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i



Key Points

- The market for internationally traded gas has now globalized, assisted by the advent of US LNG from the Lower-48. The volume of flexible LNG has increased sharply since 2016 and was instrumental in the diversion of LNG cargoes to Europe, following the loss of Russian pipeline gas in 2022. The pricing of LNG has also changed significantly since 2016, with the traditional oil-indexed long-term contracts now accounting for marginally over half of all LNG trade in 2023, as spot and hub pricing has risen sharply.
- In a globalized market, the gas price drivers are increasingly complex and simplistic analysis fails to account for these complexities. The concept of a "cost stack" where the costs of various sources of gas and LNG supply to a market can be stacked with the highest cost supply "setting" the price, was always dubious at best, as it missed other "alternative" sources such as fuel-switching and efficiencies. The concept falls down completely where gas prices are determined in a global market.
- The fundamentals of supply and demand remain the key drivers, but that does not mean that price
 equals marginal cost, which is only true in a perfectly competitive market. The marginal cost of
 supply remains an important influence on the price but in recent history the actual spot prices have
 been at, or even below, the short-run marginal cost, and a year or two later, at or well above the
 long-run marginal cost. Other factors, which can be broadly defined as "competing prices", also can
 materially impact gas prices, as well as the relative tightness of the market.
- Europe has relied heavily on Russian pipeline gas increasingly so in the 2010s and it could be said that Europe was "hooked" on Russian gas, but it was never cheap. The price of oil-indexed gas from Russia was largely significantly higher than hub priced gas in Europe and even when Gazprom moved to hub pricing, this meant the price was the same not lower. In the European market, we are all price takers.
- The criticism by some politicians and commentators that the TTF price was "no longer representative" in 2022, as prices rose sharply to very high levels, and well above other LNG and hub prices, was shown to be ill-informed. The dramatic loss of Russian pipeline gas resulted in congested infrastructure, especially in Northwest Europe and, in congested markets, differentials widened. Once the congestion was alleviated, differentials returned to normal levels. The response to these extraordinary events, was that the flexible liquid trading market worked extremely well in diverting volumes and reducing demand, however painful this may have been. Sadly the recent Draghi report seems to have repeated the ill-informed analysis of the market.
- The determination of gas prices for internationally traded gas in competitive markets is multidimensional. The value of gas in the market demand centres is the ultimate driver but this value is determined by muliple factors and influences, the importance of which can change, not just from one year to the next but one month to the next or even one day to the next. Where supply is plentiful, relative to demand, as we saw in 2019 and 2020, the short-run marginal cost of supply was a key factor and competition between gas and coal in the power market was also important. This changed in 2021, as the world recovered from Covid-19, and even more dramatically in 2022, following the Russian invasion of Ukraine. The market tightened sharply, with demand exceeding supply in Europe, and prices rose well above the long-run marginal cost of supply and there was a sharp demand response with fuel switching, efficiences, behavioural changes and even industrial closures all impacting prices.
- The value of gas rose sharply in the European market and this was transmitted to the rest of the world, especially Asian markets, through the flexible LNG market. The value of gas rose in these markets as well, not because of what was happening in their own markets, but because of the globalized gas and LNG market.



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Preface

There is nothing permanent except change

The last decade has been a period of swift evolution for international gas markets, with the additional market disruption caused by the global pandemic and an armed conflict involving one of the world's largest producers. The mid-2020s mark a "coming of age" moment for gas markets. In the 1990s and early 2000s, gas markets were either regional or dominated by point-to-point contracts with very little flexibility. The market was constrained by a handful of key buyers and sellers with gas delivered largely by pipeline, with all the limitations that implies. As Mike Fulwood argues in this major update on the OIES' 2012 book The Pricing of Internationally Traded Gas, the post 2008/9 financial crisis phase has seen traded volumes surge, participation swell and flexibility, the true definition of a fungible market, multiply.

As such, international gas markets are now populated by a raft of new suppliers and consumers, have seen the dynamic expansion of the LNG business with multiple new players on both sides of the trade, more flexible cargoes and most importantly, the trading hubs that allow price discovery and encourage broader participation further out the curve, whether for physical or paper trading. The explosion of US shale gas production has underpinned the commoditization of global gas, with its broad investor base and flexible exports to both the Atlantic Basin and the fast-growing Asia-Pacific market compounding gas-on-gas pricing.

Fulwood's paper unpicks the drivers behind global gas prices, putting to rest persistent myths and offering a complex and cool-headed framework for understanding gas pricing. The report dismisses the idea that gas prices are determined by the marginal cost; that Europe was addicted to supplies of cheap Russian gas (a study of prices show it was not particularly cheap, but was more flexible in terms of volume); or that TTF was a broken benchmark when it spiked in 2022 – all arguments that were used in varying degrees to support political arguments for price controls and other market interventions in recent years.

On the contrary, the report argues that supply and demand fundamentals remain critical drivers but that certain other features come more into play depending on whether the market is short, balanced, or well supplied. These include options for fuel switching (either coal or oil), LNG capacity utilization and other infrastructure bottlenecks, which help explain the price spreads between landed LNG and hub benchmarks. In fact, as the report explains, volatile basis spreads are not new in the complex US midstream and arguably, with the exception of 2022, the European market has been less exposed to those kind of price distortions. In fact, they reflected the unusual features of the 2022 market and showed the market was working as designed, rather than failing.

Fulwood argues that that in a well-supplied market, short-run marginal cost pricing will a key driver, as will alternative fuel switching to, for example, coal, while in a balanced market prices will reflect both short-run and long-run marginal costs. In a supply short market, long-run marginal cost pricing or above will dominate – as will demand responses to higher prices. Alternative fuels may no longer be relevant since switching has already occurred lower down the price curve. The broad conclusion is that international gas pricing does not reflect a perfectly competitive market, but increasingly shows characteristics of a maturing market, where rising trade flows and flexibility allow portfolio optimization. Rather than describing LNG as a virtual pipeline, it is now more appropriate to see it as the way in which liquidity has been injected into the global gas trade picture (pun intended).

Bill Farren-Price, Head of Gas Research, OIES



Glossary

- AR Average revenue
- ARA Coal Rotterdam coal price, market price for Europe
- ATC Average total cost
- BBL Balgzand-Bacton pipeline between Netherlands and the UK
- BCM Billion standard cubic metres of natural gas
- CME Chicago Mercantile Exchange
- EEX European Energy Exchange
- EIA US Energy Information Administration
- EU27 27 members of the European Union
- EU ETS EU emissions trading scheme
- Henry Hub The main gas pricing hub in the USA
- FID Final investment decision
- FLNG Floating liquefied natural gas tanker
- FSRU Floating storage and regasification unit
- GO Gasoil
- GOG Gas-on-gas competition from IGU Wholesale Gas Price Survey
- HSFO High sulphur fuel oil
- ICE Exchange where physical gas and futures are traded (Intercontinental Exchange)
- IEA International Energy Agency
- IGU International Gas Union
- JCC Japan Crude Cocktail, oil price indicator used in long-term LNG contracts
- JKM Japan-Korea pricing marker for LNG in Asia, S&P Global
- LNG Liquefied natural gas
- LRMC Long-run marginal cost
- LSFO Low sulphur fuel oil
- MC Marginal cost
- MR Marginal revenue
- MMBTU Million British Thermal Units used in gas pricing
- MMCM Million standard cubic metres of natural gas
- NBP Great Britain natural gas transmissions system National Balancing Point trading hub
- Nordstream Gas pipeline running from Russia to Germany
- NYMEX Exchange which trades Henry Hub gas futures (New York Mercantile Exchange)
- OECD Organisation for Economic Cooperation and Development
- OIES Oxford Institute for Energy Studies
- Opal Hub gas pricing hub in Wyoming
- OPE Oil price escalation from IGU Wholesale Gas Price Survey
- PEGN Point d'échange de gaz Nord, France gas trading hub
- PITG The Pricing of Internationally Traded Gas, OIES book edited by Jonathan Stern
- PSV Punto di Scambio Virtuale, Italy gas trading hub
- PVB Virtual balancing point, Spain gas trading hub
- SRMC Short-run marginal cost
- THE Trading Hub Europe, Germany gas trading hub
- TTF Title Transfer Facility, Netherlands trading hub
- VTP Virtual trading point, Austria gas trading hub
- Waha Hub gas pricing hub in West Texas



Contents

Key Pointsii				
Ackn	owledgements	. iii		
Prefa	Prefaceiv			
Gloss	sary	v		
Conte	Contents			
Figur	es and Tables	vii		
Exec	utive Summary	. ix		
Glo	balization of Gas Markets	ix		
The	e Four Fallacies	х		
Mu	lti-Dimensional Analysis and the Value of Gas	.xv		
Exp	Explaining Historical and Future Gas Price Movementsxvii			
Co	nclusion	viii		
1. li	ntroduction	1		
2. 0	Blobalization and Competitive Markets	2		
a)	Analysis of IGU Survey Data	2		
b)	The Beginnings of the Globalization of Gas Markets	7		
c)	Globalization: Progress since 2012	9		
d)	Is Hub Development necessary for Globalization?	13		
e)	Conclusions	15		
3. F	allacy No 1: The Cost Stack	16		
a)	What is the Cost Stack?	16		
b)	Modifying the Cost Stack	17		
c)	A Global Cost Stack?	19		
d)	Conclusions	20		
4. F	allacy No 2: Price equals Marginal Cost	20		
a)	Price equals Marginal Cost: Economics 101	20		
u, b)	Long Run and Short Run Marginal Cost	23		
c)	What are the other influences on gas prices?	24		
d)	Market Tightness	28		
а) е)	How can 2022 be explained?	30		
f)	Conclusions	31		
5 F	Conclusions	32		
J. 1	Russian das to Europe	32		
b)	Price of Russian Cas	33		
c)	The Costs of Russian Cas	34		
d)	Conclusions	35		
6 E	Conclusions	36		
0. I	The TTE rollercoaster in 2022	36		
a) b)	Feenomics of Congestion and Infrastructure Constraints	20		
(U	Other Examples of Congestion and Infrastructure Constraints	30 44		
() d		41		
u) 7 '	Cullusiuls	43 AF		
<i>i</i> . F	Development of Merkete	40 45		
a)	Development of Huba	45		
(a (-		40		
C)		47		
d)		48		
e)	Globalization and the Value of Gas	50		
t)	Conclusions	53		



8.	Explaining Historical and Future Gas Price Movements	54		
а	a) Historical Gas Price Movements	54		
b	b) Future Gas Price Movements	71		
С	c) Conclusions	75		
9.	Conclusions: Globalization and the Value of Gas			
а	a) Globalization and Competitive Markets			
b	b) The Cost Stack Fallacy			
с	c) Price Equals Marginal Cost Fallacy	78		
d	d) Cheap Russian Gas Fallacy	79		
е	e) TTF is Broken Fallacy	80		
f)) The Value of Gas	80		
g	g) Historical Pricing Developments and the Hypothesis	84		
h	n) Future Market Developments	85		
i)) The Final Word	86		
Annex 1: Bibliography				
Annex 2: NexantECA World Gas Model 88				
Anr	Annex 3: Development of Hubs			

Figures and Tables

х
xi
cii
iii
/ii
iii
4
5
6
6
7
9
1
2
3
6
8
9
0
1
3
4
5
6
7
8
9
0
1
2



Figure 32: Price of Imported Russian Gas v Spot Prices – 1998 to 2015. 34 Table 1: Cost of Russian Gas to Germany – Average 2015 to 2020. 35 Figure 33: Thr, NBP, LNG NWE and Japan Spot Prices 2022. 36 Figure 34: UK and Belgium/Netherlands Pipeline Flows 39 Figure 35: LNG Imports: Dunkirk, Zeebrugge and Gate 40 Figure 35: US Natural Gas Pipeline Map. 42 Figure 37: US Natural Gas Pipeline Map. 42 Figure 38: US Hub Differentials from Henry Hub 43 Figure 34: Util-Dimensional Analysis of Gas Price Drivers 49 Figure 40: Connecting the Globalised Gas Market 51 Figure 43: Stadow Prices and Market Tightness – 2006 to 2016. 56 Figure 43: Abadow Prices – 2005 to 2016 o. 2016 56 Figure 43: Stadow Prices – 2016 to Mid-2021. 59 Figure 44: Japan Spot and Contract Prices – 2001 to 2021 o. 2021 6. 58 Figure 44: Long Run and Short Run Shadow Prices – 2017 to 2021 6. 60 Figure 44: Stado Prices and Contract Prices – 2016 to Mid-2021 6. 61 Figure 45: LNG Export Costs VTTF and Japan Spot Prices – 2016 to Mid-2021 6. 62 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 6. 62 Figure 51: LNG Export Costs VTTF and Japan Spot Price	Figure 31: Europe Supply – Demand Balance	33
Table 1: Cost of Russian Gas to Germany – Average 2015 to 2020	Figure 32: Price of Imported Russian Gas v Spot Prices – 1998 to 2015	34
Figure 33: TTF, NBP, LNG NWE and Japan Spot Prices 2022. 36 Figure 34: UK and Belgium/Netherlands Pipeline Flows 39 Figure 35: European Hub Differentials from TTF 41 Figure 36: European Hub Differentials from TTF 41 Figure 37: US Natural Gas Pipeline Map 42 Figure 38: US Hub Differentials from Henry Hub 43 Figure 40: Connecting the Globalised Gas Market 51 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016 55 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016 56 Figure 42: Shadow Prices – 2005 to 2016 to 2016 56 Figure 42: Shadow Prices – 2016 to Mid-2021 58 Figure 44: Japan Spot and Contract Prices – 2006 to 2016 57 Figure 42: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016 58 Figure 43: Long Run and Short Run Shadow Prices – 2017 to 2021 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 62 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021 62 Figure 52: TTF Netback to Henry Hub – 2016 to Mid-2021 64 Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to Mid-2021 63 Figure 54: Supply – Demand Chartz – 2019 and 2020	Table 1: Cost of Russian Gas to Germany – Average 2015 to 2020	35
Figure 34: UK and Belgium/Netherlands Pipeline Flows 39 Figure 35: LNG Imports: Dunkirk, Zeebrugge and Gate 40 Figure 35: LNG Imports: Dunkirk, Zeebrugge and Gate 41 Figure 37: US Natural Gas Pipeline Map 42 Figure 38: US Hub Differentials from Henry Hub 43 Figure 30: Connecting the Globalised Gas Market 51 Figure 40: Connecting the Globalised Gas Market 51 Figure 41: Spot Prices – 2005 to 2016 54 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016 56 Figure 43: Dapot and Contract Prices – 2006 to 2016 56 Figure 44: Japan Spot and Contract Prices – 2006 to 2016 57 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016 58 Figure 46: Spot Prices – 2016 to Mid-2021 60 Figure 47: Market Tightness – 2016 to Mid-2021 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 60 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021 61 Figure 52: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to Mid-2021 64 Figure 54: Supply – Demand Charts – 2019 and 2020 66 Figure 55: Spot Prices – 2020 to 204 to 2024 67 Figur	Figure 33: TTF, NBP, LNG NWE and Japan Spot Prices 2022	36
Figure 35: LNG Imports: Dunkirk, Zeebrugge and Gate 40 Figure 33: European Hub Differentials from TTF 41 Figure 33: US Hub Differentials from Henry Hub 43 Figure 33: Multi-Dimensional Analysis of Gas Price Drivers 49 Figure 41: Spot Prices – 2005 to 2016 54 Figure 41: Spot Prices – 2005 to 2016 55 Figure 43: TTF, Coal and Oil Prices – 2006 to 2016 55 Figure 44: Spot Prices – 2016 to Mid-2021 59 Figure 44: Spot Prices – 2016 to Mid-2021 69 Figure 44: Spot Prices – 2016 to Mid-2021 60 Figure 44: Spot Prices – 2016 to Mid-2021 60 Figure 49: TTF and Coal Prices – 2015 to Mid-2021 60 Figure 49: TTF and Coal Prices – 2015 to Mid-2021 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 61 Figure 51: UNG Export Corts v TTF and Japan Spot Prices – 2016 to Mid-2021 63 Figure 52: TTF Netback to Henry Hub – 2016 to Mid-2021 63 Figure 55: Shadow Prices and Market Tightness – 2020 to 2024 64 Figure 56: Shadow Prices and Market Tightness – 2020 to 2024 64 Figure 56: Shadow Prices and Market Tightness – 2020 to 2024 68 Figure 56: Shadow Prices and Market Tightness – 2020	Figure 34: UK and Belgium/Netherlands Pipeline Flows	39
Figure 36: European Hub Differentials from TTF. 41 Figure 37: US Natural Gas Pipeline Map 42 Figure 38: Wulti-Dimensional Analysis of Gas Price Drivers 43 Figure 40: Connecting the Globalised Gas Market 51 Figure 41: Spot Prices – 2005 to 2016 54 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016 56 Figure 43: TTF, Coal and Oil Prices – 2006 to 2016 56 Figure 43: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016. 57 Figure 44: Japan Spot and Contract Prices – 2006 to 2016 57 Figure 45: Dopt Prices – 2016 to Mid-2021 59 Figure 45: Long Run and Short Run Shadow Prices – 2017 to 2021 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 61 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021 63 Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to Mid-2021 64 Figure 54: Supply – Demand Charts – 2019 and 2020 66 Figure 55: Japan Spot and Contract Prices – 2016 to Mid-2021 63 Figure 55: Shot Prices – 2020 to Mid-2024 67 Figure 55: Sup Prices – 2020 to Mid-2024 67 Figure 56: Shadow Prices and Market Tightness – 2020 to 2024. 68	Figure 35: LNG Imports: Dunkirk, Zeebrugge and Gate	40
Figure 37: US Natural Gas Pipeline Map42Figure 38: US Hub Differentials from Henry Hub43Figure 38: US Hub Differentials from Henry Hub43Figure 38: US Hub Differentials from Henry Hub43Figure 40: Connecting the Globalised Gas Market51Figure 41: Spot Prices – 2005 to 201654Figure 42: Shadow Prices and Market Tightness – 2006 to 201655Figure 43: TTF, Coal and Oil Prices – 2006 to 201656Figure 44: Japan Spot and Contract Prices – 2006 to 201657Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 201658Figure 47: Market Tightness – 2016 to Mid-202159Figure 47: Market Tightness – 2016 to Mid-202160Figure 47: Market Tightness – 2016 to Mid-202160Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-202161Figure 52: TTF Netback to Henry Hub – 2016 to Mid-202163Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 55: Spot Prices – 2020 to Mid-202467Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 68: LNOE Export Capacity Utilisation to 203072Figure 61: LNOE Export Capacity Utilisation to 203072Figure 63: LNOE Export Capacity Utilisation to 203073Figure 64: Connecting the Globalised Gas Market83Figure 65: The UK Cost Stack 202177Figure 66: Price	Figure 36: European Hub Differentials from TTF	41
Figure 38: US Hub Differentials from Henry Hub 43 Figure 39: Multi-Dimensional Analysis of Gas Price Drivers 49 Figure 41: Spot Prices – 2005 to 2016 54 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016 55 Figure 43: TTF, Coal and Oil Prices – 2006 to 2016 56 Figure 43: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016 57 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016 58 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016 59 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016 60 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2017 to 2021 60 Figure 45: Long Run and Short Run Shadow Prices – 2017 to 2021 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 62 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021 63 Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020 66 Figure 54: Supply – Demand Charts – 2019 and 2020 66 Figure 55: Spot Prices – 2020 to 1024 67 Figure 54: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 2023 70 Figure 55: Spot Prices – 2020 to 2024 68 </td <td>Figure 37: US Natural Gas Pipeline Map</td> <td> 42</td>	Figure 37: US Natural Gas Pipeline Map	42
Figure 39: Multi-Dimensional Analysis of Gas Price Drivers49Figure 40: Connecting the Globalised Gas Market51Figure 41: Spot Prices – 2005 to 201654Figure 42: Shadow Prices and Market Tightness – 2006 to 201655Figure 43: TTF, Coal and Oil Prices – 2006 to 201656Figure 44: Japan Spot and Contract Prices – 2006 to 201657Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016.58Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016.58Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016.59Figure 47: Market Tightness – 2016 to Mid-2021.60Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021.60Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021.61Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021.63Figure 53: Shufti-Dimensional Analysis of Gas Price Drivers – 2016 to 2020.66Figure 54: Supply – Demand Charts – 2019 and 2020.66Figure 55: Spot Prices – 2020 to 2024.69Figure 58: Japan Spot and Contract Prices – 2020 to 2024.69Figure 58: Japan Spot and Contract Prices – 2020 to 2024.69Figure 58: Japan Spot and Contract Prices – 2020 to 2024.69Figure 58: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 2023.70Figure 61: LNG Export Capacity Utilisation to 2030.72Figure 62: Gas Demand Growth to 2030.73Figure 63: LNG Export Capacity Utilisation to 2030.74Figure 64: Multi-Dimensional Analysis	Figure 38: US Hub Differentials from Henry Hub	43
Figure 40: Connecting the Globalised Gas Market 51 Figure 41: Spot Prices – 2005 to 2016. 54 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016. 55 Figure 43: TTF, Coal and Oil Prices – 2006 to 2016. 57 Figure 44: Japan Spot and Contract Prices – 2006 to 2016. 57 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016. 58 Figure 46: Spot Prices – 2016 to Mid-2021. 60 Figure 47: Market Tightness – 2016 to Mid-2021. 60 Figure 49: TTF and Coal Prices – 2015 to Mid-2021. 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021. 61 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021. 63 Figure 52: TTF Netback to Henry Hub – 2016 to Mid-2021. 64 Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020. 65 Figure 55: Spot Prices – 2020 to Mid-2024. 67 Figure 56: Shadow Prices and Market Tightness – 2020 to 2024. 68 Figure 57: TTF and Coal Prices – 2020 to 2024. 69 Figure 57: TTF and Coal Prices – 2020 to 2024. 69 Figure 58: Japan Spot and Contract Prices – 2020 to 2024. 69 Figure 61: LNG Export Capacity Utilisation to 2030. 72	Figure 39: Multi-Dimensional Analysis of Gas Price Drivers	49
Figure 41: Spot Prices – 2005 to 2016. 54 Figure 42: Shadow Prices and Market Tightness – 2006 to 2016. 55 Figure 43: TTF, Coal and Oil Prices – 2006 to 2016. 56 Figure 44: Japan Spot and Contract Prices – 2006 to 2016. 57 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016. 58 Figure 46: Spot Prices – 2016 to Mid-2021. 60 Figure 47: Market Tightness – 2016 to Mid-2021. 60 Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021. 60 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021. 61 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021. 62 Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020. 65 Figure 53: Stout Frices – 2020 to Mid-2021. 64 Figure 55: Spot Prices – 2020 to Mid-2024. 67 Figure 55: Spot Prices – 2020 to Market Tightness – 2020 to 2024. 68 Figure 65: Madow Prices and Market Tightness – 2020 to 2024. 69 Figure 65: Japan Spot and Contract Prices – 2020 to 2024. 69 Figure 63: LNG Export Capacity Growth to 2030. 72 Figure 63: LNG Export Capacity Growth to 2030. 73 Figure 63: LNG Export Capacity Utilisation to 2030.	Figure 40: Connecting the Globalised Gas Market	. 51
Figure 42: Shadow Prices and Market Tightness – 2006 to 201655Figure 43: TTF, Coal and Oil Prices – 2006 to 201656Figure 44: Japan Spot and Contract Prices – 2006 to 201657Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 201658Figure 46: Spot Prices – 2016 to Mid-202159Figure 47: Market Tightness – 2016 to Mid-202160Figure 47: Market Tightness – 2016 to Mid-202160Figure 47: TF and Coal Prices – 2015 to Mid-202161Figure 50: Japan Spot and Contract Prices – 2016 to Mid-202162Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-202163Figure 52: TTF Netback to Henry Hub – 2016 and Nid-202164Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202469Figure 57: TTF and Coal Prices – 2020 to 202469Figure 68: Japan Spot and Contract Prices – 2020 to 202469Figure 61: LNG Export Capacity Growth to 203073Figure 63: LNG Export Capacity Growth to 203073Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202170Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: Capacity Growth to 203073Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Connecting the Globalised G	Figure 41: Spot Prices – 2005 to 2016	54
Figure 43: TTF, Coal and Oil Prices – 2006 to 2016 56 Figure 44: Japan Spot and Contract Prices – 2006 to 2016 57 Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016. 58 Figure 46: Spot Prices – 2016 to Mid-2021 60 Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021 60 Figure 48: TTF and Coal Prices – 2015 to Mid-2021 61 Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021 61 Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021 63 Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020. 65 Figure 54: Supply – Demand Charts – 2019 and 2020. 66 Figure 55: Spot Prices – 2020 to Mid-2024. 67 Figure 56: Japan Spot and Contract Prices – 2020 to 2024. 68 Figure 57: TTF and Coal Prices – 2020 to 2024. 69 Figure 58: Japan Spot and Contract Prices – 2020 to 2024. 69 Figure 63: LNG Export Capacity Growth to 2030. 72 Figure 63: LNG Export Capacity Utilisation to 2030. 72 Figure 63: LNG Export Capacity Utilisation to 2030. 74 Figure 63: Nulti-Dimensional Analysis of Gas Price Drivers – 2024 to 2030. 75 Figure 64: Multi-Dimensional Analysis of Gas	Figure 42: Shadow Prices and Market Tightness – 2006 to 2016	. 55
Figure 44: Japan Spot and Contract Prices – 2006 to 2016.57Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016.58Figure 46: Spot Prices – 2016 to Mid-2021.60Figure 47: Market Tightness – 2015 to Mid-2021.60Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021.60Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021.61Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021.63Figure 52: TTF Netback to Henry Hub – 2016 to Mid-2021.64Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020.65Figure 54: Supply – Demand Charts – 2019 and 2020.66Figure 55: Spot Prices – 2020 to Mid-2024.67Figure 56: Shadow Prices and Market Tightness – 2020 to 2024.68Figure 57: TTF and Coal Prices – 2020 to 2024.69Figure 68: Japan Spot and Contract Prices – 2020 to 2024.69Figure 61: LNG Export Capacity Growth to 2030.72Figure 62: Gas Demand Chart – 2021.71Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030.73Figure 65: The UK Cost Stack 2021.77Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030.75Figure 65: The UK Cost Stack 2021.77Figure 66: Price of Imported Russian Gas Vspot Prices – 1998 to 2015.79Figure 67: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030.75Figure 68: Connecting the Globalised Gas Market83Figure 70: Henry Hub: Calculated v Actual.89 <t< td=""><td>Figure 43: TTF, Coal and Oil Prices – 2006 to 2016</td><td>. 56</td></t<>	Figure 43: TTF, Coal and Oil Prices – 2006 to 2016	. 56
Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016.58Figure 45: Spot Prices – 2016 to Mid-2021.60Figure 47: Market Tightness – 2016 to Mid-2021.60Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021.61Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021.61Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021.63Figure 52: TTF Netback to Henry Hub – 2016 to Mid-2021.64Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020.65Figure 54: Supply – Demand Charts – 2019 and 2020.66Figure 55: Spot Prices – 2020 to Mid-2024.67Figure 56: Shadow Prices and Market Tightness – 2020 to 2024.69Figure 57: TTF and Coal Prices – 2020 to 2024.69Figure 60: Supply – Demand Chart – 2021.70Figure 61: LNG Export Capacity Growth to 2030.72Figure 62: Gas Demand Growth to 2030.73Figure 63: LNG Export Capacity Utilisation to 2030.74Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030.75Figure 65: The UK Cost Stack 2021.77Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 2015.79Figure 67: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2024.83Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030.75Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2024.85Figure 70: Henry Hub: Calculated v Actual <td< td=""><td>Figure 44: Japan Spot and Contract Prices – 2006 to 2016</td><td>. 57</td></td<>	Figure 44: Japan Spot and Contract Prices – 2006 to 2016	. 57
Figure 46: Spot Prices – 2016 to Mid-2021	Figure 45: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2016	. 58
Figure 47: Market Tightness – 2016 to Mid-2021	Figure 46: Spot Prices – 2016 to Mid-2021	. 59
Figure 48: Long Run and Short Run Shadow Prices – 2017 to 202160Figure 49: TTF and Coal Prices – 2015 to Mid-202161Figure 50: Japan Spot and Contract Prices – 2016 to Mid-202162Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-202163Figure 52: TTF Netback to Henry Hub – 2016 to Mid-202164Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 54: Supply – Demand Charts – 2019 and 202066Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: TTF and Coal Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Ghart – 202171Figure 63: LNG Export Capacity Utilisation to 203073Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 75: UK Gas Transmission System94	Figure 47: Market Tightness – 2016 to Mid-2021	. 60
Figure 49: TTF and Coal Prices – 2015 to Mid-202161Figure 50: Japan Spot and Contract Prices – 2016 to Mid-202162Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-202163Figure 52: TTF Netback to Henry Hub – 2016 to Mid-202164Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 54: Supply – Demand Charts – 2019 and 202066Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: TTF and Coal Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 60: Supply – Demand Chart – 202171Figure 61: LNG Export Capacity Growth to 203072Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers83Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 75: UK Gas Transmission System <td>Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021</td> <td>. 60</td>	Figure 48: Long Run and Short Run Shadow Prices – 2017 to 2021	. 60
Figure 50: Japan Spot and Contract Prices – 2016 to Mid-202162Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-202163Figure 52: TTF Netback to Henry Hub – 2016 to Mid-202164Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 54: Supply – Demand Charts – 2019 and 202066Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: TTF and Coal Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Growth to 203073Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers82Figure 70: Henry Hub: Calculated v Actual90Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System94	Figure 49: TTF and Coal Prices – 2015 to Mid-2021	61
Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-202163Figure 52: TTF Netback to Henry Hub – 2016 to Mid-202164Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 54: Supply – Demand Charts – 2019 and 202066Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: TTF and Coal Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Chart – 202171Figure 63: LNG Export Capacity Utilisation to 203073Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 70: Henry Hub: Calculated v Actual90Figure 71: TTF: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual90Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 50: Japan Spot and Contract Prices – 2016 to Mid-2021	. 62
Figure 52: TTF Netback to Henry Hub – 2016 to Mid-202164Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 202065Figure 54: Supply – Demand Charts – 2019 and 202066Figure 55: Spot Prices – 2020 to Mid-202467Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: TTF and Coal Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 60: Supply – Demand Chart – 202170Figure 61: LNG Export Capacity Growth to 203072Figure 63: LNG Export Capacity Utilisation to 203073Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual90Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021	. 63
Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020	Figure 52: TTF Netback to Henry Hub - 2016 to Mid-2021	. 64
Figure 54: Supply – Demand Charts – 2019 and 2020	Figure 53: Multi-Dimensional Analysis of Gas Price Drivers – 2016 to 2020	. 65
Figure 55: Spot Prices – 2020 to Mid-2024	Figure 54: Supply – Demand Charts – 2019 and 2020	. 66
Figure 56: Shadow Prices and Market Tightness – 2020 to 202468Figure 57: TTF and Coal Prices – 2020 to 202469Figure 58: Japan Spot and Contract Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 60: Supply – Demand Chart – 202171Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Growth to 203073Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers82Figure 69: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 55: Spot Prices – 2020 to Mid-2024	. 67
Figure 57: TTF and Coal Prices – 2020 to 202469Figure 58: Japan Spot and Contract Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 60: Supply – Demand Chart – 202171Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Growth to 203073Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 56: Shadow Prices and Market Tightness – 2020 to 2024	. 68
Figure 58: Japan Spot and Contract Prices – 2020 to 202469Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 202370Figure 60: Supply – Demand Chart – 202171Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Growth to 203073Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 57: TTF and Coal Prices – 2020 to 2024	. 69
Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 2023	Figure 58: Japan Spot and Contract Prices – 2020 to 2024	. 69
Figure 60: Supply – Demand Chart – 2021	Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 2023	. 70
Figure 61: LNG Export Capacity Growth to 203072Figure 62: Gas Demand Growth to 203073Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 60: Supply – Demand Chart – 2021	. 71
Figure 62: Gas Demand Growth to 203073Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202489Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 61: LNG Export Capacity Growth to 2030	. 72
Figure 63: LNG Export Capacity Utilisation to 203074Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 203075Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 62: Gas Demand Growth to 2030	. 73
Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030	Figure 63: LNG Export Capacity Utilisation to 2030	. 74
Figure 65: The UK Cost Stack 202177Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 201579Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 64: Multi-Dimensional Analysis of Gas Price Drivers – 2024 to 2030	. 75
Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 2015	Figure 65: The UK Cost Stack 2021	. 77
Figure 67: Multi-Dimensional Analysis of Gas Price Drivers82Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 2015	. 79
Figure 68: Connecting the Globalised Gas Market83Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 202485Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 67: Multi-Dimensional Analysis of Gas Price Drivers	. 82
Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2024	Figure 68: Connecting the Globalised Gas Market	. 83
Figure 70: Henry Hub: Calculated v Actual89Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 69: Multi-Dimensional Analysis of Gas Price Drivers – 2005 to 2024	. 85
Figure 71: TTF: Calculated v Actual90Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 70: Henry Hub: Calculated v Actual	. 89
Figure 72: China Spot: Calculated v Actual90Figure 73: Japan Spot: Calculated v Actual91Figure 74: Henry Hub Schematic92Figure 75: UK Gas Transmission System94Figure 76: Netherlands Gas Transmission System95	Figure 71: TTF: Calculated v Actual	. 90
Figure 73: Japan Spot: Calculated v Actual 91 Figure 74: Henry Hub Schematic 92 Figure 75: UK Gas Transmission System 94 Figure 76: Netherlands Gas Transmission System 95	Figure 72: China Spot: Calculated v Actual	. 90
Figure 74: Henry Hub Schematic 92 Figure 75: UK Gas Transmission System 94 Figure 76: Netherlands Gas Transmission System 95	Figure 73: Japan Spot: Calculated v Actual	. 91
Figure 75: UK Gas Transmission System 94 Figure 76: Netherlands Gas Transmission System 95	Figure 74: Henry Hub Schematic	. 92
Figure 76: Netherlands Gas Transmission System	Figure 75: UK Gas Transmission System	. 94
	Figure 76: Netherlands Gas Transmission System	. 95



Executive Summary

In 2012, the Oxford Institute for Energy Studies (OIES) published a unique seminal book entitled The Pricing of Internationally Traded Gas¹ - hereinafter referred to as PITG. It was, and remains, unique in the sense that it was "the first academic book in any language to be devoted entirely to the pricing of international traded gas" ²,³, in the words of the editor, Jonathan Stern. The book addressed the question as to why natural gas had been very different to other commodities in that "it failed to conform to the basic precept of economics – they should be set by the forces of supply and demand"⁴. As PITG noted "for much of their history, natural gas markets have been isolated – at best regionalized rather than internationalized (let alone globalized) – and dominated by monopoly suppliers at both domestic and international levels"⁵. PITG also noted that this situation was changing (as of 2012), with developments in North America in the 1980s, the UK in the 1990s and "is beginning to change elsewhere – starting in continental Europe – in the 2010s"⁶. The conclusions of PITG were that, while in the past gas pricing had been different, "in the future it is likely to become more similar to other commodities"⁷. One of the issues addressed in PITG was whether, from 2012 onwards, the gas market would involve more globalization, cartelization, or a continuation of regional pricing.

This paper covers, what is loosely called, international gas prices in competitive markets. This is broadly similar to the term "internationally traded gas" in PITG. PITG covered the period to 2012, but a lot has changed in the markets in the past 10 years or so, with a continuation of gas markets liberalization, punctuated by "Black Swan" events such as Covid-19 and Russia's invasion of Ukraine. The paper includes an explanation of the events and drivers of gas prices over the last 15 years. However, prior to that, the progress on the globalization of gas markets is covered, and then the focus will be on challenging, what the author believes are, flawed assumptions and analysis often propagated by "experts", journalists, commentators, politicians etc., when they are striving for simplistic explanations of why natural gas prices are rising (or falling). Finally, the author's hypothesis (or concept) as to the drivers of gas prices in competitive markets will be discussed.

Globalization of Gas Markets

The pricing of gas in international trade has seen a continuous move towards gas-on-gas (GOG) pricing since 2005, according to the annual wholesale gas price surveys conducted by the International Gas Union (IGU)⁸. Initially this was led by the pipeline import market in Europe, as markets were liberalised and long-term contracts renegotiated, and since 2016 by growth in the LNG market, with GOG increasing its share in all regions. This rise in GOG pricing included Europe as LNG imports rose with a significant proportion of the increase coming from the US. The largest LNG importing region – Asia – also saw a sharp rise in GOG pricing, both in spot LNG and also more contracted LNG linked to Henry Hub prices.

The progression of spot prices, at least from 2016 onwards, suggests that there was a greater connectivity of prices, at least between Asia and Europe. It could even be argued that, for much of the period from 2016, there has been an equalization of prices, once transportation differentials are taken into account.

The increasing connectivity in the LNG market can be illustrated by analysing both the increasing flexibility of LNG trade and the geographical trade flows. The growth of US LNG exports since 2016 has driven a significant rise in the volume of flexible LNG. Figure 1 shows the growth in flexible LNG volumes since 2015. Flexible LNG is either uncontracted (spot) LNG or contracted LNG with no destination clause – which is pretty much all US LNG.

The growth of flexible LNG has significantly improved connectivity between different regional markets. In 2015, Pacific Basin (east of Suez) exporters had more flexibility in volume terms, with the Atlantic

¹ Stern, J.P. (2012). The Pricing of Internationally Traded Gas, (ed), OIES/OUP

² PITG, p 1

³ A 1998 IEA book considered natural gas pricing in the US and UK markets and focussed mainly on the experience of liberalization. IEA (1998) *Natural Gas Pricing in Competitive Markets*, Paris: OECD/IEA

⁴ PITG, p 38

⁵ PITG, p 38

⁶ PITG, p 39

⁷ PITG, p 489

⁸ IGU (2024). Wholesale Gas Price Survey 2024 Edition. International Gas Union. www.igu.org



Basin (west of Suez) exporters having a share only around 1/3rd, and the Pacific Basin exporters 2/3rd. By the end of 2023, this had almost completely reversed with the Atlantic Basin exporters share averaging just under 60 percent. Importantly, however, it is also notable that in the last 6 months of 2023, total flexible exports – Atlantic and Pacific Basins combined – was some 57 percent of total LNG exports, having risen from 32 percent in the first 6 months of 2015. It is this rise in flexible LNG that has led to the ability for Atlantic Basin exporters to switch volumes between West of Suez and East of Suez, which has been amply demonstrated in the last few years.



Figure 1: Atlantic Basin and Pacific Basin Exports Flexibility 2015 to 2023

Source: Kpler, NexantECA World Gas Model

In PITG, Rogers⁹ was relatively pessimistic on the progress towards the development of one or more hubs in the Asian market, and thought that this might hold back the full globalization of the gas market, and hence connectivity between regional markets and prices. While the establishment of hubs in Asian markets seems as remote as ever, the increased flexibility of LNG volumes and the rise in GOG pricing in Asian markets, to 35 percent of total Asian LNG imports in 2023, from 20 percent in 2016, suggests there is a large core of LNG available to trade in the region. As such, while Asia is far from being a liquid trading market, akin to North America and Europe, it does, in this author's view, qualify as a competitive market, at least for enough LNG to suggest that the global gas market is well connected and globalized.

The Four Fallacies

The four fallacies are as follows:

- **The Cost Stack** the price of gas in a market is determined by looking at the physical flows of supply to that market and the associated costs, with the highest cost supply determining the price.
- **Price equals Marginal Cost** the highest cost supply to a market or group of markets will determine the price in that market(s), in line with economic theory.
- Europe was hooked on cheap Russian gas Europe, especially Germany, relied on large imports of Russian gas, which was supposedly cheaper than other sources of gas supply.
- The TTF price is high...the market is broken TTF prices soared in 2022 as Russia invaded Ukraine and were much higher than neighbouring hubs, such as NBP, and the Northwest Europe LNG price, therefore the TTF market was broken and the price should be capped.

⁹ PITG, p 420-421



The Cost Stack Fallacy

The cost stack is a simple graphical representation of the costs in the gas value chain for each source of supply to a specific market such as the UK, whether it is domestic production, pipeline imports or LNG imports from a variety of sources. The concept is that the highest cost source of supply is the marginal cost and hence sets the price in the market. An example of the cost stack is in Figure 2 for the UK using gas flows from 2021¹⁰ - before the Russian invasion of Ukraine. The simplicity of the graphic helps to explain why the cost stack is so beloved of consultants and analysts in trying to explain what is driving prices and, looking forward, how prices, based on this simple model, might develop. Figure 2 also compares the resulting "marginal cost" with the actual NBP price¹¹ for the year.



Figure 2: The UK Cost Stack 2021¹²

Source: NexantECA World Gas Model

There are a number of flaws in the cost stack approach. Firstly, it does not take account of fuel switching, such as between coal and gas in the power sector. At the margin, in the power generation mix, the choice for incremental generation may be between importing more LNG and burning more coal. The coal price (adjusted for the relative carbon cost and different efficiency) relative to the gas price is just as much part of the cost stack as the additional cost of delivered LNG from, say, the US. It is not just fuel switching in the power sector that is relevant, there is also potential fuel switching in industry, usually with oil, incentives to efficiency as prices rise, behavioural changes (turning down the thermostat) and even industrial closures impacting gas demand.

Secondly, the cost stack for one market, such as the UK, even with fuel switching included, does not take into account the interconnections with continental Europe. 2022 saw the UK importing large quantities of LNG, effectively to re-export the volumes to continental Europe. Thirdly, Europe is not an isolated market, and is one part of the globalized gas market. If demand in Europe increases, and the increased volumes come from, say, the US, it is not necessarily the delivered cost of US LNG which sets the price of TTF. If the volumes are diverted from, for example, Asian markets such as Japan, how does Japan replace those volumes? What happens in a globalized market, is that the increase in

¹⁰ IEA data from NexantECA World Gas Model. Costs also from NexantECA World Gas Model

¹¹ Average month-ahead price from Argus

¹² The costs represent the marginal cost from the NexantECA World Gas Model and are the highest cost of production or the infrastructure and are most likely well above the average cost.



demand in one market, leads to multiple effects rippling through many other markets. Tracking all these changes to calculate the marginal cost would be a herculean task.

The marginal cost of supply to each market can, however, be calculated with global gas models, which are linear programmes, as they generate the shadow price – effectively the marginal cost of supply to each individual market. OIES uses the NexantECA World Gas Model, which generates the shadow price (marginal cost). However, this cannot be represented in a simple cost stack graph, as the global market is a complex interaction of multiple flows, costs and demand responses.

Price Equals Marginal Cost Fallacy

A lot of the analysis of what determines the gas price in markets focusses on the marginal cost of supply clearing the market for a given level of demand. The hypothesis that price equals marginal cost in long-run equilibrium is only true in a perfectly competitive market, the conditions for which the global gas market does not meet.

While the marginal cost is not, in an imperfect market like gas, *the* price setter, it still has a significant influence. Most of the analysis focusses on the long-run marginal cost (LRMC) but in the period between 2017 and 2021, the TTF and Japan spot prices varied widely around LRMC and SRMC (short-run marginal cost). They were both above the LRMC¹³ in 2018, before going below it in 2019 and 2020, and back above it again in 2021. In 2019 the prices were between the LRMC and the SRMC, while in 2020 the actual prices were at or even below the SRMC. The last few years suggest that the spot prices move between the LRMC and SRMC and even above the former or, occasionally, below the latter. Even if price was equal to marginal cost in the market, or that was an important driver, it is not clear, at certain times, whether this is LRMC or SRMC.



Figure 3: Coal and Gas Prices in Europe

Source: Argus Media and author's calculations

¹³ As represented by the shadow price in the NexantECA World Gas Model



Some of the other factors influencing the spot prices can be broadly categorised as "competing fuels or prices". The coal price (adjusted for efficiency and the relative carbon cost) competes with the gas price in power generation and this has been observed particularly in the US and Europe, as shown in Figure 3 for Europe. From 2016 to 2021, the TTF price and the adjusted coal price, tracked each other fairly closely.

Oil is also still a competing fuel to gas in many industrial processes. In the Asian market there are still a significant number of long-term contracts which are linked to oil prices. The long-term oil-indexed contract prices for, say, Japan will influence the spot price, since buyers can nominate more under their contracts, if the spot price is higher than the contract price, and down to the minimum take-or-pay levels if the spot price is lower. In addition, at certain gas price levels there are incentives for behavioural changes – turning down thermostats for example – and for more efficient use of gas in industrial processes. At some price level, as we saw in 2022, industries can close completely.

Another "competing price" influence could be the delivered cost of US LNG to Europe and Asia, with the delivered cost calculated on both a long-run full cost basis and a short-run variable or marginal cost basis. Between 2016, when US Gulf Coast LNG exports started up, and the end of 2020, both TTF and Japan spot price ranged somewhere between the long-run and short-run delivered cost of US LNG, before surging above the long-run cost in 2021 and 2022.

A final impact on spot prices is how tight the market is. If there is plenty of spare capacity in, say, Russian production – as it was before 2021 – then Europe could easily meet any increase in demand by buying more Russian gas. The availability of spare LNG export capacity is also a key factor. In 2019, the sharp rise in global LNG supply exceeded the growth in demand, with the result that Europe absorbed the rising supply in storage, with prices falling sharply. The utilisation of LNG export capacity¹⁴ fell to 93 percent in 2019 and to below 90 percent in 2020. In the current market environment, after the Russian invasion of Ukraine, which sent prices skyrocketing, there is little or no spare LNG export capacity – utilisation is at 98 percent, as shown in Figure 4. This market remains tight with prices still much higher than in 2019 and 2020.



Figure 4: LNG Export Capacity Utilisation

Source: NexantECA World Gas Model and author's calculations

¹⁴ Total global LNG imports divided by total available LNG export capacity.



Cheap Russian Gas Fallacy

Until recently Russia was a large supplier of pipeline gas to Europe and, in the last few years, LNG from Novatek's Yamal project. From the 1990s to 2010 Russian pipe imports supplied around 25 percent of Europe's gas demand. This percentage then rose in the 2010s, as Nordstream came online, peaking at 37 percent in 2017. Since then the percentage has fallen back significantly and - after the Russian invasion of Ukraine – to 10 percent in 2023. It can certainly be said that many countries in Europe had been heavily dependent on Russian gas if not hooked on it.

However, it was a fallacy that Russian gas was cheap. When Russian gas was linked to oil prices, for the most part these oil-indexed contract prices were above hub prices such as NBP and TTF. When the pricing under the contracts moved predominantly towards hub pricing, Russian gas was priced largely at the same as other sources of gas, whether pipeline or LNG, and so was neither cheaper nor dearer. In a liquid trading market, all participants are price-takers. The idea that Russian gas was cheap may be a hangover from the days of barter trade, with the perception that it was low cost, but this changed as oil-indexed contracts were introduced.

While the selling price of Russian gas was not low, it is true to say that Russian gas was relatively low cost – hence the possible confusion. However, the low cost of producing and transporting Russian gas to Europe meant that the pipeline exports were generally very profitable for both Gazprom and the Russian state.

TTF is Broken Fallacy

Significant differentials opened up between TTF on the one hand, and NBP, LNG NWE and Asian spot prices from April 2022 through to the last couple of months of the year. These differentials, with TTF at a significant premium to other prices, combined with the extremely high level of prices – as Russian pipe exports to Europe declined sharply – led to the European Commission, notably Ursula von der Leyen and Kadri Simson, and other politicians, to claim that TTF was no longer fit for purpose. Von der Leyen noted that "*The main price benchmark for all gas traded in the EU, the Title Transfer Facility (TTF), is no longer representative of the imported gas.*"¹⁵ While Simson said "While TTF was a good proxy for the EU gas prices when we received large amounts of Russian pipeline gas, this is no longer the case."¹⁶ These comments, and many others, may have been made as a panic reaction to rapidly rising prices, but seemingly did not take account of the economics of congested markets and what happens if there are infrastructure constraints. This is a great example of politicians – and everybody else – being very keen on market forces when they produce an outcome they like, for instance the very low prices in 2020, and very negatively when they produce an outcome they don't like (2022).

The TTF premium to NBP coincided exactly with the period when the Interconnector pipeline between UK and Belgium and BBL between UK and the Netherlands were operating at maximum export capacity from the UK. With no more room in the pipelines, the NBP price weakened relative to TTF, with the constrained Northwest and Central European markets unable to receive any more gas. Once the pipelines exporting from the UK were not operating at full capacity in November 2022, the TTF/NBP differential almost completely disappeared and returned to "normal" levels.

The other constraint was at the three regasification terminals serving Northwest Europe in 2022 – Dunkirk (France), Zeebrugge (Belgium) and Gate (Netherlands). From early 2022, the terminals were operating at or well above their nameplate capacity- in the case of Zeebrugge and Gate at some 30 percent or more above nameplate capacity¹⁷. These terminals continued to operate at effectively full capacity until the middle of 2023. However, towards the end of 2022, the Eemshaven FSRU in the Netherlands began operations, which alleviated the capacity constraints, followed by a couple of German FSRUs in early 2023. The TTF differential to the LNG NWE price was removed at the end of 2022 as prices converged again, with the constraints released.

Widening differentials between TTF and other hubs in continental Europe were also noted in 2022. TTF was at a premium to PEGN and PVB – the French and Spanish hub prices – from April to November

¹⁷ The real capacity of an LNG import terminal (and export terminal for that matter) is a vague concept, and what determines the capacity can be any one of a number of factors – number of tankers that can dock each week, unloading times, storage capacity, vaporisation rate and the entry capacity to the pipeline system. The nameplate is generally a conservative figure the engineers will guarantee.

¹⁵ https://www.euractiv.com/wp-content/uploads/sites/2/2022/10/Letter-2.pdf

¹⁶ https://ec.europa.eu/commission/presscorner/detail/en/SPEECH_22_6245



2022, reflecting pipeline capacity constraints in moving gas from west to east, especially at the French border with Germany. However, THE (Germany), VTP (Austria) and PSV (Italy) had higher prices than normal relative to TTF, reflecting the much larger impact the loss of Russian pipeline gas had on those markets, with some constraints on the ability to move gas eastwards when the usual flows had been westwards.

There are other examples, notably in the US gas market, where wide differentials between hubs opened up because of pipeline constraints. For example, at the Opal Hub in Wyoming rising gas production outstripped pipeline export capacity and the differential between Opal and Heny Hub only disappeared when the Rockies Express pipeline was built to move gas to the Chicago and Ohio markets. At the Waha Hub in West Texas rapidly rising associated shale gas production overwhelmed the ability to move gas from west to east, with Waha then at a significant discount to Henry Hub. This was alleviated for a little while when new pipeline capacity was built, but the still rising production has produced new constraints.

The key conclusion is that when there are infrastructure constraints leading to congested markets, differentials between markets, impacted by the constraints, will widen, often by large amounts. These abnormal differentials disappear once the constraints are alleviated. The fact that TTF rose to large premiums over NBP and LNG prices in 2022 did not mean that, somehow, the TTF was not working properly or not representative of EU gas prices. The suggestion by the European Commission, notably Ursula von der Leyen and Kadri Simson, that this was the case, may have been a panic reaction, but it still rested on deeply flawed analysis and a lack of understanding of the economics of congested markets. The recent Draghi report¹⁸ also misunderstood what happened in the gas market in 2022 and made proposals to attempt to go back to a pre-liberalised world of over 20 years ago, which seems to be somewhat naïve. In fact, in the face of enormous disruption to the European and global gas markets, the liquid trading market actually worked extremely well. Patrick Heather has written regularly on the liquidity of European trading hubs, with the latest instalment being published recently¹⁹.

Multi-Dimensional Analysis and the Value of Gas

The development of the global gas market and, before that, gas markets in individual countries and regions, was essentially no different to the development and origins of most markets for goods and services. Weekly markets, in local towns, sold a variety of goods, focused on food and produce. This type of market can be traced back to medieval times, when chartered markets and new towns were established across Western Europe. These medieval markets often laid down rules and regulations over who could offer goods for sale and control the quality of such goods, enforced by law and regulation. As markets developed in Europe and elsewhere, at centres of consumption and transit hubs, trade between these markets developed, sometimes over long distances, with China's Silk Road – both by land and sea – being a prime example.

The development of hubs in the gas market – either physical or virtual – is not a new idea, but a continuation of the medieval markets of hundreds of years ago, as is the long-distance trade of LNG, similar to the seaborne trade of the Silk Road. Gas hubs developed as a result of the liberalization of gas markets in the US and Europe. Henry Hub was the first and started as a physical location in Louisiana at the Henry gas processing plant, but in reality the hub is much wider, covering the area where multiple pipelines interconnect. Rules and regulations for trading at the hub on standard contracts promoted the use of the hub as a key trading point. The NBP hub in the UK drew a lot on Henry Hub experience but was a "virtual" hub, essentially comprising the whole of the GB national gas transmission system. Again, a standardized contract developed which encouraged trading. TTF in the Netherlands, which is now the preeminent European gas hub, largely copied the NBP model.

The development of trading at the prompt and forward led to the development of price indices with the month ahead, or M+1, being the most heavily traded in both the US and Europe. On the back of the physical trading at the hubs, financial futures markets developed, linked to the physical hub traded month-ahead contract. The financial markets developed to such an extent that the trading on these markets now outweighs the physical trading, and there is little difference between the two, other than the financial markets not going to physical delivery.

¹⁸ Draghi. M. (2024). *The Future of European Competitiveness*, European Commission.

¹⁹ Heather. P. (2024). European Traded Gas Hubs: the markets have rebalanced, OIES NG 192.



The big rise in prices in Europe in 2022, following the Russia invasion of Ukraine, led some commentators and politicians to blame excessive speculative trading for the increases. A report by Oxera²⁰ dispelled this notion concluding that, overall, there was no evidence of excessive speculation driving prices or volatility.

What drives natural gas prices is complex. Multiple factors impact prices, including costs and competing prices, as noted in previous sections. The underlying forces of supply and demand still, however, represent the primary drivers of gas prices. The forces of supply and demand – and the myriad other drivers – manifest themselves differently depending on the state of the market. The price drivers are not linear and attempting to portray them on a simple two-dimensional chart is unlikely to be accurate. A multi-dimensional approach is needed to analyse gas prices.

The hypothesis in this paper starts from the perspective that a multi-dimensional approach is needed to analyse gas prices. Specifically, the state of the gas market – is it supply-long or a tight market – will dictate which of the price drivers and influences are more or less important, and especially whether the market is in a short-run or long-run marginal cost world, or somewhere in between.

Figure 5 attempts to represent these multi-dimensional factors on a two-dimensional chart. The chart shows a price curve for gas – rising as the market gets tighter – and plotting the key drivers of prices at different points on the curve. It combines these drivers with the state of the market – is it supply long or supply short – and shows whether short-run or long-run marginal cost pricing predominates. The state of the market is the primary driver of gas prices and this translates into the relative importance of short-run or long-run marginal cost pricing. Depending on what sort of world or state of the market we are in, will then determine what the most important secondary drivers will be. These secondary drivers can be loosely described as the competing prices.

The hypothesis – and the chart – can be described as follows:

- In a supply-long world, short-run marginal cost pricing will predominate. The key competing prices
 are likely to be, in the LNG market, the variable or short-run cost of delivering US LNG to markets
 and in the end-use markets, the competing coal price²¹. The long-run or full cost netback from
 Europe and Asian spot prices to the US may also impact Henry Hub prices.
- In a more balanced world neither supply-long nor supply-short we may be somewhere in between short-run and long-run marginal cost pricing and other competing prices are likely to come into play. The long-run or full cost of delivering US LNG to markets may be a key influence and also, in the end-use markets, HSFO prices in industry and oil-indexed contract prices (at least in the Asian LNG markets) are likely to be key drivers.
- In a supply-short world, long-run marginal cost pricing will predominate. In this state of the market, higher levels of oil product prices may factor in but also, we are likely to see significant demand responses in industry in terms of efficiency gains and, if prices get driven higher, behaviour changes in households (turn down the thermostat) and potentially industrial closures. The impact of coal prices, for example, will no longer be a factor, with any switching from gas to coal in power generation having already happened.

In summary, as the state of the market changes – or as it tightens – the world moves from more shortrun pricing to long-run pricing and different "competing prices" are more or less important. However, the chart in Figure 5 should be regarded as a "schematic", presenting the stages that the gas price moves through as the market changes. In particular, where the competing prices have been placed in the chart, is illustrative and should not be taken as firm indications of the relative importance or even order. The competing prices may also be relevant or have an impact over a wide range of market states and gas prices. For example, if the coal market is very tight and coal prices high, this could be a factor much higher up the range of gas prices, even towards long-run marginal cost. The market is very dynamic and can be fast-moving, so this is very much a framework for analysis.

This multi-dimensional approach in essence sets the value of gas in traded, competitive markets. All participants become price-takers. With a globalized gas market, the values of gas in different markets are interconnected, especially European and Asian markets. If the price or value rises in, say, the Asian

²⁰ Oxera (2022). The European Gas Market, Report prepared for ICE. Oxera Consulting

²¹ Adjusted for efficiency and relative carbon costs



markets then the TTF price can be pulled up to keep the relative values in balance, and vice-versa. As LNG is moving around the globe, the value of the cargo is changing, depending on the relative prices at the hubs and its location. This can prompt diversions of cargoes to higher value markets. The underlying cost of the gas and the associated infrastructure, such as the type of tanker, becomes irrelevant once the cargo has left the export terminal. All that matters is the value of gas at that location.



Figure 5: Multi-Dimensional Analysis of Gas Price Drivers

US LNG SRC: Short-run marginal cost of delivered US LNG SR Netback: Short-run netback from TTF/Asian spot to Henry Hub HSFO Price: High sulphur fuel oil price GO Price: Gasoil price LR Netback: Long-run netback from TTF/Asian spot to Henry Hub US LNG LRC: Long-run marginal cost of delivered US LNG LSFO Price: Low sulphur fuel oil price

Source: Author's Analysis

Explaining Historical and Future Gas Price Movements

The historical analysis of prices can be divided into three periods – pre-2016 and the advent of US LNG, 2016 to mid-2021 and mid-2021 to date. Prior to 2016 and the advent of US LNG, the global gas market was not fundamentally functioning as a globalized market. The US had decoupled from the rest of the global gas market, the European market had largely completed its liberalization by the early 2010s and spot prices (NBP and TTF)) had decoupled from oil prices (or oil-indexed contract prices) around 2010 and supply and demand fundamentals drove the spot prices. There were few diversions and trading of LNG between the Asian and European markets, with only Qatar having any significant ability to flex cargoes between the two markets. Japan spot prices were largely driven by oil-indexed contract prices. The market was generally balanced between short-run and long-run pricing, with only 2009-10 and 2016 being relatively supply long.

From 2016 on, US LNG entered the market and the process of globalization began to speed up. Gason-gas pricing in the LNG market rose significantly over the period to 2021 and the destination flexibility of US LNG saw more inter-basin arbitrage. TTF prices began to compete with adjusted coal prices and also were moving within the long-run and short-run marginal cost of delivered US LNG. Japan spot prices also moved within the long-run and short-run marginal cost of delivered US LNG and also seemed to decouple from oil-indexed contract prices when the LNG supply surge hit in 2019. From a balanced, but tightish, market in 2018, in 2019 and 2020 the market became very supply long and both TTF and Japan spot prices were driven down towards short-run marginal costs.



The recovery in demand in 2021 as economic activity began to pick up post Covid-19, led to sharply rising prices, especially as LNG export capacity was reduced with the maintenance catch up from 2020 and the fire at the Hammerfest plant in Norway. Russia had begun withdrawing spot sales at the St Petersburg exchange in the second half of 2021, ostensibly in response to high demand in Russia. This was followed by the Russian invasion of Ukraine in 2022, with prices rising to unprecedented levels. The global market was definitely in a supply short situation, with market tightness and long-run marginal costs rising sharply. Any linkage between spot gas prices and either coal prices, the delivered cost of US LNG or oil prices was overwhelmed by rising gas prices. The "competing" fuels, to the extent they might have been an influence, would be in the range of oil switching in industrial use, behavioural changes in households and buildings (turning the thermostat down) and even industrial closures at the very high prices. 2022 was a world of demand destruction, especially in Europe. In 2023, the market began to rebalance but still remained in a supply-short world, with prices above long-run marginal costs.



Figure 6: Spot Prices 2005 to 2024

Source: Argus, S&P Global Platts, NYMEX

Looking forward, the tight long-run pricing world is expected to persist in 2025 and it is only in 2026-27 that the market rebalances significantly. As the growth in LNG supply outweighs the rising demand, the market starts to become supply long in 2028, with even more of a glut in 2029-30, with pricing moving well into short-run marginal cost range, probably similar to 2019 and 2020. However, a different supply-demand balance than OIES are projecting could change the outlook significantly. Much higher demand in China and India, for example, maybe adding 5 percent or more to LNG demand, would leave a more balanced market and not supply long.

Conclusion

Right at the beginning, the question was posed as to whether gas pricing is "different" to other commodities, as noted in PITG²². This was answered by Stern²³, in the last sentence of PITG, that "in future it is likely to become much more similar to other commodities". This conclusion was made some 12 years ago. The arguments and evidence presented in this paper would suggest, in the author's view,

²² Stern, J.P. (2012). The Pricing of Internationally Traded Gas, (ed), OIES/OUP.

²³ PITG, p 489



that gas has achieved the goal of becoming "similar to other commodities". We have achieved a globalized gas market, at least in internationally traded gas, especially following the advent of US LNG in 2016 and the continuous growth of gas-on-gas pricing in the LNG market, following the earlier changes in Europe.

The globalization and pricing changes are now reflected in a complex multi-dimensional market, with the value of gas in the demand centres being the key driver. How this value is determined is complex, with multiple influences which can change over short periods of time. The analysis of this complex market, does not lend itself to simplistic and wrong-headed "soundbites". The fallacies of the cost stack, price equals marginal cost is all that matters, cheap Russian gas and "TTF is broken", are, and were, just fallacies, and no substitute for sound analysis.

The fundamentals of supply and demand – which do include elements of marginal cost pricing – remain the key driving forces of the value of gas in the market, but, as shown in this paper, there are multiple other drivers to be taken into account, now gas is "similar to other commodities".



1. Introduction

In 2012, the Oxford Institute for Energy Studies (OIES) published a unique seminal book entitled The Pricing of Internationally Traded Gas²⁴ - hereinafter referred to as PITG. It was, and remains, unique in the sense that it was "the first academic book in any language to be devoted entirely to the pricing of international traded gas"²⁵²⁶, in the words of the editor, Jonathan Stern. The book included eight chapters covering developments in gas pricing in different regions of the world, with additional analysis covering why natural gas had been very different to other commodities in that "it failed to conform to the basic precept of economics – they should be set by the forces of supply and demand"²⁷. As PITG noted "for much of their history, natural gas markets have been isolated – at best regionalized rather than internationalized (let alone globalized) – and dominated by monopoly suppliers at both domestic and international levels"²⁸. PITG also noted that this situation was changing (as of 2012), with developments in North America in the 1980s, the UK in the 1990s and "is beginning to change elsewhere – starting in continental Europe – in the 2010s"²⁹.

The conclusions of PITG were that while in the past gas pricing had been different, "in the future it is likely to become more similar to other commodities"³⁰. One of the issues addressed in PITG was whether, from 2012 onwards, the gas market would involve more globalization, cartelization, or a continuation of regional pricing. It is certainly not the intention of this paper to repeat, duplicate or update the analysis and regional coverage of PITG, which would be a herculean task! However, in trying to answer the question as to what drives international gas prices, a key issue will be the extent to which the gas market has become more globalized. PITG did cover the changes in markets which were driving changes in gas pricing and, while not repeating this analysis here, it will be referred to as required in this paper.

This paper covers what is loosely called international gas pricing in competitive markets. This is broadly similar to the term internationally traded gas in PITG, but the author did not necessarily want to restrict the analysis to gas which was traded internationally. After all the most famous gas trading hub price -Henry Hub³¹ in the USA – is widely used in international trade but is fundamentally determined by very liquid trading in the USA. PITG covered the period to 2012, and a lot has changed in the markets in the past 10 years or so, with a continuation of gas markets liberalization, punctuated by "Black Swan" events such as Covid-19 and Russia's invasion of Ukraine. An explanation of the events and drivers of gas prices over the last 15 years or so is covered in Section 8. However, prior to that, and after covering, in Section 2, what is meant by gas prices in competitive markets and the progress on the globalization of gas markets, the focus of the paper will be on challenging what the author believes are flawed assumptions and analysis often propagated by "experts", journalists, commentators, politicians etc.., when they are striving for simplistic explanations of why natural gas prices are rising (or falling). Sections 3 through 6 will cover what the author believes are four fallacies often seen in the analysis of natural gas prices, while section 7 will put forward the author's hypothesis (or concept) as to how the drivers of gas prices in competitive markets should be analyzed. Hence the sub-title of this paper - Four Fallacies and a Hypothesis³².

The four fallacies are as follows:

• **The Cost Stack** – the price of gas in a market is determined by looking at the physical flows of supply to that market and the associated costs, with the highest cost supply determining the price.

²⁴ Stern, J.P. (2012). The Pricing of Internationally Traded Gas, (ed), OIES/OUP

²⁵ PITG, p 1

²⁶ There was a 1998 IEA book which considered natural gas pricing in the US and UK markets which focussed mainly on the experience of liberalization. IEA (1998) *Natural Gas Pricing in Competitive Markets*, Paris: OECD/IEA

²⁷ PITG, p 38

²⁸ PITG, p 38

²⁹ PITG, p 39

³⁰ PITG, p 489

³¹ For a brief description of Henry Hub see page 9, Fulwood, M. (2018). *Asian LNG Trading Hubs: Myth or Reality,* Columbia SIPA, Center on Global Energy Policy

³² With apologies to Richard Curtis, the writer of the 1994 film Four Weddings and a Funeral, staring Hugh Grant and Andie McDowell. https://www.imdb.com/title/tt0109831/



- **Price equals Marginal Cost** the highest cost supply to a market or group of markets will determine the price in that market(s), in line with economic theory.
- **Europe was hooked on cheap Russian gas** Europe, especially Germany, relied on large imports of Russian gas, which was supposedly cheaper than other sources of gas supply.
- The TTF price is high...the market is broken TTF prices soared in 2022 as Russia invaded Ukraine and were much higher than neighbouring hubs, such as NBP, and the Northwest Europe LNG price, therefore the TTF market was broken and the price should be capped.

Finally, the author's hypothesis is based less on the cost of gas but more a multi-dimensional approach, incorporating numerous additional influences, as well as the impact of globalization on the value of gas traded in and between markets.

2. Globalization and Competitive Markets

The title of this paper refers to "international gas prices in competitive markets". Competitive markets are defined as those markets where the prices of natural gas are determined by the interaction of supply and demand. What is meant by a market is not necessarily a single or even a combination of geographic areas or countries, and a market could still be deemed competitive even if, in some elements of the market, the price is not determined by the interaction of supply and demand.

Clearly those markets which are liquid trading markets, such as North America and much of Europe, with well-developed liquid hubs, are competitive and the spot and hub prices from those markets are from markets deemed competitive. However, a competitive market does not necessarily need a liquid trading hub to be deemed competitive. The global LNG market, with significant spot and flexible LNG volumes being traded, can be deemed as, at least in part, competitive. However, just over half the global LNG market still contracts for gas on longer term oil indexed pricing, where the price is not determined by the interaction of supply and demand. In very broad terms, the category of gas-on-gas competition (GOG) from the International Gas Union's (IGU) annual survey of wholesale gas prices, can be said to cover the definition of competitive markets. This is elaborated further below.

This section also addresses the issue of the globalization of gas markets. The concept of globalization considered here, relates to international gas trade connectivity, principally between the key North American, European and Asian markets (or at least part of the Asian markets). Other markets, for example, in South America, which also import LNG can also be considered as international traded markets. In addition, some competitive gas markets, such as Australia, are not specifically addressed in this paper. The global gas market can be considered to be broadly globalized and connected, if key prices move in parallel, without all gas markets seen to participate at the global level.

a) Analysis of IGU Survey Data

The most recent IGU Wholesale Price Survey³³ was for the year 2023 and looked at the changes in wholesale price formation mechanisms over the period 2005 to 2023. The focus of the survey is on wholesale prices, which can cover a wide range. In fully liberalised traded markets, such as the USA and the UK, the wholesale price would typically be a hub price (e.g. Henry Hub or the NBP). In many other countries, where gas is imported, it could typically be a border price. The more difficult cases are countries where all gas consumed is supplied from domestic production, with no international trade (either imports or exports) and the concept of a wholesale price is not recognised. In such cases the wholesale price could be approximated by wellhead prices or city-gate prices. Generally, the wholesale price is likely to be determined somewhere between the entry to the main high-pressure transmission system and the exit points to local distribution companies or very large end users.

The 2023 IGU Wholesale Gas Price survey was the sixteenth undertaken in a series which began at the start of the 2006 to 2009 IGU triennium culminating in the World Gas Conference in Buenos Aires. Previous surveys were undertaken for the years 2005, 2007, 2009, 2010, and then annually from 2012. In preparation for the initial 2005 survey³⁴, a series of discussions were held at the IGU group meetings,

³³ IGU (2024). Wholesale Gas Price Survey 2024 Edition. International Gas Union. www.igu.org

³⁴ The author of this paper – Mike Fulwood – also conducts the survey on behalf of the IGU and compiles the reports.



in 2006 and early 2007, on the definition of different types of price formation. It was decided to use for categorisation purposes the wholesale pricing mechanisms, summarised in the box below.

	ES OF PRICE FORMATION MECHANISMS
Oil Price Escalation (OPE)	The wholesale gas price is linked, usually through a base price and an indexation clause (sometimes with a slope to the oil price), to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases, coal prices can be used as can electricity prices.
Gas-on-Gas Competition (GOG)	The wholesale gas price is determined by the interplay of direct gas supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (e.g. on exchanges such as NYMEX or ICE). Not all gas is bought and sold on a short-term fixed price basis and there will be longer term contracts, but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Also included in this category are spot LNG cargoes, any pricing which is linked to hub or spot prices and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The wholesale gas price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Usually there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers trading bilaterally.
Netback from Final Product (NET)	The wholesale gas price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.
Regulation: Cost of Service (RCS)	The wholesale gas price is determined, or approved, formally by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.
Regulation: Social and Political (RSP)	The wholesale gas price is set, on an irregular basis, probably by a Ministry, on a political/social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise – a hybrid between RCS and RBC.
Regulation: Below Cost (RBC)	The wholesale gas price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.
No Price (NP)	The wholesale gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
Not Known (NK)	No data or evidence.

Source: IGU



There are a number of categories which are broadly regulated – RCS, RSP, RBC and NP. The rest can be broadly said to be "market-related" pricing in that they are the result of either trading activities and/or negotiated prices between parties, often linked to external prices or indices. However, to call them "market-related" is not to say that they come from competitive markets – as defined earlier with the interplay of supply and demand. Competitive markets can be said to be all part of the GOG category, although not all of the GOG category is necessarily defined as being a competitive market. GOG is not one homogeneous category and can be considered to comprise the following types of pricing mechanisms:

- **Trading** what is generally thought of as GOG where the price is determined by the interplay of supply and demand and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). This will also include longer term contracts into markets where there is little or no trading at hubs, but where the price is linked to hub prices in markets where there is liquid trading.
- **Bilateral** there is no trading market or hub but there are multiple buyers and sellers distinguishing this from BIM providing the competitive element. This is largely in parts of Australia, Russia, Argentina and now China. In many of these markets, the GOG pricing will be influenced by significant regulated segments.
- **Spot LNG** spot LNG cargoes where the price of the cargoes reflects the current supply-demand situation. Can also include tenders for multiple cargoes but less than one year.

The Trading and Spot LNG categories can generally be defined as being part of our competitive markets for the purpose of this paper.

Figure 7, taken from the 2023 IGU Wholesale Gas Price Survey, shows the development at the World level of the changes in wholesale price formation mechanisms.





Source: IGU

Overall, over the 2005 to 2023 period, OPE has declined by 6 percentage points, GOG has risen by 18.5 percentage points, BIM has declined by 2.5 percentage points, RCS has risen by 8 percentage points, RSP risen by 1 percentage point and RBC declined by 18 percentage points. In terms of absolute volumes, OPE increased by some 45 bcm, and GOG by 1,145 bcm – a 130% increase. BIM and NET were also down slightly. The regulated categories in total saw their volume increase by some 90 bcm. Global gas consumption in 2005 was some 2,860 bcm and had risen to 4,096 bcm by 2023, an increase of some 1,136 bcm, slightly less than the rise in the volume of GOG over the same period. Effectively, all the rise in global gas consumption between 2005 and 2023, has been matched by rising GOG consumption, although that hides the fact that consumption has risen strongly in many countries with



heavily regulated markets, such as in the Middle East, and there have been significant changes towards GOG in other markets, notably in Europe, and in LNG markets in Asia and Asia Pacific.

In 2012, when PITG was published, the GOG share was 41 percent having risen from 31 percent in 2005, and in 2023 the share was some 50 percent, so the rise in GOG was already significant by 2012. The Bilateral share of GOG was some 8 percent of total world consumption in 2023, compared to 6 percent in 2012 and 1 percent in 2005³⁵. The "competitive market" GOG share of total world consumption, therefore rose from some 30 percent in 2005 to 35 percent in 2012 and to 42 percent in 2023. This has been a fairly steady growth rate.

Figure 8 shows the changes in GOG over the sixteen surveys by the three different categories of consumption – domestic production, pipeline imports and LNG imports.



Figure 8: Changes in GOG by Consumption Category 2005 to 2023

Source: IGU

The rise in the domestic production share was largely in 2009 when the Bilateral category in Russia increased, together with some changes in Europe. Since then, the share has been relatively stable. On the import side the changes can be seen in two distinct periods. From 2005 through 2016, the rise in the share in pipeline imports was very large and was almost all in Europe, as the market liberalised. Since 2016 the rise in the GOG share has been driven by the rise in GOG in LNG imports. GOG in LNG imports largely ranged between 25 and 30 per cent between 2010 and 2016. Since 2016, the share of GOG rose to just over 40 percent in 2019 and to marginally under 50 percent in 2023.

Looking at total imports, in 2023 GOG (all Trading or Spot LNG) was some 56 percent of the total, with OPE at 37 percent and Bilateral Monopoly at some 7 percent – all in the Former Soviet Union and the Middle East. In 2005, the GOG share was some 21 percent and in 2012 it was some 38 percent. GOG passed the OPE share in 2015.

Almost all the GOG pipeline imports are in North America and Europe, with as noted earlier the rise to 2016 occurring in Europe. The LNG imports and the rise has been more widely spread. Figure 9 shows GOG LNG imports in volume terms between 2005 and 2023. GOG is predominantly in Europe, Asia and Asia Pacific³⁶. GOG, in 2023, was over 80 percent of LNG imports into Europe and comprised all LNG imports into Latin America. In the wider Asian LNG markets, GOG is becoming increasingly important even in the face of continuing large quantities of oil-indexed long-term contracts. In 2023

 ³⁵ The big rise in the Bilateral share occurred in 2009 when part of Russia domestic production changed to Bilateral GOG as the independent producers in Russia were allowed to compete with Gazprom for sales to large industrials and power plants.
 ³⁶ These are IGU definitions of regions. Asia covers China and the South Asia sub-continent – India, Pakistan and Bangladesh. Asia Pacific is the rest of what is commonly called Asia.



GOG LNG imports (mostly spot LNG) accounted for some 35 percent of total LNG imports in the combined Asia and Asia Pacific regions (using IGU definitions). This compares to 20 percent in 2016. The significant importers of spot LNG in Asia and Asia Pacific include China, India, Pakistan, Bangladesh, Japan, South Korea, Chinese Taipei, Singapore and Thailand.



Figure 9: GOG LNG Imports 2005 to 2023

Source: IGU

Figure 10: Competitive Markets 2023 (Trading and Spot LNG)



Source: IGU



The competitive markets for the purposes of the analysis of gas price drivers in this report are defined as the trading markets and spot LNG markets from the IGU's GOG category. The trading markets are those markets where the GOG category is the main pricing category³⁷ and the spot LNG markets are those markets where there are spot LNG cargoes but are not defined as trading markets. These countries are shown in Figure 10. In total the GOG traded markets and spot LNG account for some 40 percent of total world consumption in 2023.

b) The Beginnings of the Globalization of Gas Markets

The discussion of the IGU surveys has noted the progress towards more GOG pricing via both trading markets and spot LNG, which suggests that, since the PITG book in 2012, there has, prima facie, been progress towards a more global market and global price linkage. As noted by Jonathan Stern in the **PITG Conclusions:**

"Discussion of globalising gas prices should therefore not (necessarily) be taken to mean an equalization of gas prices - allowing for transportation differentials - around the world. A more restricted definition of globalization is that prices in one region are increasingly influenced by supply and demand events in other regions, in other words, greater connectivity, rather than uniformity of prices."38

Figure 11 plots the spot prices in Europe, Asia and the USA since 2005 – although the Japan spot markers did not begin until March 2009 with JKM³⁹.



Figure 11: Spot Prices 2005 to 2024

Source: Argus, S&P Global Platts, NYMEX

More detailed analysis of spot prices will be covered in Section 8, but in terms of the PITG definition of greater connectivity of prices, at least between Asia and Europe, this would seem to have been achieved, certainly from 2016 onwards. It could even be argued that, for much of the period from 2016, there has been an equalization of prices, once transportation differentials are taken into account. In respect of the US, there are good reasons why the prices seem decoupled from the rest of the world and these will be explored later.

³⁷ This includes markets such as Morocco and Tunisia which are not competitive markets but do import gas priced as GOG.

³⁸ PITG, p 483

³⁹ The Japan-Korea Marker compiled by S&P Global Platts



Returning to PITG, Chapter 12, authored by Howard Rogers, considered the interaction between pipeline gas and LNG – Does Greater Connectivity equal Globalization? Rogers identified three conditions for establishing global price linkage⁴⁰:

Condition 1: The existence of infrastructure to enable natural gas to move between regional markets and of sufficient volumes of "flexible" or "divertible" natural gas.

Condition 2: The creation of supply chains which allow the diversion of flexible gas supply between regional markets in response to supply-demand imbalances and price disparities (arbitrage).

Condition 3: The motivation and ability of one or more of the three key agents in an existing regional gas supply chain to move away from oil-indexed contracts to hub-based pricing.

In respect of **Condition 1**⁴¹, Rogers noted that North America was isolated from the rest of the world as the growth in shale gas dramatically reduced the need for the US to import LNG via its extensive regasification capacity. Other regions such as Europe and Asia had developed significant regasification capacity and, on a contractual basis, there was growth in short-term LNG and additional optionality had been negotiated in some European LNG import contracts. The prospects of Condition 1 being met, according to Rogers, rested on the development of LNG export capacity in the US as shale gas production grew.

For **Condition 2**⁴², the issue, as Rogers noted, was in the ability to create arbitrage opportunities, principally between spot gas and oil-indexed gas under long-term contracts, which was happening in the European markets, particularly between the UK and continental Europe. Volumes were exported from the UK when NBP prices were lower than oil-indexed contract prices in continental Europe, which they were for much of the period between 2001 and 2012⁴³. In the few periods when NBP prices were higher than oil-indexed prices, continental European buyers were incentivized to nominate up the volumes under the long-term contracts and reduce purchases of spot NBP gas. Rogers also noted that the tightening Asian market between 2006 and 2008, pushed Asian spot prices higher and attracted flexible cargoes away from the Atlantic Basin.

The three key agents in **Condition 3**⁴⁴ were the Upstream Supplier, the Midstream Utility and the End Consumer. Rogers noted that the surplus supply conditions that existed in the European markets in 2009 and 2010, had driven spot prices well below oil-indexed long-term contract prices. Together with the EU energy liberalization packages this led to the beginnings of the renegotiation of contracts away from oil-indexed pricing. The move away from OPE to GOG in the key Northwest Europe (NWE)⁴⁵ market was well documented in the IGU Wholesale Price Surveys. GOG rose from 28 percent of total NEW gas consumption in 2005 to 72 percent in 2012. In 2005, GOG was pretty much all in the UK (Ireland, Belgium and Netherlands had very small amounts) but by 2012, GOG was the dominant mechanism in the Netherlands, Belgium, Luxembourg and Denmark as well as the UK and Ireland, and was around 50 percent of total consumption in Germany and 40 percent in France. By 2015, OPE had virtually disappeared in Northwest Europe and rapid progress towards GOG was being made in Central Europe⁴⁶ and Italy.

Rogers concluded⁴⁷ that "with infrastructure and flexible supply creating greater connectivity between the major regional trading markets, a degree of globalization is inevitable. However, without the development of hub-pricing in all three major regional markets, the extent of this globalization will be limited. Hub-pricing at scale in Asia seems at least a decade away, but developments in other markets may put pressure on the JCC system to change".

⁴⁰ PITG, p 380-391

⁴¹ PITG, p 380-382

⁴² PITG, p 383-387

⁴³ PITG, Fig 12.6, p 385

⁴⁴ PITG, p 387-391

⁴⁵ Belgium, Denmark, France, Germany, Ireland, Luxembourg, Netherlands, UK

⁴⁶ Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland

⁴⁷ PITG, p 420-421



Rogers felt that, in 2012, we were "still many years away from being able to imagine a truly global gas pricing system", but did concede that this "could be accelerated in the event that North America begins to export substantial quantities of LNG".

c) Globalization: Progress since 2012

With greater connectivity of prices, as suggested by Jonathan Stern in PITG, it might be expected that you would see greater convergence. Successive IGU Wholesale Price Surveys, including the most recent⁴⁸, undertook analysis of price convergence utilising the collected wholesale price data for each country. Convergence is calculated by the coefficient of variation (COV) of prices, which, in a specific year, is determined by the standard deviation divided by the mean value of the prices. The amount of absolute price variation (standard deviation) is thus measured relative to the average price in a certain year. A low coefficient of variation indicates a higher level of price convergence and vice-versa.

The full set of wholesale prices includes prices from all countries and markets, many of which are regulated or have significant volumes of OPE, so the prices are not just GOG, which are driven by the forces of supply and demand. Figure 12 shows the coefficient of variation for the full IGU dataset and also for those countries with GOG in their gas prices.



Figure 12: Price Convergence for Countries with GOG Prices

Source: IGU

Up until 2021 there was a general trend towards greater convergence in both the full IGU dataset (including many countries with regulated and OPE prices) and those with GOG prices. The countries with GOG prices have a lower COV than the full dataset, suggesting much closer convergence, also declining over time until 2021. In 2021 and 2022, gas prices soared for reasons well known (this will be analysed further in Section 8), and prices clearly diverged on all measures. In 2023, as prices fell back, there was more convergence.

Generally, it might be expected that greater connectivity in markets as globalisation takes place, would lead to more convergence, since disconnected markets have no reason to see prices converging. That is not to say that, even in globalised, connected markets, prices can diverge for good reasons, as is discussed in Section 7 - fallacy number 4. However, the results of the IGU analysis on price convergence is *prima facie* evidence of more connectivity and globalisation.

The Asian market, which is effectively connected to other key markets, especially North America and Europe, via LNG trade, was suggested by Rogers in PITG⁴⁹ to be lagging behind the more mature North American and European markets in terms of hub development and trading, which Rogers considered might limit the extent of globalization. Figure 8 suggested that, at least in terms of pricing mechanisms,

⁴⁸ IGU (2023). Wholesale Gas Price Survey 2023 Edition, p 53-60

⁴⁹ PITG, p 420-421



there has been a significant move to GOG pricing in LNG since 2016, with the GOG share globally reaching 49 percent of total LNG imports in 2023, compared to 23 percent in 2016⁵⁰. Much of this increase has come in the wider Asia region, as shown in Figure 9. Combining the Asia and Asa Pacific IGU regions shows that GOG pricing for LNG imports rose from 15 percent in 2016 (albeit down from 22.5 percent in 2015) to 38 percent in 2021, falling back to 33 percent in 2022, but rising back to 35 percent in 2023. The fall in 2022 was not a reflection of a move away from GOG pricing as such but that spot LNG cargoes were attracted to Europe away from Asia, especially China, as Europe lost large volumes of pipeline imports from Russia following the invasion of Ukraine. There was more spot LNG in 2022 than in 2021, just delivered to different markets.

The increasing connectivity in the LNG market can be illustrated by analysing both the increasing flexibility of LNG trade and the geographical trade flows. Analysis of LNG flows is often considered in terms of the Atlantic Basin and the Pacific Basin or West of Suez and East of Suez. In the next few figures, the term Atlantic Basin⁵¹ and Pacific Basin⁵² will be used to refer to exporters of LNG, while West of Suez⁵³ and East of Suez⁵⁴ to the LNG importers.

Figure 13 shows the respective Atlantic Basin and Pacific Basin monthly exports which go to West of Suez and East of Suez importers. The majority of Atlantic Basin volumes remain West of Suez, while almost all Pacific Basin volumes remain East of Suez. The Atlantic Basin volumes remaining West of Suez have gone below 50 percent occasionally, notably in 2021 as LNG was shipped to Asia as economies recovered from Covid-19 amid a cold winter. Pacific Basin volumes remaining East of Suez, have been in the 90 percent range for the most part.

While Pacific Basin volumes in total have grown by a relatively small amount – 2015 monthly average was some 21,400 mmcm and in 2023 the monthly average was some 24,000 mmcm. The variability of the East of Suez share was relatively small. In contrast, Atlantic Basin volumes have grown significantly from a monthly average of 5,800 mmcm in 2015 to some 17,800 mmcm in 2023. This reflected the strong growth in US export volumes beginning in 2016. The variability in the West of Suez share of Atlantic Basin export volumes is large, going below 50 percent in 2021, as noted earlier, but occasionally over 80 percent – notably in later 2022 and early 2023, as pipeline imports into Europe from Russia had fallen to very low levels.

Figure 13 covers total LNG volumes, whether contracted or spot and also whether the contracts have a specific destination in the contract or are flexible. Figure 14 splits the total volumes into those with destination clauses⁵⁵ and those which are flexible – either spot or a fob contract. The sharp rise in Atlantic Basin flexibility has been driven by the growth in US LNG since 2016, with the trendline starting at just under 50 percent in 2015 to over 90 percent at the end of 2023. The Pacific Basin has also seen some growth in flexible volumes but from around 30 percent in 2015 to around 40 percent in 2023.

⁵⁰ Although the share had fallen from 33 percent in 2015.

⁵¹ Atlantic Basin exporters are Algeria, Angola, Cameroon, Egypt, Equatorial Guinea, Nigeria, Norway, Russia (Yamal and Baltics), Trinidad and USA

⁵² Pacific Basin exporters are Australia, Brunei, Indonesia, Malaysia, Mozambique, Oman, Papua New Guinea, Peru, Qatar, Russia (Sakhalin) and United Arab Emirates

⁵³ West of Suez importers cover Europe (including Turkey), North Africa, Israel and the Americas Atlantic Coastlines

⁵⁴ East of Suez importers cover all Asia, importers on the Pacific coastline (Chile) and Middle East excluding Israel

⁵⁵ The volume for destination clause contracts is taken to be the take-or-pay level as anything above that is optional and by definition flexible





Figure 13: Atlantic Basin and Pacific Basin Exports 2015 to 2023





Source: Kpler





Figure 14: Atlantic Basin and Pacific Basin Exports 2015 to 2023 – Destination and Flexible

Pacific Basin Flexibility



Source: Kpler, NexantECA World Gas Model

The final chart (Figure 15) covering flexibility combines the Atlantic and Pacific Basins. In 2015, the Pacific Basin had more flexibility in volume terms, with the Atlantic Basin having a share only around 1/3rd, and the Pacific Basin 2/3rd. By the end of 2023, this had almost completely reversed with the Atlantic Basin share averaging just under 60 percent.

It is also notable that in the last 6 months of 2023, total flexible exports – Atlantic and Pacific Basins combined – were some 57 percent of total LNG exports, having risen from 32 percent in the first 6 months of 2015.





Figure 15: Atlantic Basin and Pacific Basin Exports Flexibility 2015 to 2023

Source: Kpler, NexantECA World Gas Model

In respect of the connectivity and globalisation of the LNG market the advent of US LNG has transformed the situation. Not only has LNG pricing moved significantly towards GOG pricing, but the whole market has moved towards greater volume flexibility, especially exports from the Atlantic Basin. The ability for Atlantic Basin exporters to switch volumes between West of Suez and East of Suez has been amply demonstrated in the last few years. Section 8 will consider these movements in more detail.

d) Is Hub Development necessary for Globalization?

Rogers⁵⁶ was relatively pessimistic on the progress in the development of one or more hubs in the Asian market, and that this might hold back the full globalization of the gas market. In North America and Europe there are well developed hubs and have been for many years. There has been much written on the development of hubs, especially in North America and Europe, and Patrick Heather, at the OIES, publishes regular analysis of the liquidity of the European gas hubs, with the most recent analysis being published in July 2024⁵⁷. The full list of the reports by Heather is contained in the bibliography to his most recent analysis⁵⁸.

The author, in his 2018 paper on Asian LNG Trading Hubs, included a detailed summary of the development of hubs, specifically Henry Hub, NBP and TTF⁵⁹. Section 7 of this paper incorporates this summary. This paper also referred to the OIES papers by Heather on European hub liquidity and also regular reports by Cornerstone Research on US liquidity – the most recent one being published in 2021⁶⁰.

With developed liquid trading hubs in North America and Europe the main issue is with the Asian market. There is clearly no liquid trading hub in Asia, but does that matter in respect of connectivity and globalization?

The author's 2018 paper was focussed on Asian LNG trading hubs, and an earlier IEA paper⁶¹ presented a very comprehensive analysis of what conditions were needed to create a natural gas trading hub in Asia. The IEA 2013 paper concluded that the "Prospects for a competitive wholesale natural gas market in Asia are limited... A competitive natural gas market in Asia would need an even more flexible LNG supply than is currently in place... Governments in the region will need to signal their willingness to facilitate competition further downstream"⁶². Five years later the author's 2018 paper⁶³

⁵⁶ PITG, p 420-421

⁵⁷ Heather. P. (2024). *European Traded Gas Hubs: the markets have rebalanced*, OIES NG 192.

⁵⁸ Heather. P. (2024), p 36

⁵⁹ Fulwood, M. (2018), p 9-24

⁶⁰ Cornerstone Research. (2021), *The Characteristics of U.S. Natural Gas Transactions*

⁶¹ International Energy Agency. (2013), Developing a Natural Gas Trading Hub in Asia, Paris: OECD/

IEA.

⁶² International Energy Agency. (2013) p 6-7

⁶³ Fulwood, M. (2018), p 50-52



reached very similar conclusions, noting that the lack of real liberalization in all the key Asian gas markets, was a barrier to the development of a domestic liquid gas trading hub. The paper also noted that the ability to create meaningful churn at a prospective LNG hub in Asia was fraught with difficulties, not least because of the nature of the LNG market and the sheer size of a single cargo of LNG, which cannot easily be dissected and traded multiple times. However, the paper was more optimistic about the creation of a reliable price benchmark for LNG in Asia. The price reporting agencies – including S&P Global Platts, Argus Media and ICIS, amongst others – have all developed price assessments for LNG in Asia. The author's paper also noted that "the increase of flexible LNG volumes, particularly from the United States, could fundamentally change the industry landscape"⁶⁴ in terms of creating a more reliable price benchmark.

JKM (Japan-Korea marker) is the most widely used benchmark for LNG in Asia. Platts JKM was launched in February 2009 and represents the daily tradeable price of spot LNG cargoes delivered into Northeast Asia. From June 2018, S&P Global Platts used a Market-on-Close (MOC) methodology to assess Platts JKM. The MOC is a structured day-long process that ends at 4:30pm Singapore time – the timestamp for Platts LNG assessments in Asia - and is an assessment process adopted widely across energy markets. During the MOC, Platts publishes real-time information from active market participants that report firm, named bids, offers and trades in order to test market value and form a representative price assessment at the close of each day.

ICE introduced a JKM LNG (Platts) Future in 2012. This is a monthly cash settled future based on the Platts daily assessment price for the LNG Japan/Korea Marker (JKM). It is traded on 10,000 MMBTU lots, and the settlement price is the declared JKM index for the month. Unlike the Henry Hub and NBP futures, therefore, there is no underlying physical market the futures market is linked to and that can be used to go to delivery as the default.

As Heather noted in his latest paper⁶⁵, "There is no doubt that the Asian JKM marker price is gaining support from the LNG industry, with producers, aggregators and buyers using it more each year. Asia has started to liberalise its gas markets but has a long way to go. Increased short term and spot LNG trades and the use of the JKM are helping the transition. The JKM, when compared to its main sphere of influence, has a churn of 0.69 times in 2023 (up from 0.59 in 2022). This is an illiquid market but is clearly showing some signs of growth".

As JKM developed it began to be used, on occasion, in LNG contracts as the price. According to S&P Global the use of JKM is more prevalent in short or medium term (up to 5 years duration) contracts and for single spot cargoes, than for long term contracts (generally 10 years or more duration and typically 20 years)⁶⁶. In respect of longer-term contracts, the use of JKM is not that widespread although typically there is always a lot of chat at conferences and in bars regarding longer term contracts priced using JKM. The author has identified 3 contracts⁶⁷ from projects which have taken FID and are under construction, which are thought to use JKM, at least in part in conjunction with other pricing parameters and are 15 to 20 years duration. These are all for North American sourced LNG. In addition, there are also a few longer-term contracts from proposed non-FID projects which incorporate JKM.

There are also the Henry Hub plus priced contracts from the USA which are likely destined for the Asian markets⁶⁸ and according to the NexantECA World Gas Model database these comprise around 50 bcm of ACQs – all having started or planned to start in the 2020s. However, given the structure of the US LNG projects which are effectively all FOB, then the total of Henry Hub linked contracts – either in operation now or coming on in the 2020s – is an ACQ of some 225 bcm (including the earlier 50 bcm)⁶⁹. Much of these volumes will go to Europe and other markets outside Asia, but Asia can expect a significant share as well, especially as some of the larger Asian buyers and traders are heavily contracted for US LNG. Before the Russian invasion of Ukraine and the sharp rise in TTF prices, there was some anecdotal evidence that TTF was being used to price LNG into Asia⁷⁰, mainly for single cargoes, but as TTF prices rose this practice seems to have fallen away.

⁶⁷ Source is NexantECA World Gas Model database

⁶⁴ Fulwood, M. (2018), p 52

⁶⁵ Heather. P. (2024), p 30-31.

⁶⁶ https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/lng/101223-market-based-lng-pricing-gains-traction-in-long-term-contracts-for-southeast-asia-

⁶⁸ The US Henry Hub contracts are largely all FOB so can be delivered anywhere the offtaker wants, but those included in the estimated 50 bcm are for smaller Asian buyers.

³⁹ Source is NexantECA World Gas Model database

⁷⁰ Author's recollection of conversations at conferences.



There is no liquid trading hub in Asia for either pipeline gas or LNG and the prospects for the development of one still seem as remote as they did when the 2013 IEA paper⁷¹ and the author's 2018 paper⁷² were published. However, the growth in Henry Hub priced LNG from the US and the continued development of liquidity in JKM, together with the interaction between JKM and TTF, suggest that there are at least reliable price benchmarks. In addition, as noted in the analysis of Atlantic and Pacific Basin flexibility, there has been significant growth in LNG flexible volumes since 2015, driven by the growth in US LNG. The sharp rise in spot prices in 2022, however, to well above the oil-linked prices, did cause some nervousness amongst Asian buyers. Recent long-term LNG contracts have witnessed a trend back to fixed destinations in long-term contracts (likely oil-indexed), according to the IEA⁷³. However, this, at least, in part, reflects a lower level of contracting for US projects.

e) Conclusions

The pricing of gas in international trade has seen a continuous move towards GOG pricing since 2005. Initially this was led by the pipeline import market in Europe, as markets were liberalised and long-term contracts renegotiated, and since 2016 by growth in the LNG market, with GOG increasing its share in all regions. This included Europe as LNG imports rose with a significant proportion of the increase coming from the US. The largest LNG importing region – Asia – also saw a sharp rise in GOG pricing, both in spot LNG and also more contracted LNG linked to Henry Hub prices.

The Pricing of Internationally Traded Gas⁷⁴ noted in the Conclusions that: "Discussion of globalising gas prices should therefore not (necessarily) be taken to mean an equalization of gas prices – allowing for transportation differentials – around the world. A more restricted definition of globalization is that prices in one region are increasingly influenced by supply and demand events in other regions, in other words, greater *connectivity*, rather than *uniformity* of prices."⁷⁵

The progression of spot prices, at least from 2016 onwards, suggests that greater connectivity of prices, at least between Asia and Europe, would seem to have been achieved. It could even be argued that, for much of the period from 2016, there has been an equalization of prices, once transportation differentials are taken into account. This greater connectivity is also supported by further analysis in the IGU Wholesale Price Surveys showing that prices were converging globally at least through 2021.

The growth of US LNG exports since 2016 has also driven a significant rise in the volume of flexible LNG in the global market. The growth of flexible LNG has significantly improved connectivity between regional markets. In 2015, Pacific Basin (east of Suez) exporters had more flexibility in volume terms, with the Atlantic Basin (west of Suez) exporters having a share only around 1/3rd, and the Pacific Basin exporters 2/3rd. By the end of 2023, this had almost completely reversed with the Atlantic Basin exporters share averaging just under 60 percent. Importantly, however, it is also notable that in the last 6 months of 2023, total flexible exports – Atlantic and Pacific Basins combined – were some 57 percent of total LNG exports, having risen from 32 percent in the first 6 months of 2015. It is this rise in flexible LNG that has led to the ability for Atlantic Basin exporters to switch volumes between West of Suez and East of Suez, which has been amply demonstrated in the last few years.

In The Pricing of Internationally Traded Gas, Rogers⁷⁶ was relatively pessimistic on the progress in the development of one or more hubs in the Asian market, and that this might hold back the full globalization of the gas market, and hence connectivity between regional markets and prices. While the establishment of hubs in Asian markets seems as remote as ever, the increased flexibility of LNG volumes and the rise in GOG pricing in Asian markets to 35 percent of total Asian LNG imports in 2023, from 20 percent in 2016, suggests there is a large core of LNG available to trade in the region. As such, while Asia is far from being a liquid trading market, akin to North America and Europe, it does, in the author's view, qualify as a competitive market for international traded gas, if not for the domestic markets⁷⁷, at least for enough LNG to suggest that the global gas market is well connected and globalized.

The question posed in PITG, right at the beginning, as to whether gas pricing is "different" to other commodities, was answered by Stern⁷⁸, in the last sentence of the book. "In future it is likely to become

⁷⁸ PITG, p 489

⁷¹ International Energy Agency. (2013)

⁷² Fulwood, M. (2018)

⁷³ International Energy Agency. (2024) Global Gas Security Review, Paris: IEA. p 64

⁷⁴ Stern, J.P. ed (2012)

⁷⁵ PITG, p 483

⁷⁶ PITG, p 420-421

⁷⁷ The domestic markets in China, Korea, Japan and Chinese Taipei are far from being liberalized


much more similar to other commodities". This was back in 2012, but based on the evidence of market development over the last 12 years and, particularly the change in LNG pricing since 2016, it would seem that gas has achieved the goal of becoming "similar to other commodities".

3. Fallacy No 1: The Cost Stack

The cost stack is a simple graphical representation of the costs in the gas value chain for each source of supply to a specific market, whether it is domestic production, pipeline imports or LNG imports from a variety of sources. The concept is that the highest cost source of supply is the marginal cost and hence sets the price in the market. Its simplicity is maybe why it is so beloved of consultants and analysts in trying to explain what is driving prices and, looking forward, how prices might develop.

a) What is the Cost Stack?

The cost stack is a graphical representation of the costs of delivering gas from different supply sources to a specific market. The source of supply can be a market's own production, imports by pipeline and/or by LNG. The different elements of the costs for each source of supply can then be added together to get a full delivered cost to that market. The individual cost elements would include the cost of production, gathering and processing costs, pipeline transportation costs, LNG liquefaction costs, LNG shipping costs, LNG regasification costs and internal market pipeline transportation costs such as entry fees to get to the hub. With the different sources of supply then ranked in ascending order of total delivered cost, a line can be drawn where the volume of supply equals the total demand in the market and the most expensive delivered gas, at that point, is effectively the marginal cost of supply. Using very basic economics this is said to be the price in the market⁷⁹.

An example of the cost stack is in Figure 16 for the UK using gas flows from 2021⁸⁰ - before the Russian invasion of Ukraine. The simplicity of the graphic helps to explain why the cost stack is so beloved of consultants and analysts. The figure compares the resulting "marginal cost" with the actual NBP price⁸¹ for the year.



Figure 16: The UK Cost Stack 2021

⁷⁹ The next section will be more of an economics lesson!

⁸⁰ IEA data from NexantECA World Gas Model. Costs also from NexantECA World Gas Model

⁸¹ Average month-ahead price from Argus



Total supply to the UK in 2021 was some 81.5 bcm, which was higher than total demand because of pipeline exports to Ireland and the EU (Belgium and Netherlands). Domestic production accounted for some 33 bcm and imports from Norway by pipeline some 29 bcm. Imports from Belgium and Netherlands was some 4 bcm and the rest imports of LNG – 15 bcm. In 2021 the imports of LNG came from Trinidad, Algeria, Nigeria and Peru in small volumes but the bulk of LNG imports came from Qatar, USA and Russia – the Yamal project.

As Figure 16 shows, the lowest "stacked" cost of supply was EU pipe imports, followed by Qatar LNG and domestic UK production⁸² – all under \$5 per MMBTU. Norway pipe imports were slightly more expensive at just under \$6, with the LNG delivered supply costs from other sources rising from just over \$6 for Russia Yamal LNG to \$9.87 per MMBTU for US LNG – which was the highest cost of supplies delivered to the UK market in 2021 and was therefore, under the cost stack methodology, the marginal cost setting the price. Unfortunately, the NBP price was much higher at \$13.87 per MMBTU (real 2022 prices) in 2021. (Prices were rising rapidly through 2021 as the world recovered from Covid-19 and there will be a more detailed analysis of historical prices in section 8).

A year earlier, in 2020, the average NBP price was some \$3.58 per MMBTU (real 2022 prices). The supply sources and cost stack for 2020 would not have looked much different from the 2021 cost stack. There were some LNG imports from Norway and Egypt but the other suppliers were the same. The costs in the value chain would also have been largely the same with just the LNG shipping costs being lower by some 30 cents per MMBTU. US LNG would again have been the "marginal" supplier with a delivered cost of around \$9.50 per MMBTU – compared to NBP at \$3.58. The cost stacks between 2020 and 2021 had hardly changed but the NBP outcomes were hugely different. This suggests that other factors were impacting the price and/or that looking at a single country is not sensible in a global market.

b) Modifying the Cost Stack

Other factors influencing the price but which could be used in a modified cost stack include potential fuel switching from gas to other fuels. The most obvious example is switching between coal and gas in the power sector. This may be more relevant for the rest of Europe, outside the UK, now that there is no coal-fired power left in the UK⁸³, but the rapid decline in coal in the UK in the 2010s was partly reflective of the impact of the high carbon and efficiency adjusted coal price relative to the gas price.

The cost stack in Figure 16 can be modified to add in coal as an "alternative" supply source. The carbon and efficiency adjusted coal price in 2021 was some \$12.67 per MMBTU⁸⁴ (real 2022 prices). If the coal price had been a factor in 2021, in terms of switching power generation to coal from gas, then it would be the effective "marginal cost" for 2021. This is shown in Figure 17 where the \$12.67 efficiency adjusted coal price is close to the actual NBP price of \$13.78. The use of coal in UK power generation did increase in 2021, reversing the continuing downward trend since 2011. However, this may have been due more to the economic recovery from Covid-19 than any switching from gas-fired power, which also increased.

In 2020, the carbon and efficiency adjusted coal price was some \$5.97 per MMBTU, which would put it in the cost stack at a similar level to pipeline gas from Norway and LNG from Russia, but above the average NBP price for 2020 of \$3.85 per MMBTU.

In determining the gas price in a particular market there is little difference, in terms of market dynamics, between meeting an increase in electricity demand with more gas, say LNG from the US, or burning more coal, if the carbon and efficiency adjusted coal price is competitive with gas. If electricity demand is met by coal-fired power rather than gas-fired power, then this is effectively a reduction in gas demand. This reduction in gas demand is as much a "supply source" as additional gas supply, such as LNG from the US.

While coal switching is an obvious example of a competing supply, it is not the only possibility. This was clear in 2022, as gas prices in Europe soared when Russia invaded Ukraine and gas was being priced out in not only the power market, but also in the industrial market, where gas competes with oil. High

⁸² The production cost for all sources is the highest of a producing field for that source – except for Qatar where it is the North field and US where it is Henry Hub

⁸³ The last coal-fired power station at Radcliffe-on-Soar closed on September 30th 2024.

⁸⁴ Calculation from NexantECA World Gas Model. Actual coal price uplifted for the relative carbon cost of coal to gas and adjusted for the greater efficiency of CCGT plants to coal-fired plants.



gas prices also prompted more efficiency in the use of gas, as well as behavioural changes in the residential market (turning the thermostat down for example) and even energy-intensive industries, heavily reliant on gas, were forced to close down. Any price-induced reduction in gas demand, whether switching away from gas in the power or industrial sectors, efficiency incentives, behavioural changes or industrial closures, is effectively the same as additional supply from any other source. As such, they are as much a part of the cost stack.



Figure 17: The UK Modified Cost Stack 2021⁸⁵

Section 2 noted that the gas market has become increasingly globalised in the last fifteen years. Liberalisation in Europe and increased connectivity suggests that much of Europe can now be considered a single integrated market for gas. The concept of a cost stack for an individual country, which is part of an integrated market would not therefore necessarily be relevant. Would a cost stack for Europe as a whole be more sensible?

In 2021, before the Russian invasion of Ukraine, some 207 bcm of Europe's⁸⁶ supply came from production within Europe – principally Norway (119 bcm), UK (33 bcm) and the Netherlands (22 bcm), around 230 bcm in pipeline imports – 160 bcm from Russia, 35 bcm from Algeria, 18 bcm from Azerbaijan with the balance from Libya and Iran, and just over 100 bcm in LNG imports. Europe's LNG imports were principally from the US, Qatar, Russia (Yamal project), Algeria and Nigeria. The sources of supply to Europe as a whole are very similar to the UK. Figure 18 is a cost stack for Europe, using these supply sources, but with the Netherlands as the market of delivery, except for Algeria and Azerbaijan pipeline volumes which are to Italy.

The Europe cost stack looks very similar to the UK stack with similar supply sources; just the cost levels are slightly different. The addition of the coal price stack – as in the modified UK stack – would give the same picture as the modified UK stack.

Source: NexantECA World Gas Model

⁸⁵ The costs represent the marginal cost from the NexantECA World Gas Model and are the highest cost of production or the infrastructure and are most likely well above the average cost.

⁸⁶ Definition of Europe includes Turkey as well as the EU and non-EU countries – UK, Norway, Switzerland and non-EU Balkans



Figure 18: Europe Cost Stack 2021



Source: NexantECA World Gas Model

c) A Global Cost Stack?

Section 2 went somewhat further than simply suggesting that Europe was a defined, separate market, arguing that the gas market is now, in actual fact, a global market. How would a cost stack look for a global market, if in fact one could be created? The whole aim of the cost stack approach is to find the marginal cost of supply and to then assert that this, therefore, determines the price of gas in the market. At the global level, this is a lot more complex than simply looking at a region like Europe. The cost stack approach also assumes that the last molecule of gas delivered to Europe, say, is the incremental or marginal cost, when in actual fact, it may not be, because the gas market is now a globalized market.

Starting with the simple UK market as an example, if the marginal molecule of gas is US LNG, then a simple answer would be that the delivered cost of US LNG - \$9.87 per MMBTU from the figures above for 2021 – is the marginal cost, for any increase in demand for gas in the UK market. However, considering the wider global market, let us assume that the only way that US LNG could be delivered to the UK market is by diverting LNG cargoes away from other markets, say in Asia, since there is no spare capacity to produce any more LNG out of the US. The US LNG cargoes, therefore, are diverted away from, say, Japan to the UK. That's all fine but what then does Japan do, as it needs to replace those cargoes. Let's assume it can source those lost cargoes from Australia. In turn, the Australian LNG producers can supply some of the lost cargoes, to Japan, from increasing production but will need to divert some cargoes away from, for example, India. India is a particularly price-sensitive market, so in part could respond by reducing demand for gas, say by burning more coal in the power sector, but also by buying replacement LNG from, for example, Nigeria, where there is spare capacity to produce more LNG. The LNG volumes from Nigeria, therefore, rebalance the market.

In this example, the increase in demand for gas in the UK market, has not been met by more US LNG, as there was no spare US LNG capacity, but by a combination of more Australian LNG to Japan, the replacement of gas by coal in India and more Nigerian LNG to India. The marginal cost, therefore, would be the weighted average of the delivered cost of Australian LNG to Japan, the adjusted price of coal to Indian power plants and the delivered cost of Nigerian LNG to India. This was a relatively simple example of what might happen if there was an increase in demand for gas in the UK, and the reality may be much more complex. Clearly it would be virtually impossible to "chart" the marginal cost from the rebalancing of global flows of gas.

The data for the cost stacks is taken from the NexantECA World Gas Model, which OIES use to generate scenarios and undertake analysis. More information on the model is contained in Annex 2.



The marginal cost of supply can be calculated for a market but then the question becomes is the actual price in the market the marginal cost of supply? This is the subject of the next section.

d) Conclusions

The cost stack is a simple graphical representation of the costs in the gas value chain for each source of supply to a specific market., but there are a number of flaws in the cost stack approach. Firstly, it does not take account of fuel switching, such as between coal and gas in the power sector. There is also potential fuel switching in industry, usually with oil, incentives to efficiency as prices rise, behavioural changes (turning down the thermostat) and even industrial closures impacting gas demand. All of these effects were seen in 2022 after the Russian invasion of Ukraine.

Secondly, the cost stack for one market, such as the UK, even with fuel switching included, does not take into account the interconnections with continental Europe. 2022 saw the UK importing large quantities of LNG to effectively re-export the volumes to continental Europe. Europe is well connected and an integrated market, with hub prices highly correlated.

However, thirdly, Europe is not an isolated market, and is one part of the globalized gas market. If demand in Europe increases, and the increased volumes come from, say, the US, it is not necessarily the delivered cost of US LNG which sets the price of TTF. Volumes might be diverted from, for example, Asian markets such as Japan. What happens in a globalized market, is the increase in demand in one market, leads to multiple effects rippling through many other markets, so tracking all these changes to calculate the marginal cost would be a herculean task.

The marginal cost of supply to each market, however, can be calculated using gas models, which are linear programmes. OIES uses the NexantECA World Gas Model, which is a linear programme, and generates the shadow price, which is effectively the marginal cost of supply to each individual market. However, this cannot be represented in a simple cost stack graph, as the global market is a complex interaction of multiple flows, costs and demand responses.

4. Fallacy No 2: Price equals Marginal Cost

a) Price equals Marginal Cost: Economics 101

The previous section exposed the fallacy of the cost stack but also showed through models that it is possible to derive the marginal cost of gas to individual markets. Does price equal marginal cost, therefore? In a perfectly competitive market, the long run equilibrium is reached where price equals marginal cost. Such markets are known as allocatively efficient where the price not only equals the marginal cost but also the average cost and the individual firm or entity is faced with an infinitely elastic demand curve – average revenue equals marginal revenue.





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In the short run, in perfectly competitive markets, the price may be above the marginal cost, with firms earning an above normal profit. However, one of the conditions for a perfectly competitive market is that there are no barriers to entry, with ease of entry and exit to the market, so the existence of above normal profits will attract new firms in and they compete away the excess profits. Only in the long run equilibrium will price equal marginal cost.

The key characteristics of perfectly competitive markets are:

- A large number of Buyers and Sellers: In a perfectly competitive market, there are numerous buyers and sellers, none of whom have a significant market share. This ensures that no single participant can influence the market price.
- **Homogeneous Products**: In perfect competition, all firms produce identical or homogeneous products, meaning consumers perceive no difference between the goods or services offered by different sellers. This also involves zero transaction costs.
- **Perfect Information**: Buyers and sellers in a perfectly competitive market have access to complete and accurate information regarding prices, quality, and availability of goods or services. This transparency ensures that consumers can make informed decisions.
- Free Entry and Exit: Firms can freely enter or exit the market without facing any barriers. This freedom of entry and exit ensures that no firm can control the market in the long run. This also requires full mobility of capital and labour

Under perfect competition all participants are price takers, with no participant having the power to set prices. The market may also be overlaid with very strong anti-competitive regulation to eliminate any anti-competitive practices.

While the individual firm is faced with an infinitely elastic demand curve, for the industry as a whole, the demand curve is the normal downward sloping demand curve, which may be elastic or inelastic depending on the industry as a whole. Where the demand curve cuts the supply curve is the price and, in the long run equilibrium, is the marginal cost for all participants.



Figure 20: Industry Supply – Demand Curve: Perfect Competition

Volume

The perfectly competitive market is an idealized construct of neoclassical economics, and while it is a useful analytical tool, it is difficult to think of any market which could be said to be perfectly competitive. Almost all markets, therefore, are a form of imperfect competition. Under imperfect competition, the price is generally above the marginal cost.



The types of imperfect competition are as follows:

- **Monopoly**: A monopoly exists when there is a single seller or producer in the market, with no close substitutes for their product. The monopolist has significant market power and can set prices independently.
- **Monopolistic Competition**: Monopolistic competition is a market structure characterized by a large number of sellers producing differentiated products. Each firm has some control over the price due to product differentiation, but there is still a relatively high degree of competition.
- **Oligopoly**: Oligopoly refers to a market structure dominated by a small number of large firms. These firms have substantial market power and often engage in strategic interactions, considering the actions of their competitors before making decisions.
- **Duopoly**: Duopoly is a special case of oligopoly where there are only two dominant firms in the market. The actions of one firm directly impact the other, leading to intense competition and interdependence.

The characteristics of imperfect competition are:

- **Fewer Market Participants**: Unlike perfect competition, imperfectly competitive markets have fewer buyers and sellers, with some participants holding a significant market share.
- **Product Differentiation**: In imperfect competition, firms often differentiate their products through branding, packaging, features, or other unique selling points to gain a competitive edge.
- Barriers to Entry and Exit: Imperfectly competitive markets may have barriers that prevent new firms from easily entering the market or discourage existing firms from exiting. These barriers can include legal restrictions, patents, high startup costs, or economies of scale.
- **Market Power**: In imperfect competition, individual firms have some degree of control over the market price and can influence it to their advantage. This allows them to earn profits by setting prices higher than the marginal cost of production.

While it has been already argued that the gas market is globalized, the regional markets display a number of differences. The gas molecule is homogeneous⁸⁷ which is one key characteristic of a competitive market. The pipeline infrastructure is a monopoly but is generally regulated, as are some elements in the LNG chain, such as some regasification facilities. The US gas market has a large number of buyers and sellers and the transparency of information on prices, combined with the homogeneity of the gas molecule, suggests that the US market has some of the characteristics of a perfectly competitive market. Similarly, the European gas trading market is also competitive. However, there are a number of large international oil and gas companies, and national oil and gas companies, who have significant market shares, although this is not to suggest that any one of them can exercise enough market power to move the price. Plus, there is no gas equivalent of OPEC in the global gas market⁸⁸. The entities participating in the gas market tend to be large, whether in developing upstream projects, LNG projects or even simply wanting to trade in the markets – a big balance sheet is needed. In natural gas, size matters, which is a significant barrier to entry and also exiting the business.

Outside the US (plus Canada) and Europe, there are a limited number of traded markets⁸⁹. The markets in Asia, at least for individual countries, are a long way from being competitive markets. However, as was argued in Section 2 these countries do participate in the global LNG market which is becoming increasingly competitive.

⁸⁷ The quality of the gas in the system is set by the pipelines with the calorific value and Wobbe number required to be in a defined range and the gas is sold and transported on an energy basis – MMBTU, gigajoule, megawatt-hour, therm etc..
⁸⁸ The Gas Exporting Countries Forum (GECF) is more a government-led industry lobby group.

⁸⁹ Australia is probably the exception



b) Long Run and Short Run Marginal Cost

While the price in a market is only equal to the marginal cost when a perfectly competitive market is in long run equilibrium, if the gas market (in any country, region or at the global level) is not a perfectly competitive market, this does not mean that the marginal cost of delivered gas has no impact on the price. On the contrary, the marginal cost of delivered gas is an important element in determining the price of gas in a market.

The charts on the cost stack in Section 2 were all derived from the total – or long run – costs of delivering gas to the UK or Europe, with the costs including both the fixed and variable costs in all elements of the gas chain. Even when the global market was being considered, with the shadow price being the marginal cost for each market, based on global cost minimisation, this was the shadow price based on the total fixed and variable costs for each element of the gas chain.

As will be shown in the sections below, the actual price outcomes in recent years have been well below the shadow prices based on long run or total costs. In the circumstances that were seen in 2019 and, especially, 2020, the pricing was arguably closer to short run rather than long run marginal costs. Short run marginal costs effectively ignore the fixed costs, or the recovery of the sunk capital costs. Figure 21 shows the long run and short run shadow prices⁹⁰ from the NexantECA World Gas Model for the Netherlands (TTF) and Japan, compared with the actual TTF and Japan spot prices for 2017 to 2021.



Figure 21: Long Run and Short Run Shadow Prices - 2017 to 2021

Source: NexantECA World Gas Model, Argus Media

25.00

The short run shadow prices are some \$3 per MMBTU or so below the long run shadow prices. The actual TTF and Japan spot prices are at, or above, the long run shadow prices in 2017 and 2018, before falling below in 2019 and then around the short run shadow prices as Covid-19 hit in 2020. In 2021, the actual prices rose sharply to well above the long run shadow prices.

Clearly, while the marginal costs – whether long run or short run – had some impact on prices, other factors were also influencing prices. In the next sub-sections, these influences will be discussed. However, before the discussion of marginal costs and shadow prices is finished – for the moment – it should be pointed out that all the costs that have been discussed in this section, and the previous

⁹⁰ The usual model run is with all fixed and variable costs included in the cost minimisation process. In short run mode all fixed costs are excluded for production and all infrastructure including pipelines, liquefaction and regasification facilities, LNG shipping and gas storage.



section on the cost stack, are estimates, taken from the NexantECA World Gas Model. These may, or may not, be accurate. As with other consultants, think tanks and academic institutions, extensive research and estimation is undertaken of costs over the whole value chain. These costs can be based on information from company accounts, national statistical services, such as the US Energy Information Administration, published papers and other institutions such as the International Energy Agency. Even with the collected information, converting fixed capital costs into unit costs requires assumptions on the discount rate and the asset life. In summary, the marginal costs are estimates and different cost assumptions could produce different marginal cost estimates. It should also not be forgotten that the marginal cost and the shadow price calculations also include estimates of the price-switching thresholds at which demand in specific sectors may switch away from gas to other fuels such as coal and oil.

c) What are the other influences on gas prices?

Outside the marginal cost of supply, the price of competing fuels can also be seen as an important influence. As has already been noted, gas competes in the end-use sectors with other fuels such as coal – predominantly in power – and oil, mainly in the industrial sector, certainly in the OECD countries. In the power sector in Europe, for example, fossil fuels have been in decline, with coal-fired power declining more rapidly than gas as shown in Figure 22.



Figure 22: Power Generation Share by Fuel – OECD Europe

Source: IEA Electricity Information



The coal share has declined from 25% in 2010 to 17% in 2022, while the gas share has recovered in the last few years back to the 2010 level. It is also instructive to just look at the relative coal and natural gas shares in power generation. The coal share of fossil fuel power generation in the EU27 was on a rising trend to around 2015 – with natural gas declining – before starting a gradual decline. The corresponding rise in the natural gas share was particularly strong in 2019 and 2020, before in 2021 and 2022, the coal share had a bit of a resurgence. These changes in relative shares correspond to the changes in the relative prices of coal and gas, as illustrated in Figure 23.



Figure 23: Coal and Gas Prices in Europe



The published Rotterdam coal price has generally always been below the TTF price, but the coal price has to be adjusted for the relative efficiency of gas-fired plants over coal plants and also the relatively higher carbon cost of coal compared to gas. This is reflected in the adjusted coal price⁹¹ in Figure 23. Up until 2015 the TTF price was well above the adjusted coal price and corresponds with the higher share of coal relative to gas. The prices came much closer together in 2016 and occasionally TTF prices were below the adjusted coal price. This was associated with a rising share of gas in fossil fuel power generation as the TTF price fell below the adjusted coal price in 2019, and well below in 2020, with a sharp rise in the gas share of fossil fuel power generation. In 2021 and 2022, the large rises in TTF, to levels well above the adjusted coal price, saw the gas share fall and the coal share of fossil fuel power generation increase.

The volume of gas used in power generation is, prima facie, sensitive to the price of gas relative to the price of coal. Other things being equal, higher coal prices allow the gas price to rise without losing market share. The reverse is also true, with declining coal prices putting downward pressure on gas prices, if gas is to maintain its market share.

Another competing fuel to gas is oil or specifically oil products such as gasoil or fuel oil. This is more so now, at least in OECD countries, in the industry sector, rather than the power sector. There was some evidence in Europe in 2022, that the very high gas prices resulted in gas being displaced in some industries, which could burn both gas and oil in their boilers, by oil products. However, generally over

⁹¹ The adjusted coal price assumes gas-fired power is 50% efficient and coal-fired power is 33% efficient, while the additional carbon cost of coal relative to gas is some 4.2 cents per MMBTU per \$1 per tonne of the EU ETS carbon price.



most of the 2000s, gas prices have been sufficiently below competing oil prices, that the impact of oil prices on gas prices has been relatively limited. In the Asian LNG market, where long-term contracts have been generally linked to oil prices, spot cargoes are competing with oil indexed cargoes for the market. Where buyers have a choice between nominating additional cargoes under their long-term contracts or purchasing spot cargoes spot prices will be influenced by the oil indexed long-term contracts. Figure 24 compares the long-term oil indexed contract prices into Japan with the Japan spot LNG price.





Source: Argus Media

From 2010 through 2018, there was quite a strong correlation between Japan contract prices (oil indexed to the Japan Crude Cocktail - JCC) and the Japan spot LNG price, suggesting a possible influence of the contact price on the spot price. This relationship broke down in 2019 and 2020 as, initially, the surge in LNG supply drove global prices down and then Covid-19 hit demand. Rising demand in 2021 led to rising spot prices, including the sharp spike in early 2021 as the very cold weather in northeast Asia set in. In 2022, the Russian invasion of Ukraine, drove spot prices in Europe and Asia to very high levels, with the oil-indexed contract prices having no impact.

The relationship between different regional spot prices can also be a factor driving prices. With the globalization of the gas market, the advent of US LNG exported in significant volumes to both Europe and Asia, provides a mechanism for linking Henry Hub prices to European and Asian prices. These relationships between different regional spot prices are not so much competing fuels to gas, but more a reflection of the connectivity between regional markets in an increasingly globalised world.

Figure 25 compares the long run cost (full cost) and short run cost (variable cost only) of Henry Hub priced US LNG delivered to the European (TTF) and Asian (Japan) markets. The full – or long run – delivered cost of US LNG is 115% of Henry Hub plus a \$3 per MMBTU tolling fee⁹² plus the shipping costs and regasification costs. The variable – or short run – delivered cost ignores the tolling fee, the fixed shipping cost (the charter fee) and any fixed regasification costs, as these are sunk costs and are payable whether a cargo is lifted or not.

In terms of US LNG to Europe, since the US started exporting from the Gulf Coast in 2016, up until early 2020, the TTF price moved between the long run and short run costs. With Covid-19 hitting gas demand in 2020, between May and September, the TTF price was below the short run US LNG cost. This prompted the shutting-in of a large number of LNG cargoes from the US, since offtakers were not

⁹² The terms of the original Cheniere contracts from Sabine Pass.



covering their variable costs. If the TTF price is above the short run cost, there is still an incentive to lift and export, as there is at least some contribution towards the fixed costs.



Figure 25: US LNG Export Costs v TTF and Japan Spot Prices

Source: Argus Media and author's calculations

There is a similar message when considering US LNG to Japan, with just the period in 2018 when the Japan spot price went above the long run cost. This made Japan a more attractive market for US LNG than Europe. From mid-2021 onwards, the TTF and Japan spot prices went above the long run cost of US LNG and, obviously, in 2022, well above.

The hypothesis advanced here is that, at least under certain market circumstances, with a flexible and global LNG market, the spot prices in Europe and Asia, will move somewhere in the range of the long run and short run delivered US LNG costs.



The relationship between Henry Hub and TTF and Japan spot prices can also work the opposite way, with Henry Hub price being influenced by the netbacks from both TTF and Japan spot prices. The hypothesis is that the higher the netback from TTF and/or Japan spot, the greater the demand pull on US gas supply and the more upward pressure on Henry Hub. Conversely, the very low TTF and Japan spot prices in 2020, led to lower netbacks to Henry Hub and downward pressure, which ultimately led to the shutting in of US LNG cargoes. As an example, the netback from TTF to Henry Hub is shown in Figure 26. The netback from TTF is calculated as TTF less the tolling fee, the 15% uplift, the shipping cost and the regasification costs, for the long run netback. The short run netback ignores the tolling fee and the fixed shipping and regasification costs. Between 2016 and early 2021, Henry Hub was between the long run and short run netback from TTF, only falling well below the netbacks in the second half of 2021 and 2022.



Figure 26: TTF Netback to Henry Hub

Source: Argus Media and author's calculations

d) Market Tightness

Having discussed competing prices (broadly defined) as an influence on spot gas prices, in addition to the marginal costs – both long run and short run – let us turn back to the basic economics of supply and demand. Figure 20 illustrated a simple industry straight line demand and supply curves. Actual supply and demand curves are a lot more complex, with the elasticity of supply and demand not being constant over the whole ranges of price and volume. Figure 27 is again illustrative, but probably a better representation of what actual supply and demand curves are for a commodity such as gas.

The elasticity of supply and demand vary over the range of price and volume. The curves intersect where both supply and demand are elastic. This means that even a relatively significant change in demand or supply – in either direction – would change the price only by a small amount. On the other hand, if the curves intersected where either, or both, supply and/or demand curves were inelastic (i.e. vertical) then a relatively small change in supply or demand would result in a significant change in price. In section 8 we will use illustrative supply – demand curves to analyse and explain price movements in recent years.

In analysing price movements though, we would need to know where, on the supply and demand curves, the market is at that moment. This will depend on how tight the market is. For example, if there is an increase in supply, as we saw, for example in 2019 with the increase in global LNG supply, the TTF price halved between the second half of 2018 and the second half of 2019, from over \$8 per MMBTU to just over \$4 per MMBTU. This was a relatively large price response, suggesting the increase in supply moved the intersection of the supply-demand curves through the inelastic part of the demand



curve towards a more elastic part⁹³, with a rise in gas demand as there was a switch to gas-fired power from coal-fired power in Europe. This was moving from a relatively tight market in 2018 to a more oversupplied market in 2019. Any further increase in supply, therefore, would not have had much of an impact on the price if all the switching to coal had happened. In contrast, in a tight market, a small reduction in supply or a small increase in demand could have a significant impact on the price.



Figure 27: Illustrative Supply – Demand Curves for Gas

Volume

How tight the market is will depend on how much spare capacity there is to provide additional supply in the event of an increase in demand. When Russia was still supplying large volumes of pipeline gas, the amount of spare production capacity, which could utilise export pipelines, represented a measure of the tightness of the market. At the moment, in a globalised gas market, the spare capacity in LNG export plants, would represent a measure of market tightness. Figure 28 shows the utilisation rate of LNG export plants.

The utilisation rate is calculated as total LNG imports divided by available LNG export capacity. Available LNG export capacity is calculated as nameplate export plant capacity, adjusted for scheduled maintenance, unscheduled maintenance, technical issues, feed gas availability and also the ability of some plants to produce more than nameplate capacity.

Figure 28 illustrates the decline in utilisation in 2009 as a result of the financial crisis hitting demand at the same time as new Qatari trains came on line. In 2016 there was a similar weakness in demand before a recovery tightened the market through 2018 notwithstanding the rise in US LNG export capacity. With additional US capacity continuing to come on line in 2019 in excess of rising demand, the utilisation rate fell, falling even further in 2020 as Covid-19 hit demand. In 2021, gas demand started rising again, but LNG export capacity actually fell slightly as there was a lot of catch-up maintenance deferred from 2020. This resulted in a sharp increase in the utilisation rate, which increased even further in 2022 as Russian pipeline exports to Europe fell sharply and demand for LNG increased sharply. The utilisation rate increased to over 98 percent, which is effectively almost full capacity. There was little change in 2023 in terms of utilisation.

⁹³ This will be revisited in section 8.



Figure 28: LNG Export Capacity Utilisation



Source: NexantECA World Gas Model and author's calculations

How tight the market is, as represented by LNG export capacity utilisation, is an important factor in driving prices, when added to the mix of marginal costs and competing prices. The tighter the market, the more likely are prices to be driven towards the top of any range, taking into account marginal costs and the various forms of competing prices. The market tightness would also be a factor in the move between long run and short run pricing. The NexantECA World Gas Model includes a spot price module, which takes into account all the factors discussed here including marginal costs, the various competing prices and market tightness. The model and module are discussed in more detail in Annex 2.

e) How can 2022 be explained?

In looking at the various figures in this section, whether on marginal costs or the range of competing prices, it has probably not escaped notice that prices in 2022 were well above the levels of any of these price levels, so what happened? Figure 29 shows the TTF, NBP and LNG Northwest Europe (NWE) prices from mid-2021, when prices began rising, to mid-2023, when they had returned to similar levels as in mid-2021. The full analysis of price movements over this period will be undertaken in section 8, but it is clear that from early 2022 to early 2023, the TTF, NBP and LNG NWE prices were well above any competing prices or marginal costs. This is true even taking into account competition with oil in industry, efficiency gains, behavioural changes and even a price level which might lead to industrial closures.

From mid-June 2022 to mid-October 2022, the TTF price was above \$40 per MMBTU. The differential between TTF, on the one hand, and NBP and LNG NWE, on the other hand, reflected infrastructure congestion, as will be discussed later. The rapid decline in Russia's pipeline exports undoubtedly put upward pressure on prices, but the huge uncertainty as to whether Europe could cope if those flows disappeared completely. In the author's opinion, there was a big "fear" premium in the market, with the fear that Russian pipeline gas imports would disappear completely. In some respects, the market had ceased to be rational.





Figure 29: TTF, NBP and LNG NWE Prices: Mid-2021 to Mid-202394

Source: Argus Media

It is very noticeable that TTF prices peaked towards the end of August at over \$90 per MMBTU, and then began a sharp decline to get below \$50 per MMBTU by the end of September (still high) and below \$30 per MMBTU by the end of 2022. By June 2023, TTF prices had dropped briefly into single figures. The peak in prices pretty much coincided with the end of flows from Russia along the Nordstream pipeline, which was before the explosions which damaged both the operational Nordstream 1 and one leg of Nordstream 2. Russian flows had been reduced to imports via Ukraine and Turkstream, and have remained broadly at those levels ever since. Once the market had taken note of the fact that Russian flows had almost disappeared and, while demand had fallen, the surge in LNG flows into the European market had not only enabled the remaining demand to be met but had also allowed storage to be filled, it seemed that the "fear" premium had gone. The fear of losing Russian pipeline gas had now disappeared since Russian gas had largely already gone. The "sky hadn't fallen in" and the premium rapidly disappeared, although a degree of nervousness, to any perceived supply issues, still remains in a tight market.

f) Conclusions

A lot of the analysis of what determines the gas price in markets focusses on the marginal cost of supply clearing the market for a given level of demand. The hypothesis that price equals marginal cost in long-run equilibrium is only true in a perfectly competitive market, the conditions for which the global gas market does not meet.

While the marginal cost is not, in an imperfect market like gas, *the* price setter, it still has a significant influence. Most of the analysis focusses on the long-run marginal cost (LRMC) but in the period between 2017 and 2021, the TTF and Japan spot prices were above the LRMC⁹⁵ in 2018, before going below it in 2019 and 2020, and back above it again in 2021. In 2019 the prices were between the LRMC and the SRMC (short-run marginal cost), while in 2020 the actual prices were at or even below the SRMC. The last few years suggest that the spot prices moved between the LRMC and SRMC and even above the former or, occasionally, below the latter. Even if price was equal to marginal cost in the market, or that was an important driver, it is not clear, at certain times, whether this is LRMC or SRMC.

Other factors influencing spot prices can be broadly categorised as "competing fuels or prices". The coal price (adjusted for efficiency and the relative carbon cost) competes with the gas price in power generation as has been observed particularly in the US and Europe. Oil is also still a competing fuel to gas in many industrial processes. In the Asian market there are still a significant number of long-term contracts which are linked to oil prices. The long-term oil indexed contract prices for, say, Japan will influence the spot price, since buyers can nominate more under their contracts, if the spot price is higher

⁹⁴ These are daily month-ahead price quotes.

⁹⁵ As represented by the shadow price in the NexantECA World Gas Model



than the contract price, and down to the minimum take-or-pay levels if the spot price is lower. As noted in section 2, at certain gas price levels there are incentives for behavioural changes and for more efficient use of gas in industrial processes. At some price levels, as we saw in 2022, industries can close completely. An additional "competing price" influence could also be the delivered cost of US LNG to Europe and Asia respectively, with the delivered cost calculated on both a long-run full cost basis and a short-run variable or marginal cost basis.

A final impact on spot prices is how tight the market is. If there is plenty of spare capacity in, say, Russian production – as there was in the past – then Europe could easily meet any increase in demand by buying more Russian gas. The availability of spare LNG export capacity is also a key factor. In 2019, the sharp rise in global LNG supply exceeded the growth in demand, with the result that Europe absorbed the rising supply with prices falling sharply. In 2021, the market tightened as economic activity picked up post Covid-19, and Russian supplies to Europe were being slowly squeezed, as Gazprom withdrew spot sales from the St Petersburg exchange. In the current (late 2024) market environment, after the Russian invasion of Ukraine, which sent prices skyrocketing, there is little or no spare LNG export capacity. This market remains tight with prices still much higher than in 2019 and 2020.

Many factors impact the spot price. While the marginal cost – short run or long run – may not set the price, it is an important factor.

5. Fallacy No 3: Europe was hooked on cheap Russian gas

a) Russian gas to Europe

There was a common saying that, as Russian pipeline exports to Europe grew, Europe was becoming hooked on cheap Russian gas. Some politicians, especially from the US, often warned that Europe should not become reliant on Russian gas – calling it cheap. It is undoubtedly true that the volume of Russian pipeline gas coming to Europe has increased over time – up to 2021 at least.





Source: IEA Natural Gas Information

Pipe imports from Russia grew from just over 100 bcm in 1993 to just over 200 bcm in 2017. Germany has always been the largest importer, with well over 50 bcm a year on average from 2015 to 2021 as Nordstream came on line. Italy and Turkey were the next largest importers. Almost all the countries in Europe have received pipeline gas from Russia since 1993, apart from the more remote ones such as



the UK, Spain and Portugal⁹⁶. In 2023 the volume of Russian imports was down to 43 bcm, of which less than 20 bcm was to EU countries.

In terms of the proportion of European consumption, pipeline imports from Russia also rose over time, as shown in Figure 31. The percentage share was relatively stable from 1993 to 2000 at just over 25 percent. In the financial crisis in 2009/10 the share fell to some 23 percent, with the rebound in demand in 2010 being met by new Qatari LNG supply. As the new Nordstream supplies came on, and indigenous production in Europe began declining, the share rose to some 37 percent of total European consumption. Following the Russian invasion of Ukraine, the share declined to 20 percent in 2022 and even further in 2023. Between 2013 and 2021 inclusive, the Russian pipeline import share averaged 1/3rd of European consumption. It would be reasonable to claim that Europe was dependent on Russian gas if not hooked on it.



Figure 31: Europe Supply – Demand Balance

Source: IEA Natural Gas Information

b) Price of Russian Gas

Under the original long-term contracts, the price of Russian gas was linked to oil – principally oil product prices such as gas oil and fuel oil. As noted in section 2, the pricing of Russian gas changed in Europe as the market liberalized. By the mid-2010s, Russian gas had predominantly moved to hub pricing, but during the build-up of imports from Russia, it was oil-indexed.

In Figure 32 the BAFA price is the weighted average German gas import price including imports from Norway and the Netherlands as well as Russia, and while it was oil linked in the early 2000s, by 2015 it had largely moved to hub pricing. The figure also shows the Russia to Germany oil-indexed price (RUSGER) and the NBP and TTF spot prices. Apart from the peak winter price, the NBP price, and from 2006 the TTF price, was generally a bit lower than the BAFA and RUSGER prices through to 2008, and then from 2009 to 2014, the spot prices were significantly lower. The fact that spot prices were lower than the oil indexed prices was one of the drivers for contract renegotiations.

The key takeaway of this figure though is that Russian gas was not cheap, or at least not cheap at the price the European buyers were paying. While Europe, and Germany especially, may have been

⁹⁶ Gazprom's accounts show sales to the UK but this is not Russian gas delivered but purchases and then sales at the NBP hub



hooked on Russian gas, given the volume of imports from Russia, it was not cheap. Up until the early 2010s, most Russian gas was linked to oil prices, and for the most part these oil-indexed contract prices were above hub prices such as NBP and TTF. This differential was especially marked between 2009 and 2014, which was a key reason triggering the multiple contract renegotiations and the move to hub pricing. The history of this has been extensively covered at OIES by Stern and Rogers, including in the major book on international gas pricing – PITG – referred to in previous sections. In particular Chapter 4 of PITG, authored by Stern and Rogers, discussed the transition to hub-based gas pricing in continental Europe⁹⁷. When Russian prices were oil-indexed they were generally higher than hub prices – and not cheaper – and when the pricing under the contracts moved towards hub pricing, Russian gas was priced the same as other sources of gas whether pipeline or LNG, and so neither cheaper or dearer. In a liquid trading market, all participants are price-takers.





Source: Argus Media

c) The Costs of Russian Gas

Part of the confusion in thinking that Russian gas is cheap is that the costs of production and transportation to the European market are generally thought to be relatively low. Table 1 shows the estimated costs of producing and transporting gas from the main Russian fields in the Urals to Germany via the Nordstream pipeline when it was still operational.

There can be a range of costs partly due to whether the full long-run marginal costs (LRMC) are considered or whether just the short-run marginal costs (SRMC), which are just the variable costs of production and transportation. In addition, there is a wide range of production costs for Gazprom fields in the Urals, depending on the age of the fields.

⁹⁷ PITG, p 145-177



Real 2022 \$/MMBTU	SRMC		LRMC	
	Low	High	Low	High
Production	0.66	0.97	1.09	2.78
Russia Pipeline	1.04	1.04	1.04	1.04
Nordstream	0.56	0.56	1.59	1.59
Total (Pre Export Tax)	2.26	2.57	3.72	5.41
Export Tax	0.97	1.10	1.59	2.32
Total (Post Export Tax)	3.23	3.67	5.31	7.73

Table 1: Cost of Russian Gas to Germany – Average 2015 to 202098

Source: NexantECA World Gas Model

Another factor to consider is the export tax which Gazprom had to pay to the Russian Government, which is levied at 30 percent of the delivered sales price. Under the old oil-linked contract prices this would have been 30 percent of that delivered price, but once the pricing formulae moved to spot prices, it would have been 30 percent of the spot price in the relevant market. The table above calculates the export tax by uplifting the additive costs by 30 percent as a notional calculation of the "delivered" cost. In reality the 30 percent export tax would depend on the contract price or the spot price.

The range of the pre-export tax costs is between \$2.26 per MMBTU under SRMC and \$5.41 per MMBTU under LRMC. As noted earlier, by the mid-2010s most of Gazprom's sales into Europe had moved effectively to hub pricing. However, if we take the average oil indexed contract price between, say, 2006 and 2012 inclusive which was some \$11.91 per MMBTU (real 2022\$), the 30 percent export tax would have been some \$3.57 per MMBTU. The total costs, including the export tax, therefore would have ranged between \$5.83 per MMBTU (\$2.26 plus \$3.57) under SRMC and \$8.98 per MMBTU (\$5.41 plus \$3.57). With an average contract price of \$11.91 per MMBTU in the 2006 to 2012 period, this gave a healthy profit for Gazprom of around \$3 per MMBTU for the full LRMC calculation and over \$6 per MMBTU for the variable SRMC calculation. From the overall Russian state perspective – since the export tax is simply an intra-state transfer – the profit margin is another \$3.57 per MMBTU higher.

Since the early 2010s however, Gazprom has been more exposed to the spot price. The breakeven price for Gazprom, under the full LRMC calculation, would be around \$7.75 per MMBTU (export tax of \$2.32 plus the full LRMC of \$5.41). Under SRMC, the breakeven price for Gazprom would be around \$3.70 per MMBTU (export tax of \$1.11 plus \$2.57) for the High SRMC and \$3.25 for the Low SRMC (export tax of \$0.975 plus \$2.26). On an annual average, between 2013 and 2021 inclusive, the TTF price (in real 2022\$) has been below the full LRMC breakeven price for Gazprom of \$7.75 per MMBTU in 2016, 2017, 2019 and 2020. However, only in 2020 was the TTF price below the High SRMC Gazprom breakeven price, but at \$3.50 per MMBTU was still above the Low SRMC Gazprom breakeven price.

While Russian gas has never been cheap for European buyers, it has been highly profitable in most years in covering the full LRMC for Gazprom and in every year, except possibly 2020, in covering the SRMC for Gazprom. At the overall Russian state level, it has been highly profitable in every year on a cash basis, if only the variable costs needed covering.

d) Conclusions

Until recently Russia was a large supplier of pipeline gas to Europe, and in the last few years also LNG from Novatek's Yamal project. From the 1990s to 2010 Russian pipe imports supplied around 25 percent of Europe's gas demand. This percentage then rose in the 2010s, peaking at 37 percent in 2017. Since then, the percentage has fallen back, significantly so after the Russian invasion of Ukraine. It can certainly be said that Europe was heavily dependent on Russian gas if not hooked on it.

However, it was a fallacy that Russian gas was cheap. When Russian gas was linked to oil prices, for the most part these oil-indexed contract prices were above hub prices such as NBP and TTF. When the

⁹⁸ These averages in US dollars are taken from the NexantECA World Gas Model and should be taken as broad indications. The Russian production and pipeline costs are priced in roubles and the actual dollar value will vary in relation to the exchange rate, so in any one year the values may be quite different.



pricing under the contracts moved towards hub pricing, Russian gas was priced the same as other sources of gas whether pipeline or LNG, and so neither cheaper or dearer. In a liquid trading market, all participants are price-takers.

While the selling price of Russian gas was not cheap, it is true to say that Russian gas was relatively low cost – hence the possible confusion. However, the low cost of producing and transporting Russian gas to Europe, meant that the pipeline exports were generally very profitable for both Gazprom and the Russian state.

6. Fallacy No 4: The TTF price is high...the market is broken

a) The TTF rollercoaster in 2022

Section 4 included a brief discussion of what happened to prices in the European gas market in 2022 and we will return to this in section 8. As Russia invaded Ukraine and the gradual, then accelerated, decline in pipeline imports began, the gas market went into some kind of meltdown, and governments, politicians and less-than-expert commentators became very exercised about the TTF price. Figure 33 shows the TTF, NBP, Northwest Europe LNG and Japan spot prices⁹⁹.





Source: Argus Media

The main statistical takeaways from this figure are that all four prices were largely converged or the same until the beginning of April 2022. The LNG NWE and ANEA prices largely tracked each other for the whole of 2022. From the beginning of April 2022, TTF was at a significant premium to NBP, especially until they converged again at the end of October. And TTF was at a premium to LNG NWE (and ANEA) almost until the end of the year. The result of both the very high price levels and the divergence of TTF prices from NBP and LNG prices, led to the cry that the TTF market was "broken", hence the push for the ill-informed price cap on TTF and the search for alternative pricing benchmarks.

Apart from the record high TTF prices, the trigger for the belief that the TTF market was "broken" was the observation that TTF was at a large premium to LNG NWE and NBP as well as Asian spot LNG

⁹⁹ These are all the month-ahead price

¹⁰⁰ ANEA – the Argus Northeast Asia LNG price is Japan spot.



prices. The European Commission led by Ursula von der Leyen (UDL), the Commission President, and Kadri Simson, the Energy Commissioner, pursued the theme that something needed to be done about the TTF price. In a letter¹⁰¹ to the European Council on 5th October 2022, UDL wrote that:

"Today, much of Europe pays a higher price for its gas, in particular LNG, than its global competitors. The main price benchmark for all gas traded in the EU, the Title Transfer Facility (TTF), is no longer representative of the imported gas."

The letter went on to say that the Commission was starting work on a *"complementary EU price index to better reflect Europe's energy reality of today and ensure a better functioning market conducive to lower prices."* UDL also said that they were considering a limitation on the TTF price.

Following the October 5th letter Kadri Simson (KS) stated at a press conference on 12th October 2022¹⁰², following an informal meeting of EU energy ministers: *"The TTF gas benchmark is a crucial area," she said, noting it was no longer representative of the reality of market fundamentals and had become "artificially inflated".*

KS further echoed this theme a week or two later in a speech¹⁰³ launching the Commission's proposals on joint purchasing, a new price benchmark and a planned cap on TTF prices (the quaintly named market correction mechanism), noting that *"While TTF was a good proxy for the EU gas prices when we received large amounts of Russian pipeline gas, this is no longer the case."*

Before the October 5th 2022 letter, UDL in her state of the union address on September 14th 2022 said¹⁰⁴ "Our gas market has changed dramatically: from pipeline gas to increasing amounts of liquid natural gas". The TTF has not adapted, she added, and so the commission would start work on a new LNG index."

The OIES has written widely on the joint purchasing mechanism, the LNG index and the market correction mechanism, exposing the fundamental flaws in all of them. It is not the intention of this paper to repeat this analysis and the reader is directed to the papers in these footnotes¹⁰⁵¹⁰⁶¹⁰⁷. This paper will focus on the panic reaction of the European Commission and the deeply flawed superficial analysis that led to the claims that TTF was "no longer representative…had become artificially inflated…and was no longer a good proxy for the EU gas prices." In addition, to assert that there is a difference between pipeline gas and LNG¹⁰⁸, betrays a singular lack of understanding of basic chemistry! This is a great example of politicians – and everybody else – being very keen on market forces when they produce an outcome they like; e.g. the very low prices in 2020, and very negatively when they produce an outcome they do not like (2022).

The proponents of this analysis failed to understand the economics of congestion and the role of infrastructure bottlenecks¹⁰⁹. While the economics of congestion is not always covered in first year undergraduate economics courses, by the final year, any half decent economics degree will have done (the author's first Economics degree certainly covered it, although this was many years ago!). The economics of congestion is often used to consider congestion pricing. A useful summary of congestion pricing, with some examples, is in the link in the footnote below¹¹⁰. It is often used in road pricing e.g. congestion charges and, more recently, in ride-sharing apps such as Uber and Lyft. Utilities also use congestion pricing in peak use times.

While the initial reaction of the European Commission to the rapidly rising TTF prices, that somehow the TTF "market was broken", may be partly attributable to panic, it does appear that there has still not been any deep or thoughtful analysis of what the real causes of widening differentials in the market

¹⁰¹ https://www.euractiv.com/wp-content/uploads/sites/2/2022/10/Letter-2.pdf

¹⁰² https://montelnews.com/news/1358853/eu-to-rein-in-inflated-ttf-prices-but-cap-consensus-lacking

¹⁰³ https://ec.europa.eu/commission/presscorner/detail/en/SPEECH_22_6245

¹⁰⁴ https://www.economist.com/finance-and-economics/2022/09/15/the-european-commission-searches-for-a-gas-price-villain

¹⁰⁵ Fulwood. M. (2022). The Consequences of Capping the TTF Price, OIES Oxford Energy Comment.

¹⁰⁶ Barnes. A. (2022). EU Commission proposal for joint gas purchasing, price caps and collective allocation of gas: an assessment. OIES NG 176

¹⁰⁷ Barnes. A. (2023). EU Joint Purchasing of Gas – an assessment. Naturgy Foundation, OIES NG 184

¹⁰⁸ LNG is a form of transporting gas just like a pipeline.

¹⁰⁹ Which is rather strange as the EU has been very good at promoting investments in gas networks over time to remove infrastructure constraints and bottlenecks.

¹¹⁰ https://www.investopedia.com/terms/c/congestion-

pricing.asp#:~:text=Congestion%20pricing%20is%20considered%20a,a%20resource%20during%20peak%20demand.



were. This is illustrated in the recent report by Mario Draghi on the future of European competitiveness¹¹¹. The report notes that "*LNG prices are typically higher than pipeline gas on spot markets owing to liquification and transportation costs.*"¹¹² No evidence is presented for this assertion (as there is none) as the LNG Northwest Europe (NWE) price is almost all the time below the TTF price. That the LNG NWE price was much lower than TTF in 2022 was also used as "evidence" that the TTF was "broken". The report also claims that "*In 2022, US LNG shipments were around 50% more expensive than average pipeline gas imported into the EU*"¹¹³, citing a paper by Di Comite and Pasimieni ¹¹⁴, although the chart in this paper does not appear to show this¹¹⁵. It may be that there is some confusion between the costs of US LNG and the estimated cost of pipeline gas as opposed to actual prices in the market, or a misunderstanding of the data used.

The Draghi report further suggests that there should be a move away from spot-linked sourcing of gas¹¹⁶. The suggestion is that gas purchasing should move closer to a fixed pre-determined cost rather than to spot market prices. There is currently nothing to prevent European buyers entering into long-term contracts with US projects on a Henry Hub plus basis, as other offtakers of US LNG have been doing since US Gulf Coast LNG started up in 2016. However, purchasing gas on that basis exposes the buyers to the basis differential risk between Henry Hub and TTF.

The mechanism proposed by the Draghi report is to enhance the joint procurement¹¹⁷ by a single EU buyer in the hope that this would lead to more stable and lower prices. It even suggests that prices could be linked to Henry Hub prices and possibly fixed (cost-plus). Again, there is nothing to prevent current Europe buyers contracting on a Henry Hub linked basis and even at fixed prices but this requires willing sellers to participate in this process, as well as taking on the basis risk. The Draghi proposal seems to be more wishful thinking and an attempted return to a pre-liberalised market of over 20 years ago.

The Draghi analysis of the very high energy costs in 2022 was that the market structure and system was at fault, not the dramatic loss of gas supply from Russia. In actual fact the response of the market was to reduce gas demand and encourage more LNG to come to Europe. This was painful but the flexible and liberalised markets worked exactly as they were supposed to.

b) Economics of Congestion and Infrastructure Constraints

In 2022 gaps opened up between TTF and NBP, and TTF and the Northwest Europe LNG price (and hence the Asian spot LNG price). Between TTF and these other prices there are normally differentials (basis differentials), which reflect relative transportation costs and regasification charges, but the differentials in 2022 far exceeded these norms.

The differential that arose between NBP and TTF reflected the infrastructure constraints on the pipelines between the UK and Belgium (Interconnector) and the UK and Netherlands (BBL). These are both bidirectional pipelines. Figure 34 shows the daily flows from the beginning of 2020 to the end of March 2023. Imports into the UK are negative values and exports from the UK are positive values. 2020 and 2021 illustrated the "normal" state of flows between the UK and continental Europe. The UK would export to Europe in the summer months and import from continental Europe in the winter months. In the summer of 2020, the UK exported gas to continental Europe, and then in winter 2020/21 imported gas, effectively using continental Europe as gas storage. This usual state of affairs changed dramatically in 2022, as Russian pipeline exports to Europe declined, and the UK imported much larger volumes of LNG and then, effectively re-exported these volumes via the Interconnector and BBL. From early April 2022 to early November 2022, the Interconnector and BBL pipelines were operating, pretty much at maximum capacity, exporting gas from the UK. The Interconnector maximum export capacity is around 60 mmcmd and BBL maximum export capacity is around 15 mmcmd. Between the beginning of April and the end of October the average export flow in total, to both Belgium and the Netherlands, was just under 70 mmcmd. This period of running at pretty much maximum export capacity coincided exactly with the period that TTF was at a significant premium to NBP. From early November 2022, the export

¹¹¹ Draghi. M. (2024). The Future of European Competitiveness, European Commission.

¹¹² Draghi.M, Part A p 39 and Part B p 9.

¹¹³ Draghi.M, Part B p 9.

¹¹⁴ Di Comite, F, Pasimeni, P., Decoupling from Russia: Monitoring Supply Chains Adjustment in the EU, 2023.

¹¹⁵ Di Comite, F, Pasimeni, P, p 27.

¹¹⁶ Draghi.M, Part B p 26.

¹¹⁷ Draghi.M, Part B p 27.



flows diminished and the NBP/TTF wide differential disappeared. It is also noticeable that the pipelines remained in export mode from the UK throughout the 2022/23 winter, because of continental Europe's need for gas.





Source: ENTSOG

The differential between TTF and LNG NWE prices reflected infrastructure constraints also but this time in the regasification terminals in Northwest Europe, specifically, Dunkirk (France), Zeebrugge (Belgium) and Gate (Netherlands). The newer terminals in the Netherlands and Germany did not become operational until late 2022 and 2023. Figure 35 shows the monthly LNG imports for Dunkirk, Zeebrugge and Gate terminals between the beginning of 2021 and the end of 2023.

The total nameplate capacity for the three terminals is some 34 bcm/year, or just under 3 bcm/month (3,000 mmcm). The total imports of LNG in 2022 were some 42 bcm, well above the nameplate capacity. Dunkirk nameplate capacity is 12 bcm and through 2022 largely ran at 1,000 mmcm/month. However, both Zeebrugge and Gate ran at well over their nameplate. Zeebrugge's nameplate was some 9 bcm/year and imported 13.5 bcm in 2022, while Gate nameplate capacity was some 12 bcm/year and imported just over 15 bcm in 2022. Even adding some 30 percent to both Zeebrugge and Gate capacity¹¹⁸ to more reflect actual available capacity over a whole year, would not quite cover the total monthly flows in 2022.

The clear message, however, is that for most of 2022, the ability to import LNG into the three terminals was constrained. Again, the period of constrained LNG import capacity coincided with the large divergence between TTF and LNG NWE (and Asian spot LNG). The divergence began in mid-March 2022 and the prices did not really converge again until December 2022, by which time the new Eemshaven FSRU had started up in the Netherlands, alleviating some of the constraints, followed by the Wilhelmshaven and Brunsbuttel FSRUs in German in early 2023.

¹¹⁸ The real capacity of an LNG import terminal (and export terminal for that matter) is a vague concept, and what determines the capacity can be any one of a number of factors – number of tankers that can dock each week, unloading times, storage capacity, vaporisation rate and the entry capacity to the pipeline system. The nameplate is generally a conservative figure the engineers will guarantee.



Figure 35: LNG Imports: Dunkirk, Zeebrugge and Gate



Source: Kpler. GIIGNL, NexantECA World Gas Model

TTF had significant differentials with NBP and LNG NWE for much of 2022 but what of the other European hubs? Figure 36 shows the differentials between TTF and 5 other European hubs – THE (Germany), VTP (Austria), PSV (Italy), PEGN (France) and PVB (Spain) – for 2021 through 2023. The real divergence in prices began around April 2022, widening significantly in the second half of the year and only beginning to narrow in early 2023. THE, VTP and PSV prices rose to premiums to TTF while PEGN and PVB were at a discount.

The discounts to TTF for PEGN and PVB were not that surprising, since the constraints and bottlenecks in the European pipeline system are significant where gas is trying to move from west to east, particularly from France. The interconnection between France and Germany was designed to move gas from Germany to France and there is little ability to move gas from France to Germany. France has export points with Belgium, one of which is a direct connection from the Dunkirk LNG terminal, but in total these comprise some 16 bcm, which is significant but would become quickly constrained in a tight market.

The hubs which rose to a premium over TTF were THE, VTP and PSV, all in countries – Germany, Austria and Italy - which were most impacted by the decline in gas from Russia, with constraints which prevented gas flowing into Northwest Europe from Norway and via the Netherlands and Belgium.

A paper¹¹⁹ by the author, published in September 2022, identified a sub-region within Europe which would be the most adversely affected by the loss of pipe imports from Russia, with severe consequences in the event of a cold winter. The countries in this sub-region were Germany, Czech Republic, Slovakia, Austria and Hungary, together with the Netherlands and Belgium as suppliers to the region. It was not surprising, therefore, that hub prices in the sub-region were at a premium as the supply became constrained.

¹¹⁹ Fulwood. M. (2022). Europe's Infrastructure and Supply Crisis, OIES Oxford Energy Comment.



Figure 36: European Hub Differentials from TTF



Source: Argus Media

c) Other Examples of Congestion and Infrastructure Constraints

Europe is not the only gas market where significant price differentials have opened up between gas hubs. There have been examples in the US as shale gas production grew in different regions. Two of those instances are discussed here. For readers not necessarily familiar with the US natural gas market, the map in Figure 37 is the US natural gas transmission network with relevant hubs and pipelines noted.

The first instance relates to the wide differentials between the Opal Hub in Wyoming and Henry Hub in Louisiana, which is the main US price benchmark. The Opal Hub price was at a significant discount to Henry Hub from 2005 to early 2010. The Colorado and Wyoming basins had traditionally fed the western US markets, especially California via the Kern River pipeline, which began operations in 1992. As production in Colorado and Wyoming grew in the late 1990s and early 2000s, the pipeline capacity to take gas from these states to key markets was filled up. As a result, the prices at the Opal Hub declined relative to other hubs. There was congestion at the entry (or receipt) points to the pipelines and producers would "bid" down the price they received for their gas to get into the pipelines. This large discount – often in the \$3 to \$5 per MMBTU range – prompted the producers to support a new pipeline – the Rockies Express - to flow gas from west to east to the much higher priced markets in Chicago and Ohio, which were at a premium to Henry Hub.

The Rockies Express pipeline was completed in 2009 with the capacity to flow some 37 bcm/year of gas¹²⁰. As a consequence, the differentials between Opal Hub and Henry Hub (as well as other hubs) narrowed significantly, easily paying for the costs of the pipeline.

¹²⁰ France consumed 37 bcm in 2022 just to compare the size of the pipeline.



Figure 37: US Natural Gas Pipeline Map



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

An irony, however, of the Rockies Express pipeline is that it has never operated anywhere near its full west to east capacity, as the Ohio and Chicago markets were increasingly fed by the rapid rise in shale gas production from the Marcellus and Utica basins. The rise in shale gas production was so large that the eastern leg of the Rockies Express reversed its flow to move gas from eastern Ohio to the Chicago markets. The fact that the Rockies Express pipeline did not operate anywhere near the full capacity booked by the producers did not matter, since the discount at the Opal Hub to other hubs narrowed dramatically and the producers received higher prices for their gas.

The second instance is more recent and relates to the Permian basin shale oil and gas in West Texas. This gas is predominantly associated gas from shale oil production. The discount to Henry Hub became apparent in 2018 and 2019 – and has also re-emerged recently. Shale gas production¹²¹ from the Permian basin had already begun to rise rapidly from around 2012 – when it was some 12 bcm – through 2017 when it reached some 46 bcm. This rise could be met largely by existing intrastate pipeline capacity but as this became constrained, the Waha Hub price opened up a large discount to Henry Hub, with prices in some cases turning negative – as it was associated gas and the oil was still very profitable to produce. This prompted the construction of multiple new intrastate pipelines to evacuate the associated gas. As these pipelines were completed, the differentials¹²² narrowed but recently have reemerged on the back of rapid production growth. Permian basin shale gas production in 2023 reached 168 bcm – the same level of gas production as Qatar. As with the Opal Hub example, the congestion caused by trying to get gas into restricted pipeline capacity led to widening differentials, which were alleviated once more capacity was built.

¹²¹ Source for shale gas production is the US Energy Information Administration

¹²² The huge spike in February 2021 was when the wells froze in West Texas as a result of the freezing weather



Figure 38: US Hub Differentials from Henry Hub



d) Conclusions

The significant differentials that opened up between TTF on the one hand, and NBP, LNG NWE and Asian spot prices in 2022, led to the European Commission, notably Ursula von der Leyen and Kadri Simson, and other politicians, to claim that TTF was no longer fit for purpose. Ursula von der Leyen noted that "*The main price benchmark for all gas traded in the EU, the Title Transfer Facility (TTF), is*



no longer representative of the imported gas."¹²³ While Kadri Simson said "While TTF was a good proxy for the EU gas prices when we received large amounts of Russian pipeline gas, this is no longer the case."¹²⁴ These comments and many others were a panic reaction by politicians who needed to be seen to be `doing something' and finding somebody or something to blame. There appeared to have been no attempt to understand that these differentials reflected infrastructure constraints.

The TTF premium to NBP coincided exactly with the period when the Interconnector pipeline between UK and Belgium and BBL between UK and the Netherlands were operating at maximum export capacity from the UK. Once the pipelines exporting from the UK were not operating at full capacity in November 2022, the TTF/NBP differential almost completely disappeared and returned to "normal" levels.

The other constraint was at the three regasification terminals serving Northwest Europe in 2022 – Dunkirk (France), Zeebrugge (Belgium) and Gate (Netherlands). From early 2022, the terminals were operating at or well above their nameplate capacity. However, towards the end of 2022, the Eemshaven FSRU in the Netherlands began operations, which alleviated the capacity constraints, followed by a couple of German FSRUs in early 2023. The TTF differential to the LNG NWE price was removed at the end of 2022 as prices converged again, with the constraints released.

Widening differentials between TTF and other hubs in continental Europe were also noted in 2022. TTF was at a premium to PEGN and PVB, reflecting pipeline capacity constraints in moving gas from west to east, especially at the French border with Germany. However, THE (Germany), VTP (Austria) and PSV (Italy) had higher prices than normal relative to TTF, with constraints on the ability to move gas eastwards when the usual flows had been westwards.

There are other examples, notably in the US gas market, where wide differentials between hubs opened up because of pipeline constraints. The examples were the Opal Hub in Wyoming, where rising gas production outstripped pipeline export capacity, and the Waha Hub in West Texas, where rapidly rising associated shale gas production overwhelmed the ability to move gas from west to east, with Waha then at a significant discount to Henry Hub.

The key conclusion is that when there are infrastructure constraints leading to congested markets, differentials between markets, impacted by the constraints, will widen, often by large amounts. These abnormal differentials disappear once the constraints are alleviated. The fact that TTF rose to large premiums over NBP and LNG prices in 2022 did not mean that, somehow, the TTF was not working properly or not representative of EU gas prices. The suggestion by the European Commission, notably Ursula von der Leyen and Kadri Simson, that this was the case, was a panic reaction, with little or no attempt to understand the economics of congested markets. The recent Draghi report also misunderstood what happened in the gas market in 2022 and made proposals to attempt to go back to a pre-liberalised world of over 20 years ago, which seems to be somewhat naïve. In fact, in the face of enormous disruption to the European and global gas markets, the liquid trading market actually worked extremely well, as will be argued in Section 8. Patrick Heather has written regularly on the liquidity of European trading hubs, with the latest instalment being published recently¹²⁵.

¹²³ https://www.euractiv.com/wp-content/uploads/sites/2/2022/10/Letter-2.pdf

¹²⁴ https://ec.europa.eu/commission/presscorner/detail/en/SPEECH_22_6245

¹²⁵ Heather. P. (2024).



7. Hypothesis: Multi-Dimensions and The Value of Gas

a) Development of Markets

The development of the global gas market and, before that, gas markets in individual countries and regions, was essentially no different to the development and origins of most markets for goods and services. In talking about markets, people often think of the weekly market in their local town, selling a variety of goods, focused on food and produce. This type of market can be traced back to medieval times, when chartered markets and new towns were established across Western Europe¹²⁶.

In economics, the market is often described in abstract terms as an intersection of supply and demand, with competitive forces assumed to generate an equilibrium market price. As noted in Casson and Lee¹²⁷, "this raises the question of where the market is actually located and where the people who use the market actually reside. The answers to these questions lead to the concept of the market as a place, serving a particular area in which its participants reside. The participants meet at the market because it is an information hub."

Market behavior has generally been governed by rules relating to price, quality control, freedom of entry etc.., enforced by law, by agreement and social convention. This provides reassurance to customers and maintain the reputation of the market system. This is true for all markets and not just regulated natural monopolies, such as utilities.

The establishment of markets at transport hubs and/or centres of consumption, enabled long-distance trade to take place, further stimulating the growth of hubs. The Silk Road from China is a good example. In early western Europe, marketplaces often developed close to castles, monasteries or royal/aristocratic residences, trading not only necessities but also luxuries. If these markets were situated close to rivers, which could be bridged, they promoted the development of a town.

The period between 1050-1330 saw a rapid expansion in the number of markets and fairs¹²⁸. These were easier to identify and document in regions where there was a distinct franchise, such as England, where the right to establish and operate a market was granted by the Crown. Fairs often provided supplies of high-value commodities, but largely only on a once-a-year basis. With the growth of the population and towns, shops were developed and open all year round, complementing markets and fairs. With the development of new products, especially in clothing, the small shops expanded into department stores, selling an ever-increasing range of products and services. This was followed in recent times by the development of shopping centres, malls and out-of-town outlet centres.

The enduring feature of medieval markets and fairs, shops, department stores and, more recently, shopping centres and malls, is the physical locations where buyers and sellers meet to trade. With the development of the internet, a substantial amount of trade has moved online, or become virtual, in some cases leading to the demise of shops and department stores.

This short digression into the development of markets is designed to show that the current local, regional and global gas markets are no different from those markets in medieval times, and the whole market structure for trading gas is built on this. Hubs were not an invention of gas traders and the developing gas market, but the concept is seven to eight hundred years old. Similarly, the long-distance trade of gas via pipeline and LNG, mirrors long-distance trade in goods many hundreds of years ago. More recently, the concept of a virtual gas hub, such as NBP and TTF, is conceptually little different from the online shopping revolution seen recently. The early markets and fairs were also subject to licences and regulations, notably on the quality of the product. The ease with which gas can be traded relies heavily on the homogeneity of the gas molecule, which is governed by the gas quality specifications laid down, mainly in the regulations of the pipeline transporters, but overseen by regulatory bodies.

¹²⁶ For a brief history of the development of markets see Casson, M. and Lee, J.S. (2011). *The Origin and Development of Markets: A Business History Perspective,* Business History Review 85 (Spring 2011) p 9-37. Harvard College

¹²⁷ Casson, M. and Lee, J.S. (2011). p 13 ¹²⁸ Larger markets usually held annually



b) Development of Hubs

The development of hubs is described in more detail in Annex 3. There is a brief summary here. The regulatory and operational aspects of these hubs are designed to make the buying, selling and trading of natural gas easy to undertake

Henry Hub is owned and operated by Sabine Pipe Line LLC and its affiliates. It is actually one end of the Sabine Pipeline, which is a bidirectional mainline pipeline that stretches from Port Arthur, Texas, to the Henry Hub. It is an interstate pipeline that is certified as an open-access gas transporter, and it is directly connected to four industrial consumers and one producer. Henry Hub is interconnected to eight interstate pipelines and three intrastate pipelines. It also has a direct connection to storage facilities. These facilities are salt-dome caverns characterized by high deliverability and high cycling rates, which allow for several withdrawal and injection cycles each year. The transfer of gas from one pipeline to another via the Sabine Pipeline / Henry Hub is facilitated by Sabine Hub Services through its IHT (Intra-Hub Transfers) service. IHT is a nonjurisdictional accounting service used to track multiple title transfers of natural gas packages at a market centre. This enables the simple trading of gas at the Henry Hub.

Unlike Henry Hub, which is a physical point on the Sabine Pipeline system and enables interconnections with multiple pipelines, the NBP or National Balancing Point is what is known as a "virtual" point. The pipeline system in the UK operates an entry-exit system for booking and paying for transmission capacity and for the nomination and scheduling of gas flows. The system entry points are largely the coastal terminals, while the exit points are offtakes from the national transmission system to local distribution zones or to major off-takers, such as power plants. The NBP is effectively the whole of the national transmission system since when gas enters the system, it is effectively at the NBP until it exits the transmission system.

While Henry Hub and the Sabine Pipeline allow for the transfer of gas between many different interconnecting pipelines, in the UK there is only one transmission pipeline system. Apart from that, there is great similarity between the way the Sabine Hub Services IHT works and the way the UK system works through the nominations process.

The TTF in the Netherlands is also a "virtual" trading point whose structure was largely based on the NBP and is described in more detail in Annex 3.

Even though Henry Hub is a physical hub and NBP and TTF are "virtual" hubs, they essentially serve the same purpose in that they are all "meeting points" or market centres at which parties can buy and sell gas with the title transferring between them under agreements put in place by the hub or pipeline operators using the nominations processes. While NBP and TTF are described as virtual hubs, they are in essence little different to Henry Hub. NBP and TTF are virtual in the sense that there is no exact physical location on a map where they can be identified. However, they are both products of the physical gas transmission systems in the UK and the Netherlands, respectively, just as Henry Hub is the product of the physical Sabine Pipeline. NBP and TTF physically represent the entirety of the UK and Netherlands gas transmission systems in that as soon as gas enters each of those systems, it is "at" NBP or TTF until the gas exits those systems.

In some respects, the NBP and TTF trade nominations process makes trading somewhat easier than at Henry Hub, promoting multiple trades of the same molecules of gas. However, this can also be achieved at Henry Hub if the parties nominating under the IHT can net off flows. For example, if a party is delivering 100 units of gas to interconnection pipeline A but also receiving 60 units of gas from interconnection pipeline A, then the party only needs to deliver 40 units of gas on a net basis to balance its flows under the IHT.

HH, NBP AND TTF are all in countries with significant domestic production and gas storage facilities.

The trading of gas at hubs sets a price in the market. As noted earlier, the most heavily traded and liquid period is for the month-ahead. For physical trading, the Henry Hub month ahead price is set during what is known as bid week. Bid week is the last five business days immediately preceding the first of each month. Although the daily spot market for natural gas in the US is active and trading can occur at any time, the largest volume of trading occurs on these five days, when monthly transactions for baseload gas deliveries the following month are typically completed. The average bid week prices are then used to set monthly indices commonly used to price indexed gas contracts.

For NBP and TTF the comparable indexes are set as the average of the daily closing prices for the month-ahead contract (M+1) in the preceding month. Rather than the five business days immediately



preceding the first of each month – as for bid week in the US – it is all the business days, immediately preceding the first of each month, which are averaged to set the monthly index.

The concept of bid week in the US looks remarkably similar to the medieval markets or fairs which occurred, on a weekly or monthly basis at the locations or hubs. All the buyers, sellers and traders were aware of the market taking place, where and when, and turned up to engage in trading.

c) Financial Markets

The establishment of hubs was instrumental in enabling the physical trading market to develop and grow. As liquidity increases and physical trading grows, then the possibility of developing a futures or financial market arises.

The first natural gas futures market was introduced by CME NYMEX in April 1990, with Henry Hub being the underlying physical location for the market. A participant in the CME NYMEX gas futures market will automatically go to physical delivery unless the open position is closed before expiration. The delivery process resulting from the futures contract represents the linkage between the physical market and the financial market. The Henry Hub contract is traded in monthly periods for the current year and the following 12 years. The volume for a single monthly contract is 10,000 MMBTU. The ICE (Intercontinental Exchange) also has a Henry Hub futures contract similar to CME NYMEX, which trades for monthly periods but with a single contract of 2,500 MMBTU, mostly for monthly trades but sometimes for daily. The trading time horizon is for 13 years, similar to CME NYMEX. However, the ICE contract is cash settled and doesn't go to physical delivery, with any open contracts being automatically cashed out at the NYMEX settlement price. If any party wants to convert to physical delivery, then this has to be done in bid week, in the first two days, since all open positions in CME NYMEX Henry Hub futures close on the third business day before the end of the month.

The UK NBP futures contract was started by the International Petroleum Exchange (now owned by the ICE) in February 1997. The NBP futures not only has monthly contracts—running for 78 to 83 months but also 11 to 13 quarters, 13 to 14 seasons (winter/summer), and 6 years. The trading unit is a lot - 1,000 therms per day - and the minimum trading amount is five lots or 5,000 therms per day. For a 30day month, the total minimum volume would be 150,000 therms, which is equivalent to 15,000 MMBTU—larger than the NYMEX monthly minimum trade. The NBP futures contract is deliverable if the contract is not closed out before reaching the settlement day. In practice, however, virtually all contracts are closed (and cashed) out before the settlement day is reached. Following on from the NBP futures contract, futures contracts were developed for TTF by ICE and the European Energy Exchange (EEX).

The futures market has developed to such an extent that the volume of trading on the futures market now far outweighs the volume of trading on the physical market, as noted by Cornerstone¹²⁹ and Heather¹³⁰. The enormous volume of trading taking place on the futures markets, especially by purely financial players such as banks and hedge funds, has led some commentators and politicians to claim that this speculative activity had driven TTF prices to levels significantly above the "true" market price. Hence, in part, the rationale for the fallacious claims that the TTF market was broken – see Section 6 of this paper. As noted, part of this argument related to the futures market¹³¹. The report reviewed what had happened in the European gas market in 2022 and came to the same conclusion as this paper, that the TTF price was much higher than other benchmark prices in Europe because of infrastructure constraints and these differentials disappeared once the constraints were resolved. The Oxera report also contained a section on the impact of speculative trading on gas pricing¹³². The report noted that:

"Speculators play an important role in gas markets by providing liquidity and taking the other side of the trade to hedgers. While commodity markets including the gas market cannot function without the presence of speculative trading, some concerns have been raised about the potential risk that 'excessive' speculation in gas futures has amplified the

¹²⁹ Cornerstone Research. (2021)

¹³⁰ Heather. P. (2023)

¹³¹ Oxera (2022). The European Gas Market, Report prepared for ICE. Oxera Consulting

¹³² Oxera (2022). p 54-58



price and volatility in the market over the levels that can be justified by the underlying fundamentals alone."

As the Oxera report noted, a functioning market requires some degree of speculation to balance out hedging demands. The report used a measure of speculation level called Working's T index¹³³. The Working's T-index aims to capture the level of speculation in excess of what is required in a balanced market for hedging purposes. In a market where long hedging positions exceed short hedging positions, the index is calculated as a ratio of 'other' long positions to total (long and short) hedging positions. Vice versa, in a market where short hedging positions exceed long hedging positions, the index is calculated as a ratio of 'other' hedging. A 'high' T-index does not by itself imply excessive speculation, but the index may provide a useful overview of the prevalence of speculation over time.

The report included a figure presenting the Working's T-index values for the TTF Gas futures. This showed that "despite the increased volatility in 2022, there has not been a significant increase in excessive speculation as defined by the index. Since the start of 2022, the T-index has fluctuated between 40% and 65%, well below the highs of over 150% seen in 2018"¹³⁴. The figure also showed that the T-index in 2022 was at similar levels to the index in 2020 and 2021 and lower than the T-index in 2019.

It is important not to confuse excessive speculation with high volatility of gas prices. In fact, the volatility of TTF prices in 2022 – as measured by the standard deviations of daily returns over a ten-day rolling window (annualised) – was not that different from the volatility levels since the beginning of 2019, apart from a short period coinciding with the Russian invasion of Ukraine. However, this measure of volatility – using the standard deviation – is normalised by the level of prices¹³⁵. Clearly, as a figure¹³⁶ in the Oxera report shows, the absolute volatility rose sharply towards the end of 2021 and into 2022, simply because absolute prices were rising.

The Oxera report concluded that, overall, there was no evidence of excessive speculation driving prices or volatility. In addition, the bid-ask spreads were stable, in line with historical trends, open interest values were stable and the trading base remained diverse¹³⁷.

d) Multi-Dimensional Approach

As has been discussed earlier, the drivers of natural gas prices are complex. While the discussion of fallacy number 2 – that price equals marginal cost – showed that there are multiple factors impacting prices, the underlying forces of supply and demand still represent the primary drivers of gas prices. However, the forces of supply and demand – and the myriad other drivers – manifest themselves differently depending on the state of the market. The price drivers are not linear and attempting to portray the influences on gas prices on a simple two-dimensional chart is unlikely to stand the test of time.

The hypothesis described here starts from the perspective that a multi-dimensional approach is needed to analyse gas prices. Specifically, the state of the gas market – is it supply-long or a tight market – will dictate which of the price drivers and influences are more or less important, and especially whether the market is in a short-run or long-run marginal cost world, or somewhere in between.

Figure 39 attempts to represent these multi-dimensional aspects on a two-dimensional chart. The chart shows a price curve for gas – rising as the market gets tighter – and plotting the key drivers of prices at different points on the curve, combining these drivers with the state of the market – is it supply long or supply short – and whether short-run or long-run marginal cost pricing predominates. The state of the market is the primary driver of gas prices and this translates into the relative importance of short-run or long-run marginal cost pricing. Depending on what sort of world or state of the market we are in, will then determine what the most important secondary drivers will be. These secondary drivers can be loosely described as the competing prices. These were discussed in section 4 covering fallacy number 2 that price equals marginal cost.

¹³⁶ Oxera (2022). Figure 5.20, p 57

¹³³ Working, H. (1960), Speculation on hedging markets, Food Research Institute Studies, 1:2, pp. 1–36

¹³⁴ Oxera (2022). p 54

¹³⁵ Standard deviation measures the variance relative to the mean, so if the average price is increasing the absolute variation is also increasing for a constant standard deviation.

¹³⁷ Oxera (2022). p 3.



The hypothesis – and the chart – can be described as follows:

- In a supply-long world, short-run marginal cost pricing will predominate. The key competing prices
 are likely to be, in the LNG market, the variable or short-run cost of delivering US LNG to markets
 and in the end-use markets, the competing coal price¹³⁸. The long-run or full cost netback from
 Europe and Asian spot prices to the US may also impact Henry Hub prices. A rise in absolute
 volatility in prices might also be expected.
- In a more balanced world neither supply-long nor supply-short we may be somewhere in between short-run and long-run marginal cost pricing and other competing prices are likely to come into play. The long-run or full cost of delivering US LNG to markets may be a key influence and also in the end-use markets, HSFO prices in industry and oil-indexed contract prices (at least in the Asian LNG markets) are likely to be key drivers.
- In a supply-short world, long-run marginal cost pricing will predominate. In this state of the market, higher levels of oil product prices may factor in but also, we are likely to see significant demand responses in industry in terms of efficiency gains and, if prices get driven higher, behaviour changes in households (turn down the thermostat) and potentially industrial closures. The impact of coal prices, for example, will no longer be a factor, with any switching from gas to coal in power generation having already happened.

In summary, as the state of the market changes – or as it tightens – the world moves from more shortrun pricing to long-run pricing and different "competing prices" are more or less important.



Figure 39: Multi-Dimensional Analysis of Gas Price Drivers

US LNG SRC: Short-run marginal cost of delivered US LNG SR Netback: Short-run netback from TTF/Asian spot to Henry Hub HSFO Price: High sulphur fuel oil price GO Price: Gasoil price Source: Author's Analysis

LR Netback: Long-run netback from TTF/Asian spot to Henry Hub US LNG LRC: Long-run marginal cost of delivered US LNG LSFO Price: Low sulphur fuel oil price

However, the chart should be regarded as a "schematic", presenting the stages that the gas price moves through as the market changes. In particular, where the competing prices have been placed in the chart, are illustrative and should not be taken as firm indications of the relative importance or even order. The competing prices may also be relevant or have an impact over a wide range of market states and gas

¹³⁸ Adjusted for efficiency and relative carbon costs



prices. For example, if the coal market is very tight and coal prices high, this could be a factor much higher up the range of gas prices, even towards long-run marginal cost. The market is very dynamic and can be fast-moving, so this is very much a framework for analysis. In the next section on explaining historical and future gas price movement, we will return to this chart and attempt to place different years and/or periods on the chart and explain why.

It is also important to note that prices can go below short-run marginal cost and above long-run marginal cost so these are not floors or ceilings. This will be further illustrated in the next section.

Another way of thinking about the dynamic and multi-dimensional nature of gas prices and the key drivers, might be as ordering a meal in a restaurant. In a tight, supply-short market, you might want a hot, spicy dish adding in a bit of "efficiencies", "behaviour changes" and if very, very spicy some "industrial closures" – accompanied by a full-bodied red wine. In a more balanced market, maybe a bit less spicy just adding in "oil-indexed contract prices" and "US LNG LRC", accompanied by a light red wine. While in a supply-long market, a very mild meal adding the least spicy "coal price" and "US LNG SRC", accompanied by a chilled white wine!

e) Globalization and the Value of Gas

In section 2 it was concluded that the global gas market is now well connected and globalized, with the advent of US LNG exports playing a big part in this globalization. While prices globally are not necessarily the same, they would tend to converge in a globalized market and be driven by the same underlying factors.

The previous sub-section outlined the numerous drivers of gas prices and how they interacted at different times and in differing states of the market. The underlying marginal costs – whether short run or long run – are key factors, together with the tightness of the market and also the variety of "competing prices". The combination of supply and demand and the various competing prices, will determine a price which clears the market, at the perceived value of gas. All participants become price-takers. If one party values a product more highly than another party then the former will pay the price and buy the product. This is true for any good or service, whether it be gas, apples or tickets to a Taylor Swift concert! The brutal reality of this fact was exposed in 2022, when European buyers valued gas more highly than buyers in Pakistan, and were prepared to pay a higher price, which led to Europe getting the LNG and Pakistan going short, with resulting power cuts.

Figure 39, on the multi-dimensional nature of gas price drivers, showed the importance of supply and demand, but also brought in the influences of other factors to determine the ultimate price, based on the value in the market. While costs of delivering gas to the market are an important factor, the other influences will also determine the value of the gas in the market. If one or more suppliers have a cost base which is too high then they will stop supplying the market, until such time as the value of gas in that market rises again. This was well illustrated in 2020, when the prices in Europe and Asia were so low that, even on a short-run marginal cost basis, it did not make economic sense for offtakers of US LNG to lift cargoes and ship them, so they were shut in, until the value of gas rose again.

In the global gas market, therefore, the key markets are in Europe, Asia and North America. The value of gas in these markets can be represented by TTF, Northeast Asia spot prices¹³⁹, and Henry Hub. These markets, and others, are interconnected, largely, through LNG movements, with Henry Hub "exporting" LNG to multiple markets. Conceptually, LNG can be considered to move from producing markets to LNG "pools" and on to the consuming markets. The seaborne trade of LNG, over long distances, is somewhat akin to the medieval Silk Road from China to the west. A conceptual map of connections between producing markets, LNG "pools" and consuming markets is shown in Figure 40.

¹³⁹ Such as JKM or ANEA



Figure 40: Connecting the Globalised Gas Market




The map does not show every single market nor supply source or even hubs, but all the key ones. Demand centres are in the grey boxes and are North America, Northwest Europe, Southern Europe, Latin America, South Asia, Southeast Asia, China and Japan, Korea and Taiwan¹⁴⁰. Supply centres are in blue boxes but only represent the main exporting countries and/or regions, with production within regions, which just supply that region only, ignored. The supply centres are North America, Trinidad, Peru, Norway, North Africa, West Africa, East Africa, Middle East, Caspian, Russia West, Russia East and Asia Pacific¹⁴¹. The pricing centres, or hubs, are yellow circles and linked to demand centres – Henry Hub to North America (and to supply as well), TTF to Northwest Europe and Southern Europe and Northeast Asia Spot to China and Japan, Korea and Taiwan. Panama and Suez canals are the light green circles.

The LNG "pools" (light orange boxes) are designed to represent the notional points through which LNG passes on its way between supply centres and demand centres. The notional points are Pacific East, West Atlantic, North Atlantic, South Atlantic, Mediterranean, Indian Ocean, Singapore¹⁴², Northeast Asia and Pacific West. The notional points are connected to each other via the solid red lines, while supply centres feed in through the dashed red lines and the demand centres offtake via the dotted red lines. Pipelines are represented by the purple lines.

The value (or price) of gas is determined at the hubs, through the multi-dimensional analysis of gas price drivers. The hub "value" then transfers to the demand centres – for TTF this would be to NWE and SE – and from the demand centres to the LNG "pools". At each LNG "pool", therefore, there will be a notional value of gas or LNG. At the NAT pool, it would correspond to the netback from TTF via NWE. The NAT value can then netback to other pools such as MED, WAT and SAT and so on. Via MED the value from TTF can netback to INOC (going via Suez), or also to INOC via SAT. The value of gas or LNG at INOC, however, could also be the netback from the Northeast Asia "hub" via CN and JKT and then NEA and SG pools. If the globalized market is working as expected then the hub prices and relative values at the pools would adjust, to equalize the value netbacks at INOC.

LNG from North America¹⁴³ (NA) has multiple routes to the Asian markets or the NEA pool. The route could be from WAT via the Panama Canal and PACE and PACW. It could also be via NAT, MED, the Suez Canal and then INOC and SG, and finally from WAT via SAT (around the Cape of Good Hope) and to INOC and beyond. This gives three possible value netbacks to WAT from the NEA pool, which if the market is working in a globalized way, should equate.

Calculating the netbacks between the LNG pools should reflect the relative shipping costs, but while they can be calculated on various assumptions to provide an estimate, it is not necessarily straight forward. What type of LNG tankers should be used, together with various assumptions on speed, fuel used etc, and also, whether the calculation should be on a full, or long run, cost basis or on a variable, or short run, cost basis.

Just as with the multi-dimensional analysis of the gas price drivers, the conceptual map of the connected globalised gas market, represents a framework for considering the drivers of international gas prices. The map reflects the value of gas at different points around the world, irrespective of the source or cost of the different supplies of gas at those points. The cost of supplying gas or LNG can be calculated, under various assumptions, delivered to various points, and then compared with the value at those points. This will simply provide information on the relative profitability of different sources of supply to that point and eventually to a hub. For example, for the value at NAT, LNG from Qatar, whichever route is taken – via Suez or Cape of Good Hope – is likely to be more profitable (the cumulative costs are lower) than LNG from the US or elsewhere.

¹⁴⁰ Middle East would also be a demand centre but has been omitted for simplicity.

¹⁴¹ Asia Pacific comprises the LNG exporting countries of Australia, Papua New Guinea, Indonesia and Malaysia.

¹⁴² Singapore is the Malacca Straits area.

¹⁴³ The map currently ignores Canadian west coast LNG, which would connect into the PACE pool



f) Conclusions

The development of the global gas market and, before that, gas markets in individual countries and regions, was essentially no different to the development and origins of most markets for goods and services. Weekly markets, in local towns, sell a variety of goods, focused on food and produce. This type of market can be traced back to medieval times, when chartered markets and new towns were established across Western Europe. These medieval markets often laid down rules and regulations over who could offer goods for sale and control the quality of such goods, enforced by law and regulation.

The development of hubs in the gas market – either physical or virtual – is not a new idea, but a continuation of the medieval markets of hundreds of years ago, as is the long-distance trade of LNG, similar to the seaborne trade of the Silk Road. Gas hubs developed as a result of the liberalization of gas markets in the US and Europe. Henry Hub was the first and started as a physical location in Louisiana at the Henry gas processing plant. Rules and regulations for trading at the hub on standard contracts promoted the use of the hub as a key trading point. The NBP hub in the UK drew a lot on Henry Hub but was a "virtual" hub, essentially comprising the whole of the GB national gas transmission system. Again, a standardized contract developed which encouraged trading. TTF in the Netherlands, which is now the preeminent European gas hub, largely copied the NBP model.

The development of trading at the prompt and forward led to the development of price indices with the month ahead, or M+1, being the most heavily traded in both the US and Europe. On the back of the physical trading at the hubs, financial futures markets developed, linked to the physical hub traded month-ahead contract. The financial markets developed to such an extent that the trading on these markets now outweighs the physical trading, and there is little difference between the two, other than the financial markets not going to physical delivery.

The big rise in prices in Europe in 2022, following the Russia invasion of Ukraine, led to some commentators and politicians to blame excessive speculative trading for the increases. A report by Oxera¹⁴⁴ dispelled this notion concluding that, overall, there was no evidence of excessive speculation driving prices or volatility.

What drives natural gas prices is complex. There are multiple factors impacting prices, including costs and competing prices, as noted in previous sections. The underlying forces of supply and demand – and the myriad other drivers – manifest themselves differently depending on the state of the market. The price drivers are not linear and attempting to portray them on a simple two-dimensional chart is unlikely to be accurate. A multi-dimensional approach is needed to analyse gas prices. Specifically, the state of the gas market – is it supply-long or a tight market – will dictate which of the price drivers and influences are more or less important, and especially whether the market is in a short-run or long-run marginal cost pricing is likely to predominate, with competing coal prices also a factor. If the market is supply-short or tight, then long-run marginal cost pricing is likely to predominate, with competing is likely to predominate, with competing coal prices also a factor. If the market states which could demand reductions also key factors. In between there are a whole range of market states which could be somewhere between short-run and long-run pricing with multiple difference competing price drivers.

This multi-dimensional approach in essence sets the value of gas in these markets. All participants become price-takers. With a globalized gas market, the values of gas in different markets are interconnected, especially European and Asian markets. If the price, or value, rises in, say, the Asian markets then the TTF price can be pulled up to keep the relative values in balance, and vice-versa. As LNG moves around the globe, the value of the cargo changes, depending on the relative prices at the hubs and its location. This can prompt diversions of cargoes to higher value markets. The underlying cost of the gas and the associated infrastructure, such as the tanker, becomes irrelevant once the cargo has left the export terminal. All that matters is the value of gas at that location.

¹⁴⁴ Oxera (2022). The European Gas Market, Report prepared for ICE. Oxera Consulting



a) Historical Gas Price Movements

The previous section set out a hypothesis on what drives international natural gas prices, noting that a multi-dimensional approach was required. The state of the gas market – is it supply-long or a tight market – will dictate which of the price drivers and influences are more or less important, and especially whether the market is in a short-run or long-run marginal cost world, or somewhere in between. This multi-dimensional approach in essence sets the value of gas in these markets, with all participants becoming price-takers. With a globalized gas market, the values of gas in different markets are interconnected, especially European and Asian markets.

This section will analyse historical gas price movements in the context of the hypothesis of the multidimensional approach and the value of gas. The periods considered will be before 2016 and the startup of US LNG, 2016 to miid-2021 moving from an oversupplied to a balanced market in 2018, before another supply surge in 2019, followed by the impact of Covid-19 in 2020 and the demand recovery in 2021, and finally mid-2021 to date, covering the Russian invasion of Ukraine and the rebalancing of the market starting in 2023.

i. Pre-2016 and US LNG

The pre-2016 period will largely consider the ten years up to 2016, starting around the same time the IGU began their wholesale price surveys. The world in 2005 was certainly not globalized and the only really liberalized trading markets were in the US and the UK – liberalization had not spread to the rest of the EU in 2005¹⁴⁵. EU liberalization took place largely over the ten years up to 2015. Figure 41 shows the evolution of spot prices from 2005 through to 2016. The TTF price series did not start until 2006¹⁴⁶. What is noticeable about the period from 2005 up until 2009, was that Henry Hub and European spot prices were highly correlated and close together. This was before the shale gas boom in the US and the US was still importing significant volumes of LNG.





Source: Argus Media, SP Global

¹⁴⁵ Australia's gas market was also liberalised at that time.

¹⁴⁶ The Japan spot series is a combination of the S&P Global JKM and Argus ANEA assessments but prior to 2009 estimated spot cargoes from Argus.



The US decoupled from the rest of the world from 2010 onwards as shale gas production grew and imports of LNG declined. In 2007, the US was the fourth largest importer of LNG in the world behind Japan, Korea and Spain, importing some 22 bcm. By 2013 LNG imports were less than 3 bcm, mainly to Boston to alleviate constraints in New England.

Turning to the European and Asian markets over the period, there were a number of significant events. Global economic growth was relatively robust from 2005 until the financial crash at the end of 2008 and into 2009. This was reflected in oil prices (Brent) rising from an average of \$55 a barrel in 2005 to over \$130/barrel in mid-2008, before they fell to \$40/barrel in December 2008. They recovered to back over \$100/barrel in early 2011 and remained there until early 2014 when they began to fall back sharply. The financial crisis of late 2008 weakened global gas demand and this put downward pressure on global commodity prices including spot gas prices. Then in March 2011, the Fukushima incident led to the closure of Japan's nuclear fleet, with a corresponding increase in demand for alternative power generation fuels – oil, coal and natural gas.

Figure 42 summarises the movements in the shadow price (LRMC) and the tightness of the market¹⁴⁷ over the period to 2016.



Figure 42: Shadow Prices and Market Tightness – 2006 to 2016

Source: NexantECA World Gas Model

The Europe and Asia Pacific¹⁴⁸ markets were relatively tight through the period to 2009, until the financial crisis. As gas demand was hit, this coincided with the Qatari expansion bringing additional

¹⁴⁷ See Annex B for a description of market tightness

¹⁴⁸ Asia Pacific in this chart is defined as the Asia Pacific importers – Japan, Korea and Taiwan



LNG supply on line. This combination impacted Asia Pacific tightness more because that region was more dependent on LNG imports. The shadow price for Europe¹⁴⁹ was relatively stable over the period at around \$5/MMBTU in real 2023 prices, only rising at the end of the period. For Asia Pacific¹⁵⁰, the shadow price was around \$6/MMBTU until the beginning of 2012 when it jumped sharply, reflecting the impact of the Fukushima accident and subsequent nuclear power closures on LNG demand, with a higher cost supply needed, together with some demand response to the higher prices. The gradual fall in spot prices, for both TTF and Japan spot, from 2014 and through 2015 and 2016, reflected an easing of the market tightness, in Europe especially, and a fall in the shadow price for Japan. Gas demand in Europe was falling over this period from a peak in 2010 and pipeline supply from Russia was rising.

The TTF price is compared below with the adjusted coal price¹⁵¹ and the Brent oil price in \$/MMBTU. Apart from brief periods in 2007, 2009/10 and right at the end of 2016, the TTF price was significantly above the adjusted coal price, and generally well below the oil price. While the oil price might have been expected to have an influence on the TTF price, at least indirectly through the oil-indexed contract prices. However, the impact of oil-indexed contract prices on the TTF price was diminished and largely eliminated completely in the early 2010s as the European market switched to gas-on-gas pricing. The adjusted coal price, in part, was well below the TTF price, since the EU ETS carbon price was mostly below \$10/tonne.



Figure 43: TTF, Coal and Oil Prices – 2006 to 2016

Source: Argus Media

For the Asia Pacific market i.e. Japan, the spot price was highly correlated with, and influenced by, the oil-indexed contract price. The growth of spot cargoes in Japan was relatively modest until the advent of US LNG from 2016 onwards, and the main driver, therefore, of the spot price was likely to be the competing oil-indexed contract price. As Figure 44 shows, the spot and oil-indexed contract prices were both highly correlated and close together, suggesting, in the absence of a globalized gas market, that local and regional influences predominated.

¹⁴⁹ This is for the Netherlands (TTF)

¹⁵⁰ Shadow price is for Japan

¹⁵¹ Adjusted for the relative carbon cost of coal and relative efficiency





Figure 44: Japan Spot and Contract Prices - 2006 to 2016

Source: Argus Media, S&P Global

In the ten-year period to 2016, before the advent of substantial quantities of US LNG, the three main markets (the US, Europe and Asia) were, for the most part, separate markets, and there was no effective globalized gas market. The US market effectively decoupled from the rest of the world from around 2010 as the rapid growth of shale gas began and the need for LNG imports reduced dramatically. The European and Asian markets had some connection via LNG trade, but the market remained heavily contracted under mostly oil-indexed contracts. The level of gas-on-gas competition (traded markets and spot LNG), in global LNG imports, between 2010 and 2016 averaged some 25%, with Europe mostly traded markets and the wider Asia Pacific region all spot LNG. While there were some diversions and trading between regions, this was relatively limited with only Qatar having any significant flexibility.

As a consequence, spot prices in Europe were driven by regional supply-demand fundamentals, with occasional interaction, at lower spot price levels, with the adjusted coal price in the power sector. As European markets completed the process of market liberalisation, any relationship or interaction between spot gas prices and either oil prices or oil-indexed contract prices disappeared. Looking back, it seems that spot gas prices decoupled from oil prices in the early 2010s. This was very noticeable in 2014 when TTF declined from \$13/MMBTU in January 2014 to less than \$8 in early 2015. Oil prices, on the other hand, remained well over \$100/barrel through most of 2014, only beginning to decline in September of that year.

In contrast, spot prices in Asia Pacific – specifically the Japan spot price – continued to be highly correlated and influenced by the oil-indexed contract price, as well as by local supply-demand fundamentals, notably after the Fukushima incident when demand for LNG increased sharply.

Figure 39 in section 7 illustrated the multi-dimensional approach to analysing gas prices. Figure 45 replicates that figure but shows where the years in this period might fit. Most of the years are in the range of a balanced market, with only the 2009-10 financial crisis and then 2016 when LNG supply was increasing, tending more towards short-run marginal cost.





Source: Author's Analysis

ii. 2016 to Mid-2021

In 2016 spot prices in Europe and Asia had come down from the 2013 to 2015 levels. While gas demand was rising, there was increasing LNG supply from Australia and the start-up of new US LNG, plus more availability of LNG from Algeria. In addition, Europe was able to make use of increasing pipeline supply from Russia and Algeria, further easing the market. TTF prices averaged around \$4.50/MMBTU in 2016 and Japan spot at \$5.75 was lower than the previous lows in 2009.

While demand continued to grow through 2017 and 2018, LNG supply was increasing rapidly from the US, Australia and then the start-up of Yamal LNG in 2018. In 2018, however, there was a relatively cold winter and Europe drew down heavily on its storage stocks. Gas in storage in Europe declined by some 73 bcm between November 1 2017 and March 31 2018 – the largest ever withdrawal. This led to a need to refill a similar amount by the end of October 2018, which put upward pressure on TTF prices, especially with pipeline supplies to Europe not growing as much.

In 2019, there was a huge 75 bcm increase in available LNG export capacity, as a lot more US and Australian LNG came on line and Yamal in Russia ramped up to full capacity. This rise in LNG supply outweighed increasing demand, with the excess LNG finding a home in European storage, putting downward pressure on prices, with TTF reaching a low of \$3.56/MMBTU in July 2019. Japan spot was well below \$5 in the third quarter of 2019, reflecting the increasing globalisation of the gas market, with European and Asian prices increasingly moving together.

In 2020, Covid-19 hit demand, with LNG export capacity projects continuing to ramp up. As a result, prices fell even further, with TTF falling below \$3/MMBTU for the March 2020 contract and not going back above \$3 until October 2020. A low of \$1.55/MMBTU was reached in June 2020. Japan spot prices also went below \$3/MMBTU between May and August 2020. TTF actually fell below \$3 before Covid-19 hit demand so the fundamentals were already sending the price down further. The author wrote a paper in October 2019 arguing that the TTF price was heading below \$3 in 2020, followed by further papers on the subject in 2020¹⁵². With the very low prices for much of 2020, one market response was

¹⁵² Fulwood, M. (2019), Could we see \$2 gas in Europe in 2020, OIES Oxford Energy Comment

Fulwood, M. (2020), \$2 gas in Europe is here: who will blink first? OIES Oxford Energy Comment

Fulwood, M. and Sharples, J. (2020), \$2 gas in Europe (Part III): Down, Down, Deeper and Down OIES Oxford Energy Comment



for offtakers of US LNG to not lift – and shut-in – their contracted cargoes, since the price they would receive in the European and Asian markets would not even have covered their variable costs. It is estimated that maybe some 15 bcm of US LNG was shut in during 2020, representing some 18 percent of total available US LNG export capacity.



Figure 46: Spot Prices – 2016 to Mid-2021

Source: Argus Media, S&P Global

As the economies began to reopen in late 2020 and into 2021, gas demand began to rise, especially in Asian markets. This was compounded by a cold northern hemisphere winter, hence the sharp rise in Japan spot prices in February 2021 to over \$18/MMBTU. European prices were rising because of the tightening market, but did not spike like Asian prices as Europe could access its abundant storage. TTF prices began rising more rapidly in the summer because of the need to refill storage.

The movements in gas storage in Europe are often heavily correlated with movements in spot TTF prices. Both in 2018 and 2021, the need to refill storage, following large winter withdrawals, led to rising prices. In summer 2019, Europe was able to accept the extra supply of LNG by filling up storage.

Compared to TTF and Japan spot, Henry Hub prices were relatively stable over the period. Henry Hub had largely decoupled from the rest of the global gas market but increasing LNG exports began to recouple the US to the rest of the global gas market.

Figure 47 considers the market tightness from 2016 to mid-2021. Europe shows a rise in market tightness from 2016 to 2018 and then a fall to 2020, before the beginnings of an increase in 2021. However, these changes were relatively gradual, compared to Asia Pacific (the importers), which is more reliant on LNG, so the market tightness reflects the LNG market a lot more than Europe. There was a similar rise in tightness in Asia Pacific and Europe through 2018, but in 2019 and 2020, the fall in Asia Pacific was much sharper, reflecting the LNG supply surge, while Europe's pipeline supply was tightening compared to 2016.







Source: NexantECA World Gas Model

Figure 21 in section 4 is a chart of the long run and short run shadow prices from the NexantECA World Gas Model between 2017 and 2021, with the actual spot prices also plotted. This figure is reproduced n Figure 48. The long run shadow prices average around \$7.50/MMBTU for TTF and just over \$8 for Japan spot. However, the argument is made, that in supply-long periods short-run marginal cost pricing may be more relevant and the short run shadow prices averaged under \$5/MMBTU for TTF and just over \$5 for Japan spot.





Source: NexantECA World Gas Model, Argus Media



The short run shadow prices also are much closer to the outturn spot prices in 2019 and 2020. In 2021, actual spot prices rose sharply above the long run shadow prices, which were rising.

Figure 49 shows TTF and coal prices from 2015 to mid-2021. 2015 is chosen as the start year since, in that year, TTF prices were above the adjusted coal price, only going down to the coal price level in 2016, as TTF prices fell. The competitiveness of TTF relative to coal was helped by the rising EU ETS price, until the decline in TTF prices in 2019 and 2020 took TTF well below the adjusted coal price. As was shown in section 4, lower TTF prices than coal prices in 2019 and 2020 resulted in a significant increase in the share of gas relative to coal in EU power generation.



Figure 49: TTF and Coal Prices – 2015 to Mid-2021

Source: Argus Media

In the period 2006 to 2016, the Japan spot price was highly correlated with and close to the oil-indexed contract price. Figure 50 looks at this relationship from 2016 to mid-2021. The strong relationship seemed to continue until the beginning of 2019, at which point Japan spot prices fell well below the oil-indexed price and it could be argued that the relationship had broken down. This reflected, firstly the huge LNG supply surge in 2019 followed by the impact of Covid-19 on demand in 2020.

It was also from 2016 onwards that the rapid rise in gas-on-gas (GOG) pricing in LNG began as US LNG came online. At the global level, from an average of around 25% in the early 2010s, the GOG share had risen to 46% by 2021 and in volume terms from around 85 bcm in 2016 to 220 bcm in 2021. This growth is making Asian markets less dependent on contract LNG linked to oil prices and more on spot and flexible LNG.

61





Figure 50: Japan Spot and Contract Prices - 2016 to Mid-2021

Source: Argus Media, S&P Global

With the advent of US LNG exports from the Gulf Coast in 2016, and their subsequent rapid growth, it was noted in previous sections that the full (or long-run) cost and the variable (or short-run) cost of delivering US LNG to markets could be key drivers of spot prices in those markets. Figure 25 in section 4 plotted the long-run and short-run costs of delivering US LNG to the European and Asian markets, compared with the actual TTF and Japan spot prices. For the 2016 to mid-2021 period these charts are reproduced below.

The full – or long run – delivered cost of US LNG is 115% of Henry Hub plus a \$3/MMBTU tolling fee¹⁵³ plus the shipping costs and regasification costs. The variable – or short run – delivered cost ignores the tolling fee, the fixed shipping cost (the charter fee) and any fixed regasification costs, as these are sunk costs and are payable whether a cargo is lifted or not.

In terms of US LNG to Europe, since the US started exporting from the Gulf Coast in 2016, up until early 2020, the TTF price moved between the long run and short run costs. With Covid-19 hitting gas demand in 2020, between May and September, the TTF price was below the short run US LNG cost. This prompted the shutting-in of a large number of LNG cargoes from the US, since offtakers were not covering their variable costs. If the TTF price is above the short run cost, there is still an incentive to lift and export, as there is at least some contribution towards the fixed costs.

There is a similar message when considering US LNG to Japan, with the Japan spot price being higher than the long run cost only in 2018, apart from the cold weather induced spike in February 2021. In the period from 2016 to mid-2021 spot prices in Europe and Asia generally moved somewhere in the range of the long run and short run delivered US LNG costs.

¹⁵³ The terms of the original Cheniere contracts from Sabine Pass.





Figure 51: US LNG Export Costs v TTF and Japan Spot Prices – 2016 to Mid-2021

Source: Argus Media and author's analysis

The relationship between Henry Hub and TTF and Japan spot prices can also work the opposite way with Henry Hub price being influenced by the netbacks from both TTF and Japan spot prices. The hypothesis would be that the higher the netback from TTF and/or Japan spot, the greater the demand pull on US gas supply and the more upward pressure on Henry Hub. Conversely, the very low TTF and Japan spot prices in 2020 led to lower netbacks to Henry Hub and downward pressure, which ultimately led to the shutting in of US LNG cargoes. As an example, the netback from TTF to Henry Hub is shown in Figure 52. The netback from TTF is calculated as TTF less the tolling fee, the 15% uplift, the shipping cost and the regasification costs, for the long run netback. The short run netback ignores the tolling fee and the fixed shipping and regasification costs. Between 2016 and mid-2021, Henry Hub was generally between the long run and short run netback from TTF, apart from the short period in 2020, coinciding with the shut-ins of some cargoes.

With the growth of shale gas production from the late 2000s, and the consequential reduction in the need for the US to import LNG, it was argued earlier that the US market had decoupled from the rest of the global gas market in the 2010s. With the rapid growth in US LNG exports, there is now a strong argument to suggest that there has been some recoupling of the US market with the rest of the global gas market. US LNG exports now make a significant demand on US gas supply, although domestic demand still dominates the market.





Figure 52: TTF Netback to Henry Hub - 2016 to Mid-2021

Source: Argus Media and author's analysis

In the previous sub-section, it was concluded that the three key markets of North America, Europe and Asia were largely separate regional markets before 2016. The US had decoupled completely from other markets and while there was some connectivity via LNG between Europe and Asia, this was somewhat limited. Spot prices in Asia still seemed to be largely driven by their relationship with oil-indexed contract prices, Europe had decoupled from oil prices post 2010, as the markets liberalised, and prices were largely driven by the regional supply-demand balance. The advent of US LNG, and with it, the increased flexibility of cargo destination has changed the global gas market. Japan spot prices in both Asia and Europe fell in 2019 and 2020 to well below long-run marginal costs and more towards short-run marginal costs. TTF prices also seemed to have a much closer relationship with adjusted coal prices, and both TTF and Japan spot stayed largely in a range between the short-run and long-run marginal cost of delivered US LNG.

We can now add the period from 2016 to 2020 to the multi-dimensional chart. 2016 was already on the previous period chart and was a supply-long year, so tending towards short-run pricing. 2017 and 2018 were more balanced with 2018 probably being one of the tightest markets since 2005, as the cold weather drove up demand and prices. In contrast, 2019 and then 2020, because of the glut of supply, followed by the impact of Covid-19 on demand, saw prices drop well into the short-run pricing zone.

64





Source: Author's Analysis

The years 2019 and 2020 lend themselves to illustrating what happened through supply and demand curves (as does 2021 but that is covered in the next sub-section). In section 4 an illustrative non-linear supply-demand chart was presented for gas. This illustrative chart has been adapted to show how the supply and demand balance changed in 2019 from 2018 and then 2020 from 2019.

As noted earlier, 2018 was, at the time, a relatively tight year. 2019 saw a big surge in LNG supply, at a point in time where TTF and adjusted coal prices were closely competing. The TTF price in 2019 dropped sharply, therefore, with an increase in demand for gas in the power sector, along a relatively inelastic part of the demand curve.

In contrast, 2020 saw a shift in demand compared to 2019, as Covid-19 hit. This brought the price down significantly, with the lower supply largely accommodated by the shutting-in of US LNG, along a more inelastic part of the supply curve.

These supply-demand curves are illustrative and are not meant to give a precisely accurate representation of what happened in the actual market, but to act as a guide to explain the changes. The next sub-section will use 2021 as an example.



Figure 54: Supply – Demand Charts – 2019 and 2020 2018 to 2019 Demand Supply 2018 Supply 2019 Price Volume 2019 to 2020 Demand 2019 Supply - Demand 2020 Price

Volume

Source: Author's analysis

iii. Mid-2021 to date

The sharp decline in prices in 2020 as a result of Covid-19 was outlined in the previous sub-section. As the various lockdowns were lifted, economic activity began to pick up, especially in the Asian markets. Added to this there was a widespread cold northern hemisphere winter in Q1 2021, which led to LNG being diverted away from Europe to the Asian markets. Spot prices in Europe did not initially rise with Asian prices, since Europe drew down on storage to meet demand. However, Europe's need to replenish storage stocks began to push up TTF and Asian prices. With demand in Asia, especially China, continuing to rise, the situation was compounded by a fall in available LNG export capacity, as many plants scheduled catch-up maintenance, delayed from 2020, and a fire at the Hammerfest plant in Norway took it offline until the middle of 2022. The situation was further exacerbated towards the end of the year, as Gazprom suspended sales of spot gas on the St Petersburg exchange. This tightening of the market was reflected in an increase in the utilisation of the capacity of available LNG export plants from 89 percent in 2020 to 96 percent in 2021. Even before the Russian invasion of Ukraine, TTF and Japan spot prices had risen to over \$35/MMBTU (January 2022), so tight was the market.

The sharp rise in prices from an already high level, following the Russian invasion of Ukraine, was briefly noted in section 6. Europe and the US responded by putting sanctions on all kinds of activities, although not on the purchase of Russian gas. However, a number of events resulted in a gradual decline



in imports of Russian gas by pipeline to Europe, starting with the Presidential Decree from Putin that unfriendly countries must henceforth pay for their Russian gas supplies in Roubles, rather than Dollars or Euros. When some European buyers refused to comply, their supplies were halted. Then the Yamal-Europe line was effectively closed when, on May 11, the Russia government placed sanctions on EuRoPol Gaz, which operated the Polish section, although Poland had already stopped taking Russian gas. In June 2022 Gazprom announced it was reducing the flow from 167 mmcm/d to 100 mmcm/d and on 16 June further down to 67 mmcm/d, justifying its actions by technical problems at Portovaya¹⁵⁴ – a giant compressor station feeding Nord Stream with gas. Nord Stream then entered its annual maintenance period in July 2022, to emerge briefly in August until flows stopped completely at the end of the month, before the pipeline (and one string of Nord Stream 2 as well) was blown up in September.



Figure 55: Spot Prices – 2020 to Mid-2024

Source: Argus Media, S&P Global

From an average of 240 mmcmd in January 2022, Russian pipeline flows to Europe fell to 160 mmcmd in June 2022 and to 74 mmcmd in September – with flows only on Turkstream and via Ukraine. Europe dealt with the loss of Russian pipeline supplies in two ways. Firstly, there was a sharp reduction in demand in industry and buildings¹⁵⁵. In respect of our multi-dimensional figure in section 7, we were well into oil-switching in industry, efficiency improvements and even some industrial closures. In the buildings sectors, there were behavioural changes, as thermostats were turned down. Secondly, Europe imported a lot more LNG, with imports rising over 60 bcm – or 60 percent – in 2022 over 2021. This was aided by a return to rising available LNG export capacity – in spite of the fire at Freeport in the US, which closed the terminal until well into 2023 – and reduced demand for LNG in China, as China locked down again. In addition, demand was lower than might have been expected because of a mild winter. In effect, Europe got lucky, to such an extent that storage was relatively easily filled up to, and, above the EU's newly imposed targets.

The TTF price, in the author's opinion, was also very high because of "fear". There was a fear, following the Russian invasion of Ukraine, that Russian flows would decline rapidly and even stop abruptly. The flows did decline rapidly and, almost at the same time as the Nord Stream pipeline was blown up, prices began falling back quite sharply. TTF prices (month-ahead) peaked at just under \$70/MMBTU in September but were back to \$35 by December 2022. Russian flows stabilised at their much-reduced levels of September, and despite the big loss of Russian pipeline gas, the market had readjusted to the "new normal" – the "fear" of losing Russian gas had gone away, because the Russian gas had already gone away and the "sky hadn't fallen in".

¹⁵⁴ This has been described in detail in Fulwood, M, Sharples, J, Stern,J and Yafimava,K. (2022), *The Curious Incident of the Nord Stream Gas Turbine* OIES Oxford Energy Comment

¹⁵⁵ Not in the power sector in 2022 as poor wind and nuclear shutdowns increased demand for fossil fueled power.



Prices fell further in 2023 as the market rebalanced and almost returned to levels similar to the mid-2010s. The average TTF price for the 12-month period from July 2023 to June 2024, was just over \$10/MMBTU, similar to the average for 2014.

The other noticeable price movement in 2022 was in Henry Hub prices, which had only rarely gone above \$4/MMBTU since 2010. However, in the final quarter of 2021, prices went above \$5 and then in 2022 to \$6, then \$7 and \$8 and even over \$9/MMBTU in September 2022. The average for 2022 was some \$6.64/MMBTU, compared to \$3.84 in 2021 and \$2.74 in 2023. Analysis by the US Energy Information Administration¹⁵⁶, suggested this was due to high first quarter demand on cold weather and freeze-offs affecting gas production, together with growing demand for US LNG. In the summer there was also higher demand for gas because of the need for cooling and to refill storage, which had been depleted in the cold winter.

Figure 56 considers the market tightness and shadow prices (LRMC) from 2020 to 2024 Q1. From the low levels of 2020, as noted above, there was a continued rise in tightness in both Europe and Asia Pacific (key importers), reaching record high levels.

This rising tightness was also accompanied by a sharp rise in the shadow price (LRMC) in 2022, as Russian pipe supplies to Europe diminished and more expensive supplies had to be acquired, but principally as the shadow prices began to reflect the costs of switching fuels in industry, efficiency improvements, behavioural changes and industry closures – effectively demand destruction – as was outlined in section 4.



Figure 56: Shadow Prices and Market Tightness – 2020 to 2024

Source: NexantECA World Gas Model

¹⁵⁶ https://www.eia.gov/todayinenergy/detail.php?id=55119



From 2016 to mid-2021 it was noted that TTF had a much closer relationship with adjusted coal prices, that Japan spot prices had decoupled from oil-indexed contract prices and both TTF and Japan spot traded largely within the range between US LNG long-run and short-run delivered costs. The sharp rise in prices in 2021 and 2022, meant that the relationships in the 2016 to mid-2021 period were largely replaced. Both TTF and Japan spot prices went well above the long-run delivered costs of US LNG. The TTF and adjusted coal price chart from 2020 to 2024 is in Figure 57.

TTF prices went above the adjusted coal price in the last quarter of 2021 and remained well above it until the middle of 2023 when they converged again. In 2022, both gas and coal-fired power generation increased in Europe, despite the high prices as nuclear, in France in particular, declined, and hydro and wind were also lower. In 2023 and into 2024, both gas-fired and coal-fired power have been in sharp decline, as nuclear, hydro and wind rebounded. However, with gas now being competitive against coal again, the decline in the coal share has been greater, in percentage terms, than the decline in the gas share



Figure 57: TTF and Coal Prices - 2020 to 2024

Source: Argus Media





Source: Argus Media, S&P Global



Japan spot prices decoupled from oil-indexed contract prices at the beginning of 2019, generally being below the oil-indexed price. The spot price went well above it from mid-2021, and has only converged again since the middle of 2023. Whether this is simply a coincidence or prices are recoupling again, it is too early to tell.

The previous period from 2016 to mid-2021 saw the globalization of the gas market, as US LNG entered the market. The relationship between TTF and adjusted coal prices disappeared as TTF prices rose sharply, and it was clear they were driven by a rapidly tightening market and sharply rising long-run marginal costs. Japan spot prices were driven up by rising TTF prices, competing in the globalized market for scarce gas and LNG.

We can now add the years from 2021 to 2023 to the multi-dimensional chart. With the high price over the last few years 2021, 2022 and 2023 are all well into the supply short and long run marginal cost area and well above even the long run marginal cost, certainly for 2022 for the reasons outlined earlier. 2024 is not completed yet but, based on the year so far, it would seem to be similar to 2023 – still a tight market year.



Figure 59: Multi-Dimensional Analysis of Gas Price Drivers – 2021 to 2023

As suggested in the sub-section covering 2016 to 2021, the year 2021 is a good example for the supply and demand curve chart. There were two distinct changes in the market occurring in 2021. Firstly, a large rise in demand – shifting the demand curve to the right – as the world economy recovered from Covid-19 – and also, compared to 2020 a reduction in supply – the supply curve shifts to the left. The end result is a large increase in the price and a much smaller increase in the volume at the new market clearing price.

70

Source: Author's analysis



Figure 60: Supply – Demand Chart – 2021



Volume

Source: Author's analysis

b) Future Gas Price Movements

In the historical section, specific time periods and years were plotted on the multi-dimensional chart, in order to understand how they might fit into the hypothesis from section 7. In this sub-section, we will not attempt to provide actual price forecasts, but to suggest how the next few years might develop in the context of the multi-dimensional approach. The remaining years of this decade up to 2030 will be considered, with the underlying assumption that the now globalised gas market will remain and that the trend, identified by the IGU Wholesale Gas Price Surveys, towards more market-based, or gas-on-gas pricing, will continue. Firstly, the supply situation will be considered, then demand projections before pulling these together to assess the likely trends in prices.

i. Supply Outlook

The main growth in global gas supply over the next few years, at least for internationally traded gas, is largely via LNG. Russian pipe exports to Europe declined sharply in 2022, as described in earlier sections, and it is not assumed that these flows to Europe will return. Indeed, as of January 1st 2025, it is assumed that there will be no further flows to Europe via the Ukraine route from Russia, following the end of the transit deal. From 2025 onwards, it is assumed that the only pipeline flows of Russian gas will be via Turkstream to Turkey and also to Bulgaria and on into the Balkans and Hungary.

In Asia, there has been much discussion of the Power of Siberia 2 pipeline from the main Russian gas fields in western Siberia, via Mongolia and on to China. However, negotiations have stalled as China looks to take advantage of Russia's weak bargaining position. It is not assumed that Power of Siberia 2 comes on before 2030, with the early to mid-2030s more likely.

Growing LNG supply, therefore, is the key driver over the next five years or so. Figure 61 shows the year-on-year change in available LNG export capacity through to 2030. Following the huge surge in LNG export capacity in 2019, growth slowed in 2020, and capacity actually declined in 2021, as noted earlier, as technical and feedgas issues and extended maintenance curtailed capacity. Capacity growth resumed in 2022, 2023 and 2024. Between 2018 and 2024, available LNG export capacity grew by some 130 bcm (30 percent), with 60 percent of this occurring in 2019. The US accounted for three-quarters of this growth and Russia and Australia most of the rest.

71



Year on Year Change in LNG Export Capacity

Figure 61: LNG Export Capacity Growth to 2030



Source: NexantECA World Gas Model, OIES analysis

The projected growth between 2024 and 2030 is some 335 bcm (60 percent rise), with North America accounting for half the growth and the Middle East (mainly Qatar) for another 30 percent and the rest mainly from Sub-Saharan Africa and Russia – as Arctic 2 finally ramps up. Most of the anticipated capacity growth is from projects which have taken FID, with others likely to take it soon. The surge in LNG growth is expected to begin in 2025. Some of the 2025 growth is from projects which may start up towards the end of this year, such as Greater Tortue (Senegal and Mauritania) and Plaquemines LNG and Corpus Christi Phase 3 in the US. Projects expected to come on in 2025 include LNG Canada and Energia Costa Azul (Mexico). 2026 should see further expansions at Plaquemines and Corpus Christi and Golden Pass, the Pluto expansion in Australia and a larger FLNG in the Congo are also scheduled for that year, and possibly Cap Lopez in Gabon and the first of the Qatari expansions.

2027 should see further Qatari expansions, plus Woodfibre (Canada), NLNG Train 7 (Nigeria) and potentially the next FLNG in Sabah (Malaysia). 2028 should begin to see some projects which have some uncertainty, either because they have not yet taken FID and/or may be impacted by the current pause in the US on non-FTA approvals from the DOE. These include Cameron Phase 2, Rio Grande, Port Arthur, Calacasieu Pass Phase 2 and the Mexico Pacific project. More certain are further Qatari trains and ramp ups and Cedar FLNG in Canada. In 2029/30, the final Qatari expansion trains will come on, plus Mozambique LNG Trains 1 and 2, together with additional Middle East capacity in UAE and Oman, plus Papua LNG, if it takes FID by next year. Clearly some uncertainties remain and there are other projects not mentioned here which are less well advanced but could conceivably come on in the timeframe.

ii. Demand Outlook

The demand outlook is a lot more uncertain than the supply outlook. Between 2018 and 2024, there was a roller coaster ride for demand, impacted by Covid-19 and the price shocks in 2021 and 2022. Global gas demand grew by some 275 bcm over the six years – about 1 percent a year on average, with North America, China and the Middle East accounting for over 340 bcm, offset by declines in Europe and Japan, Korea and Taiwan.

From 2024 to 2030, OIES are projecting growth of some 420 bcm – about 1.3 percent a year – so slightly faster than 2018 to 2024. Over half the growth comes from China and the Middle East, but a recovery in Europe (as coal plants are closed), South Asia and ASEAN also contribute to the growth.



North America declines, reflecting the impact of the Inflation Reduction Act in the US as gas-fired power peaks and buildings demand declines. The growth in Middle East demand is met by growing Middle East production, but growth in China, Europe, Central and South America, South Asia and ASEAN plus a small rebound in Japan, Korea and Taiwan amounts to some 260 bcm, and these are the regions which will demand more LNG.



Figure 62: Gas Demand Growth to 2030

Source: NexantECA World Gas Model, OIES analysis

The projections for global and regional gas demand are the latest OIES projections - other organisations have differing views. This may be especially true of some of the Asian markets such as China and India, but also Europe. The sensitivity of the price assessments, using the multi-dimensional approach will be addressed below, rather than a long commentary on the many differences there might be between demand and supply projections.

iii. Price Assessments

The projected supply and demand can be brought together to help with a broad assessment of where prices might go. Figure 28 in section 4 showed the historic LNG export capacity utilisation rate, which is calculated as total LNG imports divided by available LNG export capacity. Available LNG export capacity is calculated as nameplate export plant capacity, adjusted for scheduled maintenance, unscheduled maintenance, technical issues, feedgas availability and also the ability of some plants to produce more than nameplate capacity.

It was noted in section 4 that, how tight the market is, as represented by LNG export capacity utilisation, is an important factor in driving prices, when added to the mix of marginal costs and competing prices. This tightness will help determine where on the multi-dimensional chart the price range may settle. Figure 63 is a projection of the LNG export capacity utilisation to 2030.

In 2022 the utilisation rate rose to 98 percent, which is virtually full capacity once the boil-off gas in the LNG tankers has been accounted for¹⁵⁷. The market still remained tight through 2023 and 2024 and, looking forward, even into 2025 despite the growing LNG export capacity. It is only in 2026 and 2027 that the utilisation rate begins to fall to some 95 percent in 2027. This level still represents a relatively tight, but more balanced, LNG market, similar to 2018 and 2005 to 2007. 2028 is the beginning of the

¹⁵⁷ The amount of LNG loaded at the export point is more than the delivered amount due to boil off gas used as a fuel in the tanker – unless reliquefied.



sharp fall in utilisation – down to 90 percent and then even further to around 85 percent by 2030, which would be an historically low level.

The measured level of LNG export capacity utilisation is highly sensitive to the assumptions on supply and demand. The projected supply may not be in service on time, or some of those projects which have not taken FID may, potentially not happen at all. In addition, the level of demand could be underestimated, especially in China and India. The available LNG export capacity in 2024 is estimated at some 570 bcm rising to 700 bcm in 2026, 800 bcm in 2028 and just under 900 bcm by 2030. The difference between the tight, but balanced, LNG market in 2027, with around 95 percent utilisation, and the 90 percent utilisation just a year later is a change in the supply-demand balance of only some 40 to 45 bcm. 90 percent utilisation is similar to the 2020 Covid-19 year and just below the 2019 level. The 85 per cent utilisation level projected for 2030 is only another 40 to 45 bcm change in the supply-demand balance away.



Figure 63: LNG Export Capacity Utilisation to 2030

These relatively small changes in the LNG supply-demand balance highlight how sensitive the market is, resulting in, potentially, quite large changes in prices. There are two caveats to the above analysis. Firstly, the model has been run in a full long-run cost mode, and, secondly, is that it is a first order, partial equilibrium, analysis. It does not immediately reflect, therefore, the impact of potentially much lower prices on gas demand, if there was a move towards more short-run pricing. The multi-dimensional and globalized gas market hypothesis, outlined in section 7, argues that the relative tightness or softness in the market is a driver of whether we are in a world of short run or long run pricing or somewhere in between.

If, as suggested in Figure 63, the market is so supply long by 2030, then it would seem likely that we are well into a world of short run pricing, and with lower prices a demand response with more gas being consumed is likely. If the model is run in short-run marginal cost mode, rather than long-run, the result is, obviously much lower prices, but also, more gas and LNG being consumed.

The utilisation rate increases to some 92 percent in 2030, in short-run mode, as opposed to 85 percent in long-run mode. This represents a difference in demand for LNG of some 60 bcm¹⁵⁸, with the 92 percent similar to 2019 utilisation levels.

74

Source: NexantECA World Gas Model

¹⁵⁸ The increase in demand was predominantly across all Asian markets but also some in Europe.



Figure 64 looks to place the years 2025 to 2030 on the multi-dimensional chart. The market is still relatively tight in 2025, but eases in 2026 and 2027, beginning the move away from long-run pricing. 2028 accelerates the move towards short-run pricing and by 2029-30, we would expect to be well into the short-run pricing range, similar to 2019 and 2020. However, as noted above, higher demand and/or lower supply, would make a material difference to the balance, and it would not take that much of a change to move the balance away from short-run pricing to a more balanced mid-range, or even to a much tighter long-run pricing market.



Figure 64: Multi-Dimensional Analysis of Gas Price Drivers - 2024 to 2030

Source: Author's analysis

The analysis has deliberately not attempted specific price projections to 2030. However, for information, the model run on which the analysis in this sub-section is based, projects TTF prices of just under \$8/MMBTU (in real 2023 prices) and Japan spot just over \$8, in long-run pricing mode. In short-run pricing mode, the prices are some \$3/MMBTU lower so around \$5. This would be similar to the range of 2019 and 2020 levels, in real 2023 prices, of just under \$6 in 2019 and just under \$4 in 2020 for TTF and \$1 or so higher for Japan spot.

c) Conclusions

The hypothesis of the multi-dimensional approach to the drivers of international gas prices, in a globalized gas market, was set out in section 7. Prior to 2016 and the advent of US LNG, the global gas market was not fundamentally functioning as a globalized market. The US had decoupled from the rest of the global gas market, the European market was liberalizing and spot prices (NBP and TTF) had decoupled from oil prices (or oil-indexed contract prices) around 2010 and supply and demand fundamentals drove the spot prices. There were few diversions and trading of LNG between the Asian and European markets, with only Qatar having any significant ability to flex cargoes between the two markets. Japan spot prices were largely driven by oil-indexed contract prices. The market was generally balanced between short-run and long-run pricing, with only 2009-10 and 2016 being relatively supply long.

From 2016 on, US LNG entered the market and the process of globalization began to speed up. Gason-gas pricing in the LNG market rose significantly until 2021 and the flexibility of US LNG saw more inter-basin arbitrage. TTF prices began to compete with adjusted coal prices and also were moving within the long-run and short-run marginal cost of delivered US LNG. Japan spot prices also moved within the long-run and short-run marginal cost of delivered US LNG and seemed to decouple from oil-



indexed contract prices when the LNG supply surge hit in 2019. From a balanced, but tightish, market in 2018, in 2019 and 2020 the market became very supply long and both TTF and Japan spot prices were driven down towards short-run marginal costs.

The recovery in demand in 2021 as economic activity began to pick up post Covid-19, led to sharply rising prices, especially as LNG export capacity was reduced with the maintenance catch up from 2020 and the fire at the Hammerfest plant in Norway. This was followed by the Russian invasion of Ukraine in 2022, with prices rising to unprecedented levels. The global market was definitely in a supply short situation, with market tightness and long-run marginal costs rising sharply. Any linkage between spot gas prices and either coal prices, the delivered cost of US LNG or oil prices was overwhelmed by rising gas prices. The "competing" fuels, to the extent they might have been an influence, would be in the range of oil switching in industrial use, behavioural changes in households and buildings (turning the thermostat down) and even industrial closures at the very high prices. 2022 was a world of demand destruction, especially in Europe. In 2023, the market began to rebalance but still remained in a supply short world, with prices above long-run marginal costs.

Looking forward the tight long-run pricing world is expected to persist in 2025 and it is only in 2026-27 that the market rebalances a little. As the growth in LNG supply outweighs rising demand, the market starts to become supply long in 2028, with even more of a glut in 2029-30, and pricing moving well into short-run marginal costs, probably similar to 2019 and 2020. However, a different supply-demand balance than OIES are projecting, could change the outlook significantly. Much higher demand in China and India, for example, maybe adding 5 percent or more to LNG demand, would leave a more balanced market and not supply long.

9. Conclusions: Globalization and the Value of Gas

a) Globalization and Competitive Markets

The seminal book entitled The Pricing of Internationally Traded Gas¹⁵⁹ (PITG) noted that, at least in the past (prior to 2012), natural gas had been very different to other commodities in that "it failed to conform to the basic precept of economics – they should be set by the forces of supply and demand". PITG noted "for much of their history, natural gas markets have been isolated – at best regionalized rather than internationalized (let alone globalized) – and dominated by monopoly suppliers at both domestic and international levels". It was also noted that this situation was changing (as of 2012), but that the gas market had not yet become a globalized competitive market, although some domestic markets, notably the US and the UK, and some EU countries, were competitive.

Rogers¹⁶⁰, in PITG Chapter 12, was relatively pessimistic on the progress for the development of one or more hubs in the Asian market, and that this might hold back the full globalization of the gas market, and hence connectivity between regional markets and prices. The development of a liquid trading hub in Asia, to complement the North American and European hubs, was considered to be a necessary condition for a globalized, competitive market. The author also still shared this view in 2018 in a paper on Asian LNG Trading Hubs¹⁶¹.

The advent of US LNG, from the Lower-48, in 2016, driving a significant rise in the volume of flexible LNG, began to transform the global LNG market (with significant consequences for regional markets). The standard contracting structure of US LNG, is for the offtakers to take delivery of the LNG at the outlet of the export plant, together with a financial obligation only for the capacity tolling fee for the export plant, and not the gas commodity. This made it fundamentally different from a traditional LNG contract, with take-or-pay for the whole value chain. Taking ownership of the LNG, on an fob basis, also provided the flexibility with no restrictions on the destination of the LNG.

The growth of flexible LNG has significantly improved connectivity between different regional markets. In the last 6 months of 2023, total flexible exports, from both the Atlantic and Pacific Basins, was some 57 percent of total LNG exports, having risen from 32 percent in the first 6 months of 2015. It is this rise in flexible LNG that has led to the ability for Atlantic Basin exporters to switch volumes between West

¹⁵⁹ Stern, J.P. (2012). The Pricing of Internationally Traded Gas, (ed), OIES/OUP

¹⁶⁰ PITG, p 420-421

¹⁶¹ Fulwood, M. (2018). Asian LNG Trading Hubs: Myth or Reality, Columbia SIPA, Center on Global Energy Policy.



of Suez and East of Suez. In effect, this flexible LNG operates in much the same manner as a spot cargo.

This growth in US LNG and its flexibility has also been reflected in the way LNG has been priced. Gason-gas competition (GOG) pricing, according to the annual IGU surveys¹⁶², ranged between 25 and 30 percent of total trades between 2010 and 2016, but then has risen consistently to marginally under 50 percent in 2023. In the key Asian markets, GOG pricing had risen to 35 percent of total Asian LNG imports in 2023, from 20 percent in 2016, and suggests there is a large core of LNG available to trade in the region. While Asia is far from being a liquid trading market, akin to North America and Europe, it does therefore, even in the absence of a hub, qualify as a competitive market, with at least enough flexible and tradable LNG to suggest that the global gas market is well connected and globalized.

The question posed in PITG, right at the beginning, as to whether gas pricing is "different" to other commodities, was answered by Stern¹⁶³, in the last sentence of the book that "in future it is likely to become much more similar to other commodities". This was back in 2012 but, based on the evidence of market development over the last 12 years and, particularly the change in LNG pricing since 2016, it would seem that gas has achieved the goal of becoming "similar to other commodities".

However, before addressing the main objective of this paper as to what drives international gas prices in competitive markets, we need to put to rest four fallacies that are often paraded as "explanations" of gas price drivers, but are based on incomplete or inadequate or simplistic analysis (or all three!) of gas pricing.

b) The Cost Stack Fallacy

The cost stack is a simple graphical representation of the costs in the gas value chain for each source of supply to a specific market, whether it is domestic production, pipeline imports or LNG imports from a variety of sources. The concept is that the highest cost source of supply is the marginal cost and hence sets the price in the market. Its simplicity is maybe why it is so beloved of consultants and analysts trying to explain what is driving prices and, looking forward, how prices might develop. An example for the UK is in Figure 65, based on supply sources for 2021.



Figure 65: The UK Cost Stack 2021

Source: NexantECA World Gas Model

The figure shows the different elements of costs in the gas value chain which make up the total delivered cost, including production costs and all the different infrastructure costs. The actual NBP price is also shown for comparison with the highest cost source of supply, which in 2021, appeared to be US LNG.

 ¹⁶² The latest survey is IGU (2024). Wholesale Gas Price Survey 2024 Edition. International Gas Union.
¹⁶³ PITG, p 489



There are a number of reasons why this simplistic approach is flawed. Firstly, it does not take account of fuel switching, such as between coal and gas in the power sector. At the margin, in the power generation mix, the choice for incremental generation may be between importing more LNG and burning more coal. Switching to coal away from gas is effectively saying that coal is an alternative source of supply and has a marginal cost, therefore. There is also potential fuel switching in industry, usually with oil, incentives to efficiency as prices rise, behavioural changes (turning down the thermostat) and even industrial closures impacting gas demand. All of these can be seen as alternatives to additional gas and, therefore, merit a place in the cost stack.

Secondly, the cost stack for one market, such as the UK, even with fuel switching included, does not take into account the interconnections with continental Europe. Europe is well connected and an integrated market, with hub prices highly correlated, with relatively stable differentials. A cost stack can be calculated for the wider European market.

However, thirdly, Europe is not an isolated market, and is one part of the globalized gas market. If demand in Europe increases, and the increased volumes come from, say, the US, it is not necessarily the delivered cost of US LNG which sets the price of TTF. If the volumes are diverted from, for example, Asian markets such as Japan, how does Japan replace those volumes? Possibly additional LNG from another supplier or by diverting volumes from other markets again. Gas demand, in a totally different market, could also be reduced, depending on the price. In a globalized market, the increase in demand in one market, can lead to multiple effects rippling through many other markets, but tracking all these changes to calculate the marginal cost would be a complex task.

The marginal cost of supply to each market, however, can be calculated using gas models, which are linear programmes. OIES uses the NexantECA World Gas Model, which is a linear programme, and generates the shadow price, which is effectively the marginal cost of supply to each individual market. This is not a simple cost stack graph, however, as the global market is a complex interaction of multiple flows, costs and demand responses.

c) Price Equals Marginal Cost Fallacy

While it is possible to calculate the marginal cost to each market, even in a complex global market, will this actually determine the gas price, or are there other factors involved? The notion that price equals marginal cost comes from basic first year undergraduate economics, but it is only true, in equilibrium, in a perfectly competitive market, which is a theoretical concept to allow the development of other strands of economic analysis. Indeed, much of the study of markets in economics is devoted to markets which are imperfect. The gas market, despite exhibiting some characteristic of perfect markets, such as the homogeneity of the product and multiple buyers and sellers, falls down on some of the other characteristics, with barriers to entry and exit, especially in LNG.

While price may not equal marginal cost, that does not mean that marginal cost, or the balance of the forces of supply and demand, are not important, or even key, factors. It is just that this is not the whole story. Furthermore, the distinction between long-run marginal cost (LRMC) and short-run marginal cost (SRMC), is also important. While in a long-run equilibrium balanced market, it might be expected that the price would tend towards LRMC, there have been plenty of examples where the price has been demonstrably below LRMC, and closer to SRMC – notably in the 2019 supply glut and the 2020 Covid-19 year. Also, the gas price was clearly above LRMC in 2022, following the Russian invasion of Ukraine, although this was an exceptional circumstance.

Some of the other factors influencing the price have already been mentioned in the Cost Stack fallacy. These include the adjusted coal price¹⁶⁴ relative to gas in power generation, oil product prices in industry fuel-switching, behavioural changes in households and businesses (turning down the thermostat) and efficiency improvements in response to higher prices. Other competing prices influencing the spot gas price could include the long-term oil indexed contract prices for, say, Japan, since buyers can nominate more under their contracts if the spot price is higher than the contract price, and down to the minimum take-or-pay levels if the spot price is lower.

Since the advent of Lower-48 US LNG in 2016, another "competing price" influence is likely the delivered cost of US LNG to Europe and Asia, with the delivered cost calculated on both a long-run full cost basis and a short-run variable or marginal cost basis. Between 2016 and the end of 2020, both the

¹⁶⁴ Adjusted for the relative carbon cost of coal and the relative efficiency in power generation.



TTF and Japan spot price ranged somewhere between the long-run and short-run delivered cost of US LNG, before surging above the long-run cost in 2021 and 2022. This relationship could also work in reverse, with the long-run and short-run netbacks from TTF and Japan spot to the US Gulf Coast, impacting the Henry Hub price.

Finally, the state of the market in the context of how tight it is, seems to have been a key influence in how prices have developed. The relative tightness represents a good indicator of the balance of supply and demand. If there is plenty of spare capacity in, say, Russian production – as was the case pre-2021 – then Europe could easily meet any increase in demand by buying more Russian gas. The availability of spare LNG export capacity is also a key factor. In 2019, the sharp rise in global LNG supply exceeded the growth in demand, with the result that Europe absorbed the rising supply with prices falling sharply. In the current market environment, after the Russian invasion of Ukraine, which sent prices skyrocketing, there is little or no spare LNG export capacity. The market has, to some extent, rebalanced but it is still considered to be relatively tight.

All these factors are incorporated, very broadly in the spot price module of the NexantECA World Gas Model. This module is discussed in more detail in Annex 2.

d) Cheap Russian Gas Fallacy

There was a common saying that, as Russian pipeline exports to Europe grew, Europe was becoming hooked on cheap Russian gas. Some politicians, especially from the US, often warned that Europe should not become reliant on Russian gas – calling it cheap. There are two elements to this, firstly that Europe was dependent on gas from Russia and secondly that it was low cost, therefore Europe was getting it cheap.

From the 1990s to 2010 Russian pipe imports supplied around 25 percent of Europe's gas demand. This percentage then rose in the 2010s, as Nordstream came online, peaking at 37 percent in 2017. Since then, the percentage has fallen back, significantly so after the Russian invasion of Ukraine. It can certainly be said that Europe was heavily dependent on Russian gas if not hooked on it. But this was the volume of Russian gas not the cost.



Figure 66: Price of Imported Russian Gas v Spot Prices – 1998 to 2015

Source: Argus Media

Under the original long-term contracts, the price of Russian gas was linked to oil – principally oil product prices such as gas oil and fuel oil. In Figure 66 the BAFA price is the average German gas import price so also includes imports from Norway and the Netherlands as well as Russia, and while it was oil linked in the early 2000s, by 2015 it had largely moved to hub pricing. The key takeaway of this figure is that Russian gas was not cheap, or at least not cheap at the price the European buyers were paying. While Europe, and Germany especially, may have been hooked on Russian gas, given the volume of imports from Russia in the figures above, it was not cheap. Up until the early 2010s, most Russian gas was linked to oil prices, and for the most part these oil-indexed contract prices were above hub prices such as NBP and TTF. This differential was especially marked between 2009 and 2014, which was a key



reason triggering multiple contract renegotiations and the move to hub pricing. When the pricing under the contracts moved towards hub pricing, Russian gas was priced the same as other sources of gas whether pipeline or LNG, and so neither cheaper nor dearer. In a liquid trading market, all participants are price-takers.

While the selling price of Russian gas was not cheap, it is true to say that Russian gas was relatively low cost – hence the possible confusion. However, the low cost of producing and transporting Russian gas to Europe meant that the pipeline exports were generally very profitable for both Gazprom and the Russian state.

e) TTF is Broken Fallacy

Following the Russian invasion of Ukraine, significant differentials opened up between TTF on the one hand, and NBP, LNG NWE and Asian spot prices from April 2022 through to the last couple of months of the year. These differentials, with TTF at a significant premium to other prices, combined with the extremely high level of prices, led the European Commission, notably Ursula von der Leyen and Kadri Simson, and other politicians to claim that TTF was no longer fit for purpose. These comments and many others represented a failure to understand the economics of congested markets and what happens if there are infrastructure constraints.

The TTF premium to NBP coincided exactly with the period when the Interconnector pipeline between UK and Belgium and BBL between UK and the Netherlands were operating at maximum export capacity from the UK. With no more room in the pipelines, the NBP price weakened relative to TTF, with the constrained Northwest and Central Europe market unable to receive any more gas. Once the pipelines exporting from the UK were not operating at full capacity in November 2022, the TTF/NBP differential almost completely disappeared and returned to "normal" levels.

The other constraint was at the three regasification terminals serving Northwest Europe in 2022 – Dunkirk (France), Zeebrugge (Belgium) and Gate (Netherlands). From early 2022, the terminals were operating at or well above their nameplate capacity. These terminals continued to operate at effectively full capacity until the middle of 2023. However, towards the end of 2022, new terminals came on stream and alleviated the capacity constraints. The TTF differential to the LNG NWE price was removed at the end of 2022 as prices converged again, with the constraints released.

Widening differentials between TTF and other hubs in continental Europe were also noted in 2022. TTF was at a premium to PEGN and PVB – the French and Spanish hub prices – from April to November 2022, reflecting pipeline capacity constraints in moving gas from west to east, especially at the French border with Germany. However, THE (Germany), VTP (Austria) and PSV (Italy) had higher prices than normal relative to TTF, with some constraints on the ability to move gas eastwards when the usual flows had been westwards. There are other examples, notably in the US gas market, where wide differentials between hubs opened up because of pipeline constraints.

The key conclusion is that when there are infrastructure constraints leading to congested markets, differentials between markets, impacted by the constraints, will widen, often by large amounts. These abnormal differentials disappear once the constraints are alleviated. The fact that TTF rose to large premiums over NBP and LNG prices in 2022 did not mean that, somehow, the TTF was not working properly or not representative of EU gas prices. The suggestion by the European Commission, notably Ursula von der Leyen and Kadri Simson, that this was the case, was a panic reaction, with little or no attempt made to understand the economics of congested markets. The recent Draghi report¹⁶⁵ also misunderstood what happened in the gas market in 2022 and made proposals to attempt to go back to a pre-liberalised world of over 20 years ago, which seems to be somewhat naïve. In fact, in the face of enormous disruption to the European and global gas markets, the liquid trading market actually worked extremely well.

f) The Value of Gas

The hypothesis being put forward is that the globalized market, which has been especially rapid since the advent of Lower-48 US LNG, has led to price linkage between what were localised regional markets. Ito find what the key price drivers are requires a multi-dimensional approach, with a focus on the value of gas.

¹⁶⁵ Draghi. M. (2024).



In many respects, the global gas market and, before that, gas markets in individual countries and regions, is essentially no different to the development and origins of most markets for goods and services. Weekly markets, selling a variety of goods, focused on food and produce, can be traced back to medieval times, when chartered markets and new towns were established across Western Europe. Rules and regulations were laid down on quality, access, timings and other guidelines, not that dissimilar to regulations on trading and access to infrastructure.

The development of hubs in the gas market – either physical or virtual – is not a new idea, but a continuation of the medieval markets of hundreds of years ago, as is the long-distance trade of LNG, similar to the seaborne trade of the Silk Road. Gas hubs developed as a result of the liberalization of gas markets in the US and Europe. There is no actual hub in the Asian markets, similar to Henry Hub or TTF, but, as has been argued earlier, the growth of flexible LNG since 2015, and the rapid growth in more gas-on-gas pricing in the LNG market, has effectively created a competitive market on a global basis.

On the back of the development of the physical hubs and markets, financial markets were developed. These have grown to such an extent that the trading on the financial markets now outweighs the physical trading, and there is little difference between the two, other than the financial markets not going to physical delivery. The big rise in prices in Europe in 2022, following the Russia invasion of Ukraine, led some commentators and politicians to blame excessive speculative trading for the increases. A report by Oxera¹⁶⁶ dispelled this notion concluding that, overall, there was no evidence of excessive speculation driving prices or volatility.

It became clear, in discussing the four fallacies, that the drivers of natural gas prices are varied and complex. The multiple factors impacting prices, include marginal costs – whether short-run or long-run – and a whole myriad of competing prices. The underlying forces of supply and demand still, however, represent the primary drivers of gas prices, but the forces of supply and demand – and the other drivers – manifest themselves differently depending on the state of the market. The price drivers are not linear and attempting to portray them on a simple two-dimensional chart is unlikely to be accurate. A multi-dimensional approach is needed to analyse gas prices.

Figure 67 attempts to represent these multi-dimensional aspects on a two-dimensional chart. The chart shows a price curve for gas – rising as the market gets tighter – and plotting the key drivers of prices at different points on the curve, combining these drivers with the state of the market – is it supply long or supply short – and whether short-run or long-run marginal cost pricing predominates. The state of the market is the primary driver of gas prices and this translates into the relative importance of short-run or long-run marginal cost pricing. Depending on what sort of world or state of the market we are in, will then determine what the most important secondary drivers will be. These secondary drivers can be loosely described as the competing prices, as discussed earlier.

In the chart, in a supply-long world, short-run marginal cost pricing will predominate. The key competing prices are likely to be, in the LNG market, the variable or short-run cost of delivering US LNG to markets and in the end-use markets, the competing coal price¹⁶⁷. In a more balanced world – neither supply-long nor supply-short – we may be somewhere in between short-run and long-run marginal cost pricing and other competing prices are likely to come into play, such as the long-run or full cost of delivering US LNG to markets, and also in the end-use markets, HSFO prices in industry and oil-indexed contract prices (at least in the Asian LNG markets). In a supply-short world, long-run marginal cost pricing will predominate. In this state of the market, higher levels of oil product prices may factor in but also, we are likely to see significant demand responses in industry in terms of efficiency gains and, if prices get driven higher, behaviour changes in households (turn down the thermostat) and potentially industrial closures. The impact of coal prices, for example, will no longer be a factor, with any switching from gas to coal in power generation having already happened. In summary, as the state of the market changes – or as it tightens – the world moves from more short-run pricing to long-run pricing and different "competing prices" are more or less important.

However, the chart should be regarded as a "schematic", presenting the stages that the gas price moves through as the market changes. In particular, where the competing prices have been placed in the chart, is illustrative and should not be taken as firm indications of the relative importance or even order. The competing prices may also be relevant or have an impact over a wide range of market states and gas

¹⁶⁶ Oxera (2022). The European Gas Market, Report prepared for ICE. Oxera Consulting

¹⁶⁷ Adjusted for efficiency and relative carbon costs



prices. The market is very dynamic and can be fast-moving, so this is very much a framework for analysis.

The underlying marginal costs – whether short run or long run – are key factors, together with the tightness of the market and also the variety of "competing prices". The combination of supply and demand and the various competing prices, will determine a price which clears the market, at the perceived value of gas. All participants become price-takers. If one party values a product more highly than another party then the former will pay the price and buy the product. This is true for any good or service, whether it be gas, apples or tickets to a Taylor Swift concert! The brutal reality of this fact was exposed in 2022, when European buyers valued gas more highly than buyers in Pakistan, in that they were prepared to pay a higher price, which led to Europe getting the LNG and Pakistan going short, with resulting power cuts.



US LNG SRC: Short-run marginal cost of delivered US LNG SR Netback: Short-run netback from TTF/Asian spot to Henry Hub HSFO Price: High sulphur fuel oil price GO Price: Gasoil price LR Netback: Long-run netback from TTF/Asian spot to Henry Hub US LNG LRC: Long-run marginal cost of delivered US LNG LSFO Price: Low sulphur fuel oil price

Figure 67, on the multi-dimensional nature of gas price drivers, shows the importance of supply and demand, but also brings in the influences of other factors to determine the ultimate price, based on the value in the market. While costs of delivering gas to the market are an important factor, the other influences will also determine the value of the gas in the market. If one or more suppliers have a cost base which is too high then they will stop supplying the market, until such time as the value of gas in that market rises again. This was well illustrated in 2020, when the prices in Europe and Asia were so low that, even on a short-run marginal cost basis, it did not make economic sense for offtakers of US LNG to lift cargoes and ship them, so they were shut in, until the value of gas rose again.

In the global gas market, therefore, the key markets are in Europe, Asia and North America. The value of gas in these markets can be represented by TTF, Northeast Asia spot prices¹⁶⁸, and Henry Hub. These markets, and others, are interconnected, largely, through LNG movements, with Henry Hub "exporting" LNG to multiple markets. Conceptually, LNG can be considered to move from producing markets to LNG "pools" and on to the consuming markets. The seaborne trade of LNG, over long distances, is somewhat akin to the medieval Silk Road from China to the west. A conceptual map of connections between producing markets, LNG "pools" and consuming markets is shown in Figure 68.

Source: Author's Analysis

¹⁶⁸ Such as JKM or ANEA



Figure 68: Connecting the Globalised Gas Market





The map does not show every single market nor supply source or even hubs, but all the key ones. Demand centres are in the grey boxes, supply centres are in blue boxes but only represent the main exporting countries and/or regions, with production within regions, which just supply that region only, ignored. The hubs are yellow circles and linked to demand centres – Henry Hub to North America (and to supply as well), TTF to Northwest Europe and Southern Europe and Northeast Asia Spot to China and Japan, Korea and Taiwan. Panama and Suez canals are the light green circles.

The LNG "pools" (light orange boxes) are designed to represent the notional points through which LNG passes on its way between supply centres and demand centres. The notional points are Pacific East, West Atlantic, North Atlantic, South Atlantic, Mediterranean, Indian Ocean, Singapore¹⁶⁹, Northeast Asia and Pacific West. The notional points are connected to each other via the solid red lines, while supply centres feed in through the dashed red lines and the demand centres offtake via the dotted red lines. Pipelines are represented by the purple lines.

The value (or price) of gas is determined at the hubs, through the multi-dimensional analysis of gas price drivers. The hub "value" then transfers to the demand centres – for TTF this would be to NWE and SE – and from the demand centres to the LNG "pools". At each LNG "pool", therefore, there will be a notional value of gas or LNG. That value can then netback to other pools and so on. The value from TTF can netback to Asian "pools" via Suez, or the Cape of Good Hope. The value of gas or LNG at different "pools", however, could also be the netback from the Northeast Asia "hub". If the globalized market is working as expected then the hub prices and relative values at the pools would adjust, to equalize the value netbacks at the different "pools" and ultimately markets.

Calculating the netbacks between the LNG pools should reflect the relative shipping costs, but while they can be calculated on various assumptions to provide an estimate, it is not necessarily straight forward. What type of LNG tankers should be used, together with various assumptions on speed, fuel used etc, and also, whether the calculation should be on a full, or long run cost basis or on a variable, or short run, cost basis.

Just as with the multi-dimensional analysis of the gas price drivers, the conceptual map of the connected globalised gas market, represents a framework for considering the drivers of international gas prices. The map reflects the value of gas at different points around the world, irrespective of the source or cost of the different supplies of gas at those points. The cost of supplying gas or LNG can be calculated, under various assumptions, delivered to various points, and then compared with the value at those points. This will simply provide information on the relative profitability of different sources of supply to that point and eventually to a hub. For example, for the value at NAT, LNG from Qatar, whichever route is taken – via Suez or Cape of Good Hope – is likely to be more profitable (the cumulative costs are lower) than LNG from the US or elsewhere.

g) Historical Pricing Developments and the Hypothesis

The hypothesis on globalization and the value of gas, argued that the state of the gas market – is it supply-long or a tight market – will dictate which of the price drivers and influences are more or less important, and especially whether the market is in a short-run or long-run marginal cost world.

Prior to 2016 and the advent of US LNG, the global gas market was not fundamentally functioning as a globalized market. The US had decoupled from the rest of the global gas market, the European market had decoupled from oil prices (or oil-indexed contract prices) around 2010, as liberalization took hold and supply and demand fundamentals drove the spot prices. Japan spot prices were largely driven by oil-indexed contract prices. The market was generally balanced between short-run and long-run pricing, with only 2009-10 and 2016 being relatively supply long.

From 2016 on, US LNG entered the market and the process of globalization began to speed up. Gason-gas pricing in the LNG market rose significantly over the period to 2021 and the flexibility of US LNG saw more inter-basin arbitrage. TTF prices began to compete with adjusted coal prices and also were moving within the long-run and short-run marginal cost of delivered US LNG. Japan spot prices also moved within the long-run and short-run marginal cost of delivered US LNG and also seemed to decouple from oil-indexed contract prices when the LNG supply surge hit in 2019. From a balanced,

¹⁶⁹ Singapore is the Malacca Straits area.



but tightish, market in 2018, in 2019 and 2020 the market became very supply long and both TTF and Japan spot prices were driven down towards short-run marginal costs.

The recovery in demand in 2021 as economic activity began to pick up post Covid-19, led to sharply rising prices, especially as LNG export capacity was reduced with the maintenance catch up from 2020 and the fire at the Hammerfest plant in Norway. This was followed by the Russian invasion of Ukraine in 2022, with prices rising to unprecedented levels. The global market was definitely in a supply short situation, with market tightness and long-run marginal costs rising sharply. Any linkage between spot gas prices and either coal prices, the delivered cost of US LNG or oil prices was overwhelmed by rising gas prices. The "competing" fuels, to the extent they might have been an influence, would be in the range of oil switching in industrial use, behavioural changes in households and buildings (turning the thermostat down) and even industrial closures at the very high prices. 2022 was a world of demand destruction, especially in Europe. In 2023, the market began to rebalance but still remained in a supply short world, with prices above long-run marginal costs. This situation has persisted into 2024. Figure 69 plots the spot prices, for years or periods on the multi-dimensional chart, as a broad indication of the range that market was in at that time.

The clearly supply-long periods of the financial crisis and the periods of LNG supply surges, plus the impact of Covid-19 can be clearly identified, as can the very tight 2021 to date period following the recovery from Covid-19 and the Russian invasion of Ukraine. Outside these periods, however, the market could be said to be more balanced.





Source: Author's Analysis

h) Future Market Developments

Looking forward, the developments, at least through 2030, would appear to be – in the absence of any more "Black Swan" events – a continuation of the growth of the importance of US LNG and the trend in LNG pricing away from oil indexation and towards gas-on-gas pricing. This will be occurring in a period of enormous growth in LNG export capacity. Between 2024 and 2030, available LNG export capacity is projected to grow by some 60 percent, reaching some 900 bcm in 2030. This growth seems likely to outstrip rising global gas demand, even though growth in Asia is likely to be strong, and Europe's dependence on LNG is also increasing. There appears to be no prospect of Russian pipeline gas returning to Europe in any significant volumes, with only the route via Turkstream being available to bring Russian volumes to EU countries once the transit deal via Ukraine ends in December 2024.



Russia has been looking at the Power of Siberia 2 pipeline from the western Siberian gas fields, via Mongolia to China. However, no agreement with China has been negotiated, so it does not seem likely to come on stream until after 2030.

In the current tight market, the utilisation of available LNG export capacity is around 98 percent¹⁷⁰, which is effectively full capacity. With the growth of available LNG export capacity outstripping demand growth, the utilisation rate is expected to decline. However, it is only in 2026 and 2027 that the utilisation rate begins to fall, reaching some 95 percent in 2027. This level still represents a relatively tight, but more balanced, LNG market. 2028 is the beginning of the sharp fall in utilisation – down to 90 percent and then even further to around 85 percent by 2030, which would be an historically low level. 2028 could be heading towards supply long short-run pricing, while 2029 and 2030 would, on these numbers be well into short-run pricing.

LNG export capacity utilisation is highly sensitive to the assumptions on supply and demand. Delays in supply, or much higher demand, especially in China and India, could dramatically alter the situation. Available LNG export capacity, in 2030, is some 900 bcm. A 1 percent point difference in capacity utilisation, therefore is only 9 bcm. The difference between the very tight utilisation of 98 percent, and a supply-long market of 90 percent, as in 2020, is only around 70 bcm. Another supply shock and/or a more rapid than expected growth in demand in, say, China and India, could bridge this gap.

The other element to note is that if prices did fall significantly from 2028 onwards, maybe back to the 2019 and 2020 levels, then these lower prices could stimulate demand. This happened in Europe as gas displaced coal, but by the end of this decade, assuming coal plants in Europe are closed as scheduled, then any demand response is less likely. This is not the case, however, in some Asian markets, such as Japan and Korea, where coal is still expected to be significant in the power generation mix and lower prices could stimulate demand. Modelling using the NexantECA World Gas Model suggests this could, globally, add some 60 bcm to global gas demand, mainly in Asia, with spot prices in Europe and Asia at just over \$5/MMBTU¹⁷¹, predominantly in short-run pricing mode. This is some \$3 less than long-run pricing mode.

i) The Final Word

Right at the beginning of this paper, the question was posed as to whether gas pricing is "different" to other commodities, picking this up from the OIES book on The Pricing of Internationally Traded Gas (PITG)¹⁷². This was answered by Stern¹⁷³, in the last sentence of PITG, that "in future it is likely to become much more similar to other commodities". This conclusion was made some 12 years ago. The arguments and evidence presented in this paper would suggest, in the author's view, that gas has achieved the goal of becoming "similar to other commodities". We have achieved a globalized gas market, at least in internationally traded gas, especially following the advent of US LNG in 2016 and the continuous growth of gas-on-gas pricing in the LNG market, following the earlier changes in Europe.

Globalization and pricing changes are now reflected in a complex multi-dimensional market, with the value of gas in the demand centres being the key driver. How this value is determined is complex, with multiple influences which can change over short time periods. The analysis of this complex market, does not lend itself to simplistic and wrong-headed "soundbites". The fallacies of the cost stack, price equals marginal cost is all that matters, cheap Russian gas and "TTF is broken", are, and were just fallacies, and no substitute for sound analysis.

The fundamentals of supply and demand – which does include elements of marginal cost pricing – remain the key driving forces of the value of gas in the market, but, as shown in this paper, there are multiple other drivers to be taken into account, now gas is "similar to other commodities".

¹⁷⁰ Global LNG imports divided by total available LNG export capacity.

¹⁷¹ Real 2023\$

¹⁷² Stern, J.P. (2012). *The Pricing of Internationally Traded Gas*, (ed), OIES/OUP.

¹⁷³ PITG, p 489



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Annex 2: NexantECA World Gas Model

The NexantECA World Gas Model (WGM) is a linear programme which automatically generates the shadow price for each node (or country) for every quarter through to 2050. The linear programme in the model is set up to minimise the total costs of supplying the whole world for a given level of demand. The constraint in the linear programme is that Total Supply minus Total Demand must equal zero for every node in every quarter. The shadow price is the amount the cost minimisation function would increase by, if that constraint was relaxed by one unit. In other words, if demand in the UK node increased by one unit, what would it cost to supply that one unit, taking into account all the changes, whether increased supply, diversions of flows and any reduction in demand because of higher prices¹⁷⁴. In effect the shadow price in the model is the marginal cost, without needing to generate a cost stack, which in any case is not accurate for an individual country or even region because of the globalized nature of the world gas market.

The model includes a spot price module, which takes into account all the factors discussed in Section 4 including marginal costs, the various competing prices and market tightness. WGM calculates the marginal cost of supply i.e. the shadow price and a whole range of competing prices, including those noted in Section 4. The marginal costs (either long run or short run) and a blended calculation of the competing prices set a range in which the spot price might settle. The market tightness then influences where in the range the spot price will settle. The marginal cost and competing prices do not necessarily act as a floor and a ceiling and spot prices may go out of this range for a period before being pulled back in.

The marginal cost is calculated as the shadow price on the constraint that requires supply = demand at each node. The shadow price at any node in any quarter measures the increased cost that would be incurred if demand was increased by 1 bscm at that node and quarter. In other words, it is the marginal cost of supply at the node in that quarter. To take an example, if we increase the demand at UK by 1 bscm in a quarter the model may respond by increasing production by 1 bscm in Norway and sending that to UK. The marginal cost would be the cost of the extra production plus transport to UK. However, as noted in Section 4, the optimum solution is a lot more complex with multiple small adjustments and knock-on effects. In practice, in WGM, the shadow price can be found through a formula in the linear programme.

Competing prices can be the price of alternative fuels, such as oil or coal, or alternative gas prices, such as LNG or pipeline contract prices. The spot price module allows for more than one competing price – up to three – and these are combined (weighted) depending on the degree of "market tightness". The choice of competing prices to gas is dependent on the market but typically the three would include a "low", "medium" and "high" competing price:

- The "low" price might be coal (competing with gas in power), adjusted for relative efficiency and carbon price/tax;
- The "medium" price could be a competing long term contract price, linked wholly or partly to oil prices; and
- The "high" price might be a specific oil index benchmark price or an oil product price such as fuel oil.

The relative weights of the three competing prices to calculate one competing price is a function of the market tightness. A very tight market would give more weight to the "high" competing price, and less to the "medium" and "low" and vice versa. Apart from the extreme degrees of tightness, typically most weight is given to the "medium" competing price.

Market tightness for a specific market can come from the three different sources of supply – domestic production, pipeline imports and LNG imports. In each case the actual or forecast level of production or supply, relative to estimated capacity is calculated:

• For domestic production it is the level of production relative to capacity for that country, or group of countries;

¹⁷⁴ The World Gas Model incorporates a demand side response function, which reduces the level of gas demand if the gas price in the solution exceeds a specified competing fuel price, such as the carbon and efficiency-adjusted coal price.



- For pipeline imports it is the level of production for the main countries supplying the imports relative to production capacity in those countries e.g. Russia for Europe; and
- For LNG imports it is the level of global LNG output relative to global liquefaction capacity.

For each of these an effective load factor is calculated and these are then weighted together, based on the proportions of domestic production, pipeline imports and LNG imports for each group of countries or regions, to provide one market tightness index.

Figures 70 to 73 show the backcasting of the calculated spot price compared to the actual outturn spot price. The calculated spot price, as it is historical, has all the outturn data on competing prices and the level of actual production and actual demand' This data is run through the spot price module. In effect the calculated spot price, using actual historical data, is what the spot price projection would have been if all the key assumptions had been known to be accurate. This backcasting of the calculated spot price compared to the actual outturn price is undertaken for Henry Hub, TTF, China LNG spot price and Japan LNG spot price.

For Henry Hub, the R² of the calculated v actual is 69%. The turning points are reasonably accurately tracked, although the levels are not always as close together.

For TTF, the R² of the calculated v actual is 56%. This is significantly lower than for Henry Hub but it is impacted by the sharp rise in 2022 prices, which the projection did not match, perhaps not surprisingly. Again, the turning points are reasonable accurately tracked and the levels, apart from 2022 and some of 2021, also reasonably close. In 2019 and 2020, actual prices were below calculated prices, where there was a large element of short-run pricing, while the calculated prices were based on long-run marginal cost.

For China Spot, the R² of the calculated v actual is 60%. Again, the turning points are reasonable accurately tracked and the levels, apart from 2008/9 and 2022, also reasonably close, although China recorded spot prices were not as high as Europe and Japan in 2022.

For Japan Spot, the R^2 of the calculated v actual is 50% - the same as for Henry Hub. However, the 2022 spike negatively impacts the R^2 , and excluding that, the turning points and levels appear remarkably close. As for TTF, in 2019 and 2020, actual prices were below calculated prices, where there was a large element of short-run pricing, while the calculated prices were based on long-run marginal cost.



Figure 70: Henry Hub: Calculated v Actual

Source: NexantECA World Gas Model, Argus Media



Figure 71: TTF: Calculated v Actual



Source: NexantECA World Gas Model, Argus Media

Figure 72: China Spot: Calculated v Actual

China Spot LNG



Source: NexantECA World Gas Model, Argus Media



Figure 73: Japan Spot: Calculated v Actual



Source: NexantECA World Gas Model, Argus Media



Annex 3: Development of Hubs¹⁷⁵

This Annex looks at the development of hubs in North America and Europe – specifically Henry Hub, NBP and TTF. The regulatory and operational aspects of these hubs are designed to make the buying, selling and trading of natural gas easy to undertake.

i. Henry Hub

Henry Hub is owned and operated by Sabine Pipe Line LLC and its affiliates. It is actually one end of the Sabine Pipeline, which is a bidirectional mainline pipeline that stretches from Port Arthur, Texas, to the Henry Hub. It is an interstate pipeline that is certified as an open-access gas transporter, and it is directly connected to four industrial consumers and one producer. Henry Hub is interconnected to eight interstate pipelines and three intrastate pipelines. Henry Hub also has a direct connection to storage facilities. These facilities are salt-dome caverns characterized by high deliverability and high cycling rate, which allow for several withdrawal and injection cycles each year.

Henry Hub is shown, in a simplified schematic Figure 74, with the pipeline interconnections.



Figure 74: Henry Hub Schematic

Source: RBN Energy LLC, CGEP.

In reality, however, the pipelines are located significant distances apart and connect across the spaghetti bowl of pipelines that crisscross Vermillion Parish in South Louisiana.

In addition, the Henry Hub is not all at Henry, Louisiana. In fact, the Henry gas processing plant shut down more than 15 years ago, and the hub interconnects to Sabine are scattered across the area around Henry. Thus, the name Henry Hub is more a remnant of its origins and a concept, not a place where a lot of pipelines all connect at a single point. Despite the slight misnomer, the concept does still apply. The Sabine system really does provide interconnects to 11 pipelines designated the Henry interconnects: Columbia Gulf (CGT), Gulf South, Bridgeline Intrastate, NGPL, Sea Robin, Southern Natural (SONAT), Texas Gas, Williams/Transco, Trunkline, Arcadian, Jefferson Island Storage, and of course Sabine. And Sabine continues westward, where it connects to another 13 facilities in Louisiana

¹⁷⁵ This Annex is largely taken from the author's paper on Asian LNG trading hubs. Fulwood, M. (2018)



and nine more in Texas. In addition, as the Sabine Pipeline is bidirectional, effectively gas delivered into Sabine from a connecting pipeline can be redelivered to any other interconnecting pipeline.

The transfer of gas from one pipeline to another via the Sabine Pipeline / Henry Hub is facilitated by Sabine Hub Services through its IHT (Intra-Hub Transfers) service. IHT is a nonjurisdictional accounting service used to track multiple title transfers of natural gas packages at a market centre.

Any party wanting to trade gas through Henry Hub needs to apply to Sabine Hub Services for an IHT number, which becomes that party's unique identifier. After a party trades (buy/sell) natural gas at the Hub, its scheduler will submit a nomination to Sabine Hub Services via e-mail or by using the "Online Nominations" screen on the Sabine Hub Services website. This nomination will detail all of the IHT purchases (upstream) transactions as well as the IHT sales (downstream) transactions. Each line item on the nomination will have an IHT counterparty number and a volume in dekatherms per day. The total of the upstream transactions will equal the total of the downstream transactions. All counterparties must balance their IHT (upstream equals downstream) each day.

Any physical gas entering the hub to a party's IHT account must enter the hub via a pipeline transportation agreement. On the IHT nomination, the upstream transaction capturing this transportation of physical gas will detail the pipeline transportation agreement number as well as the volume. Any physical gas exiting your IHT account is "IHT'd" to the downstream pipeline. On the IHT nomination, the downstream transaction capturing this transportation of physical gas will detail the pipeline transportation of physical gas will detail the pipeline transportation of physical gas will detail the name of the downstream pipeline point, the pipeline transportation agreement number that will pick up the gas, and the volume.

ii. NBP

Unlike Henry Hub, which is a physical point on the Sabine Pipeline system and enables interconnections with multiple pipelines, the NBP or National Balancing Point is what is known as a "virtual" point. Figure 75 is a map of the UK's gas transmission system, owned and operated by National Grid. The red lines show the gas transmission system and the black triangles the terminals, where pipe gas enters the system; the red squares are the LNG terminals, both pipe and LNG, where gas enters the system.

National Grid in the UK operates an entry-exit system for booking and paying for transmission capacity and for the nomination and scheduling of gas flows. The system entry points are largely the terminals shown on the map, while the exit points are offtakes from the national transmission system to local distribution zones or to major off-takers, such as power plants. The NBP is effectively the whole of the national transmission system since when gas enters the system, it is effectively at the NBP until it exits the transmission system.

While Henry Hub and the Sabine Pipeline allow for the transfer of gas between many different interconnecting pipelines, in the UK there is only one transmission pipeline system. Apart from that, there is great similarity between the way the Sabine Hub Services IHT works and the way the UK system works through the nominations process.

The UK gas system is governed by the Uniform Network Code —essentially a gas transportation agreement. The NBP was established in the original network code as the balancing point—hence the name—at which all shippers on the system had to balance their gas flows, with gas entering the system being balanced with gas exiting the system. The NBP was never intended as a "trading" point or hub at which gas could be traded, but the way the network code was drafted allowed trading to develop. Shippers on the system are required to make input nominations for gas entering the system at entry points and output nominations for gas exiting the system at exit points. The code allows that the sum of input nominations on any one day need not be equal to the sum of output nominations under the code. The trade nominations can either be a "disposing trade nomination"—a sale—or an "acquiring trade nomination"—a purchase. Under the code, the sum of disposing trade nominations on any one day must equal the sum of acquiring trade nominations on that day.

It was this provision in the code allowing trade nominations that promoted the use of NBP as the trading hub in the UK and, for a long time, the primary trading hub in Europe. All any party had to do to trade gas was to apply to become a shipper to the pipeline and to the regulator Ofgem (Office for Gas and Electricity Markets), which was not a particularly difficult process. Once a Shipper license was granted, the party could then easily trade gas at the NBP using the trade nominations process. The shipper did not even have to bring gas into the system through the entry points or take gas off the system at the exit points to trade gas since they could just use the trade nomination process, which many early



participants did. In many respects, the virtual hub structure in the UK allows for the trading of physical gas in a simpler manner than in the United States at, say, Henry Hub, where the hub is set up to actually move physical gas from one interconnecting pipeline to another. This requires participants to enter into multiple transportation agreements and physically actually move the gas on these pipelines and so be involved in the gas industry. Under the UK system, a party can trade physical gas with no supply and no customers but just with other counterparties.





Source: International Energy Agency and Department of Business, Energy, and Industrial Strategy

iii. TTF

In many respects, the Netherlands TTF is much the same as the UK NBP in that it is a virtual balancing point on the Gasunie Transport Services system, shown in Figure 76. It is important to distinguish between Gasunie Transport Services (GTS), which is the transmission system operator, and Gasunie. The former balances the grid and manages TTF, whereas the latter also has interests in the GATE LNG terminal in Rotterdam, storage capacity in Zuidwending, the BBL pipeline to the United Kingdom, a part of the German transmission grid, and Nord Stream 1. There is a Chinese wall between GTS and Gasunie.

94





Figure 76: Netherlands Gas Transmission System

Source: International Energy Agency

The system is very similar to the UK system, with entry points at the borders and exit points to the Dutch distribution system and power plants, but the Gasunie system also has multiple exit points at borders to other countries.

Gasunie set up TTF in 2003. It was modelled on the NBP, but it was set up as a hub immediately, and it was no "accident" like NBP. TTF is a virtual marketplace, where gas is traded that has already been introduced into the transport system, which makes it easily tradeable. The gas is registered by means of a "nomination" from certified shippers. Nominations are electronic notifications stating the volume of gas transferred, the period, the quality of the gas, and the buying and selling parties. Even though this trade in gas is a mutual process between Gasunie customers, they need to notify Gasunie of these transactions. Thus Gasunie always knows who owns the gas and can balance the system. TTF, however, only deals with gas that is already in the system, or "entry-paid" gas, and as such mirrors the trade nomination process in the UK Uniform Network Code.



The creation of TTF was part of an effort to liberalize natural gas markets that was dictated by the European Commission in Brussels. It is worth noting that the European Commission published various legislative proposals that indicated that physical and legal unbundling of public and commercial activities was the best means to create competitive markets. The minister of economic affairs at the time (Brinkhorst) was a fervent supporter of this doctrine, and consequently the Netherlands went further in implementation than most member states (with notably the United Kingdom leading the way). In essence, the Dutch state purchased the transportation assets, deemed key to preserve public interests, from its owners (collectively organized in the so-called Gasgebouw) and created a new legal entity to operate them. Somewhat confusingly, the name "Gasunie" migrated with this new entity, and the remaining commercial activities had to be carried out by a company that required a new name (GasTerra), which remained part of the Gasgebouw.

Initially, support for TTF was, understandably, not overwhelming. At that time, Zeebrugge was the emerging trading hub in Continental Europe, but it was physical and quite closely linked to NBP. By requiring trade to go through the new exchange rather than on the border, incumbents lost a significant revenue stream and initially fought it. The independent regulatory authority Nederlandse Mededingsautoriteit demanded that GTS use an entry-exit model as in operation in the United Kingdom. There were concerns at the time—for instance, that the Dutch network had been designed to market the specific low calorific Groningen gas rather than facilitate competition—but in the end, and with expansion of the domestic network and nitrogen capacity, the market accepted the new direction. It is worth noting that there were tensions between existing players, legal requirements in the form of European directives, and the interpretation thereof by the independent regulatory authority (which in this case arguably was strictly legal, even though the Dutch state lost a revenue stream over this).

Once TTF was created in 2003, it took time to get used to this new model. The newly named GasTerra was assumed to offer commodity on the newly created exchange, but on the other hand, there was concern that, given its dominance on the local market, the regulatory authority would intervene. Major shareholders in GasTerra likely also had strong views on the path forward. One could argue that without liquidity, and limited price transparency, it was difficult for market actors to purchase additional natural gas or sell excess commodity. In other words, the relevant legislation might have been in place, but the market needed maturing. A specific initial complication in the case of the Netherlands was that trade initially was essentially split between low calorific and high calorific natural gas, with quality conversion as an added service. In the end, a compromise agreement was reached (or forced by the regulatory authority), and GasTerra started trading various products on TTF, notably by 2005. In January 2009, the costs of quality conversion were socialized, and from then onward, trade on TTF could take place in MWh. In 2011, GasTerra started offering within day and day ahead products on TTF to further incentivize wholesale trade.