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Oil–gas price relationships on three continents: Disruptions and equilibria

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ABSTRACT

In this paper, we revisit traditional gas pricing formulas and show the ever-changing relationships between natural gas and oil prices in Europe, the United States, and Japan between 2009 and 2021. The results suggest a stronger oil–gas link for all investigated markets after 2019, significantly impacted by fundamental supply and demand factors. However, the strength of the equilibria link differs across markets due to different price formation processes under the impact of the COVID-19 pandemic and the Ukraine war. For Japanese LNG prices, our results imply an enduring impact of oil-price indexation with a tight link to monthly crude prices. TTF and monthly oil prices enter a temporary equilibrium in times of high market volatility, whereby the long-term equilibrium dissipates. Despite the absence of oil indexation in the North American market, we find evidence of re-coupling of oil and gas prices given the demand shock of the COVID-19 pandemic. These findings are relevant to policy makers to assess market inefficiencies caused by the European gas crisis.

1. Introduction

Natural gas is considered to play a vital role in the global energy transition, due to its flexible use in power generation and lower CO_2-to-energy content compared to other fossil fuels. Besides nuclear energy, the EU has therefore classified investment into natural gas infrastructure as sustainable, when aligning with long-term decarbonization targets. In many parts of the world, the import price of natural gas has historically been linked to the price of refined oil products. This is intuitive, as natural gas is often a byproduct in the discovery of oil reservoirs and has been used as a substitute for fuel oils and other distilled products for electricity generation and heating. Before the establishment of natural gas markets, the liquidity and transparency of the oil market granted protection against oligopolistic control and regional gas price bubbles. Especially from the perspective of natural gas importers, however, oil prices do not reflect the unique demand and supply characteristics of natural gas. Zhang et al. (2018b) thereby suggest that independent natural gas hub prices are associated with less extreme price movements compared to oil prices, while Shen et al. (2018) indicate risk transmission from global oil markets to natural gas. A gradual transition towards hub gas pricing in Europe and an increasing spot trade in the Asian LNG market weaken the role of oil prices as the primary driver of natural gas prices in both markets (Zhang and Ji, 2018). Furthermore, Wang et al. (2019) document a declining impact of oil prices on North American natural gas prices and a growing importance of supply and demand fundamentals.

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Oil and gas prices as well as their joint dynamics are increasingly subject to financial markets and the financialization of commodity futures. For instance, Bianchi et al. (2020) argue that after 2013, the enduring financialization of commodity futures has led to a tighter co-movement between equity and energy markets because of the function of energy commodities as inputs to economic production. Behmiri et al. (2019) outline that higher market volatility and weaker economic conditions coincide with larger correlations between commodity futures, whereas Bunn et al. (2017) indicate that increased speculation in the oil market strengthens the oil–gas price correlation.

The traditional oil–gas price link has been challenged by several market developments, namely the switch to hub pricing for gas, historical demand and supply disequilibria, the financialization of commodities, or political shocks. The COVID-19 pandemic has led to an unprecedented paradigm combining both demand destruction and a simultaneous supply shock wave, which has propagated towards the energy sector. In this study, we show that the global health crisis has led to new trends in oil-linked natural gas prices while accelerating some existing ones.

The individual gas markets analyzed in this study developed differently with respect to their link to oil: Large discoveries of unconventional resources (e.g. shale gas) in the early 2000s in the United States and Canada manifested the role of Henry Hub prices as a benchmark of an already independent North American natural gas market.[1] In contrast, the import-dependent Asian and European markets have not experienced the same penetration of competitive market pricing of natural gas because of the contractual link of gas import prices to long-term averages of oil prices (Erdős and Ormos, 2012). In Europe, the persistence of oil indexation by the single largest importer, Gazprom, led to cointegration between natural gas and oil prices into the early 21st century (Li et al., 2014). After 2012, however, Dutch and Norwegian sellers, and eventually also Gazprom, linked their contracts increasingly to gas hub prices, such as the Dutch Title Transfer Facility (TTF). Because of these changes, the share of oil indexation in pipeline-imported natural gas to Europe declined from 91% to 19% in the period from 2005 to 2020, while hub pricing rose from 7% to 81% (IGU, 2021). In Japan, Asia's largest market for natural gas, only recent years have shown the emergence of a long-awaited independent Asian benchmark price for LNG, Platts Japan Korea Marker (JKM). However, besides a sharp increase in spot LNG after 2017, in the Asia-Pacific region, the share of spot and short-term deliveries in total LNG imports rose to only 25% in 2020, with the remainder largely indexed against the average price of crude oil, such as Japan Customs-cleared crude oil (JCC) (IGU, 2021).

The energy crisis that started in 2021 put continuous upward pressure on gas prices, which spiked in the context of the Russian invasion of Ukraine. This highlighted the importance of LNG as a flexible natural gas option also for Europe, given the lack of alternatives to pipeline imports from Russia. The EU, therefore, seeks to diversify its natural gas imports through the construction of new LNG terminals and improved linkages between existing regasification facilities in Spain and Central Europe (European Commission, 2022b). Aiming to eliminate dependence on Russian gas by 2030, the EU's REPowerEU plan further seeks to bolster supply security by initiating joint purchase agreements and requiring a mandatory 90% filling-level of gas storage by November. In the context of an unfolding natural gas shortage, this study aims at contributing to a renewed understanding of the oil–gas price relationship and of the role of oil prices in preventing the development of regional natural gas price bubbles. Given the mandate of natural gas as a bridge fuel for the energy transition in Europe, this study aims also to shed light on the exposure of the natural gas-based energy transition to crude oil prices.

This study focuses on the short- and long-term link between gas and oil across continents, which shows a sinuous path over time. Apart from short-term dynamics, the North American Henry Hub prices followed a stable long-term relationship with crude oil prices until the beginning of the 21st century (Brown and Yücel, 2008). Shale gas discoveries after 2005, however, led to an unstable cointegration relationship (Ramberg and Parsons, 2012) and finally a decoupling from oil prices (Geng et al., 2016). Japanese and European prices at the same time continued to share a long-term trend with crude oil prices, albeit allowing for regime-switching (Brigida, 2014), or experiencing periodic decoupling (Asche et al., 2017). The period from 2002 to 2010 is generally characterized by a weakening price link in all markets, whereas Erdős (2012) shows that LNG import prices to Japan follow a more sluggish reaction to oil prices and import prices from Russia show early signs of independence. More recently, Zhang and Ji (2018) show that the relationship between oil and gas prices is more stable in Europe than in Japan, despite a higher share of oil-indexation in Japanese import contracts than in Europe. Given the increase in LNG trade and especially US exports after 2015, the question arises to which extent these developments affect the oil–gas price relationships also on the import-dependent European and Japanese gas markets. This is further stressed by the joint US-EU agreement on the delivery of an additional 15 bcm LNG in 2022 from the US to Europe, which is to be increased to 50 bcm yearly by 2030 (European Commission, 2022a).

The contribution of this paper is twofold. Firstly, we extend previous work by Erdős and Ormos (2012) and Zhang and Ji (2018) with an extended sample and application of long-term oil prices to detect oil indexation-driven effects on gas prices during the COVID-19 pandemic. Secondly, we assume a comprehensive overview of natural gas markets worldwide: We assess the decoupling hypothesis of natural gas prices from oil price developments in North America; we also investigate the effects of a declining relevance of oil-indexation in Europe as well as of a shift towards short-term pricing in Japan. We analyze regional oil–gas price ratios by applying variance ratio and cointegration tests, as well as by testing for long-memory with the two-step feasible exact local Whittle estimator in fixed samples and in rolling windows. We further assess the impact of fundamental variables on the oil–gas link in the frame of a Vector Error Correction Model (VECM) and discuss oil–gas equilibria and disruptions in the light of demand–supply factors. We thereby extrapolate on the future of oil–gas relationships in the context of the REpowerEU energy transition initiative (European Commission, 2022b), which defines pathways for reducing import dependency on Russian natural gas.

[1] Historically, the prices of the West Texas Intermediate (WTI) and of the Henry Hub maintained a 10-1 relationship, meaning that one barrel of the WTI crude oil priced at around 10 times 1 million British thermal units (MMBtu) of the Henry Hub natural gas. In the early 2000s, this ratio declined by roughly 40% to 6-1, which is close to thermal parity (Hartley et al., 2007).

Our results suggest equilibrium relationships between monthly gas and oil prices in all regions between 2015 and 2021. We find shorter shock persistence in oil and gas ratios in North America between 2019 and 2021. Also for Japanese LNG prices, the rolling window analysis confirms a quicker mean reversion speed towards the long-term equilibrium relationship with monthly oil prices. The relationship between Dutch TTF and oil prices enters a temporary equilibrium relationship in times of high market volatility, such as in 2014 and in 2020–2021, whereby the relevance of long-term indexation dissipates. Furthermore, our findings indicate a trend reversal in the hypothesized decoupling of oil and gas prices under the influence of price shocks, oil market financialization, US gas production, and a swift shift from oil and gas over- to under-supply. The rest of the paper is organized as follows: In Section 2, we give a review of relevant literature streams. In Section 3, we describe the input data. Section 4 presents the methods applied, followed by the results in Section 5. We discuss our findings in Section 6 and Sections 7 and 8 conclude the paper.

2. Literature review

The emergence of natural gas in oil extraction and substitutability in consumption led to a significant effect of oil price changes on the price of gas over the last decades (e.g. Brown and Yücel, 2008; Ramberg and Parsons, 2012). Brown and Yücel (2008) and Hartley et al. (2008) find that prior to the emergence of the shale gas in North America in the early 2000s, Henry Hub prices were in a long-term equilibrium with oil prices when accounting for weather, seasonality, storage, and production disruptions. During this period, gas and fuel oil were competing in consumption, and technological fuel switching constraints in electricity production in the early 2000s have kept oil and natural gas from severely decoupling (Hartley et al., 2008). In a follow-up work, Hartley and Medlock III (2014) find that while affected by the exchange rate, oil and gas prices are still cointegrated between 1995 and 2011, whereby the integration weakens due to decreasing substitutability. Erdős (2012) shows however that prior to 2009 both US Henry Hub and the British Natural Balancing point (NBP) gas prices reverted back to a long-term equilibrium with oil prices after exogenous shocks. The authors indicate that the strongest integration is found for the European index. Similar results were found by Brigida (2014) for Henry Hub and by Asche et al. (2017) for NBP when applying regime-switching models.

The accelerating shale boom in the United States in the early 2010s introduced an unprecedented spread in regional gas prices. Corbeau and Ledesma (2016) identify four drivers of this price divergence in the form of excess and low-cost supply, Brent prices above 100 US dollars per barrel (USD/bbl), recession in Europe, and the Fukushima crisis in Japan. Research recognizes that the advent of shale gas led to a decoupling and a structural break in the relationship between US Henry Hub and oil prices after 2009 (Erdős, 2012; Asche et al., 2012; Geng et al., 2016; Caporin and Fontini, 2017; Chiappini et al., 2019). Due to the de facto export ban until 2015, [2] surging inventory levels and low penetration of other markets are considered the main drivers of the resulting low gas prices in the North American market in 2010 (Chiappini et al., 2019). Consequently, a more short-term volatile gas market emerged with a weakening tie to oil prices (Ramberg and Parsons, 2012). Caporin and Fontini (2017) suggest that the increased competitive advantage of gas over oil resulting from low prices contributed to the decoupling. For the period from 1998 to 2015, Geng et al. (2016) and Batten et al. (2017) confirm that the previously existing cointegration relationship between Henry Hub and WTI prices has dissolved, driven by the emergence of shale gas, which spurred the evolution of natural gas from a balancing fuel to a baseload fuel competing with coal. Furthermore, Zhang et al. (2018a) found that oil price dynamics are the third strongest determinant of gas price changes between 2002 and 2016, following the impact of consumption and production.

Whereas the North American gas market decoupled as a consequence of domestic shale extraction and political will (Ramberg and Parsons, 2012), Europe, on the other hand, in the late 2010s was in the process of transitioning from oil-indexation towards competitive market pricing. However, in the context of decreasing continental resources in Europe, nearly 80% of gas imports via pipeline in 2005 were oil-indexed (Stern and Imsirovic, 2020). Erdős (2012), Asche et al. (2013), and Lin and Li (2015) show cointegration of German gas import and oil prices before 2009. Similarly, Asche et al. (2012) found that the British NBP prices share a long-term equilibrium relation with oil before 2010. In an SVAR model frame, Nick and Thoenes (2014) indicate that between 2008 and 2012 oil and coal prices were key drivers of the price development at the German gas hub NetConnect Germany (NCG). However, Chiappini et al. (2019) find that 2010 marks a structural change in the cointegrating relationship of most European hubs with oil prices. The authors show a weaker long-term relationship between oil and NBP prices since December 2009 and with TTF prices since May 2014. For the subsequent years, Chiappini et al. (2019) find increasing integration among European gas hub prices and between European- and Henry hub prices, whereas the long-term relationship between oil and gas prices weakens towards 2017. Following a VAR approach, Zhang et al. (2018a) confirm the finding of decoupling oil and gas prices in Europe, thereby also emphasizing the need for time-variant analysis. For German import prices, the authors' rolling window model shows a declining impact of oil prices from 2010 to 2014, while the impact of fundamentals remains largely unchanged.

In Japan, imports of gas have been historically indexed against the average price of JCC. Lin and Li (2015) find that the cointegrating relation between oil and gas import prices in Japan between 1992 and 2012 is weaker than for German import prices, due to a temporary decoupling (Zhang and Ji (2018)). The persistent use of oil-indexation in Japanese gas prices is reflected in their dynamics absorbing the most significant negative shocks from crude oil volatility compared to European- and US gas prices until 2011 (Ji et al., 2014). However, for the subsequent years, Lin and Li (2015) show independent volatility between natural gas and oil for Japan, but significant volatility transmission from oil to the European and the US natural gas markets. Furthermore, the risk

[2] The United States government passed legislation, known as the "The Energy Policy Modernization Act of 2015", and established a new process for approving natural gas exports to countries that do not have a free trade agreement with the United States. Natural gas exports consequently rose from 1.78 trillion cubic feet (tcf) in 2015 to 6.65 tcf in 2021 (EIA, 2023).

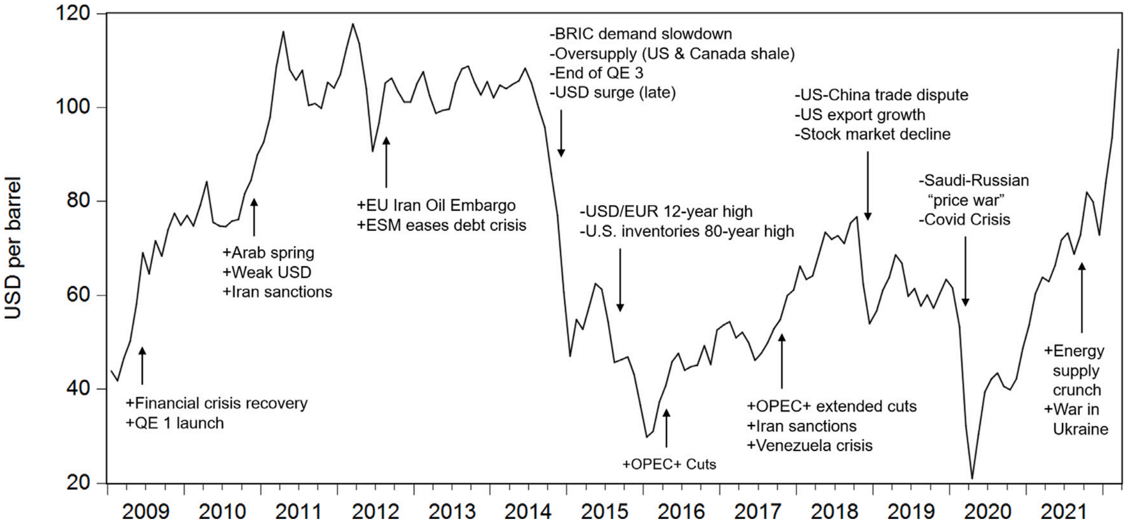

Fig. 1. Crude oil price development 2009 - March 2022.

avoidance mechanisms (floor and cap prices) in indexation formulas led to a temporary decoupling in the case of very high and very low oil prices in Japan (Lin and Li, 2015; Zhang and Ji, 2018). Batten et al. (2017) on the other hand argue that a shift from long- to short-term pricing in Asia may be contributing to a convergence of oil and gas prices in the region, as these short-term contracts are directly linked to the price of Brent or JCC. Furthermore, recent years brought a gradual shift towards shorter duration in long-term LNG import contracts (Neumann et al., 2015). However, a growing number of short-term traded LNG deliveries to Asia are priced off Platt's Japan-Korean Marker (JKM) (Stern and Imsirovic, 2020), thus not oil-indexed. A number of researchers request the establishment of Japanese trading hubs (e.g. Shi and Variam (2016)). Defendants of oil-indexation however argue that the Asian premium indeed originates from different market fundamentals (Neumann and Von Hirschhausen, 2015). Advocates of hub-based pricing argue that gas fundamentals are better reflected in hub prices, which are less susceptible to speculation and show less extreme price movements than in the case of oil indexation (Zhang et al., 2018b,a).

Apart from oil prices and fundamentals, natural gas prices are expected to respond increasingly to financial markets because financial trading induces a cyclical tendency that strengthens the link between commodity and equity market indices (Singleton, 2014). Basak and Pavlova (2016) in a theoretical paper show evidence for shocks transmission from the fundamentals of some commodities to the prices of others. Zhang et al. (2017) find that stock market volatility is becoming increasingly important for Henry Hub natural gas prices and Behmiri et al. (2019) show that market volatility coincides with higher correlations between commodity futures. Wang et al. (2019) further indicate that speculative long positions significantly impact natural gas prices, while Bunn et al. (2017) show that speculation in the oil market increases the oil–gas price correlation. In the wake of the financialization of commodity markets, a loosening contractual oil link in gas imports contributes to gas market integration: For the period after 2014, Chiappini et al. (2019) show a trend towards strengthening cointegration between oil-decoupling European and North American Henry Hub prices. Price convergence across these fundamentals-driven natural gas markets stems from common exposure to global supply and shared price susceptibility to the volatility of financial markets.

The literature points towards an ever-changing oil–gas relationship in the North American, European, and Japanese markets. Research overwhelmingly supports the decoupling of Henry Hub prices from oil, while the European gas market, after a long history of oil-indexation, has largely decoupled. JCC oil prices are still determinant for Japanese LNG import prices, whereas shorter gas contract duration and spot trade against the JKM marker may further loosen the price link. Decoupling from oil prices, a more flexible LNG trade mode, as well as the financialization of energy commodities, are drivers of the convergence in regional gas prices. Our study aims at revisiting traditional oil–gas pricing formulas in the wake of loosening traditional oil indexation and increasing use of hub pricing mechanisms.

3. Data

As the world's largest natural gas hub by volume, Henry Hub prices have become the benchmark for natural gas prices in North America. Albeit a recent increase in trade against Platts JKM spot marker, Japanese LNG import prices serve as the Asian benchmark price in our study. The Dutch TTF has established itself as the most liquid European trading hub and the prime hub benchmark in Europe, ahead of the British NBP. The liquidity of trading hubs can be expressed by their respective churn rates, defined as total trading volume divided by net consumption, whereas for the JKM spot marker, the rate is given by dividing total trading volume by total LNG imports. Churn rates take into account the volume and frequency of trading activity and are less susceptible to market volatility and transaction size than bid–ask spreads. Accordingly, in 2020 Henry Hub shows very high liquidity with a churn rate of

Table 1
Pearson correlation matrix: Log returns of oil and gas prices.

Correlation	Oil_t	$OilMA3_t$	$OilMA3_{Lt}$	$OilMA6_t$	$OilMA6_{Lt}$	HH_t	LNG_t	TTF_t
Oil_t	1							
$OilMA3_t$	−0.0052	1						
$OilMA3_{Lt}$	−0.1905	0.7171	1					
$OilMA6_t$	−0.0444	0.5674	0.7300	1				
$OilMA6_{Lt}$	−0.1276	0.3373	0.6009	0.8910	1			
HH_t	0.1098	0.1630	0.1751	0.1379	0.1549	1		
LNG_t	−0.0868	0.1007	0.4335	0.6477	0.6492	0.2507	1	
TTF_t	0.1770	0.3595	0.3155	0.2997	0.2750	0.1734	0.0527	1

Notes: MA3 refers to the three months moving-average and MA6 to the 6 months moving-average oil prices. The subscript $_L$ denotes that an additional lag of one month has been applied to calculate the price series.

47.2 for North America and Mexico, while the TTF shows a churn rate of 21.4 for its European area of influence[3] (Heather, 2021). Lastly, Platt's JKM shows a churn rate of only 0.79 for China, Japan, Korea, and Taiwan, justifying the use of Japanese LNG import prices as a benchmark price for Asia in our study.

Because of the traditional use of different benchmarks in the crude oil markets (e.g. Brent for Europe, Dubai Fateh for Japan, West Texas Intermediate for the US), no single benchmark crude can be applied for the analysis of all three regional gas markets. Therefore, we assume a global oil market and treat oil as a homogeneous commodity: Monthly oil prices are calculated as the average of the three benchmarks: Brent, West Texas Intermediate (WTI), and Dubai Fateh, quoted in USD/bbl, as published by the World Bank. Given the monthly frequency, the slump in WTI during the COVID-19 crash does not critically show in the data (see Fig. 1). For the calculation of oil–gas price ratios and the graphical representation thereof, we employ the energy equivalent of 5.8 MMBtu per barrel of crude oil.

Monthly price data for crude oil (Oil), Henry Hub natural gas (HH), and Japanese LNG are collected from the World Bank commodity database, whereas TTF prices are derived from Refinitiv. For the latter, monthly averages are calculated from a daily data series. For crude oil and Henry Hub prices, we apply spot prices, while Japanese LNG prices are the country's monthly import expenses for natural gas. The TTF series consists of futures prices for month-ahead delivery, traded with the highest volume at the hub. Out of several oil price averages, Table 1 indicates that Japanese LNG and TTF prices jointly show the highest correlation with the 6-month average of the monthly oil price series, without lag. We, therefore, apply a long-term average oil price (MAOil), calculated as the 6 months moving average of the monthly oil price series.

The time frame of this study stretches from January 2009 to December 2021 and an extended sample is used for the rolling window analysis (March 2005–December 2021). All natural gas prices are denoted in US dollars per million British thermal units (USD/MMBtu) to which TTF prices are converted from their original quotation in Euro/MWh, following conversion factors of the Norwegian Petroleum Directorate.[4]

3.1. Oil market 2009 - March 2022

Fig. 1 offers an overview of the crude oil price development between 2009 and 2021. Understanding the crude oil price development is crucial when investigating the relationship between natural gas and oil prices, due to their historical price dependency. Furthermore, Section 2 indicates an evolving price link between the two commodities, following changing regimes of the leading crude oil price. Therefore, considering crude oil price developments is of relevance in our dynamic analysis of the oil–gas price relationship.

We observe a stark increase in crude oil prices from about 40 USD in 2009 to almost 120 USD/bbl in 2011, following the Federal Reserve's and other central banks' quantitative easing in the recovery of the financial crisis of 2008/2009. Furthermore, the Arab Spring in 2011 spurred fears of supply shocks from Libya and Syria, leading oil prices to climb above 100 USD/bbl. We next observe a period of high crude oil prices around 100 USD/bbl, stretching from 2011 until 2014. In the later months of 2014, however, OPEC countries did not respond to the explosive oversupply of North American shale by supply cuts, which coincided with the demand slowdown for oil from BRICS countries.[5] Further influenced by the end of the third round of the US Federal Reserve's quantitative easing and bond purchasing program (QE 3), crude oil prices consequently fell below 50 USD/bbl in January 2015. Driven by US oversupply, an 80-year high in the filling level of the US strategic oil reserve was recorded at the end of 2015, before crude oil prices reached 29.78 USD/bbl in January 2016.

The declining price trend was reversed by a joint supply cut of OPEC countries together with Russia (OPEC+), which in November 2016 reduced their production by 1.2 million barrels per day. These cuts were further extended in May 2017 and led, together with the worsening crisis in Venezuela, to an increase in crude oil prices to about 77 USD/bbl in October 2018. The end of 2018 marks a temporary trend shift, which coincided with an interest rate increase to 2.5% in the US and a substantial stock market decline.

[3] The area of influence for the TTF includes France, Germany, Austria, Switzerland, as well as Belgium and Luxembourg.

[4] 1 kWh = 3412 MMBtu, https://www.npd.no/en/about-us/information-services/conversion-table

[5] BRICS countries are Brazil, Russia, India, China, and South Africa.

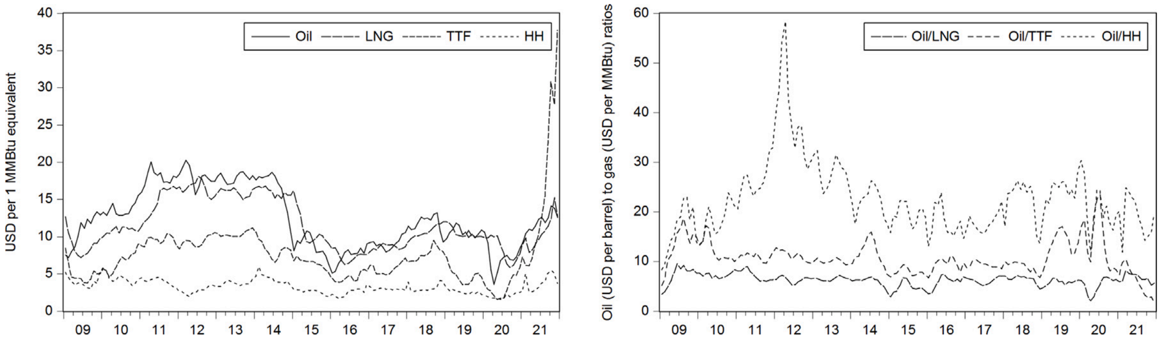

Fig. 2. Left: Price development of crude oil, Japanese LNG, TTF, and Henry Hub prices between 2009 and 2021. Right: Oil-to-gas price ratios between 2009 and 2021.

Falling oil prices were fundamentally driven by growing US exports, but also increased supplies from Iran after the US granted waivers to eight countries to circumvent sanctions and again import crude oil from Iran. Prices declined to about 60 USD/bbl at the end of 2019, after which, following the disagreement on supply cuts with Russia, Saudi Arabia increased the global supply level by offering buyers price discounts of 6-8 USD/bbl price discounts in March 2020. The so-called Saudi–Russian price war was followed by the COVID-19 crisis in 2020 and the halt of global supply chains and passenger travel, which consequently led to a sharp decline in crude oil demand. One day prior to expiry, the May 2020 WTI contract even recorded a negative price on April 20th, 2020, due to a lack of storage capacity.

In the following months, global vaccination campaigns and gradual re-openings, along with central banks' expansive monetary intervention stabilized both financial and commodity markets, which helped crude oil prices recover above 40 USD/bbl at the end of 2020. In the face of declining upstream investment in many industrialized countries, the price increase continued into a swift climb towards a multi-year high in 2021, when oil prices reached more than 80 USD/bbl, driven by an increase in economic activity and the absence of OPEC supply increases. Lastly, crude oil prices rose above 100 USD/bbl in March 2022, following the Russian invasion of Ukraine in February, after which many European importers' decision to either partially or completely halt oil imports from Russia led to a shortening global supply.

3.2. Descriptive statistics

Fig. 2 shows the development of the three featured natural gas prices and crude oil from January 2009 to December 2021, as well as the development of the related oil-to-gas ratios. Japanese LNG prices follow oil prices with a delay and appear less volatile, motivating the use of a moving average oil price series for assessing the relationship between oil and gas in Japan. We further observe that TTF prices for most parts of the sample tend to mirror major price changes in oil as well, but, apart from the onset of the energy crisis in 2021, however, with more underpricing than Japanese LNG. Henry Hub prices on the other hand chart the lowest and no co-movement with oil prices is observed.

The right panel of Fig. 2 indicates that for the vast majority of the sample, all oil–gas price ratios chart higher than the thermal parity of crude oil at 5.8, indicating underpricing of natural gas relative to oil. Japanese LNG thereby shows the most stable relationship with oil over time and, besides temporary overpricing such as in the winter of 2015/2016, displays the largest underpricing with an average oil–gas price ratio of 6.29. The oil/TTF price ratio follows a largely stable path until the end of 2018when indexation clauses in import contracts for Norwegian and Russian natural gas had largely switched from oil to gas hub prices. We observe a sharp rise in TTF prices and a consequential fall in the oil/TTF price ratio in 2021, driven by fears of supply shortages. Lastly, given largely independent oil and natural gas pricing in North America, the oil/Henry Hub ratio appears least stable over the duration of our sample. While highly underpriced, we find a significant spike in early 2012, following a mild winter and significant production increases of shale gas.

Table 2 provides the descriptive statistics for the five price series used in this study. With an average price of 3.29 USD/MMBtu, Henry Hub prices show the highest underpricing, followed by TTF prices with an average of 7.52 USD/MMBtu. Japanese LNG shows the highest average natural gas price at 11.54 USD/MMBtu, closest to the average price of crude oil of 12.42 USD/MMBtu (72.04 USD/bbl). The underpricing of Henry Hub prices to oil amounts to −276.99%, −65.29% for TTF, and only −7.66% for Japanese LNG. The minimum and maximum of LNG prices are closely matched by those of long-term average oil prices, hinting towards the historical contractual link between LNG imports and crude oil prices in Japan. The moving average oil price series as well as LNG and TTF prices reject normality at 1%, whereby Henry Hub and monthly oil prices reject normality only at 5%.

Table 3 presents the results of two unit root tests, the augmented Dickey–Fuller (ADF), and the Phillips–Perron (PP) tests, as well as of the Kwiatkowski–Phillips–Schmidt–Shin (KPSS) test for stationarity. For Henry Hub prices, we find evidence for the rejection of a unit root via the ADF and the PP tests at 5%, whereby the KPSS test yields insufficient evidence for the rejection of stationarity. For TTF and LNG natural gas prices, as well as for monthly and moving average oil prices, the results of the ADF, PP, and KPSS tests are also converging. In all cases, the ADF and PP tests show no significant rejection of the unit root null, while the KPSS tests show evidence for a rejection of stationarity at either 5% or 10%.

Table 2
Descriptive Statistics.

	Obs	Mean	Min	Max	Std. Dev.	Skewness	Kurtosis	J.-B. Prob.
Oil_t	156	12.42	3.63	20.31	4.14	0.21	1.87	0.01
$MAOil_t$	156	12.40	5.99	18.99	4.01	0.28	1.71	0.00
TTF_t	156	7.52	1.57	37.69	4.44	3.74	22.64	0.00
LNG_t	156	11.54	5.88	18.11	3.32	0.39	1.85	0.00
HH_t	156	3.29	1.61	5.97	0.93	0.49	2.78	0.04

Here and in the remainder of the paper Oil_t denotes the average of the monthly price of the three benchmark fuels Brent, WTI, and Dubai Fateh. $MAOil_t$ is the 6 month average of Oil_t.

Table 3
Unit root test results: Price series.

Test statistic Series	ADF	PP	KPSS
Oil_t	−3.033	−2.530	0.141*
$MAOil_t$	−2.374	−1.751	0.151**
TTF_t	0.864	3.352	0.128*
LNG_t	−2.129	−1.753	0.163**
HH_t	−4.002**	−3.977**	0.083

H0 ADF and PP: Unit root, H0 KPSS: Stationarity.
All tests including intercept and trend.
Critical values at 1%: ADF −4.021, PP −4.018, KPSS 0.216.
Critical values at 5%: ADF −3.440, PP −3.439, KPSS 0.146.
Critical values at 10%: ADF −3.145, PP −3.144, KPSS 0.119.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

We gain further insight into the individual data series by application of the variance ratio test by Lo and MacKinlay (1989), which indicates the percentage share of a series' random walk component. The concept of the variance ratio test is centered around the idea that in its data interval the variance of increments of a random walk X_t is linear (Chen et al., 2008). The variance ratio is defined as:

$$VR(q) = \frac{\sigma^2(q)}{\sigma^2(1)} \tag{1}$$

where $\sigma^2(q)$ is $1/q$ times the variance of $X_t - X_{t-q}$ and $\sigma^2(1)$ is the variance of $X_t - X_{t-1}$. Further background and the test statistic can be found at Lo and MacKinlay (1989). An interpretation of variance ratio test results in economic time series is persistence and mean reversion, whereby a ratio below one indicates that there are transitory factors influencing price variation (Poterba and Summers, 1988). Further background is available from Charles and Darné (2009) or Chen et al. (2008). The findings on the price series (Table 4) suggest that only the Henry Hub prices show stationary components of 40.4%, 53.7%, and 66.3% at 6, 12, and 24 months intervals, respectively. We find that averaged oil prices show ratios above one, indicating persistence with a 1% rejection of the H0 of a random walk (Poterba and Summers, 1988). LNG prices indicate persistence as well, with a rejection at the 5% significance level at the 6 and 24 months intervals and at 10% for 12 months. Longer test periods of 24 months thereby coincide with the largest test statistics and hence the strongest evidence for H0 rejection. Monthly oil prices show a rejection of the random walk null at 10% at the 24 months interval, indicating evidence for long-term persistence in the series. The results of the variance ratio test provide further insights into the behavior of our price data. Consistent with the unit root tests presented in Table 3, the test yields evidence for stationary components only for the Henry Hub gas price series.

3.3. Exogenous variables

As discussed in previous sections, oil and gas prices and their historical link have been challenged by several demand and supply shocks, under different developments of production conditions. To derive an understanding of the impact of fundamental factors on regional oil–gas price relationships, we consider several monthly exogenous variables. For oil supply, we use the monthly production output of OPEC and because the USA became the world's largest oil producer in 2018, we also employ US crude oil production data. We proxy oil demand by oil consumption-weighted GDP per capita and account for the financialization of oil trade by analyzing the open interest values in Brent futures contracts. For natural gas supply, we employ US gas production data and for the import-dependent Japanese and European markets, variables for heating demand and gas storage are used. Table 5 provides an overview of exogenous variables.[6]

[6] In addition to these fundamental variables, we tested for the effect of geopolitical risk and climate policy uncertainty with the indices provided by Caldara and Iacoviello (2021) and Gavriilidis (2021), respectively. However, these variables showed no significance in the estimation.

Table 4
Variance ratio test: Price series.

Test series	Period	z-statistic	p-value	VR
Oil_t	6	1.572	0.116	1.406
	12	1.566	0.118	1.534
	24	1.713*	0.087	1.773
MAOil_t	6	6.019***	0.000	3.155
	12	6.260***	0.000	3.806
	24	7.023***	0.000	4.753
TTF_t	6	0.807	0.419	1.501
	12	0.318	0.751	1.248
	24	0.192	0.848	1.169
LNG_t	6	1.976**	0.048	1.534
	12	1.789*	0.074	1.634
	24	2.152**	0.031	2.0101
HH_t	6	−1.325	0.185	0.596
	12	−1.375	0.169	0.463
	24	−1.343	0.179	0.337

H0 of Lo and MacKinlay (1989) variance ratio test: Random walk.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 5
Exogenous variables: definitions.

Variable	Description	Source	Unit
$Oilprod_{US_t}$	US field production of crude oil	EIA	Thousand barrels per day
$Oilprod_{OPEC_t}$	OPEC oil production	EIA	Thousand barrels
$GDP_{w.PC_t}$	Oil consumption weighted GDP per capita	EIA	Index, 2015 Q1 = 100
OI_{Brent_t}	Open interest Brent futures contracts: Number of unsettled contracts month +1	Refinitiv	Number value
$Gasprod_{US_t}$	US natural gas marketed production	EIA	Million cubic feet
HDD_{EU_t}	Heating degree days EU[a]	Eurostat	Degrees Celsius
HDD_{JP_t}	Heating degree days Japan[a], is calculated from mean of min–max temp. of main cities	Japanese electricity market data hub	Degrees Celsius
$GasStoreEU_t$	Natural gas storage EU-27	GIE AGSI	TWh
$GasStoreJP_t$	Japan LNG inventory	Refinitiv	Thousand cubic meters
$Gazprom_t$	Dummy indicating the impact of suppressed filling of Gazprom-owned gas storage starting in April 2021	–	Dummy trend

[a]HDD is calculated as follows: If $T_m \leq 15$ then $[HDD = \sum i(18 - T_m^i)]$, else 0, where T_m^i is the mean temperature on day i.

4. Modeling approach

In this section, we revisit the traditional oil–gas pricing relationships. Given that the series' statistical properties have changed compared to prior estimates in Erdős and Ormos (2012), we reexamine the long-term equilibrium dynamics, long-memory, and the impact of fundamental variables on the equilibrium relations. Hence, we test for cointegration, long-memory, and estimate Vector Error Correction Models (VECM).

4.1. Historical oil–gas links

Historically, prices for natural gas in Europe and Japan have been contractually linked to oil prices. Russian imports to Germany have thereby long constituted a price benchmark for the European market. Because of the substitutability of oil products with natural gas in heating, the import price has been linked to the average of several preceding months' prices for heavy fuel and gas oil for a specific negotiated period of time. Importers and exporters thereby negotiate the contract length as well as the duration of the averaging period, a possible lag, and the validity period. No single universally-applied formula exists, but a multitude of formulas bilaterally-negotiated in import contracts. Assuming a quarterly clearing price, a traditional representation following Erdős and Ormos (2012) is given by:

$$P_{RUS_t} = \alpha + \beta_1 P_{RUS_{t-1}} \frac{1}{2} \left(\frac{\bar{F}_t}{\bar{F}_{t-1}} + \frac{\bar{G}_t}{\bar{G}_{t-1}} \right) + \varepsilon_t \tag{2}$$

where P_{RUS_t} is the quarterly price of Russian natural gas, α is a constant, $\bar{F}_t$ is the price for fuel oil over the last 6 months, $\bar{G}_t$ is the average price of gas oil over the last 6 months, and ε_t is the error term. Given the high correlation between refined oil products and crude oil, a common approach in the literature (Erdős and Ormos, 2012) is to approximate the former with crude oil prices and the relationship between TTF hub and averaged oil prices can be represented as:

$$P_{TTF_t} = \alpha + \beta_2 \bar{P}_{Oil_t} + \varepsilon_t \tag{3}$$

where α is a constant, P_{TTF_t} is the monthly TTF price, $\bar{P}_{Oil_t}$ is the average oil price over 6 months, and ε_t is the error term. This price relationship is an estimate for the degree that oil indexation is used by market participants and the degree to which oil prices transpire on to TTF hub prices.

The price for LNG imports to Japan has historically been linked to crude oil rather than to refined oil products (Hafner and Luciani, 2022), specifically to the Japanese Crude Cocktail (JCC), the recorded import expenses for oil in Japan. The traditional relationship between Japanese LNG import prices and oil prices can be described as:

$$P_{LNG_t} = \alpha + \beta_3 \bar{P}_{JCC_t} + \varepsilon_t \tag{4}$$

where P_{LNG_t} is the import price for LNG in Japan and $\bar{P}_{JCC_t}$ is the 6 months average price of JCC. The constant α thereby captures the degree of risk aversion negotiated between importers and exporters, while the coefficient β expresses sensitivity to oil prices. Assuming a global oil market, we apply a basket of crude prices instead of JCC prices for assessing the relationship between oil and natural gas in Japan as well.

Lastly, given the absence of oil-price indexation following market liberalization in North America in the early 2000s, a representation for the traditional relationship between Henry Hub natural gas and monthly crude oil prices is:

$$P_{HH_t} = \alpha + \beta_4 P_{Oil_t} + \varepsilon_t \tag{5}$$

where α is a constant, P_{HH_t} are US Henry Hub prices, P_{Oil_t} is the monthly price of WTI or another benchmark fuel, and ε_t is the error term.

4.2. Cointegration analysis

To test for a joint long-term trend in the time series, we test for cointegration using the Johansen vector autoregressive (VAR) approach (Johansen, 1991). A cointegration relationship allows for short-term deviations, whereby a long-term equilibrium exists. If natural gas and oil prices were to be cointegrated, this would suggest the existence of market forces linking the two series together. The Johansen test is a maximum likelihood procedure, based on a vector error correction model (VECM) of the form:

$$\Delta y_t = \Pi y_{t-1} + \sum_{i=1}^{p-1} \Gamma_i \Delta y_{t-i} + \epsilon_t, \tag{6}$$

where

$$\Pi = -I + \sum_{i=1}^{p} \Pi_i, \quad \text{and} \quad \Gamma_i = -\sum_{j=i+1}^{p} \Pi_j \tag{7}$$

and Π contains the long-run coefficient matrix and information on the number of existing linear relations and thus the number of cointegration relationships. We apply a test specification of Eviews 10, which allows for intercepts and trends in both the data as well as in the cointegrating equation. The optimal lag length is determined by the Schwartz criterion. The VECM specification of Eq. (6) allows for the introduction of exogenous variables. These variables do not enter the cointegrating relationship, but act as exogenous factors in the system:

$$\Delta y_t = \Pi y_{t-1} + \sum_{i=1}^{p-1} \Gamma_i \Delta y_{t-i} + \phi X_t + \epsilon_t, \tag{8}$$

where ϕ is a vector of coefficients and X_t is a vector of exogenous variables presented in Table 5.

4.3. Long memory in oil–gas price ratios

Because the differentiation between $I(0)$ and $I(1)$ processes may be too restrictive, we test oil–gas price ratios for long-memory and determine the order of fractional integration. Contrary to stationary processes, long-memory processes exhibit non-intuitive properties with implications for forecasting, low-frequency variations, and trends (Graves et al., 2017). Thereby fractional models are found to be not necessarily superior in short-term forecasts, but their properties may be beneficial for long-term predictions (Granger and Joyeux, 1980), because of their different assumptions about the effects of shocks compared to conventional models (Baillie, 1996). Long-memory models are characterized by "non-negligible dependence" between present and all past observations (Graves et al., 2017). The difference to typical ARMA models lies in the persistence of autocorrelations, which in long-memory processes show longer decay following power law, instead of the typical geometrical decay rate of an ARMA model (Graves et al., 2017). Following Hosking (1981), a long-memory model for a series y_t can be defined as:

$$(1-L)^d y_t = u_t; \quad u_t \sim iid(o, \sigma^2), \tag{9}$$

where d is a non-integer value, the order of integration L is the lag operator, and u_t is a standard white noise process with zero mean and constant variance σ^2. The unrestricted degree of differencing d may take any real value and is not restricted to integers. For $0 < d < 0.5$, fractionally-differenced processes are stationary but have long memory, or in other words are capable of modeling long-term persistence. For $0.5 < d < 1$, a given process is nonstationary but, contrary to an $I(1)$ process, exhibits mean reversion

Table 6
Unit root test results: Oil to gas ratios.

Test statistic Series	ADF	PP	KPSS
$(\text{Oil/TTF})_t$	−3.055	−3.578**	0.095
$(\text{Oil/LNG})_t$	−5.724***	−4.447***	0.142*
$(\text{Oil/HH})_t$	−4.061***	−3.524**	0.134*
$(\text{MAOil/TTF})_t$	−3.635**	−2.054	0.062
$(\text{MAOil/LNG})_t$	−4.562***	−4.399***	0.138*

H0 ADF and PP: Unit root, H0 KPSS: Stationarity.
All tests including time trend.
Critical values at 1%: ADF −4.019, PP −4.018, KPSS 0.216.
Critical values at 5%: ADF −3.439, PP −3.439, KPSS 0.146.
Critical values at 10%: ADF −3.144, PP −3.144, KPSS 0.119.
Lag selection ADF by SIC.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

and long-memory and shocks eventually dissipate (Zhang and Ji, 2018). Further background on fractional integration and long-memory processes can be obtained from Beran et al. (2016). We apply the two-step feasible exact local Whittle estimator (Shimotsu, 2010), based on the two-step exact local Whittle (ELW) estimator (Shimotsu and Phillips, 2006). The procedure applies a tapered estimator in the first stage estimation and shares the same limiting distribution and consistency with the ELW for $d \in (-\frac{1}{2}, 2)$ but further accounts for an unknown mean and a polynomial time trend (Shimotsu, 2010). We obtain the integration parameter d by minimization of the objective function:

$$Q_m(G,d) = \frac{1}{m}\sum_{j=1}^{m}[log(G\lambda_j^{-2d}) + \frac{1}{G}I_{(1-L)^d y_t}(\lambda_j)]. \tag{10}$$

We apply the estimator in static samples as well as in a rolling windows estimation to yield a time-varying estimation of the order of integration parameter d.

We apply fractional integration to test for long-term memory on the oil–gas price ratio and determine the strength of the long-term equilibrium relationship between the two underlying price series. A stationary price ratio would suggest the existence of a long-term equilibrium, to which the underlying prices readjust at a speed that corresponds to the level of their order of integration. In other words, for $d = 0$ we have a standard white noise process, for $d = 1$ a unit root, for $0 < d < 0.5$ a process is stationary with long-memory, and for $0.5 < d < 1$ it is nonstationary, yet mean reverting (Nielsen and Shimotsu, 2007).

Because the rolling windows estimation provides the parameter for the end of the estimation window, we apply an extended sample dating from March 2005 until December 2021. Using a window size of 68 months, corresponding to one-third of the sample size, we provide a monthly parameter estimation from October 2010 until December 2021. The bandwidth parameter m is thereby determined by $m = T^{\delta}$ and we present results for three settings using δ of 0.55, 0.6, and 0.65. Further background on the estimation procedure can be found at Shimotsu (2010) or Nielsen and Shimotsu (2007).

5. Empirical results

5.1. Stationarity in oil–gas price ratios

Table 6 shows the results for the unit root tests of oil–gas ratios. Ambiguous findings exist for all oil–gas ratios, whereby we find significant rejections at 1% confidence levels for a unit root null in ratios of monthly and long-term average oil prices with LNG prices, suggesting long-term equilibria. For both ratios, however, the KPSS test yields a significant rejection at 10% for stationarity, indicating no cointegration in the underlying series. Similarly, the ratio of monthly oil prices and Henry Hub shows a 1% rejection for the ADF test and at 5% for the PP test, while we find a rejection at 10% for stationarity according to the KPSS test. We find no evidence for rejecting stationarity in oil-TTF ratios, whereby the two unit root tests yield contradictory evidence. The results are not surprising, given changing natural gas pricing regimes over the sample duration.

Given the ambiguous results for unit root and stationarity tests for the relations between oil and gas prices in the US and in Europe, it seems rational to assume that these price series have two components: A unit root or permanent component as well as a stationary or temporary one. We, therefore, employ the Lo and MacKinlay (1988) variance ratio (VR) test to account also for heteroskedasticity and detect both possible components. A unit root process has a variance ratio of unity and a stationary process has a zero variance ratio. If a series has both components, then it has a variance ratio between zero and unity if the returns (first log differences) exhibit negative auto-correlation, and above unity, if the returns exhibit positive auto-correlation. In Table 7, we report variance ratios at periods 6, 12, and 24 months. Table 7 shows that besides the Oil/LNG ratio at 6 months, as well as the MAOil/TTF ratio at the 6 and 12-month test periods, all other price ratios are characterized by both stationary and unit root components.

The ratio between long-term oil and LNG prices yields significant random walk rejections at 10% for the 6-month interval and at 5% for 12 months. Whereby the ratio between long-term oil and LNG prices has a stationarity component of only 43% at the 6-month interval, price ratios at 24 months show the largest stationarity component (76.8%). Consistent with the finding of a

Table 7
Variance ratio test: Price ratios.

Test ratio	Period	z-statistic	p-value	VR
$(\text{Oil/TTF})_t$	6	−0.222	0.825	0.915
	12	−0.769	0.442	0.574
	24	−0.998	0.318	0.304
$(\text{Oil/LNG})_t$	6	0.254	0.799	1.063
	12	−1.322	0.186	0.544
	24	−1.311	0.190	0.388
$(\text{Oil/HH})_t$	6	−1.049	0.294	0.730
	12	−1.319	0.187	0.525
	24	−1.033	0.302	0.504
$(\text{MAOil/TTF})_t$	6	1.480	0.139	1.650
	12	0.221	0.825	1.134
	24	−0.559	0.576	0.578
$(\text{MAOil/LNG})_t$	6	−1.934*	0.053	0.570
	12	−2.138**	0.033	0.319
	24	−1.627	0.104	0.232

H0 of Lo and MacKinlay (1989) variance ratio test: Random walk.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 8
Johansen Test for Cointegration for H0 of no cointegrating equation.

Sample	Variables	Trace Stat.	Max Eig.
2009–2021	TTF_t & Oil_t	45.577***	35.829***
	TTF_t & MAOil_t	28.656**	20.1446**
	LNG_t & Oil_t	107.819***	101.324***
	LNG_t & MAOil_t	27.537**	22.932**
2009–2015m6	TTF_t & Oil_t	25.573*	20.456**
	TTF_t & MAOil_t	32.539***	26.223***
	LNG_t & Oil_t	83.165***	73.370***
	LNG_t & MAOil_t	43.389***	26.999***
2015m7-2021	TTF_t & Oil_t	46.089***	35.765***
	TTF_t & MAOil_t	44.253***	33.984***
	LNG_t & Oil_t	53.355***	45.738***
	LNG_t & MAOil_t	32.594***	26.888***

λ_{trace} and λ_{max} with $\text{H}_0 : r = 0, H_1 : 0 < r \leq k$.
Lag selection according to SIC.
Test specification with intercepts and trends in CE and test VAR.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

unit root rejection for the Oil/LNG price ratio (Table 6), the variance ratio test also indicates that at the 24 months interval, the monthly oil-LNG ratio is largely stationary ($VR < 0.5$). The largest random walk component in long-term moves (24 months) is reported for the relationship between long-term oil and TTF prices, suggesting no stable relationship between the prices over 24-month intervals. We further note that for any test period, the relation between monthly oil prices and TTF shows a more significant stationary component than with long-term average oil prices. LNG prices, on the other hand, show larger stationary components with long-term oil prices and less stationarity (none at 6 months) with monthly oil prices, suggesting the impact of indexation to long-term oil prices. The results conclude that for most oil–gas ratios, random walk components cannot be ruled out, whereby stationarity dominates in the long-term oil-LNG relationship.

5.2. Cointegration and long memory

Table 8 presents the results of the Johansen cointegration test for an H_0 of no cointegration ($r = 0$) for the full sample as well as for the first and second sample halves. Consistent with the findings on unit roots (Table 6), for the full sample from 2009 to 2021, we find evidence for one cointegrating vector between LNG and both monthly and long-term oil prices at 1% and 5%, respectively. For TTF prices alike, we find rejections of no cointegration for their relation to monthly, as well as with long-term oil prices. For Japanese LNG and monthly oil prices, both the first and second sample halves yield rejections of the no cointegration hypothesis at 1%. Similarly, results show that LNG and long-term oil prices shared a long-term trend from 2009 to mid-2015, as well as from 2015 to 2021. With regards to TTF and monthly oil prices, the Trace test shown in Table 8 presents a rejection (rank zero) at 10% from 2009 to 2015, whereas the rejection in the period from 2015 to 2021 is at 1%. Furthermore, our results show weaker evidence for cointegration between natural gas and long-term oil prices, which hints towards breaks in the long-term trends of the underlying price series.

Table 9
Local Whittle estimation: Full sample.

2009–2021	$T = 156$		
δ	0.55	0.6	0.65
$(Bandwith)\ m = T^{\delta}$	16	21	27
$(\text{Oil/HH})_t$	0.64	0.62	0.64
$(\text{Oil/TTF})_t$	0.51	0.58	0.60
$(\text{Oil/LNG})_t$	0.24	0.29	0.39
$(\text{MAOil/TTF})_t$	0.54	0.64	0.87
$(\text{MAOil/LNG})_t$	0.62	0.62	0.62

Table 10
Local Whittle estimation: First sample half.

2009–2015m6	$T = 78$		
δ	0.55	0.6	0.65
$(Bandwith)\ m = T^{\delta}$	11	14	17
$(\text{Oil/HH})_t$	0.78	0.82	0.80
$(\text{Oil/TTF})_t$	0.43	1.07	1.19
$(\text{Oil/LNG})_t$	0.45	0.98	1.21
$(\text{MAOil/TTF})_t$	1.28	0.80	0.90
$(\text{MAOil/LNG})_t$	0.54	0.62	0.66

Table 11
Local Whittle estimation: Second sample half.

2015m7–2021	$T = 78$		
δ	0.55	0.6	0.65
$(Bandwith)\ m = T^{\delta}$	11	14	17
$(\text{Oil/HH})_t$	0.33	0.48	0.33
$(\text{Oil/TTF})_t$	0.82	0.75	0.68
$(\text{Oil/LNG})_t$	0.19	0.37	0.62
$(\text{MAOil/TTF})_t$	0.73	0.99	1.14
$(\text{MAOil/LNG})_t$	0.20	0.32	0.38

We further show estimation results of the integration order d for the full sample (Table 9), the period from 2009 to June 2015 (Table 10), and the period from July 2015 until December 2021 (Table 11), followed by a rolling window estimation for the period from October 2010 until December 2021. Table 9 indicates that for the full sample from 2009 to 2021, a long-term equilibrium exists between all natural gas and monthly oil prices: While the relationship between monthly oil and Henry Hub as well as between monthly oil and TTF prices is nonstationary, yet mean reverting ($0.5 \leq d < 1$), the finding for the monthly oil-LNG relationship is consistently stationary ($d < 0.5$). Regarding the impact of oil indexation, we find evidence for long memory in ratios of long-term oil prices with both TTF and LNG prices as well. The MAOil/LNG and the MAOil/TTF ratios are both found to be consistently nonstationary and mean-reverting, with an integration order below 1. Consistent with our findings of cointegration in Table 8, mean reversion to the equilibrium between monthly oil and TTF prices is quicker than to long-term oil prices, suggested by a smaller estimate for the integration order d.

A comparison of the integration order of oil–gas price ratios between the period from 2009 to June 2015 (Table 10) and July 2015 to 2021 (Table 11) yields the following results: Except for the MAOil/TTF and the Oil/TTF ratio at $\delta = 0.55$, oil/gas ratios show lower integration and thus quicker mean reversion in the second sample half than in the first one. Although the oil-Henry Hub ratio is in a nonstationary equilibrium from 2009 to June 2015, the speed of equilibrium adjustment is faster from July 2015 to 2021, when the ratio becomes stationary ($d < 0.5$). Similarly, for the ratios of LNG and monthly oil as well as of TTF and monthly oil prices, we report a nonstationary relationship in most settings with d values close to 1 from 2009 to June 2015. For the second sample half until 2021 however, Table 11 reports a long-memory finding for both oil–gas price ratios, a nonstationary one for Oil/TTF, and a largely stationary one for Oil/LNG. Lastly, the change in the integration of TTF and LNG gas with long-term oil prices differs between the sub-samples: While the evidence for mean reversion in the MAOil/TTF ratio weakens, LNG prices are in a stationary mean-reverting relationship with long-term oil prices in the second sample half.

The rolling windows estimation of the integration order d for the oil-Henry Hub price ratio presented in Fig. 3 supports our findings for the two sub-samples: While the oil-Henry Hub price ratio is nonstationary with long-memory ($0.5 < d < 1$) until the end of 2018, the two prices enter a largely stationary regime at the beginning of 2019, in which shocks dissipate more quickly than before. Fig. 4 depicts the development of the integration order for both the ratio between monthly oil and LNG prices as well as for long-term oil and LNG prices. Although both ratios suggest no equilibrium at the beginning of 2011, we find a nonstationary equilibrium between long-term oil and LNG prices from 2012 until the end of 2019, which becomes stationary thereafter. Monthly oil and LNG prices, on the other hand, show no equilibrium until the end of 2014, but after 2015 the order of integration of the

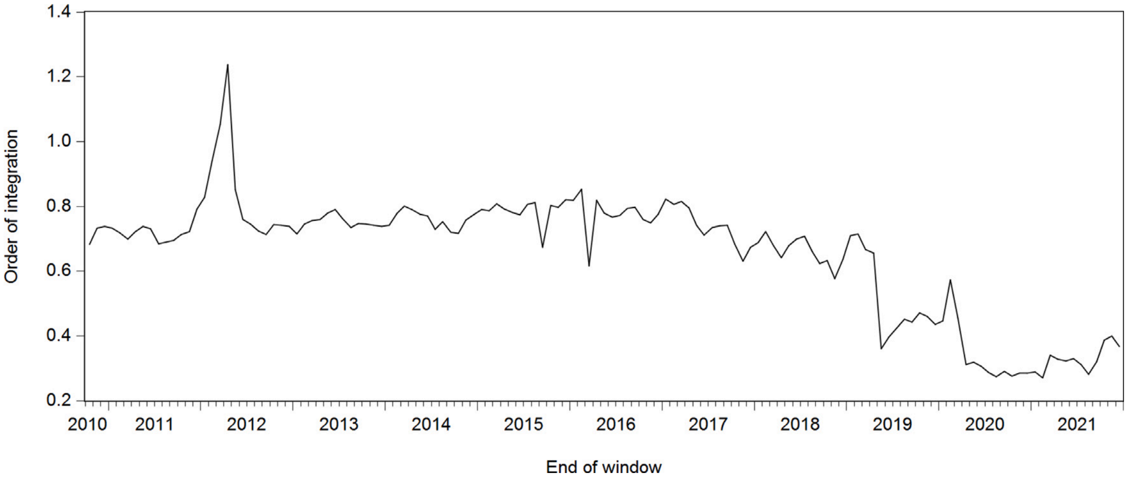

Fig. 3. Rolling window estimation of the integration order d for the oil-Henry Hub price ratio at $\delta = 0.6$: Oct 2010–Dec 2021.

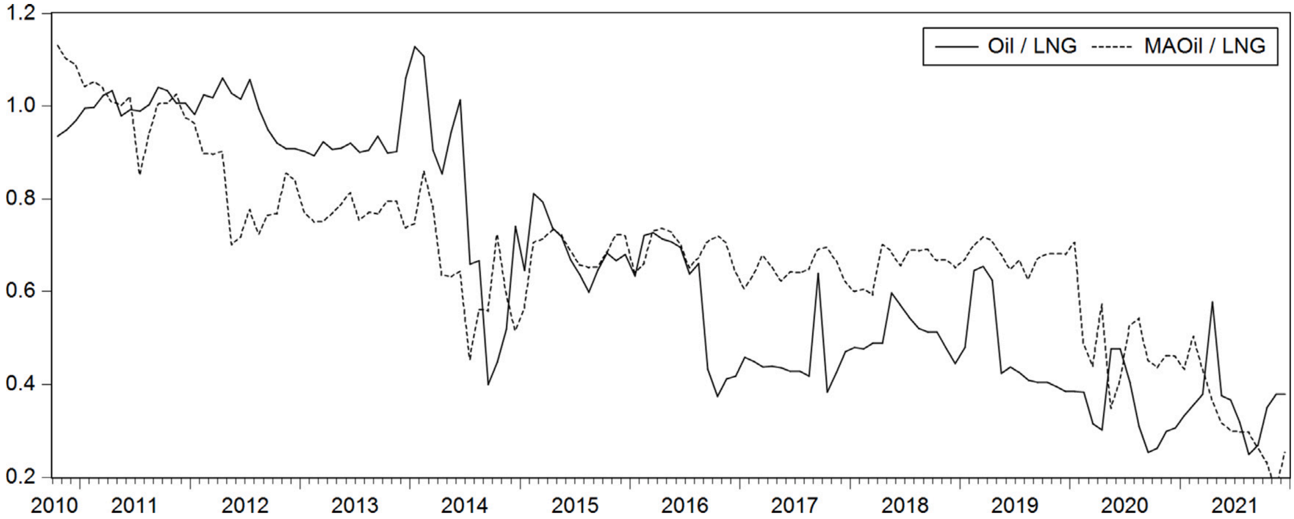

Fig. 4. Rolling window estimation of the integration order d for oil-Japanese LNG price ratios at $\delta = 0.6$: Oct 2010–Dec 2021.

oil-LNG ratio falls quicker than the ratio of MAOil/LNG prices and becomes increasingly stationary. The finding of quicker mean reversion with monthly oil prices after 2016 reflects an adjustment of Japanese LNG import contracts to monthly JCC prices. For the period after 2019, Fig. 4 indicates that both price ratios are mean reverting until the end of the sample, with temporary stationary regimes ($0 < d < 0.5$). Lastly, similar to LNG prices, the estimation presented in Fig. 5 suggests that long-term oil and TTF prices are in a nonstationary equilibrium until 2014, whereas no equilibrium can be found for the monthly oil-TTF price ratio to this point. Thus, while the impact of oil indexation is reflected in the nonstationary equilibrium finding for long-term oil and TTF prices until 2014, monthly oil prices enter a nonstationary equilibrium with oil prices only temporarily after 2014. Whereas the MAOil/TTF equilibrium dissolves towards the beginning of 2019, also the monthly oil-TTF ratio shows increasing decoupling towards 2019, followed, however, by a second mean-reverting regime from 2020 to 2021.

5.3. VECM estimation

Based on the estimation results in Table 8, which indicate cointegration between monthly oil and gas prices in Japan and in Europe, we further estimate a Vector Error Correction Model (VECM) with exogenous variables for all three regions. By incorporating exogenous variables, we infer additional information on the impact of demand/supply factors on oil and gas prices and isolate the effect of economic shocks from long-run price relationships. We model all exogenous variables in first differences, to account for possible unit roots and trends. We test all nonstationary series from Table 5 for joint significance in explaining both oil and gas prices. However, besides oil consumption-weighted GDP per capita for oil and Henry Hub prices, they do not significantly contribute

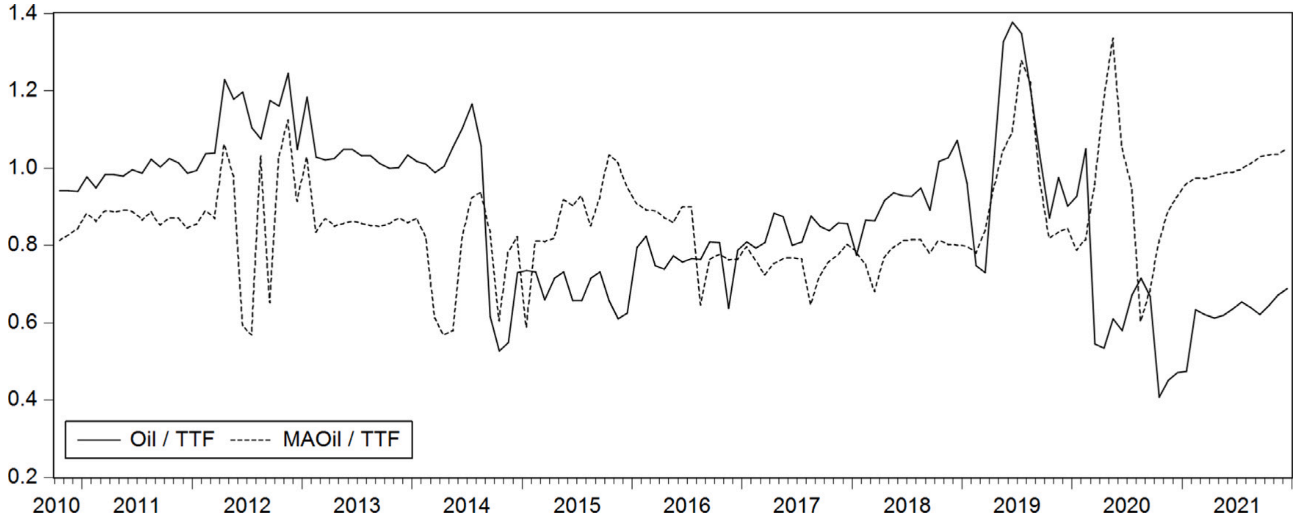

Fig. 5. Rolling window estimation of the integration order d for oil-TTF price ratios at $\delta = 0.6$: Oct 2010–Dec 2021.

Table 12
Unit root test results: 2019–2021.

Test statistic Series	ADF	PP	KPSS
HH_t	−3.1525	−3.1028	0.1957**
$GDP_{w.PC_t}$	−1.7884	−0.8843	0.1664**

H0 ADF and PP: Unit root, H0 KPSS: Stationarity.
All tests including intercept and trend.
Critical values at 1%: ADF and PP −4.2350, KPSS 0.216.
Critical values at 5%: ADF and PP −3.5403, KPSS 0.146.
Critical values at 10%: ADF and PP −3.2024, KPSS 0.119.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 13
Johansen cointegration tests for H0 of no cointegrating equation.

Sample	Variables	Trace stat.	Max Eigen stat.
2019–2021	$HH_t\&Oil_t$	15.6054**	14.2835**
2019–2021	$HH_t\&Oil_t\&GDP_{w.PC_t}$	32.3892**	21.8257**

λ_{trace} and λ_{max} with $H_0 : r = 0$, $H_1 : 0 < r \leq k$. No further rejections.
Lag selection according to SIC.
Test specification with intercept and trend in test VAR and intercept in CE.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

to strengthening the long-term oil–gas cointegrating link. Table 12 suggests a unit root finding for Henry Hub prices between 2019 and 2021. We further test for cointegration between monthly crude oil and Henry Hub prices in this period. Table 13 at 5% and 10% significance levels provides evidence for a cointegrating link between crude oil and Henry Hub prices from 2019 to 2021. The long-term equilibrium relation is further confirmed in a three-variable setup cointegration between crude oil, Henry Hub prices, and consumption-weighted GDP per capita. We consequently estimate a VECM with three endogenous variables.

For North America, the results in Table 14 support our equilibrium finding established through fractional integration for the period between 2019 and 2021. We find that oil, gas, and weighted GDP per capita share a long-run equilibrium relationship, whereby only Henry Hub and oil prices show significant error correction terms. An increase in OPEC oil production lowers the oil price, while an increase in US gas production lowers the price for Henry Hub gas. Furthermore, however, Table 14 also indicates that at 5% significance level, an increase in US oil production lowers the price for Henry Hub gas, suggesting a fundamental link between oil production and the price of gas. We further reveal that the open interest in Brent futures has a significant positive impact not only on crude oil but also on Henry Hub gas prices.

For the oil-LNG pair, we provide estimation results for two sub-samples, January 2009–June 2015 and July 2015–December 2021. For the VEC specification for Japanese LNG and monthly crude oil (Table 15), the Schwarz Information Criterion (SIC) selects three lags for the oil prices for the first- and only two lags for the second sample half, suggesting less relevance of lagged oil price changes on the LNG import price. We find that the strong long-run link to oil prices declines from −0.99464 to −0.84104 and further observe that also the speed of adjustment to the long-run equilibrium is slightly reduced in the second sub-sample compared to the

Table 14
VECM estimation: Henry Hub and monthly crude oil prices, and oil consumption-weighted GDP per capita.

		2019–2021		
		ΔHH_t	ΔOil_t	$\Delta GDP_{w.PC_t}$
Cointegrating Eq.	HH_{t-1}	1		
	Oil_{t-1}	−0.77101***		
		(0.16729)		
	$GDP_{w.PC_t-1}$	0.35538***		
		(0.12167)		
	c	−34.51459		
	ECT_{t-1}	−0.29526**	0.46803**	−0.12712
		(0.13642)	(0.18366)	(0.23529)
Independent var.	ΔHH_{t-1}	0.20065	0.14388	0.00337
		(0.16674)	(0.22448)	(0.28758)
	ΔOil_{t-1}	0.10954	0.64817***	0.56712**
		(0.13185)	(0.17751)	(0.22741)
	$\Delta GDP_{w.PC_t-1}$	0.04330	0.08009	0.43181**
		(0.10105)	(0.13604)	(0.17429)
	$\Delta Oilprod_{US_t}$	−0.00052**	−0.00012	0.00017
		(0.00025)	(0.00033)	(0.00042)
	$\Delta Oilprod_{OPEC_t}$	0.04865	−0.42736***	−0.37542*
		(0.10795)	(0.14533)	(0.18619)
	ΔOI_{Brent_t}	5.68E−06**	9.36E−06**	3.74E−06
		(2.6E−06)	(3.4E−06)	(4.4E−06)
	$\Delta Gasprod_{US_t}$	−2.14E−06***	−1.51E−06	4.89E−07
		(7.1E−07)	(9.6E−07)	(1.2E−06)
	c	−0.01354	−0.00703	−0.03426
		(0.09025)	(0.12150)	(0.15566)
	Adj. R^2	0.44848	0.54179	0.48595
	F-stat	4.55769	6.17310	5.13587

Lag selection according to SIC.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

first (−0.39174 vs −0.42921). However, between July 2015 and 2021, oil and LNG prices are affected by a number of exogenous variables that are insignificant in the first sample. In particular, we find oil prices between July 2015 and 2021 to be significantly impacted by changes in fundamental supply and demand variables, such as OPEC oil production, GDP per capita, as well as the open interest in Brent futures. LNG prices decrease in US natural gas production, which can be explained by larger imports of Henry Hub gas in Japan.

Table 16 shows VECM estimation results for TTF and monthly oil prices between January 2011–June 2015 as well as between July 2015–December 2021.[7] Conversely to the findings for LNG in Japan, we observe that the size of the long-run coefficient of oil prices and the adjustment speed to the long-run equilibrium both increase in the second sub-sample. This is intuitive, however, as monthly oil prices gained relevance for TTF over long-term averaged prices, due to the decline of indexation in Europe. We further obtain a weaker cointegrating link between oil and TTF prices than for oil and LNG prices.

Furthermore and unlike in Japan, we find no significant coefficients of lagged oil price changes on TTF price changes, indicating a larger degree of oil price independence for gas in Europe. We detect a significant impact of exogenous variables for oil and gas prices in the second sub-sample: intuitively, OPEC oil production affects crude oil prices negatively, while our demand indicator, oil consumption-weighted GDP per capita, affects oil prices positively. TTF prices are at 5% significance level positively associated with heating demand and at 1% with the failure of Gazprom to fill its storage after the heating season in April 2021. We further find only in the second sub-sample that the open interest in Brent futures affects both TTF and oil prices positively at 5% and 1% significance levels, respectively.

Lastly, to test for cross-regional market dynamics, we test cointegration in a multivariate setup for those price series, for which a unit root cannot be rejected (Tables 3 and 12). For TTF, Japanese LNG, and monthly oil prices, the cointegration results in Table 17 indicate one common trend at 5% significance level between 2009 and June 2015, representing the traditional relationship between crude oil and gas prices present in both regions. Between July 2015 and 2021, however, we find evidence for two cointegrating equations, confirming our findings regarding the greater complexity of oil–gas relationships after 2015. This complexity and thus the second equilibrium state is driven by the impact of supply and demand shocks, which transpire across natural gas regions through growing LNG trade volume. We thereby confirm the existence of a second equilibrium state also for TTF, LNG, monthly crude, and Henry Hub prices between 2019 and 2021 (Table 17).

7 AGSI GIE provides historical gas storage data from 2011 onward.

Table 15
VECM estimation: Japanese LNG and monthly crude oil prices.

		2009–2015m6		2015m7 - 2021	
		ΔLNG_t	ΔOil_t	ΔLNG_t	ΔOil_t
Cointegrating Eq.	LNG_{t-1}	1		1	
	Oil_{t-1}	−0.99464***		−0.84104***	
		(0.05319)		(0.09098)	
	Trend	0.00676		−0.00742	
		(0.00820)		(0.00720)	
	c	1.47921		−0.48920	
	ECT_{t-1}	−0.42921***	0.09181	−0.39174***	−0.07109
		(0.04230)	(0.11168)	(0.05023)	(0.07392)
Independent var.	ΔLNG_{t-1}	−0.09935	0.13095	0.08009	0.13334
		(0.08637)	(0.22804)	(0.10593)	(0.15587)
	ΔLNG_{t-2}	0.07076	−0.01477	0.05715	−0.07058
		(0.07793)	(0.20576)	(0.11738)	(0.17272)
	ΔLNG_{t-3}	−0.10037	−0.08598	–	–
		(0.07685)	(0.20291)		
	ΔOil_{t-1}	−0.41657***	0.37592**	−0.12148	0.33230**
		(0.06520)	(0.17214)	(0.08992)	(0.13232)
	ΔOil_{t-2}	−0.42154***	0.07968	−0.45618***	−0.30314**
		(0.06790)	(0.17927)	(0.08988)	(0.13226)
	ΔOil_{t-3}	−0.37268***	0.00477	–	–
		(0.07396)	(0.19528)		
	$\Delta Oilprod_{US_t}$	−0.00066	−0.00111	−0.00022	−0.00021
		(0.00040)	(0.00105)	(0.00020)	(0.00029)
	$\Delta Oilprod_{OPEC_t}$	0.08551	−0.27254	0.03435	−0.22249*
		(0.13612)	(0.35938)	(0.08820)	(0.12978)
	$\Delta GDP_{w.PC_t}$	−0.81868	2.12949	0.07531	0.34268**
		(0.66912)	(1.76664)	(0.08729)	(0.12845)
	ΔOI_{Brent_t}	1.97E−06	3.66E−06	7.26E−07	5.85E−06***
		(2.4E−06)	(6.4E−06)	(1.4E−06)	(2.1E−06)
	$\Delta Gasprod_{US_t}$	4.55E−07	−3.87E−07	−1.19E−06**	−5.46E−07
		(4.7E−07)	(1.2E−06)	(5.1E−07)	(7.5E−07)
	ΔHDD_{JP_t}	−0.00064	−0.00082	0.00105	−0.00073
		(0.00049)	(0.00128)	(0.00071)	(0.00104)
	$\Delta GasStoreJP_t$	−2.37E−07	−5.46E−07	1.65E−07	−8.72E−10
		(1.7E−07)	(4.5E−07)	(1.6E−07)	(2.4E−07)
	c	0.30418	−0.49924	0.06934	−0.03771
		(0.18931)	(0.49982)	(0.06075)	(0.08939)
	Adj. R^2	0.71183	0.01888	0.46984	0.31967
	F-stat	13.88039	1.10033	6.68651	4.01509

Lag selection according to SIC.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

6. Discussion

Our results shed light on disruptions in the historical relationship between oil and gas prices across continents. We find evidence of a stationary relationship between Henry Hub and crude oil prices from July 2015 to December 2021, which shows a clear change to the dynamics prior to 2015, where oil and gas prices are found to decouple, as shown in Zhang and Ji (2018). The rolling windows estimation indicates that the stationarity finding originates in particular from price movements between 2019 and 2021. The integration in 2019 stems from oversupply in both oil and natural gas, given the mild winters and a slowdown in economic growth, in the wake of the financial markets' decline under the impression of the US-Chinese trade dispute. Indeed, we find evidence for cointegration between Henry Hub gas and oil prices, and oil consumption-weighted GDP per capita between 2019 and 2021 (Table 14). Our VECM estimation also mirrors underlying developments on the supply side: Whereas US oil production increased by 11.23% from 2018 to 2019, natural gas production in the US saw a record high of 115,626 BBtu per day, an about 10% increase from 2018 (EIA, 2020). Oversupply in the oil market further increased in 2020, when Saudi Arabia and Russia were unable to agree on production cuts, and after the consequential breakup of OPEC+ Saudi Arabia flooded the market with 6–8 USD/bbl discounts in March 2020. At the same time, Henry Hub prices continued their decline to below 2 USD/MMBtu in February 2020, as a result of oversupply, driven by advances in shale gas extraction technology and mild weather. Furthermore, associated gas production[8] rose to about 37.7% of natural gas production in crude oil-producing regions in 2020 (EIA, 2019) and has grown from about 8% to 16% of total natural gas production between 2006 and 2018 (EIA, 2021). Our results of a negative effect of US oil production on

[8] Natural gas produced from oil wells.

Table 16
VECM estimation: European TTF and monthly crude oil prices.

		2011–2015m6		2015m7 - 2021	
		ΔTTF_t	ΔOil_t	ΔTTF_t	ΔOil_t
Cointegrating Eq.	TTF_{t-1}	1		1	
	Oil_{t-1}	−0.34149***		−0.68662***	
		(0.11105)		(0.25366)	
	Trend	−0.00295		0.02516	
		(0.01925)		(0.02371)	
	c	−3.25281		−2.94853	
	ECT_{t-1}	−0.19151**	0.24244	−0.24827**	0.04674
		(0.08136)	(0.15256)	(0.09928)	(0.06379)
Independent var.	ΔTTF_{t-1}	0.40975**	−0.17336	−0.37586***	0.13857
		(0.16283)	(0.30533)	(0.13085)	(0.08407)
	ΔOil_{t-1}	−0.00237	0.39299**	−0.10007	0.26469**
		(0.07592)	(0.14236)	(0.20091)	(0.12908)
	$\Delta Oilprod_{US_t}$	0.00054	0.00032	0.00011	−0.00014
		(0.00060)	(0.00113)	(0.00045)	(0.00029)
	$\Delta Oilprod_{OPEC_t}$	−0.34605*	−0.28406	0.01942	−0.33776***
		(0.19042)	(0.35707)	(0.18537)	(0.11910)
	$DeltaGDP_{w.PC_t}$	0.26968	4.17364	0.19188	0.25762**
		(1.43205)	(2.68530)	(0.18997)	(0.12205)
	ΔOI_{Brent_t}	−5.64E−06	−5.01E−06	6.78E−06**	6.04E−06***
		(3.7E−06)	(7.0E−06)	(3.2E−06)	(2.1E−06)
	$\Delta Gasprod_{US_t}$	−8.67E−07	−1.82E−06	−3.83E−07	−2.81E−07
		(6.9E−07)	(1.3E−06)	(1.2E−06)	(7.9E−07)
	ΔHDD_{EU_t}	5.24E−04	−2.47E−03	0.003533**	−1.11E−03
		(0.00077)	(0.00144)	(0.00160)	(0.00103)
	$\Delta GasStore_{EU_t}$	−2.07E−04	−1.18E−04	8.16E−04	2.46E−04
		(0.00099)	(0.00186)	(0.00145)	(0.00093)
	$Gazprom_t$	–	–	1.36503***	−0.13211
				(0.21182)	(0.13609)
	c	−0.10339	−1.10923	−0.34295*	0.00330
		(0.35538)	(0.66638)	(0.19064)	(0.12249)
Adj. R^2		0.15064	0.16183	0.58291	0.31913
F-stat		1.92226	2.00401	10.78303	4.28096

Lag selection according to SIC.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Table 17
Multivariate Johansen tests for cointegration.

Variables in VAR	Sample	Hypothesized No. of CE(s)	Trace stat.	Max Eigen stat.
TTF_t, LNG_t, and Oil_t	2009–2015m6	None	62.7172***	39.3659***
		At most 1	23.3513*	18.5315*
		At most 2	4.8198	4.8198
	2015m7 - 2021	None	74.6363***	41.2588***
		At most 1	33.3774***	25.9182***
		At most 2	7.4592	7.4592
HH_t, TTF_t, LNG_t, and Oil_t	2019–2021	None	77.8980***	39.1725***
		At most 1	38.7256***	25.8571***
		At most 2	12.8685	11.1091
		At most 3	1.75939	1.75939

Lag selection according to SIC.
Test specification with intercepts and trends in CE and test VAR for TTF_t, LNG_t, and Oil_t. No trend in CE for HH_t, TTF_t, LNG_t, and Oil_t in 2019–2021 sample, due to short sample length.
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Henry Hub gas prices (Table 14) mirror the strengthening tie of oil and gas production in North America, as an increase in US oil production increases the supply of US gas.

Thus, the equilibrium relation between Henry Hub and crude oil prices can be explained by the oversupply-driven joint downward price trend. While the lower gas demand from Asia further contributed to the decline in Henry Hub prices, halting air travel and supply chains at the onset of the COVID-19 pandemic caused a demand shock in oil, whereby the downturn of economic activity led to a decrease in industrial demand for natural gas. We further find that the oil-Henry Hub ratio strengthened during the joint plummeting stock and commodity prices in March 2020, followed by the oil and gas price recovery in the following months, enabled by central banks' asset purchasing programs and subsequent vaccine roll-outs and economic re-openings. Our VECM estimation (Table 14) further reveals that the financialization in oil trade affects both oil and gas prices in North America positively, supporting the finding of Bunn et al. (2017), showing a strengthening of oil–gas price correlation as a consequence of speculation in the oil market. In the later months of 2021, both oil and Henry Hub prices reached multi-year highs, whereby the increasing demand for oil was not counterbalanced by an OPEC supply increase.

Whereas in a regime of high oil prices producers would seek to maximize oil rent by increasing production output, threats of creating stranded assets had led many oil producers to hold back on investment, prompting hesitation in drilling and new field development. The upward price pressure for natural gas on the other hand was reinforced by supply shortages, resulting partially from the previous year's defaults of numerous exploration and production companies in North America. The stationary link between the oil-Henry Hub from 2019 to 2021 mainly originates from oil and gas oversupply stimulated by the adoption of hydraulic fracking and horizontal drilling, further strengthened by shocks and relief dynamics impacting simultaneously both gas and oil prices. This is confirmed by Batten et al. (2017) and Caporin and Fontini (2017), who show temporary price links between oil and gas in North America because of the adoption of similar technologies in tight oil and shale gas production.

In the Asia-Pacific region, particularly in Japan as its largest market, oil indexation remains the primary pricing technique, representing 63% of the total imports in 2020 (IGU, 2021). With most deliveries to Japan priced against the JCC, i.e. the average price of crude oil delivered, one would expect to find evidence for a long-term oil–gas price equilibrium. Indeed, fractional integration estimates over the rolling windows show a non-dissolving nonstationary equilibrium between long-term oil prices and LNG in the full sample, with temporary stationarity between July 2015 and 2021. For the analysis of short-term dynamics, we examine the ratio of monthly oil and LNG prices over rolling windows. We find that, compared to the long-term dynamics, this price ratio shows a higher degree of stationarity and thus shorter shock persistence throughout the full sample window. This result can be attributed to two dynamics: Firstly, to the shift from long- to short-term LNG contracts directly linked to crude oil prices in the Japanese market and the emergence of an Asian LNG spot market as a consequence of the 2011 Great East Japan Earthquake and the Fukushima disaster (IEA, 2019); secondly, to the higher volumes of LNG imported from North America and the US, which moved from 53.2 billion cubic feet (bcf) in 2017 to about 354.9 bcf in 2021 (EIA, 2023), increasing the LNG import price exposure to the Henry Hub price, and loosening the long-term oil–gas link in Japan. We provide evidence for the increasing impact of US gas production following the surge in US gas exports after 2015 in the VECM estimation indicating a significant negative effect of US gas production on LNG prices in Japan after 2015 (see Table 15).

Thus, in the wake of the rise of gas-hub-priced LNG from North America, hybrid gas pricing formulas have been introduced in the Japanese market, including hub pricing alongside oil indexation. Further, an increasing demand impacted the LNG prices in the second half of the sample, between July 2015 and December 2021, along with a rebound of LNG contracting activity in Asia. This explains the stationary and stable equilibrium relation between LNG and long-term oil prices during this period. Falling LNG demand between 2019 and 2020 determined the oversupply and increased volumes available for exports of Henry Hub US shale gas, while oil prices decreased in face of economic slowdown and supply surplus. In all, our results imply that Japanese LNG imports remain largely oil-linked, also in 2021, when the high Asian LNG demand determined the stark upward price pressure on spot LNG prices. Whereas the slope of the JCC-linked gas price historically ranged between 10% and 15% (Chen et al., 2021), short-term deliveries to the Asia-Pacific region were priced at more than 40% over Brent prices in 2021.[9] Our findings, therefore, indicate that Japanese LNG imports remain closely linked to crude oil prices.

Results of the cointegration analysis in the European market in Table 8 suggest a stronger long-term equilibrium relation between TTF and monthly oil prices in the second sample half (July 2015–December 2021) than in the first one (January 2009–June 2015). Despite oil indexation historically being the primary gas pricing mechanism in Europe, the share of gas priced based on gas-on-gas competition rose from 20% in 2005 to 80% in 2020 (IGU, 2021), thus suggesting a displacement of oil indexation in favor of indexation to hub prices. Indeed, the slow mean reversion observed in the long-term oil/TTF price ratio over the second sample half mirrors the decline of oil indexation and the gradual adaption of hub pricing by European importers, such as Gazprom, starting from 2014. Our rolling window estimation in Fig. 5 further indicates that the nonstationary equilibrium between long-term oil and TTF prices dissolves after 2018. Similar to Japan, for the monthly oil/TTF price ratio we find a nonstationary equilibrium relation only in the second sample half (Table 11). However, the rolling windows estimation presented in Fig. 5 indicates that equilibrium regimes in the monthly oil/TTF ratio are only temporary: We observe a temporary coupling between monthly oil and TTF prices caused by the oil price crash and falling natural gas prices as a result of the resolution of the Russia–Ukraine gas dispute in October 2014. Subsequently, the monthly oil/TTF ratio gradually decoupled until the next temporary coupling during the gas crisis in Europe in 2020 and 2021, when a stationary relationship between the two prices is observed.

The stationarity of the monthly oil/TTF ratio in early 2020 is explained by the high gas storage levels resulting from a mild 2019/20 winter season in Europe and LNG oversupply. In the same period, falling demand for crude oil was also observed, due to halting transportation amid global crude oil oversupply. Yet, in spite of oversupplied natural gas markets, major exporters such as Qatar Petroleum rejected production cuts, while the oil price war and the spur of COVID-19 infection worldwide led to a sharp price decline in global commodity markets in 2020. In all, these factors can explain the temporary equilibrium between monthly oil and TTF gas prices observed in 2020–21. Our results are thus in line with Lin and Su (2021), pointing to a significant but short-lasting increase in the total connectedness of energy commodity markets following the pandemic outbreak, yet to significantly-enhanced spillover effects of other energy commodities on natural gas. Our results stand also in line with findings by Gong et al. (2021),

[9] Note that thermal parity equates 1 barrel of oil to 5.8 MMBtu of natural gas and conversely prices 1 MMBtu of natural gas at about 17.2% of oil prices.

showing significant volatility transmissions from oil to natural gas in the aftermath of the global financial crisis and during the oil price crash in 2014. The findings of our VECM estimation support the impact of financial factors on oil and gas prices in Europe, suggesting oil market financialization to be a significant driver for oil but also gas between July 2015 and 2021, and thereby confirming the finding of Bunn et al. (2017) for North America.

The enduring equilibrium between TTF and oil prices in late 2020 and during 2021 (Fig. 5) coincides with the recovery of oil and TTF gas prices following an increase of the LNG demand in Asia, a gradual lifting of travel restrictions, and a restoration of logistics and supply-chains. Nonetheless, the downward demand shock led by the recent pandemic induced a cyclical swing in the supply side of the natural gas market: Plummeting energy prices in 2020 led to market consolidation and reduced exploration activity in North America, which has affected the availability of LNG. Confronted with the 2020/21 unusually-cold winter season and higher storage withdrawals, producers were thus unable to adequately adjust to the increasing demand from Asia, which attracted most of the available LNG deliveries and drove prices up. Consequently, and apart from the impact of exogenous supply and demand variables for crude oil after 2015, the VECM estimation for Europe in Table 16 also indicates that TTF gas prices respond dynamically to fundamental heating demand and acute supply shortages. In the context of a tightening LNG market, Europe faced diminishing domestic supply, depleted storage, exceptionally few deliveries beyond contracted levels from Russia, and an increasing need for natural gas to cope with the gradual coal phase-out in the power sector. With a 45% import dependence on Russian pipeline gas in Europe (IEA, 2022), especially the under-utilization of the Ukrainian transit and the absence of adequate storage refills in the summer of 2021 led to additional upward price pressure for natural gas. Consequently, TTF prices rose 600% year-on-year on average in December 2021, prior to the outbreak of military conflict in Ukraine in February 2022. While the lack of regasification capacity and specialized LNG tankers limited the availability of imports from alternative supply routes, no equivalent shortage in crude oil was recorded, as deliveries could more easily be sourced from world markets and thus crude oil prices rose more moderately. Consequently, the decreasing speed of mean reversion in the monthly oil/TTF price ratio at the end of 2021 (Fig. 5) indicates a new decoupling phase between oil and natural gas in Europe.

Overall, our results shed light on spillover effects between the gas and oil markets which is of major interest for risk management and hedging. We further unveil time-varying relationships between oil and gas prices across different regions under the incidence of economic and political shocks, among which the recent COVID-19 pandemic and the gas market shocks prior to the military conflict in Ukraine.

7. Conclusions

The fear of a gas shortage in Europe in 2021, stemming from changes in the traditional demand/supply dynamics, has been amplified during the military conflict in Ukraine. The stark rise in TTF prices can be attributed to supply disruptions, high carbon prices, the anticipated shutdown of three German nuclear power plants, and a consequential rise in demand for natural gas in the power sector of the EU. Fundamentally, however, the dramatic price increase was also driven by the reduction of short-term deliveries from Russia during 2021 and the absence of adequate storage build-up by Gazprom throughout the year. Oil can be easily sourced from world markets because it is easily transported by ship and EU import capacity is large. With gas, the problem is more complex, especially as LNG import infrastructure is insufficient in several affected European countries. We therefore expect the decoupling between oil and gas prices in Europe to persist. It is therefore highly relevant to keep track of the historical shock transmission mechanisms, spillover effects, and joint movements of gas and oil markets.

This study tests the traditional oil and gas relationships in Japan, Europe, and North America in a cointegration and long-memory test approach. Our results reveal that the oil price linkage follows time-varying dynamics in all three investigated natural gas markets. The advancement of hub pricing and rising LNG imports shape the natural gas price mechanism and contribute to a loosening contractual link between gas and oil in Europe. For TTF prices, results indicate that long-term oil prices do not enter the gas price formation process, but monthly oil and TTF prices enter temporary equilibria during the volatile markets of 2014 and from 2020 to 2021. The strongest oil–gas link is found for the Japanese market in the form of persisting indexation to long-term oil prices as well as in short-term dynamics. For the North American market, we find a prevailing equilibrium relation between oil and Henry Hub prices commencing in 2019, as a result of the oversupply in both oil and natural gas markets. During the COVID-19 pandemic, we observe a faster mean reversion speed in the oil/gas price ratio, which continues throughout 2021, as the US market was insulated from the extreme price shocks in the European gas market, mainly due to a lack of adequate liquefaction capacity.

We further find that long-run oil–gas price relationships have become more complex and are significantly impacted by fundamental supply and demand factors. We find that US oil production drives the price for Henry Hub gas between 2019 and 2021, as a consequence of a rise in oil-associated natural gas production in the US. We further show a rising significance of US natural gas production for LNG prices in Japan, while for Europe and the US alike, our findings support the hypothesis of a stronger oil–gas price link as a result of oil market financialization. Furthermore, our results provide evidence for cross-regional cointegration between oil and gas prices, which confirm the findings of Chiappini et al. (2019), who show increasing interdependence between European and American gas markets.

8. Outlook

The military conflict in Ukraine in 2022 has led policymakers in Europe to seek out strategies to bolster the security of natural gas supply and reduce the import dependency on Russia. In the long-term, besides a build-up of LNG import capacity, the strategy aims at increasing the share of renewable energies with a focus on the expansion of bio-methane and renewable hydrogen, accordingly to the joint European action for more affordable, secure, and sustainable energy (European Commission, 2022b). In the short term, the EU issued mandatory storage quotas requiring 90% fill levels from storage operators by the beginning of December. These quotas may prevent temporary price bubbles in the European natural gas market.

The expansion of US LNG exports and enhancements of the European LNG import capacities may strengthen the link between these regionally-separated natural gas markets and tighten the oil–gas price relationship in Europe. Allowing for a more dynamic response to overseas demand, increased linkages to the European market may also contribute to a renewed decoupling of the oil–gas price relationship in North America, which has been isolated from the European price shock due to limited liquefaction capacity. However, there is not much evidence about the impact of the Ukrainian war on oil–gas price relationships, motivating further research. In Europe, additional means to increase the security of supply in 2022 envisage the diversion of Japan-bound LNG cargoes to Europe which, along with increased connectedness of central Europe to existing regasification facilities in Spain, may enhance the robustness of the European natural gas market. Demand-side policies, such as the lifetime extension of nuclear and coal power plants, have further limited the risk of supply disruptions. A worsening gas shortage, however, due to a failure to adequately fill underground storage over the summer of 2023, together with a complete curtailment of fossil fuel imports from Russia, could enhance the upward price pressure on natural gas and contribute to a long-term decoupling between natural gas and oil prices.

CRediT authorship contribution statement

Christoph Halser: Data curation, Formal analysis, Methodology, Writing – original draft. **Florentina Paraschiv:** Conceptualization, Formal analysis, Investigation, Methodology, Supervision, Validation, Writing – review & editing. **Marianna Russo:** Formal analysis, Methodology, Supervision, Validation.

Data availability

Data will be made available on request.

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