitdagingen met zich meebrengt. Om een bijdrage te leveren aan de aanpak van deze uitdagingen, richt dit proefschrift zich op vier belangrijke kwesties in de energiesector en de financiële markten:

- 1) Hoe kunnen we de liquiditeit meten, wat verandert er in periodes van illiquiditeit en wat is de rol van de olieprijs?
- 2) Hebben fundamentele factoren gerelateerd aan 'convenience yields', invloed op de Brent-WTI-prijsspreiding voor ruwe aardolie op de spotmarkt?
- 3) Komen de elektriciteitsprijzen in Europa dichterbij met toenames van de grensoverschrijdende transportcapaciteit?
- 4) Hoe dragen hernieuwbare en nucleaire energieopwekking bij aan de vermindering van de CO₂-uitstoot?

Hoofdstuk 2 onderzoekt de onderlinge relaties van liquiditeit en olieprijsen met de financiële markt, en in het bijzonder met de energievoorraden. De liquiditeit van de energiemarkten is een belangrijke voorwaarde voor efficiënte markten. Overheden en mondiale instellingen vergroten hun inspanningen om het vertrouwen in de markten te versterken door het omgaan met crisisperiodes (hoofdzakelijk de wereldwijde financiële crisis in 2008), het stimuleren van de handel en het stimuleren van de economie. Hoewel de liquiditeit de afgelopen twee decennia in de schijnwerpers heeft gestaan,

bevindt de liquiditeit in de energiesector zich nog in een vroeg stadium van analyse. Er bestaat bijvoorbeeld geen algemeen aanvaarde definitie van liquiditeit. Liquiditeit wordt beschouwd als het gemak en de snelheid van de handel. De meting van het gemak en de snelheid van de handel is echter niet eenvoudig; liquiditeitsmaatregelen die door wetenschappers en praktijkmensen worden gebruikt, leggen slechts delen, of verschillende dimensies, van de liquiditeit vast. In hoofdstuk 2 onderzoeken we de onderlinge verbanden tussen verschillende dimensies van liquiditeit, modelleren deze in een structuur die theoretisch aantrekkelijk is, en vergelijken deze met eerdere literatuur.

Om de liquiditeit van energieaandelen te onderzoeken, richten wij ons op de *bid-ask spread*, gedefinieerd als het verschil tussen de prijs waartegen een goed kan worden gekocht en verkocht op hetzelfde moment. De hoofdgedachte van ons model is dat in een concurrerende intermediaire markt sommige liquiditeitsmaatregelen voorafgaan aan andere. Wij gebruiken een vector autoregressie (VAR) om rekening te houden met de sterk gecorreleerde liquiditeitspatronen, en wij stellen een causaliteitspatroon voor van de handelsactiviteit naar de prijsimpact en van beide naar de spread. Wij beschouwen de olieprijsen ook als een belangrijke factor van energievoorraden. Om onze vooronderstellingen te testen, gebruiken wij een structurele VAR waarin wij de marktmaker in staat stellen om de informatie over de handelsactiviteit en de prijsimpact gelijktijdig te observeren. Dit houdt in dat, hoewel de omzet afhankelijk is van eerdere waarden van alle liquiditeitsmaatregelen, dit niet tegelijkertijd gebeurt, omdat de bid-ask spread afhankelijk is van zowel eerdere als contemporaine waarden van alle liquiditeitsmaatregelen. Wij vinden dat historische waarden van alle liquiditeitsmaatregelen belangrijk zijn om elkaar te verklaren. Bovendien hebben de contemporaine waarden van de omzet, de prijsimpact en de olieprijs allemaal een significante invloed op de spread. Onze belangrijkste hypothese is dat dealers de huidige trends waarnemen en hun quotes zodoende aanpassen. Wanneer we onze steekproef opsplitsen in deelperiodes, stellen we vast dat er verschillende kenmerken van toepassing zijn gedurende verschillende periodes. De handelsactiviteit is een veel belangrijkere bepalende factor voor de prijsspreads in turbulente tijden (bijv. januari 2008-augustus 2009) dan in rustiger perioden. De impact in dergelijke periodes is vijf keer zo groot; de handel tijdens krediet- en illiquide tijden is veel risicovoller voor intermediairs en zij eisen hogere spreads ter compensatie.

Hoofdstuk 2 genereert drie relevant bijdragen. Ten eerste wordt de liquiditeit van de energiesector onderzocht en worden theoretische en empirische bevindingen in de literatuur gekoppeld aan een uiteenlopende dataset. Ten tweede wordt een nieuw intermediair perspectief voorgesteld om de onderlinge relaties van verschillende aspecten van liquiditeit te verklaren, waarbij marktmakers informatie ontvangen en hun risico's zodoende beheren. Ten derde worden subgroepen en deelperiodes onderzocht die interessante inzichten bieden over het gedrag van intermediairs.

In hoofdstuk 3 analyseren we een van de belangrijkste ontwikkelingen op de oliemarkten in de 21^{ste} eeuw, namelijk het verschil van de Brent en WTI-prijnsindexen voor ruwe olie in relatie tot de schalierevolutie. We modelleren de basisprincipes van de energiemarkt als factoren van de Brent-WTI-ruwolieprijsspreiding. Tijdens het einde van de jaren 2000 bereikten de olieprijsen een ongekend niveau; 100 dollar per vat was normaal. Deze hoge prijzen werden geëvenaard door buitensporige onzekerheid en volatiliteit; hoge prijzen veroorzaakten productie uit nieuwe en minder benutte gebieden en stimuleerden nieuwe technieken om koolwaterstoffen te bereiken die voorheen als niet-economisch werden beschouwd. Er werden diepe offshore bronnen ontgonnen en onconventionele projecten ter waarde van miljarden dollars geïnitieerd. De olie in de VS steeg van ongeveer 5 miljoen vaten per dag in 2007 naar ongeveer 12,2 miljoen vaten per dag in 2019. Deze ontwikkelingen schokten de energiemarkten en veranderden de marktstructuur volkomen. Een van de meest opvallende veranderingen was dat de prijzen van twee van de belangrijkste benchmarks voor de prijsstelling van ruwe olie in ongekende mate uiteenliepen. Decennialang was er een minimaal prijsverschil tussen Brent en WTI; door de sterke stijging van de prijzen, de nieuwe productie en de daaruit voortvloeiende handels- en prijseffecten liepen de prijzen van twee soortgelijke grondstoffen echter uiteen. Hoewel een dergelijk verschil in strijd lijkt te zijn met de *wet van één prijs* (*law of one price*, LOOP), waarbij hetzelfde product/grondstof dezelfde prijs heeft voor alle markten aangepast voor transportkosten als er geen handelsbelemmeringen zijn, bleef het lange tijd bestaan.

Hoofdstuk 3 onderzoekt enkele van de onderliggende redenen die de Brent-WTI spreiding kunnen verklaren, waarbij gebruik wordt gemaakt van inzichten uit de voorraadtheorie en de hypothese wordt getest dat fundamentele factoren die van invloed zijn op de opbrengst van de opslag ook van invloed kunnen zijn op de prijsverschillen. Wereldwijde beleggers zijn in staat om grote hoeveelheden Brent- en WTI-contracten te verhandelen binnen een liquide markt. De daadwerkelijke fysieke levering van de grondstof van het ene continent naar het andere duurt echter weken. De kosten zijn ook afhankelijk van factoren zoals de beschikbaarheid van transportmiddelen, de regionale vraag en het aanbod. Hoewel het opbouwen van voorraden beleggers die tussen de twee markten handelen loont, kunnen onzekerheid, volatiliteit en kosten hen ervan weerhouden om het risico te nemen. Het verschil tussen *spotprijzen* en *termijnprijzen*—wat kan worden geïnterpreteerd als de compensatie voor het risico van het niet inhouden van de goederen—is de onderliggende ‘convenience yield’ nadat de opslagkosten zijn verantwoord.

Dit hoofdstuk bevestigt een verband tussen fundamentele factoren die van invloed zijn op de ‘convenience yields’ op de oliemarkten, namelijk de voorraden, de rentetarieven en de volatiliteit, en het verschil in spotprijzen tussen twee van de belangrijkste ruwe-olie-indexen in de wereld. Elk van deze fundamentele factoren kunnen op zichzelf al worden beïnvloed door verschillende politiek-economische ontwikkelingen, maar ook door aspecten als geografie en technologie. Wij ondervinden dat ‘convenience yields’ van het aanhouden van Brent en WTI ruwe olie wordt beïnvloed door de

volatiliteit van het rendement van de spotprijs en door veranderingen in de WTI voorraden, maar niet door de Brent voorraden. Dit duidt zowel op verschillen in marktstructuur als op geografische verschillen tussen de twee indexen. Brent ruwe olie heeft een flexibelere logistiek, waarbij tankers ruwe olie laden voor een wereldwijde markt; dit wordt weerspiegeld door de onbeduidende veranderingen in de regionale (UK en Noorwegen) voorraden. Dit is van belang vanuit zowel een onderzoeksperspectief - omdat het bewijst dat er een verschillende dynamiek bestaat tussen twee vergelijkbare producten die ogenschijnlijk onder de LOOP vallen – en gezien vanuit financieel en zakelijk oogpunt - omdat het decennialange handelspatronen verstoort en kansen en bedreigingen veroorzaken. Wanneer we rekening houden met verschillen in futureprijzen voor een of twee maanden, constateren we dat de Brent-WTI spread over het algemeen niet langer gerelateerd is aan fundamentele factoren; voor toekomstige prijsverschillen van drie maanden of langer lijken traditionele beginselen de prijsverschillen te verklaren, wat impliceert dat de korte termijn futureprijzen rekening houden met deze beginselen en dat dit vervaagt in de loop van de tijd.

In hoofdstuk 4 wordt ingegaan op de integratie van de elektriciteitsmarkt in Europa en de rol die de netto-overdrachtscapaciteit speelt. In de afgelopen 20 jaar hebben veel lidstaten van de Europese Unie (EU) energiebeurzen gecreëerd om zowel de interne markten als het welzijn van de Europese burgers te verbeteren. Voorheen was de elektriciteitssector een sterk verticaal geïntegreerde industrie waarin de regelgevers de prijzen bepaalden. Dit typische model was afhankelijk van een evaluatie van de productiekosten en een niet-concurrerende markt. De verschuiving van verticale nationale monopolies op de elektriciteitsmarkten naar meer concurrerende structuren werd gezien als een cruciaal element van de Europese marktintegratie. Om deze verschuiving te bevorderen, zijn de EU-landen overeengekomen een meer geliberaliseerde aanpak te hanteren voor de productie, het netwerken en de groot- of kleinhandelsdistributie van elektrische energie. Deze marktherstructurering heeft geleid tot handelsactiviteiten en af en toe grote prijsvolatiliteit. De vooralsnog zeer kostbare en weinig efficiënte opslag van elektriciteit veroorzaakt een grote kans op onevenwichtigheden in vraag en aanbod en leidt tot prijsvolatiliteit. De vraag op korte termijn is inelastisch, wat betekent dat alleen een elastisch aanbod een buffer kan vormen en de kans op extreme prijsspieken kan verminderen. Transmissiebeperkingen kunnen een belangrijke oorzaak vormen voor een inelastisch aanbod: Hoe groter de markt en hoe beter de onderlinge verbindingen, hoe elastischer het aanbod van elektriciteit.

In deze context is de motivatie en de wil om een interne elektriciteitsmarkt in Europa te creëren tweeledig: de eerste is het verlagen van de gemiddelde prijs voor de consument, en de tweede is het efficiënter toewijzen van elektriciteit, met minder prijsschokken. Met dit als uitgangspunten construeren we een model waarin de prijsverschillen ook kunnen worden beïnvloed door beperkingen van de transmissiecapaciteit. Hoofdstuk 4 draagt op twee manieren bij aan de literatuur. Ten eerste is onze studie, voor zover wij weten, de eerste die de netto-overdrachtscapaciteit in Europese landen rechtstreeks modelleert als een bepalende factor voor het onevenwicht in de elektriciteitsprijs. Ten

tweede, om het effect van de transmissiecapaciteit op de prijsverschillen te onderzoeken, bouwen we een database op voor de transmissiecapaciteiten tussen zeven electriciteitsbeurzen, waarbij 11 landen in Europa betrokken zijn. Deze landen zijn goed voor een groot deel van de economische activiteit in Europa. Een belangrijke bevinding is dat bij toenemende grensoverschrijdende capaciteit de prijzen convergeren, wat de Europese economieën en consumenten ten goede komt. We stellen ook vast dat wanneer de overdrachtscapaciteit niet bilateraal is, de prijzen niet convergeren omdat vraagschokken tussen de twee regio's ongelijk worden geabsorbeerd. Onze resultaten pleiten voor het nemen van grotere initiatieven op het gebied van infrastructuurinvesteringen om een grotere marktintegratie te bereiken, alsmede voor het vrijlaten van lokale energie-opwekking van onconventionele partijen.

In hoofdstuk 5 bestuderen we het belang van hernieuwbare energie en kernenergie voor de vermindering van de CO₂-uitstoot. Met een groeiende wereldeconomie en een toenemend energieverbruik om aan de behoeften van de consumenten te voldoen, is ook de uitstoot van kooldioxide toegenomen. De reden voor de door de mens veroorzaakte emissies is dat de wereld in de afgelopen eeuw conventionele fossiele brandstoffen heeft gebruikt als drijvende kracht achter de energieproductie. Steenkool, olie en aardgas zijn nog steeds de belangrijkste energiebronnen op aarde. De conventionele brandstoffen worden echter steeds schaarser, duurder en vuiler. Er is een overweldigende toename van het wetenschappelijk bewijs dat klimaatveranderingen aanzienlijke wereldwijde risico's met zich meebrengen en dat er actie moet worden ondernomen. Het effect op de klimaatverandering en de milieukosten hebben verschillende landen ertoe aangezet een beleid op te zetten om het effect van fossiele brandstoffen te verminderen door het gebruik van alternatieve, voornamelijk hernieuwbare, energiebronnen.

In hoofdstuk 5 wordt de impact van het gebruik van kernenergie en hernieuwbare energie op de vermindering van de CO₂-uitstoot onderzocht. We ontrafelen de effecten die toe te schrijven zijn aan de energiemix en de effecten die toe te schrijven zijn aan een toenemend (of afnemend) energieverbruik, door gebruik te maken van een schaalbenadering waarbij de afhankelijke variabele een maatstaf is voor het koolstofgehalte. Dit helpt ons om twee verschillende effecten te scheiden die het absolute niveau van de koolstofuitstoot in verschillende richtingen kunnen duwen. Met deze maatregel introduceren we een nieuwe conceptuele benadering voor het analyseren van de vermindering van de koolstofuitstoot. We stellen dat we door het identificeren van de afzonderlijke effecten van nucleaire en duurzame energie op broeikasgasemissie via de CO₂-intensiteit, komen tot een meer geïnformeerde analyse en beoordeling van de vraag of de toename of afname van het energieverbruik en de koolstofuitstoot van een land het resultaat is van het gebruik van kernenergie en hernieuwbare energie.

Hoewel de resultaten in de literatuur tegenstrijdig zijn, vinden we dat de CO₂-uitstoot per energie-eenheid wordt verminderd wanneer we ofwel hernieuwbare energie ofwel kernenergie aan de energiemix toevoegen, en de resultaten zijn robuust onder alle specificaties en controles. We stellen dat

de reden voor dit duidelijke resultaat de ontrafeling van de effecten van de koolstofintensiteit en de energie-intensiteit van een economie is. Onze resultaten impliceren *niet* dat landen die hun hernieuwbare energie en kernenergie verhogen hun totale CO₂-uitstoot verlagen, omdat ze hun totale primaire energieproductie kunnen verhogen. Gezien het feit dat zij hun koolstofuitstoot per energie-eenheid verminderen, vinden wij het echter een interessant resultaat en een interessant instrument in de discussie. Er rijzen twee vragen: Kunnen we het energieverbruik in totaal verminderen (d.w.z. energie besparen)? Kunnen we de koolstofuitstoot per energie-eenheid verminderen (d.w.z. de energiemix verbeteren)? Dit zijn immers twee verschillende dingen. We testen ook de tweede vraag en stellen vast dat hernieuwbare energie en kernenergie de koolstofuitstoot in dezelfde mate verminderen. Gemiddeld heeft een toename van 1% hernieuwbare energie in de energiemix een vergelijkbaar effect op de vermindering van de CO₂-uitstoot als een toename van kernenergie met 1%. We baseren dit resultaat op grond van onderzoek in 61 landen, waaronder de grootste economieën ter wereld (met landen met en zonder kernenergie)), hoewel eerdere studies tegenstrijdige resultaten hebben getoond met betrekking tot de effectiviteit van een van beide energiebronnen bij het verminderen van de broeikasemissies.

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