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CHALLENGES TO THE FUTURE OF EUROPEAN SINGLE MARKET IN NATURAL GAS

Chi Kong Chyong

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Recent gas price dynamics in Europe shows convergence to the extent that locational price differentials approached transport tariffs and hence arbitrage was largely saturated – it is a sign of a well-functioning pan-European gas wholesale market. We employ a transaction cost economics framework to understand how we got to where we are in terms of the evolution of the gas industry structure in Europe and its institutional setup. The move towards a single market in gas, which is still ongoing, has allowed European gas consumers to benefit from transparently set, market-based wholesale prices as well as from increased market competition between suppliers. However, as the gas market in Europe matures and with the increased penetration of renewable energy generation in the electricity sector as well as overall decarbonization of the energy sector in Europe, the gas market and its current regulatory regime face a number of challenges. Addressing these challenges may require an update to the current market design and possibly drastic reforms to tariff setting in the gas transport market.

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Keywords Natural gas; European single gas market; security of supply; regulatory policy

JEL Classification L94

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Challenges to the Future of European Single Market in Natural Gas

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Abstract

Recent gas price dynamics in Europe shows convergence to the extent that locational price differentials approached transport tariffs and hence arbitrage was largely saturated – it is a sign of a well-functioning pan-European gas wholesale market. We employ a transaction cost economics framework to understand how we got to where we are in terms of the evolution of the gas industry structure in Europe and its institutional setup. The move towards a single market in gas, which is still ongoing, has allowed European gas consumers to benefit from transparently set, market-based wholesale prices as well as from increased market competition between suppliers. However, as the gas market in Europe matures and with the increased penetration of renewable energy generation in the electricity sector as well as overall decarbonization of the energy sector in Europe, the gas market and its current regulatory regime face a number of challenges. Addressing these challenges may require an update to the current market design and possibly drastic reforms to tariff setting in the gas transport market.

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1. Introduction

European gas market liberalization and the process of creating a single market in natural gas started with the first reforms in England and Wales around 1990, using unbundling and privatization of supply and distribution of gas and electricity to enhance market competition. Since then, a number of countries in Europe followed these reforms with the aim of creating a single market in gas and electricity for all the EU member states. By 2016, gas prices in Europe converged to the extent that locational price differentials approached the marginal cost of transporting gas and hence arbitrage was saturated – this was seen as a sign of a well-functioning wholesale gas commodity market in Europe.

This contribution seeks to take stock of the evolution of the European gas industry since 1990s, the effects of market liberalization and a sober look forward: '*quo vadis European gas market?*'.

The rest of this paper proceed with the analysis of the evolution of the gas markets in Europe using transaction cost economics; it then briefly outlines key literature on *ex-ante* and *ex-post* analysis of effects of gas market liberalization. We finally conclude the paper with a forward look where the European gas markets are moving to.

2. The evolution of the European gas industry from transaction cost economics perspective

The transaction cost framework is a helpful analytical tool to understand the evolution and organisational complexity of the natural gas trade in Europe. The economic literature points out to two major organisational forms that support exchanges between economic agents: (i) markets and (ii) vertical integration. In between those two extremes there are a continuum of organizational forms ranging from joint ventures to long-term contracts, (LTCs), (leading to quasi-vertical integration). The choice of organisational form depends on the characteristics of the transaction in question. Choosing an organisational form to facilitate trade has long been at the heart of economic thinking, particularly within the *transaction cost economics* literature led by scholars such as Coase, Williamson, Klein and Goldberg (Coase, 1937; Williamson, 1971; 1975; Klein et al., 1978; Klein, 1980; Goldberg, 1976; Goldberg and Erickson, 1987) and others following a similar approach. Joskow (1985) summarises the basic theory behind the transaction cost approach by explaining the choice of governance structure: markets or long-term vertical relationships. In addition to the traditional costs elements usually incurred during any production process (such as land, labour, capital and materials), there are also transaction costs associated with the exchange of economic goods between agents; for example, costs relating to drafting, enforcing and potentially breaching contracts. These transaction costs are real economic costs that should be considered alongside traditional cost items in the cost-minimising decision-making problem.

In general, there is a set of characteristics that may influence the nature and magnitude of transaction costs: (i) the uncertainty and complexity of transactions, (ii) the need for and degree of relationship-specific sunk investments to support transactions, (iii) the trade-off between the cost and benefit of internalisation versus reliance on market transactions and (iv) the regularity of transactions. Crucially, the need for and magnitude of relationship-specific investments to facilitate trade are the most important characteristics, which, in combination with the other factors mentioned, could give rise to very high transaction costs associated with potential exchanges. High uncertainty means that contracts may be incomplete, in the sense that they are unable to specify every possible state of nature that could affect the performance of the parties under the contract. As such, the incompleteness of contracts would not create significant problems were it not for the involvement of a high degree of relationship-specific assets that must be developed *ex ante* to facilitate the exchange. Furthermore, the frequency of transactions should only matter when high (sunk) investment costs were involved in establishing bilateral trade because subsequent transactions represent opportunities for haggling and the higher the frequency of those transactions, the higher the risk of opportunistic behaviour among the parties involved in the trade. According to Williamson (1983), there are four types of asset specificity that may partition an industry into a smaller number of bilateral oligopolies:

1. *Site specificity* – the vertical relationship is arranged such that related facilities are located close to one another; for example, to minimise transport and inventory costs.
2. *Physical asset specificity* – appears when investments in equipment can only be utilised by one or both parties to the transaction and there is little value in utilising these assets in alternative ways.
3. *Human capital specificity* – emerges when employees develop specific skills required for a particular transaction.
4. *Dedicated assets* – arises when investments are made only to serve a specific transaction and would not have been developed otherwise; thus, should the contract underpinning the exchanges be terminated prematurely, the dedicated asset would be underutilised.

High transaction cost structure were present at the beginning of the development of the natural gas industry in Europe and persisted until European authorities launched the liberalisation of the electricity and gas markets in Europe. As transaction cost theory predicts, the European gas industry developed based on a system of complex LTCs between buyers and sellers. LTCs drove the development of the gas trade in Europe, and the first such contracts were signed between European companies to develop the gas reserves of the giant Groningen gas field in the Netherlands (Energy Charter Secretariat, 2007).

Table 1 highlights the importance of LTCs in the development of the gas industry in Europe: The majority of the contracts were signed in the period 1991-2007, with total contract volume signed in that period exceeding 66% of average gas consumption in that same period. Note that the majority of contracts that were signed before 1990 also rolled over to the 1991-2007 period, which means that LTCs might have covered almost the entire gas consumption in Europe.

Also, two other important trends are worth noting in LTCs: (i) The share of pipeline gas contracts dominated the first two periods (before 1990 and 1991-2007), while the last two periods saw an uptake in liquefied natural gas (LNG) supply contracts; and (ii) the number of LTCs as well as the average duration decreases over time. I will discuss these trends in detail.

Table 1: Long-term gas supply contracts in Europe

	Before 1990	**1991-2007**	**2008-2014**	**2015-2018**
Number of contracts	31	121	28	18
Total ACQ*, billion cubic metres/year (bcm/y)	109	292	98	54
Average contract duration, years	23	18	15	14
Share of pipeline contracts	68%	53%	50%	22%
EU average gas consumption, bcm/y	345**	440	472	444
Share of total ACQ in consumption	32%	66%	21%	12%

*Notes: * ACQ—Annual Contract Quantity; ** 1990 consumption*
Source: Bloomberg Terminal & Neumann et al. (2015)

Consistent with the transaction cost framework, the rationale for setting up LTCs is to protect buyers and sellers from *ex post* opportunism arising from the highly asset-specific, durable and capital-intense investments involved in: (i) the development of upstream production, gas treatment and LNG facilities; (ii) long-distance international pipelines and LNG vessels; and (iii) national transmission and distribution systems at the local level. This protection takes the form of agreed-upon minimum payments to sellers irrespective of actual offtake by buyers: the so-called minimum "take-or-pay" (ToP) level.

Thus, the buyer takes volume risks, whereas the seller agrees to settle the transaction at a price that is (slightly) below the price of competing fuels, which are usually oil products. The subsequent change in contract price is pegged to a basket of oil products and other competing fuel prices at the *'burner tip'* (final markets)[2]; therefore, the seller takes price risks since s/he does not control the

[2] It is worth noting that gas to oil price linkages was quite effective in introducing competition between gas and oil products but also between upstream gas suppliers. For example, Asche et al. (2002) examined whether the German gas market is

pricing of gas and relies on the pricing dynamics of competing fuels. This arrangement ensures that gas stays competitive with other fuels in an environment when there is no gas-to-gas competition. Furthermore, the pricing in such agreements is used as a mechanism to divide the rent associated with producing, transporting and marketing gas between sellers and buyers (on using LTCs to distribute the gains from trade between contracting parties see Masten and Croker, 1985; Crocker and Masten, 1988; Mulherin, 1986).

As such, the emergence and evolution of the natural gas trade in Europe fits neatly with the transaction cost economics framework. Table 2 outlines the main characteristics of the industry using transaction cost economics terminology. From this we can see that the two most important factors that constitute the foundation of LTCs supporting gas trade and investment in Europe are: (i) industry structure (number of buyers and sellers) and (ii) asset characteristics. The latter have changed dramatically over the past 20 years: from highly asset specific (in the 1970s) to moderate or low asset specificity (as of 2016) and from highly capital intensiveness to high or moderate capital intensiveness (e.g., due to improvements in gas transport technology and hence capital costs). The reasons for this change in asset characteristics are elaborated in the rest of this section.

Table 2: Evolution of international gas trade: From LTCs to short-term and spot markets.

	1970s	**2000**	**2016**
Number of sellers	16	34	51
Number of buyers	18	56	81
Asset Specificity	High	High/moderate	Moderate/low
Asset Intensity	High	High	High/moderate
Asset Durability	20-plus years		
Transaction frequency	High		
Uncertainty	High		
Vertical coordination mechanism	Most* transactions via vertical integration and large LTCs		Half of transactions conducted on spot markets

*Notes: Numbers of sellers and buyers are based on counts of gas-exporting and -importing countries provided by the International Energy Agency (IEA) in its 2017 Natural Gas Information report (IEA, 2017); * before 2000 only USA and UK had liquid spot gas wholesale markets – the two markets accounted for 30% of global gas consumption in 2000 but some contracts (e.g., to the UK) were also LTCs but pricing were linked to spot indices.*
Source: Author's assessment.

integrated in the period of 1990-1998, that is, before major gas market integration and liberalization processes. Their cointegration tests show that that the different border prices for gas to Germany move proportionally over time, indicating an integrated gas market. They also found that Russian gas is systematically lower than Dutch and Norwegian prices which is explained by the value of flexibility and perceived political risks.

The international gas trade has expanded dramatically since the early 1970s, when the industry structure was balanced with low number of gas-exporting and -importing countries (Table 2: 16 sellers and 18 buyers). By 2000, these numbers had more than doubled to 34 gas exporters and 56 gas importers. By 2016, the market structure was dominated by buyers; the number of exporters had reached 51 while the number of buyers had increased to 81.

Clearly, the market has witnessed a dramatic increase in the total number of participants. Traditionally, gas markets have been regional in nature, reflecting large-scale infrastructure investments along the whole value chain and the capital requirements to build transport pipeline networks to supply gas to end consumers. This means that the effective number of trading partners in each of the regional markets – North America, Europe and Asia – is in fact substantially lower.

However, these regional markets have become increasingly linked by gas trade via seaborne routes, using liquefied natural gas (LNG) vessels to trade gas over greater distances. From the late 1960s until the mid-2000s, there was a general trend of cost reduction due to technological improvements across the whole LNG value chain (Greaker and Sagen, 2008; Stern, 2010). This, coupled with demand uptake in remote consumption centres relative to production locations, allowed LNG to emerge as one of the fastest-growing internationally traded commodities over 1960–2016, when annual growth in LNG exports averaged 14% pa.[3] Over this period, there was a proliferation of the number of LNG-exporting countries, starting with Algeria, the first LNG exporter: in 1975 there were only four exporters, whereas by 1995 this figure reached eight, and by 2014 there were 20 LNG exporters (including re-exports from European countries to other markets).

Furthermore, and as we shall discuss below, LNG contracts are generally comparably smaller in terms of annual offtake quantity and shorter in duration than pipeline gas contracts. This suggests, among other things, that as it is more flexible in terms of transport mode, LNG trade is less asset specific than trade via pipelines. Therefore, the uptake in LNG trade not only increased the effective number of trading partners but also introduced more flexibility to both sides of the market, thereby reducing degree of specificity of international gas trade.

Europe has fully taken advantage of this development in the LNG trade. Table 3 outlines the evolution of European gas import capacity by LNG and pipelines.

Table 3: Breaking up the pipeline oligopoly in Europe: The role of LNG

	1999	**2006**	**2016**

[3] Author's calculation based on Poten and Partners LNG trade database, accessed through the Bloomberg Terminal.

LNG import capacity: Total (bcm)	**64.3**	**90.9**	**225.6**
Belgium	5.5	5.5	9.5
France	17.9	17.9	36.2
Greece	0	1.4	5.2
Italy	3.5	3.5	15.9
Portugal	0	5.5	8
Spain	37.4	52.2	72.8
UK	0	4.9	55.2
Lithuania	0	0	4.2
Netherlands	0	0	12.7
Poland	0	0	5.3
Sweden	0	0	0.6
Pipeline import capacity: Total (bcm)	**321.2**	**332.2**	**421.2**
Russia	175	175	230
Norway	104	104	130
North Africa	42.2	53.2	61.2
EU Consumption (bcm)	**460**	**512**	**449**
Share of LNG capacity in EU consumption	14%	18%	50%
Share of pipeline capacity in EU consumption	70%	65%	94%
LNG import capacity (relative to 1999)	100%	141%	351%
Pipeline import capacity (relative to 1999)	100%	103%	131%
Number of LNG exporters: countries *(export capacity, bcm)*	11 *(145)*	13 *(254)*	20 *(465)*

Source: BP (2018), IEA (2000, 2007, 2017); pipeline import capacity—author's own assessment based on various websites of export pipelines

Table 3 shows that in 1999, the European gas industry was dominated by a few extra-EU pipeline gas suppliers: Russia was the largest both in terms of reserves (BP, 2018) and export capacity to Europe. It was an oligopolistic supply structure. However, in the period 1999-2016, European LNG import capacity expanded by 2.5 times (relative to the 1999 level) and accounted for 50% of total consumption (2016), while total pipeline import capacity grew only by 31% in the same time. This dramatic increase in LNG import capacity -- coupled with an increase in the number of LNG exporters (and total export capacity) globally -- allowed Europe to limit the potential market power of pipeline exporters: in particular, the potential market power of Russia/Gazprom. However, the increase in LNG import capacity alone might have had a limited effect without the liberalization process.

While the number of exporters and importers increased worldwide, market liberalisation and the ability to tap into global LNG markets meant that the number of buyers and sellers also increased in European gas markets, reflecting trade in organised market exchanges (gas hubs or spot markets). The liberalisation process began with the *1991 Gas Transit Directive*, and the subsequent legal battle between European antitrust authorities and major exporters to remove destination clauses from long-term pipeline and LNG import contracts. This was followed by the first two energy packages (1998 and 2003) and then by the Third Energy Package (2009).

In the 1990s and early 2000s, the EU antitrust authorities were successful in negotiations with exporters to remove the destination clauses from long-term LNG and pipeline gas contracts. These clauses were seen as major impediments to market competition in Europe as they prohibited importers from reselling gas to other market geographies and segments.

The antitrust authorities then targeted the largest European gas importers, such as GDF Suez, ENI and E.ON, expressing concern that these companies used exclusive access to gas transportation facilities to effectively limit competition in their market areas (European Commission (EC), 2009a; EC 2009b; EC 2010). As a result, these companies reached agreement with the competition authorities to reduce their long-term capacity reservations (capacity release programmes were agreed between GDF Suez, Eni and E.ON) to allow new suppliers to enter the market (EC 2009a; EC 2009b; EC 2010).

At the same time, national antitrust authorities also looked into the state of market competition further downstream, including LTCs between second-tier suppliers and larger importers. For example, Germany's national antitrust authority (BKartA) introduced limitations on contract duration and supply quotas for a period of three years (2007–2010) to enable more downstream competition by allowing second-tier buyers to switch suppliers (European Competition Network, 2010).

As a result of this regulatory intervention, many second-tier suppliers, such as power generators and local distribution companies, became part of the gas value chain.

The pricing of gas in LTCs has also undergone substantial changes. The liberalisation of gas markets in Europe coupled with (i) increased investment in LNG import terminals to benefit from global LNG trade and (ii) low gas demand following the economic crisis of 2008 and increased inter-fuel competition (e.g. uptake of coal and renewables in European electricity generation) forced European buyers to renegotiate pricing mechanisms in their traditional contracts with pipeline suppliers. As such, since around 2010, a pricing system has emerged in Europe that is based on long-term oil-indexed contracts as well as market prices settled in trading hubs (the National Balancing Point – NBP – in the UK and the TTF in Continental Europe).

Because of these regulatory interventions and changes in market dynamics, it is estimated that the overall volume of spot gas trade in Europe stood at 43% in 2013 (Société Générale, 2013), rising to 66% in 2016 (International Gas Union, 2017), with the remainder being undertaken via traditional oil-indexed long-term bilateral contracts and other pricing mechanisms.

Thus, the organisational form of gas trade in Europe has changed quite dramatically, with increasing trade volumes being transacted through organised markets rather than being dominated by bilateral contracts, as used to be the case. This point is also reinforced by the fact that the emergence of spot and futures markets in gas trade greatly reduces transaction costs of long-term contracting because (i) contracts are standardised and hence easily transferable (traded) and (ii) prices are set transparently via multiple trades rather than costly bilateral (re)negotiations (for a detailed discussion on this point see Doane and Spulber, 1994.).

Furthermore, as we shall discuss below, the industry structure in Europe developed in response to changes in regulatory developments aimed at creating a single market in gas in Europe as well as to the degree of asset specificity involved in gas trade.

In the early days of the European gas industry, buyers and sellers relied on very large LTCs (in terms of offtake quantities) to develop gas fields and finance long-distance, cross-border pipelines and transmission and distribution systems. These LTCs essentially covered at least two parts of the gas value chain: (i) production and (ii) transportation. On the buying side, buyers were vertically integrated (usually state-owned) companies, which helped them develop and control national transmission and local distribution systems as well as gas sales and marketing. On the selling side, producers were responsible for developing gas fields and the associated infrastructure as well as large-scale, long-distance pipelines that usually crossed the borders of more than one country. This is particularly true for Russian gas supplies, whose pipelines sometimes crossed more than three countries before reaching delivery points in Europe.

Thus, the traditional model – *'from wellhead to burner tip'* – was effectively broken by EU legislation introduced to increase competition and market integration at the midstream and downstream levels of the European gas markets (see discussion above). Among other fundamental changes brought about by this legislation, one particular structural shift was the so-called *'unbundling'* or breaking up of vertically integrated utility companies on the buy side, which could no longer control infrastructure components of the gas business. Transmission and distribution within Europe, seen as natural monopolies, are now managed by independent companies and are subject to regulation in terms of service quality and tariff setting.

Thus, on the buy side at least, the transportation component became a separate regulated business activity and was no longer part of the chain of traditional LTCs between producers and buyers. A second structural shift was the introduction of third-party access to transport infrastructure in Europe; i.e. should there be demand for access to transport capacity, the independent operator should grant such access subject to technical and other requirements that are transparent to all market participants. Together these two changes meant that gas transportation infrastructure in Europe no longer posed a high risk for opportunism because these regulations essentially reduced the degree of asset specificity involved in gas transactions between buyers and sellers. Although investment in transmission and distribution is still durable and capital intensive, albeit less so than it used to be, it is now less risky due to these sectors being regulated monopolies: if there is enough demand for new capacity, then the infrastructure is build and the capacity price regulated under some form of tariff regulation.

In addition to changes in how gas transport infrastructure is governed in Europe, both pipelines and LNG, as a mode of transporting gas, have been subject to substantial cost reductions – or capital intensiveness – due to technological improvements. For a detailed discussion of cost reductions in pipeline and LNG transport see, for example, Cornot-Gandolphe et al. (2003) and Jensen (2003). All else being equal, lower capital intensiveness leads to lower risks and potential losses arising from the ex post hold-up problem. The reduced risk of hold-ups together with the changes in organisational form for the investment in and management of transport assets in Europe means that there is no longer a rationale for including these assets in traditional long-term purchase contracts between buyers and sellers, as was the case when the industry began to develop in the 1960s and 1970s.

On the selling side, production facilities, such as gas wells and treatment facilities, are not highly asset specific *per se* and can be used to produce gas for sales to any buyer or market provided that transportation to these markets and buyers is already established. Thus, the high asset specificity in the gas industry lies simply in transportation assets (for a detailed discussion of this point see Doane and Spulber, 1994), and in Europe, a part of these assets is now under regulation and poses a low risk of hold-ups.

The only remaining issue is the long-distance pipelines connecting producers to European border points, most of which have already been developed as part of the first wave of LTCs between major producers (Russia, Norway and Algeria) and European buyers and have since been fully or substantially depreciated. We exclude from this discussion the issue of the transit monopoly and associated risks of supplying Russian gas to Europe, which is beyond the scope of this paper. However, let it suffice to say that the perceived high monopoly power of transit countries and associated risks of rent expropriation by such transit countries motivates producers, such as Russia, to seek new capacity that it can control via LTCs or some other form of vertical integration.[4] Nonetheless, going forward it

[4] For example, the Belarus transit system, which is co-owned by Russia and Belarus, or the Blue Stream and Nord Stream pipeline investments that helped Russia reduce its dependence on traditional transit routes were carried out as joint ventures with Russia's major gas buyers in Europe.

is expected that the need for such *'transit-bypass'* transport capacity will be minimal relative to the overall potential trade volume between Russia and Europe.[5]

Lastly, asset durability, transaction frequency and uncertainty involved in natural gas trade have not changed in a way that would undermine the role of wholesale markets and price signals as a vertical coordination mechanism between buyers and sellers. By asset durability we mean useful lifetime of gas infrastructure assets, hence it would not change dramatically in the time span considered (1970s – present). That said, if we consider the level of depreciation of existing gas transport infrastructure as asset durability then this suggest a decreasing trend because (i) most of gas transport infrastructure are substantially depreciated, or (ii), as we noted before, they are managed by independent companies and are subject to regulation in terms of service quality and tariff setting thus minimising risks of holdups. Transaction frequency remains high for the entire time horizon but are likely to increase as more transactions are made on spot markets (where contracted volume per transaction will decline relative to traditional LTCs). As for uncertainty, we should look at volume and price risks as measures of uncertainty in gas trade in Europe – both should not change dramatically over time. This is because those two risks have been managed by traditional LTCs[6] in the past and with increase in liquidity in forward contracting in spot markets (NBP and TTF, for example) (ACER, 2017) managing those risks in organised wholesale markets should offer comparable level of certainty as traditional LTCs do.

All in all, this suggests that the role of LTCs in European gas trading will diminish substantially in the coming decades due to a decrease in (i) capital intensiveness and (ii) the level of asset specificity associated with changes in the regulatory regime governing the investment in and management of transport assets in Europe in particular and liberalisation process in general as well as higher volumes of LNG in overall gas trade (LNG is a more flexible mode of trade and is hence less asset specific).

Next, we discuss some further empirical and theoretical studies on the changing nature of the gas trade in Europe and the implications for LTCs.

3. Effects of industry liberalization on gas trade in Europe

The theoretical literature on LTCs in the gas industry outlines the conditions under which markets or LTCs dominate. For example, Doane and Spulber (1994) showed that changes in the

[5] Setting aside the politics of pipeline gas sales to Europe in light of the recent geopolitical tensions between Russia, Ukraine and Europe, the need for new bypass capacity is minimal since Russia has already invested in alternative transport capacity that bypasses Ukraine substantially. Similarly, to completely circumvent Ukraine, Russia would require another transport route with roughly 50–60 bcm/year, which is about 30% of its expected total annual contract volume to Europe in the next two decades.

[6] one of the main purposes of traditional LTCs is to manage volume and price risks

regulatory framework towards increased competition through unbundling, third-party access and the regulation of pipelines in the US gas industry decreased transaction costs between buyers and sellers, thereby enhancing spot trade. As discussed above, Doane and Spulber also stressed that the reduction in transaction costs comes from the fact that third-party access and the regulation of pipelines means that purchase contracts do not need to be tied to a specific pipeline and producer–buyer pair.

Brito and Hartley (2002) applied a microeconomic (search) model and showed that the length of long-term LNG contracts was likely to diminish with (i) the decreasing capital intensiveness of the assets involved in LNG transactions, (ii) increasing cost of capital (discount rate) and (iii) a larger number of players in the market (suppliers and buyers). Brito and Hartley (2007) and Hartley (2015) also suggest that the role of long-term LNG contracts will diminish as spot market liquidity increases. In particular, Hartley (2015) uses a microeconomic model to show the link between increased LNG market liquidity, greater volumes, and destination flexibility in contracts and increased short-term and spot market trades, reinforcing increases in market liquidity.[7] Similar findings were obtained by

Parsons (1989), who applied an auction model to find the 'strategic' value[8] of long-term gas contracts signed by producers such as Russia, Norway and Canada. Parsons found that the value of such contracts for the producer diminishes as (i) the number of wholesale buyers increases and (ii) the cost structure decreases prior to spot sales (capital intensiveness).

Other empirical work analyses the impact of the changing structure and asset specificity of the European gas industry on LTCs and on contract duration in particular. For example, von Hirschhausen and Neumann (2008) conducted an econometric analysis of over 300 LTCs and found an inverse relation between contract duration and (i) deliveries to the restructured markets of the US and UK as well as to the post-1998 markets of Continental Europe (i.e. after the first energy package), (ii) contracts not linked to substantial new investment and (iii) those signed by new market entrants. All else being equal, these findings suggest that as gas markets in Europe are liberalised and mature further (i.e. there is no need for substantial investment in infrastructure) and market entry increases (as discussed in the previous section), the duration of LTCs will decrease.

A similar econometric analysis of 224 LNG contracts was conducted by Ruester (2009), who found that: (i) as asset specificity decreases, so does the duration of LNG contracts; (ii) post-2000 LNG contracts are generally shorter than those signed before that period; and (iii) in the presence of high

[7] This theoretical prediction is in line with the view of some gas market analysts in Europe, who state that if spot trade exceeds 50% of all traded volume, the move towards complete spot trade is irreversible (see e.g. presentations and speeches by Thierry Bros, former researcher from Société Générale).

[8] Defined in Parsons, 1989 as the difference between the value of the commodity in the LTC and the sales price in a more competitive market.

price uncertainty, contract duration tends to be lower. The last two conclusions are important in the sense that (i) post-2000 LNG contracts are shorter because of substantial cost reductions achieved across the whole LNG value chain and (ii) when prices are uncertain, the benefits of LTCs diminish due to potential profit from arbitrage, as prices tend to fluctuate more, while the cost of holding such contracts becomes higher in the sense of their ‘incompleteness’, as discussed in the previous section. This is especially true in the given examples of contract renegotiations between European buyers and sellers post-2008. Similar results were obtained by Chyong (2015) who showed that market liberalisation in Europe, together with a general reduction in the capital intensiveness of infrastructure assets, has indeed reduced the role of LTCs, specifically, by negatively affecting the duration of such contracts.

The literature points to the fact that European gas markets has been moving away from rigid bilateral oil-indexed long-term contracts to shorter term and spot market trading arrangements. Indeed, Miriello and Polo (2015) argued that gas wholesale trade in Europe was initially developed to cope with physical balancing needs of market participants and as these become more liquid the balancing markets became a second source of gas procurement.

Finally, to manage price risks, Miriello and Polo (2015) noted that financial instruments and forward/futures markets also gradually developed. In line with findings from the empirical institutional economics literature (e.g., Hirschhausen and Neumann, 2008), by examining institutional arrangements of gas market regulation in selected European markets Miriello and Polo (2015) noted that the UK and the Netherlands have been leading the process of market liberalization, while Germany and Italy are constrained by limited supply hence lagging behind the former two markets in terms of developing competitive wholesale markets.

As Northwest European (NWE) wholesale gas trading picked up after the liberalization processes so does the ex-post empirical analyses on gas price convergence. Siliverstovs et al. (2005) and Neumann (2009), confirm the importance of LNG trade in fostering global gas-on-gas competition and price integration, particularly the European and North American spot prices. Neumann et al. (2006) analysed price convergence between two traded gas hubs in North West Europe in 2005: the authors found that after the construction of bi-directional pipeline connecting the UK and Belgium, the prices in those two markets converged while liberalization on the European continent does not seem to be working. Note that the end of their time series analysis was 2005, that is, before the third energy package took effect. More recent empirical work analyzing price correlation and convergence for different European markets all suggest that the EU integration policies have been successful – major gas markets in Europe are fully integrated by 2013 (see e.g., Harmsen and Jepma (2011), Neumann and Cullmann (2012), Growitsch et al. (2013), Asche et al. (2013), Petrovich (2013)).

Indeed, EC (2011) concluded in its report on progress towards creating the internal gas and electricity market for 2009-2010 that there were significant barriers to open integrated and competitive markets in electricity and gas remain. However, by 2013, ACER (2014) reported increased gas wholesale price convergence across the EU and further trends towards price convergence were observed in 2014-2016 (ACER, 2015; 2016; 2017) (see Table 4). This price convergence trend was observed not just for traded markets but also between different 'immature' traded markets where gas prices are predominantly set by bilateral oil-indexed LTCs (for discussions of pricing in such LTCs see Section 2 above).

Table 4: European gas prices: 2013-2016 (€/MWh)

	2013	2014	2015	2016
Max price in the sample	37.5	32.0	27.9	19.5
Min price in the sample	27.0	21.9	21.0	14.1
Mean price in the sample	30.2	26.2	23.2	16.6
Spread: TTF—mean	3.0	2.5	2.2	1.1
Spread: TTF—min	0.2	1.8	0.0	1.4
Spread: TTF—max	10.3	8.3	6.9	4.0
Spread: max—min	10.5	10.1	6.9	5.4
Spread: TTF—oil-indexed contract prices	9.9	10.8	6.9	4.6

Notes: TTF - The Title Transfer Facility: a virtual trading point for natural gas in the Netherlands. MAX, MIN, and *MEAN are taken for a sample of annual prices for 26 EU countries; these prices were taken from the ACER gas market monitoring reports https://acer.europa.eu/en/Pages/default.aspx. Reported spreads are absolute values.*
Source: ACER's Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets for 2013-2016 years. Available for download from ACER's website: https://acer.europa.eu/en/Pages/default.aspx & Thomson Reuters for oil-indexed contract prices.

The most important factors that allowed for such a price convergence (not just between traded hubs as found by econometric analyses quoted above but between hubs and immature markets) were (i) the slump in gas demand in Europe relative contracted volume between midstream and upstream companies, and (ii) abundance of LNG volumes in the period 2009-2014. These macro and upstream trends allowed traditional oil-linked LTCs in Europe to be renegotiated and brought in line with market traded prices of North Western Europe. The importance of LNG imports in Europe in breaking up the structural linkages between gas spot and oil-linked gas prices has been shown by Koenig (2012) and Chyong and Kazmin (2015). Figure 1 suggests that since about mid-2009, the oil-indexed contract prices (BAFA[9] and Russian average contract prices delivered to Germany) began to diverge from their theoretical value (historic oil-indexed price, Figure 1). Moreover, the oil-indexed contract prices closely track the spot prices of NWE markets: TTF.

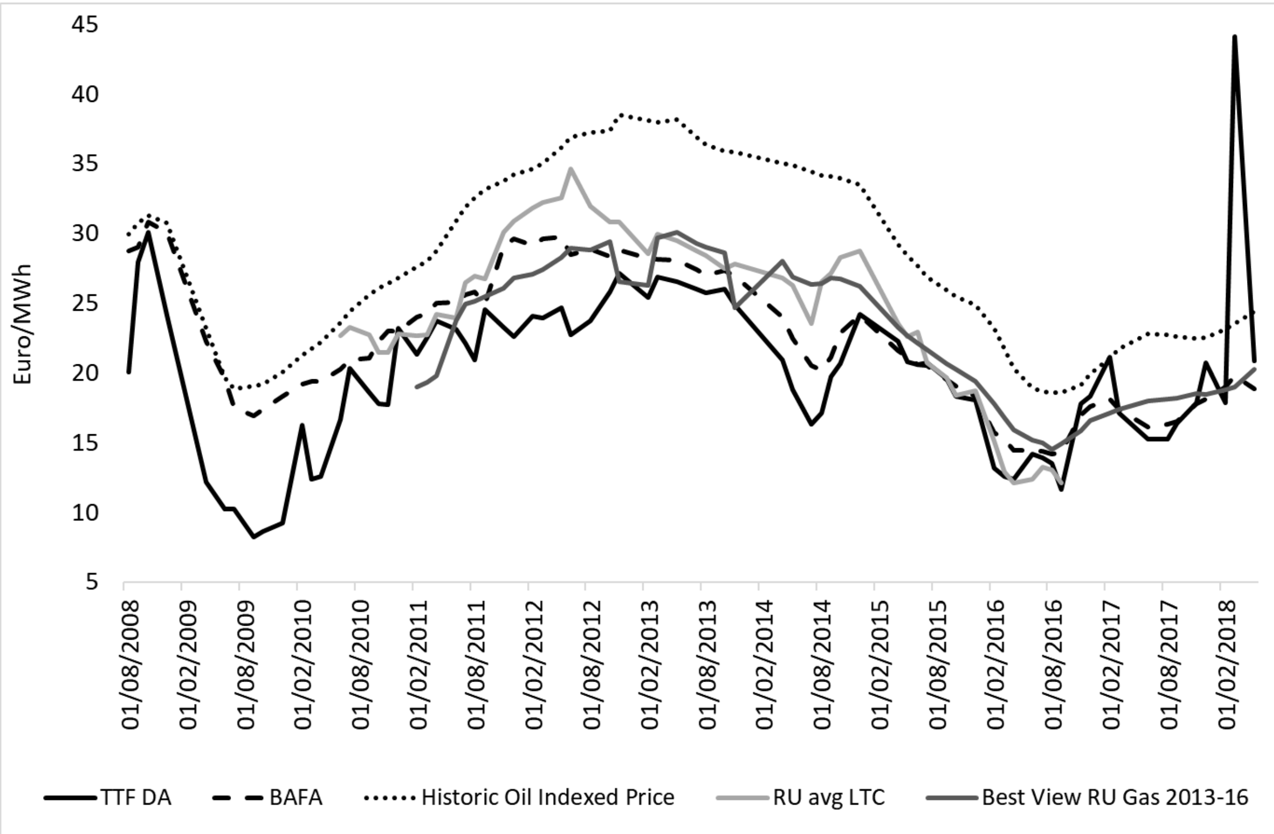

Figure 1: Evolution of spot and oil-indexed gas prices in Europe

Source: own illustration based on data from Thomson Reuters accessed through Eikon Terminal
*Notes: TTF DA: TTF Day-ahead price assessment reported by Thomson Reuters (access via Eikon Terminal); RU avg LTC is an average actual monthly price of Russian LTC gas sold at the German border as reported by Ministry of Economic Development of Russian Federation. From October 2016, the source stopped updating this price. The 'RU best view' gives a view of what prices on these contracts would have looked like against current prices. The 'RU best view' is Thomson Reuters' view of the level of contractual prices between Gazprom and the large western European buyers in the general period 2013-16. This combines an element of hub indexation (15%) with a further discount that is applied to improve competitiveness against hub prices. The historic oil-indexed price is calibrated using historic BAFA (average gas import) prices at the German border over a period when all gas coming into Germany was oil-indexed (pre-2008). It is used in this chart to predict the level at which these contracts would be now against hub prices, even though an accepted view by the European gas industry is that oil indexation is no longer relevant for pricing gas in western Europe. The formula of the oil-indexed price is given as: oil-indexed = B0 + B1 * Average oil price where Average oil price is the average of gas oil and fuel oil prices. The oil prices are averaged for between three and nine months and lagged by zero to three months to optimise the model fit.*

On the welfare benefits of having a single market in gas – the same report by ACER (2014) estimated that due to lack of gas market integration potential annual gas wholesale gross welfare losses

[9] Germany's Federal Office for Economic Affairs and Export Control

amounted to €7 bn (ACER put this figure at €11 bn for 2012). The decrease in welfare losses between these two years were mainly due to LTC renegotiations (see above). A more important benefit (perhaps less amenable to quantification) that a single gas market may bring to Europe is minimization of political consequences resulting from price differences observed between different member states (see e.g., Noel 2009).

To summarise, the theoretical literature and empirical evidence suggest that the European gas industry has changed dramatically in the last 20 years in response to regulatory, technological and industrial dynamics. The industry has gradually transformed from domination by state-owned monopolies and rigid bilateral contracts to a more competitive market.

However, there are still impediments to complete the project of creating a single market in gas in Europe which we summarise in our next section.

4. European gas markets: looking forward

In a perfectly competitive and integrated market the *'law of one price'* should be observed, that is, prices for a homogenous commodity, such as natural gas, across different locations should only differ by transaction costs (e.g., transport costs of moving gas from one location to another). Most recent gas trade data reported by ACER (ACER, 2017) suggest that price differentials between most traded hubs in Europe were even below transport tariffs. Given that price differences between traded and non-traded hubs have been moving closer due to the elimination of oil-linkages in the traditional LTCs (See section 3 above), the divergence of prices between different locations could be dictated largely either by transport tariffs and/or non-trade barriers (lack of implementation and/or derogation from certain rules of the Third Energy package, for example). The latter is monitored by the European authorities and subject to negotiations between the Commission and national authorities of each member states. The former – transport tariffs – have gained much of the attention in the current debate about the future of gas market design in Europe (see e.g., EC's (2018) commissioned work *'Study on Quo vadis gas market regulatory framework'*).

The Third Energy Package stipulates, amongst other things, the creation of entry-exit (E/E) zones managed by an independent transmission system operator (TSO) and that shippers can book entry and exit capacity rights independently, effectively creating gas transport through zones instead of contractual paths. Each of these transport zones are further supported by a virtual trading point (hub) where gas can be freely traded among shippers who have entry and/or exit capacity rights. Geographically, each of these zones roughly corresponds to a national market of a EU member state.

Transmission tariffs for the entry and exit capacities are designed for full (sunk) cost recovery: the tariffs depend on utilization of the entire gas network of each transport zone.

Thus, a principal reason that location price spreads between different European gas hubs are below cross-border transport tariffs is because suppliers and shippers hold long-term capacity bookings and regard them as sunk costs. Therefore, existing cross-border gas trade in Europe is largely influenced by short-run marginal cost of moving gas between hubs. In the process of liberalization and unbundling of network activities from competitive activities, national authorities and incumbent gas suppliers have agreed to book on a long-term basis majority of entry and exit capacities in their respective transport zones to underwrite the utilisation of their respective gas networks.

However, given that European gas network and supply structure was built largely on the assumption of expanding gas demand in Europe (see Figure 2 and Table 1), once these long-term transport capacity bookings expire (mid 2020s), locational price spreads could diverge to reflect full cost-recovery transport tariffs between transport zones.

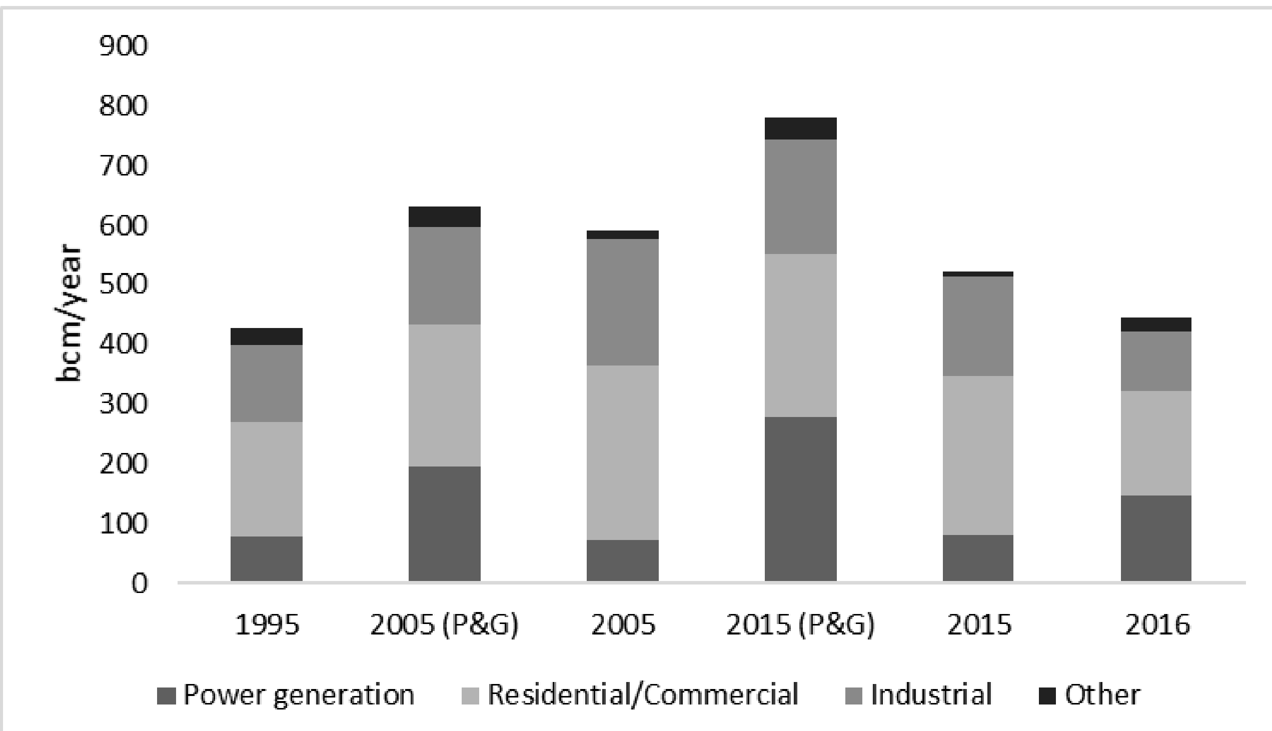

Figure 2: Realised and forecasted gas demand in Europe

Source: 1995-2015 period was reproduced based on Komlev (2016); 2016 data from Eurostat
Note: P&G means Purvin and Gerts 1998 gas demand forecast for 2005 and 2015

Thus, given that gas demand in Europe is likely to stay flat (or even fall) relative to the overall size of the transmission network, the tariffs for using the transport network will increase. This trend would be exacerbated should TSOs implement their announced investment plans for the period 2015-

2025. It is expected that the annual tariff increase should be +0.8% p.a. in the gas sector in Europe (BearingPoint & Microeconomix, 2015) in the period to 2025. Cumulative increase in some member states could be as high as 39% for the period 2015-2025. Majority of expected investment in gas network is driven by security of supply concerns in Central, Eastern and Southern Europe.

Therefore, the future of European gas market integration to a large extent (if measured by price differentials between market/transport zones) depends on the effectiveness of the current regulatory regime in ensuring cost reflective tariff setting considering falling gas demand, security of supply concerns and inherited large gas transport networks.

Possible high locational price differences may motivate 'tailored' national policy responses as European authorities are moving towards 'harmonisation' of national gas regulatory policies (which has been the main effort by the authorities since the enactment of the Third Energy Package). The following example highlights the importance of transport tariffs and shed lights to a general problem of defining gas transport markets using entry-exit zones which coincide with national borders of EU MS.

There has been a persistently high locational price spread between North West European hubs and Italy which reflect high transport tariffs between the two market regions – according to the recent ACER (2017) report, the locational price spread between PSV (Italian hub price) and TTF (North West European hub price) is ca. €2/MWh, leading to €1.4bn of loss of welfare for Italy given its current demand level.[10]

A solution to reduce this high price spread has been put forth by the Italian Ministry of Economic Development in its new energy strategy published in 2017 (MEDI, 2017). It boils down to the Italian TSO purchasing all transport capacity from TTF to PSV on a long-term basis and re-selling the capacity to market participants at short-run marginal cost (any gap between cost of buying all this capacity and the revenue received will be socialised across Italian gas consumers). The primary reason for this solution is to avoid *'tariff pancaking'* and to facilitate cross-border gas trade between the marginal source of gas for Italy, which is TTF, and its wholesale market.

There are other examples where cross-border transport tariffs reaches as high as 50% of wholesale gas commodity prices (see e.g., REKK 2016). These high cross-border tariffs happen to be predominantly in Central, Eastern and Southern Europe (CESE) countries (see e.g., REKK, 2016 and ACER, 2017) where security of supply concern is high on the political agenda and if any investment in gas infrastructure is taking place this will be based on security of supply concerns.

[10] For comparison, price spread between TTF and the German virtual trading point NCG is ca. €0.2-0.3/MWh

Thus, the risk of divergence of prices between NWE and CESE markets in the future is real with all the political consequences as discussed in Noel (2009). Chyong (2017) demonstrated this issue with some quantitative results – the author showed that in the CESE and the Baltic gas markets should Gazprom (the dominant supplier) changes its pricing strategy to lock out competition from LNG then the gas infrastructure that was initially built with security of supply in mind will see a substantial reduction in their utilization. This implies greater cross-border transport tariffs and hence possible disintegration of these markets from the rest of Europe (Chyong, 2017).

The issue of transport tariffs and the way infrastructure cost should be recovered are going to play an ever-more important role not least because of price divergence but also because this will dictate pricing strategy of dominant suppliers in those markets. This is because, from the economic point of view *'tariff pancaking'* distorts competition and cross-border trade by increasing wholesale price differentials allowing a costlier marginal source to meet demand. Put this differently, a *'clever' Stackelberg* supplier will price its gas just slightly cheaper than the most expensive supply source *plus* the transport tariff into that market.[11] *'Tariff pancaking'* also reduces the utilization of existing infrastructure and could lead to a *'death spiral'* in that lower utilization rate will increase tariffs (average cost) further and this is inefficient when average cost is increasing relative to short-run marginal cost.

Furthermore, the nature of transport cost setting in the existing entry-exit system is such that it may be influenced by political economy considerations of each members states and their TSOs managing their respective transport zones – this is especially pronounced in an oversized gas system and/or in the context of a need to invest in security of supply infrastructure. The current network codes allow much flexibility for each member states and their respective TSOs to set transport tariffs and with a large entry-exit system there are far too many *'degrees of freedom'* in setting *'cost-reflective'* tariffs.

Thus, although the price differentials between traded hubs and between traded hubs and other markets (such as markets of Central, Eastern and Southern Europe, CESE) has narrowed down dramatically in the last five years (see Section 3 above) location price spread might widen again in the future. In the past such high location price differences between NWE and CESE was predominantly due to the discrepancies between hub-based (NWE) and high oil-linked (CESE) prices as well as supply structure (see ACER 2014). Going forward, locational price spread could, to a large extent, be

[11] In the gas industry terminology, the marginal supplier will price its gas in the market according to the *netback basis* – that is, its price is just slightly lower than the hub price (spot price) plus transport cost from the hub back to the market.

dictated by regulatory measures, policies around security of supply, cost recovery and reflectivity of tariff structures for each of the transport zones in Europe.

5. Conclusions

Since the enactment of the 1991 Gas Transit Directive and subsequent energy directives and packages, the wholesale gas market in Europe is functioning as one would expect from a competitive and transparent commodity market. The move (which is still ongoing) towards a single market in gas has allowed European consumers to benefit from transparently set market-based wholesale prices as well as from increased competition between suppliers, thus, mitigating potential market power in captive markets of Central, Eastern and Southern Europe. Structural changes in both the upstream and the downstream side of the European gas markets coupled with regulatory changes allowed a smooth transition from a gas system relying on rigid bilateral oil-indexed LTCs to a healthy and competitive wholesale gas markets in Europe.

However, as the gas market in Europe matures and with the increased penetration of renewable energy generation in the electricity sector as well as overall decarbonization of the energy sector in Europe, the gas market and its current regulatory regime face a number of challenges. In particular, the current transport cost setting in the existing entry-exit system may be influenced by political economy considerations of each members states and their TSOs managing their respective transport zones. This could inevitably give rise to inefficiencies of cross-border gas trade if left unaddressed. Thus, locational price spreads will increasingly be dictated by regulatory measures, policies around security of supply, cost recovery and reflectivity of tariff structures for each of the transport zones in Europe. Addressing these challenges may require an update to the current market design and possibly drastic reforms to tariffs setting for gas transport market. A more general question that European authorities may wish to consider is whether the existing gas market institutions can ensure competitive entry of new sources of gas supplies deep into land-locked markets of Central, Eastern and Southern Europe.

Despite challenges ahead, the overall lesson to be learned from Europe is that in general terms the process of creation of a single market in gas was positive; it has created net benefits to Europe in the form of price convergence, transparency and minimization of political consequences of possible market segmentation and disintegration. But the *'devil is in the detail'* and hence applying European gas market liberalization experience to other contexts would require a deep understanding of socio-political and local market conditions.

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