SUPPLEMENTARY INFORMATION:

Market power and long-term gas contracts: the case of Gazprom in Central and Eastern European Gas Markets

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NOTE 1: CONTRACTS IN INTERNATIONAL GAS TRADE

LTCs have undergone considerable structural changes as EU gas markets have liberalised since the 1990s. Technological innovation and lower LNG transportation costs have provided a more flexible alternative to pipeline gas, diminishing the incentive for buyers to enter into long-term agreements, and opening up opportunities for diversification, arbitrage and new contract designs (Jensen 2004; Neumann and von Hirschhausen, 2004; von Hirschhausen and Neumann, 2008; Neumann et al., 2015) particularly in price formation (§0) and supply (e.g., destination) flexibility (§0). The EC's Sector Inquiry into energy markets between 2005 and 2007 concluded that pre-liberalisation era LTCs with traditional clauses were barriers to competition in wholesale gas markets (Wäktare et al., 2007). The number of active LTCs in Europe reduced from 31 before 1990 to 18 between 2015 and 2018, while the share of total gas consumption tied to LTCs shrunk from 32 % to 12%, and the average contract duration fell from 23 years to 14 years (Chyong, 2019).

The presence of LTCs and specific clauses in traditional contracts in the natural gas industry have been explained and studied using transaction cost economics theory (Joskow, 1991; Spanjer, 2009a). Given the capital-intensive and asset-specific nature of gas production and supply, LTCs offer a form of vertical integration to protect buyers and sellers against regulatory risks, distribute investment risk and ensure fixed-cost recovery (Klein et al., 1978; Williamson, 1979; Mulherin 1986). By creating long-term dependencies between buyers and sellers, LTCs protect parties against *ex post* strategic bargaining and hold-up. They may specify the quality and quantity of gas to be delivered, unit prices, buyer and seller liabilities, and review clauses to address market uncertainties over a specified time horizon. Specific LTC clauses can have long-term ramifications for national energy security and expenditures. Understandably, contract design and its impact on competitiveness of the gas market continues to attract scrutiny from major importing and exporting nations.

A.1.1. Price formation

Pricing represents one of the most important components of LTCs. Wholesale gas price formation has traditionally been done by indexing against crude oil derivatives to protect

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buyers from prices higher than those of substitutes (Serletis and Herbert, 1999; Brown and Yucel, 2008; Hartley et al, 2008). The shift toward pricing based on 'gas-on-gas' (GOG) competition has been fuelled by the substitutability of oil and gas in the European power generation sector disappearing and structural reforms of power and gas markets in Europe. The process started in the UK in early to mid-1990s (Heather, 2010), but only began in earnest in Continental Europe in the mid-2000s. By contrast, North American prices have been competitively determined by the New York Mercantile Exchange (NYMEX) at the Henry Hub (HH) since 1990 (Mazighi, 2005). Further, rising oil prices since 2008 caused higher oil-linked gas prices in European contracts to diverge significantly from spot prices (Figure A. 1). In 2012, prices of gas purchased under oil-indexation in Europe were four to six times trading-hub prices in North America.

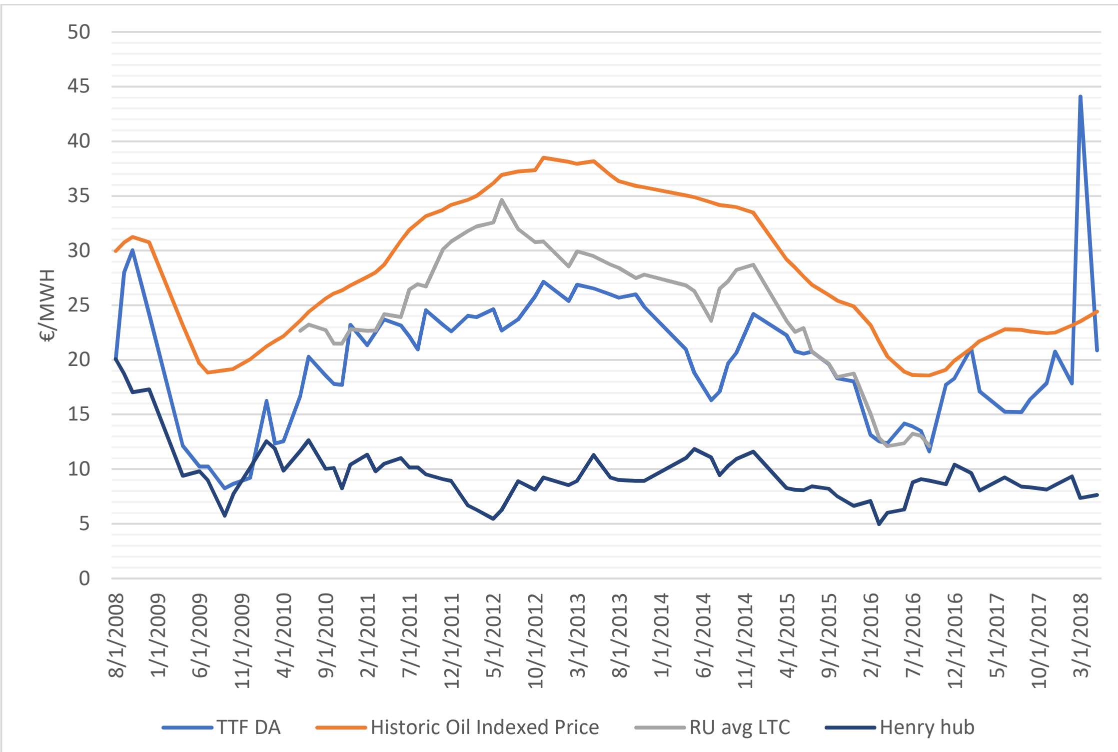

Figure A. 1: Historical wholesale gas prices under various price formation mechanisms
Source: Bloomberg and Thomson Eikon Terminals.

Note: TTF DA (Day Ahead): The Title Transfer Facility: a virtual trading point for natural gas in the Netherlands; RU avg. LTC: an average actual monthly price of Russian LTC gas sold at the German border as reported by the Ministry of Economic Development of Russian Federation. Since October 2016, the Russian Government has stopped updating this price. 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).

Figure A. 2 shows the share of pricing mechanisms in Europe and NWE based on the International Gas Union's classification of pricing mechanisms. The share of GOG pricing in Europe increased from 15% in 2005 to almost 76% in 2018, and OPE's share reduced from 78% to about 24%. The nearly 20% jump in GOG pricing in Europe between 2005 and 2010 was caused by a wave of renegotiations between European importers and exporters to introduce spot-indexation components into LTCs, particularly in the UK and Netherlands (IGU, 2012).

Gazprom first introduced elements of spot-indexation in its European contracts (with E.ON) in 2010 (Franza, 2014). A number of large importers including RWE, Uniper, DONG and Engie used available contract clauses to renegotiate LTC prices with Gazprom (Henderson and Sharples, 2018). Another 20% jump in GOG pricing is observed between 2012 and 2015, the years when DG COMP launched the investigation on Gazprom and issued the SO, respectively. The impact of this trend is evident when looking at reported historical Russian average gas prices in Germany and the Title Transfer Facility (TTF) day-ahead (DA) wholesale price (Figure A. 1) – by 2015, Russian gas price had converged to TTF DA prices. TTF in the Netherlands serves as the dominant trading hub for Continental Europe, and the National Balancing Point (NBP) for the UK, with developed futures markets and low bid-ask spreads (for details on liquidity, price risk hedge etc., see Heather 2019; De Menezes et al., 2019). By early 2018, two-thirds of all European contracts with Gazprom offered hub-linked or hybrid pricing (Henderson and Sharples, 2018).

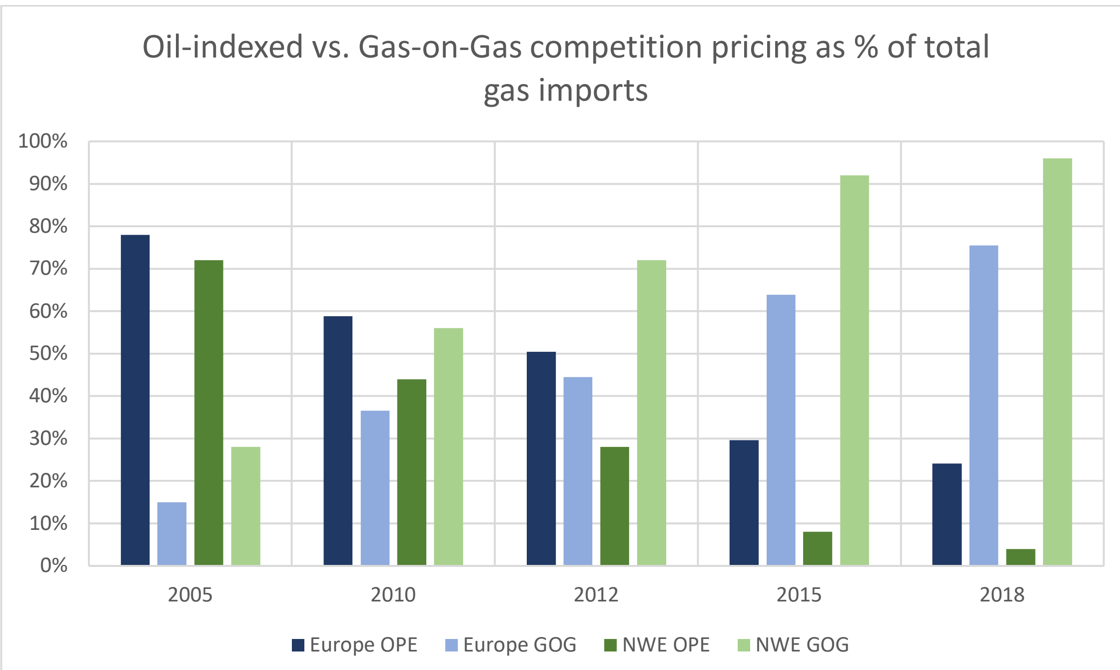

Figure A. 2: Share of OPE and GOG in wholesale pricing mechanisms in total gas consumption
Source: International Gas Union, Wholesale Gas Price Surveys 2011-2019.

Note: OPE: Oil-Price Escalation - price of gas is linked to competing fuels like crude oil or gas oil, through a base price and an escalation component; GOG: Gas-On-Gas – prices are either formed based on supply and demand and trades at physical hubs or are based on these competitive indices. It also includes LNG spot cargoes linked to hub prices. Mechanisms other than OPE and GOG also exist, for example bilateral monopoly prices, regulated prices etc.; the sum of all these mechanisms add up to 100% of the imported gas; 2007 and 2010 shares for NWE are approximate values as numbers for these years were not reported.

The mere presence of a hub does not ensure competitive wholesale prices. Structural characteristics of markets like physical interconnection to more liquid hubs, market concentration, diversity of supply, liquidity, and demand and supply fundamentals also have a strong bearing on the competitiveness of trades and thus, on wholesale prices. For example, back in 2013 when many European markets were structurally uncompetitive (Figure A. 3) we saw a clear positive correlation between market concentration and average wholesale prices in

EU MS. Furthermore, in 2017, the Polish exchange saw a decline in price convergence with the more liquid German and Czech hubs due to trade-limiting security of supply regulations and strong incumbents (ACER, 2017) despite shifting from regulated to GOG pricing in the same year (IGU, 2019).

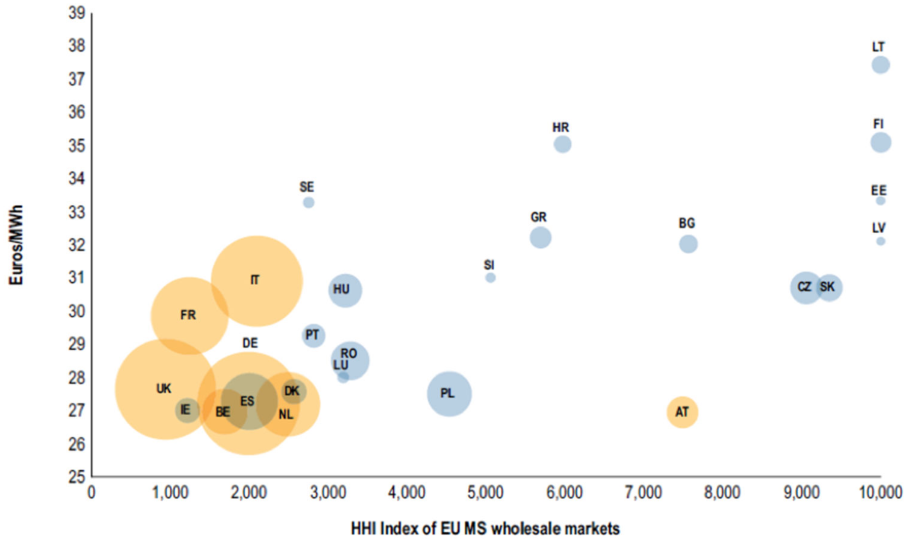

Figure A. 3: Gas wholesale prices in EU MSs compared with market concentration and gas demand in 2013
Source: ACER Market Monitoring Report 2014
Note: Circle sizes indicate gas demand; orange circles denote MS with liquid markets.

A.1.2. Competitive supply and flexibility

Traditional LTC design imposes rigidities in supply diversification as buyers and sellers seek to share volume and price risks and appropriable quasi-rents before making highly specific investments (Parsons, 1989; ESMAP, 1993; Rüster, 2009). These traditional LTC features were especially important for immature gas markets that would enable project developers to finance the entire gas value chain – from *'wellhead to the burner tip'* (Crocker and Masten, 1996). Hence, traditional LTCs restricted delivery of contract volumes to particular ports or interconnector points, through the so-called "destination clauses"[4]. Destination clauses allow sellers to restrict deliveries to designated locations, limiting the buyers' capacity to divert gas supplies for commercial reasons (arbitrage through reselling) or operational reasons (lack of storage capacity or demand). These clauses can also place restrictions on re-sale of gas purchased from the seller to other geographical markets.

Apart from destination restrictions, Take-or-Pay (ToP) clauses in LTCs oblige buyers to purchase a fixed minimum volume of gas from the seller, regardless of actual instantaneous requirements, and they bind the seller to supply the designated volumes (Creti and Villeneuve, 2004). This is in part why early storage facilities were constructed by buyers. In markets which have limited liquidity of the physical commodity and derivative products, like Asian markets, these clauses offer one means to distribute volume risk between buyers and sellers (Masten and Crocker, 1985). However, in mature gas markets like in North American and NWE, ToP

[4] 'Destination clauses' are also called 'territorial restrictions' as they limit the delivery and use of supplied gas to a single market separated along geographical boundaries or end-use industries (Talus 2011). We use the two terms interchangeably.

clauses can limit the buyer's ability to procure gas on the spot market or from other sellers, which in turn limits diversification of supply and market entry of new suppliers, thereby inducing foreclosure.

To include some flexibility in supply, traditional LTCs included profit-sharing mechanisms (PSMs). PSMs oblige buyers to share profits made on re-sale of gas with the original seller. These clauses have been deemed anti-competitive as disclosure of the re-sale destination and contract for calculating re-sale profits may reveal competitively sensitive information, and the ratio of profit sharing can potentially diminish incentives for the buyer to resell gas to another market, effectively acting as destination clauses. PSMs have been part of traditional LTCs for LNG gas imports. Globally, major gas importers have sought to phase out destination clauses and PSMs from LTCs. In Europe, since the early 2000s the EC has employed its powers to push for deep changes in traditional LTCs (Neuhoff and von Hirschhausen, 2005), particularly in clauses concerning destination restrictions or territorial re-sale (Chyong, 2019).

A.1.3. Price review clauses and welfare

LTCs are inherently incomplete since all future market states and contingencies cannot be foreseen and defined within contracts, what Williamson (1975) terms 'bounded rationality'. Due to their long durations, inflexibility and incompleteness, LTCs can impose enforcement and adjudication costs, particularly when market fundamentals start to diverge from the time when they were concluded (Crocker and Masten, 1988). Goldberg (1982) explained that price revision clauses, which use market prices as an index, allow pricing of product redefinitions over the contract duration, efficient coordination between parties through accurate price signals, and limit pre-agreement search and post-agreement jockeying. Hence, while oil-indexation may protect buyers in immature markets where oil and gas prices are cointegrated, when these prices get decoupled the absence of GOG pricing can cause welfare losses through inefficient pricing, and imposition of costs in arbitration or court-mandated revisions.

Figure A. 4 shows an estimate of the gross welfare loss[5] in EU MS caused by oil-indexation of gas prices in mature European markets, which is estimated by comparing border prices in national markets with the Dutch price based on the TTF index.[6]

[5] Welfare loss for eight CEE MS for year $n = \sum$ (total import volumes of each CEE MS in year n x import prices declared at border in year n) – (total import volumes of each CEE MS in year n x TTF prices in year n)

[6] ACER, an EU agency responsible for integration and completion of European Internal Energy Market for electricity and gas, uses similar comparison in its gas market monitoring reports to convey the potential losses to welfare of gas price divergence between European gas markets

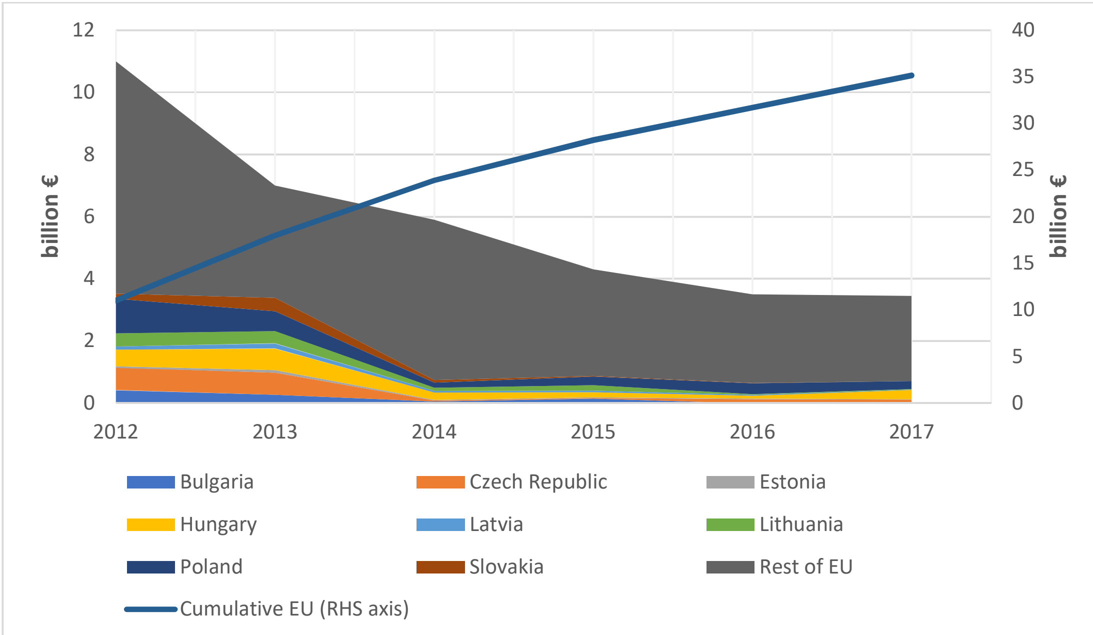

Figure A. 4: Welfare losses in EU Member States due to wholesale gas price divergence
Source: ACER Market Monitoring Reports 2012-2017; Comext database; Authors' calculations

From stable levels in 2012 and 2013 there was a steep fall in welfare losses between 2013 and 2014 with gas demand falling due to economic strain and competition from renewables (Franza, 2014), but also due to increasing price convergence between regional European markets and the TTF price index. Convergence of wholesale prices is attributable to increasing market integration and competition with the implementation of Network Codes introduced under the Third Energy Package (see ACER Market Monitoring Reports 2012-2017), and the renegotiation of traditional LTCs to include components of spot indexation. In the eight CEE countries involved in the 2012 Gazprom investigation, welfare losses in the first full year following the initiation of proceedings fell sharply as a number of LTCs were renegotiated to include hub-indexation. From 2014 through 2016, overall welfare losses continued to decline, although welfare losses in the Eight CEE have been relatively stable, and most of the fall was in the rest of the EU. From 2016 to 2017, losses did not reduce as much as in previous years due to increased price divergence between: 1) NBP and other European hubs, and 2) the two zones of the French market, both due to capacity congestion (ACER, 2017). The UK and French markets had the largest share of gross welfare losses in 2017 because of their higher import volumes compared to smaller CEE MS. Notably, in 2012 and 2017 the Eight CEE MS cumulatively imported 9.7%% and 10.6% of EU-27+UK gas imports respectively, but their share of total welfare losses only fell from 32% to 21%. Of the €3.45 billion in total EU welfare losses, €0.71 billion accrued to these CEE countries in 2017, forming about 8% of their cumulative import bill.

NOTE 2: DG COMP'S INVESTIGATIONS INTO EUROPEAN GAS MARKETS

A.2.1. An overview of antitrust and cartel cases European in gas markets

DG COMP's antitrust enforcement have been geared toward integrating regional European markets, as this is seen to increase competition in national markets, increase welfare through competitive pricing, promote security of supply and provide the EU with a strategic advantage in the global gas market. A concerted effort toward this objective began in 2005 with the EC's Sector Inquiry into competition in gas and electricity markets (EC, 2016). The Inquiry concluded with a call for stronger enforcement of antitrust laws and adoption of the Third Energy Package, which created the Agency for the Cooperation of Energy Regulators (ACER) and includes three competition-related regulations on:

- Unbundling of transportation and transmission services from production,
- Greater cross-border integration through empowered national regulators, and,
- Non-EU ownership of transmission systems.

A number of antitrust and merger investigations were triggered by the Inquiry. Market sharing agreements between the German supplier E.ON and the French supplier GdF were investigated for collusion in 2006, under which the suppliers agreed not to make sales in each other's markets. DG COMP stated that their market sharing agreement had inhibited competition in both markets, and each supplier was fined €553 million. In 2007, contracts of the Belgian supplier Distrigas with downstream users were investigated and subsequently found to be causing foreclosure by locking users into their contract volumes. In its proposed remedies, which were accepted by the DG COMP after a market test, Distrigas committed to making 70% of supplied volumes available to competitors annually.

Mergers of major suppliers were also prohibited on grounds of market concentration and potential foreclosure, such as the joint takeover of Portugal's incumbent gas company GDP by the incumbent electricity company EDP and ENI (EC, 2016). Other potential mergers were abandoned due to failure to reach settlements, like the acquisition of the Hungarian oil and gas company MOL by the Austrian oil and gas group OMV. In total, between 1994 and 2014, DG COMP investigated 351 cases in gas and electricity markets, 38 of which were antitrust investigations, the rest being merger control cases (EC, 2016). 23 of these 38 pertained to gas markets, and 22 of these involved LTCs. These cases, along with the two initiated after 2014, are summarised in Table A. 1.

A.2.2. EC Investigations into LTCs

The EC has employed antitrust enforcement and regulations, state aid and merger control, as well as its *ex-officio* investigative powers to liberalise European gas markets. DG COMP opened investigations into contractual restrictions in gas markets as early as 1998. Commitments to remove restrictive clauses that may have segmented regional EU gas markets were obtained from major exporters, as well as from national sellers of gas. The first settlement came in 2000 when Gas Natural Fenosa (now Naturgy) agreed to amend its supply contracts with the incumbent Spanish electricity generator Endesa, allowing the latter to use gas for purposes other than electricity generation, thereby ending market segmentation. Subsequently, commitments were secured from other major European national suppliers to allow third party access to transmission networks to facilitate competition; from Germany's Thyssengas in 2001 and BEB in 2003, Dutch Gasunie in 2003 and French GdF in 2004.

The landmark decision in investigations into import-related LTCs came in 2002 when Nigeria's NLNG agreed to remove territorial restrictions from its LTCs, which was followed by the restructuring of Gazprom's contracts with ENI in 2003, and with OMV and Ruhrgas in 2005 to remove similar restrictions (Wäktare, 2007). Investigations into LTCs with the Algerian national supplier Sonatrach, also initiated in 2001, took longer to settle due to the EC's insistence that its investigation was limited to compliance of structural (clauses apart from pricing) aspects with EU competition law, while the inclusion of PSMs, on which Algeria insisted, was a bilateral pricing concern of the buyer and seller (Wäktare, 2007). Notably, the NLNG investigation was settled in 2002 with a clarification from NLNG that LTCs did not include PSMs (EC, 2002).

An analysis by Spanjer (2009b) of the EC's stance in the Distrigas case of 2007 (see Table A. 1) found that the case reflected regulatory opportunism at the expense of Distrigas. Analysing the EC's previously stated positions in LTC-related competition cases, Spanjer found that while the EC acknowledged that LTCs can prevent contracting parties from exploiting regulatory loopholes and opportunism, it did not acknowledge the cost of frequent regulatory interventions as a consequence of reformed LTCs, and therefore, may be going too far to achieve competitive contractual terms.

A.2.3. The 2012 Gazprom investigation

In its 2012 Gazprom investigation, the EC emphasised the anticompetitive nature of oil-indexed pricing mechanisms in LTCs, relating it to Gazprom's dominant market position in the eight MS. Previous investigations had objected to structural aspects of pipeline gas and LNG contracts, but the pricing mechanism and frequency of price-review had been left for bilateral negotiations between Gazprom and importers. Responding to the September 2012 announcement initiating the proceedings, Gazprom claimed it was an attempt by the EC to "influence prices and result of commercial negotiations", and the following week the Russian government passed an executive order № 1285 obliging "strategic" Russian companies to seek government consent before disclosing information to foreign authorities (President of Russia, 2012).

Further, the EC's objection to Gazprom's refusal to change delivery points of pipeline gas did not have a precedent, as earlier investigations into pipeline gas contracts with Sonatrach had only concerned territorial clauses restricting use and re-sale of gas, even though Sonatrach supplied pipeline gas to European markets via connectors to Spain as well as Italy. It could be argued that if Sonatrach were to allow similar swaps between the two markets it could lead to closer integration of South European markets.

The prevailing opinion within the EC at the time was that, given the mutual interdependence of the EU and Russia on a stable buyer-seller relationship and in view of the potentially larger role for Gazprom in a liberalised European market, it would be in Gazprom's interest to accept the EC concessions and settle for a 'commitments decision' (Sartori 2013).

Failure to reach a settlement could result in a formal EC 'prohibition' investigation, potentially proceeding to the Court of Justice of the EU and snowballing into an expensive and prolonged geopolitical stand-off (Riley, 2012). Gazprom would lose its major buyer and the EU would have to look for alternative exporters – more than 115 bcm were tied through LTCs until 2020 and about 65 bcm through 2030, compared to EU's 2013 imports of 153 bcm (Dickel et al., 2014). In February 2017, Gazprom proposed commitments pursuant to Article 9 of the Council Regulation 1/2003 to address the EC's objections, without any admission of competition law infringement[7]. Gazprom proposed committing to:

1) Remove all clauses that would hinder re-sale of its gas to other customers once and for all, and facilitate cross-border gas trade in CEE gas markets by allowing Gazprom's customers in those countries to change delivery points;
2) Introduce competitive gas price benchmarks[8] into price review clauses contained in its long-term gas sales contracts with MS5 customers, and increase the frequency and speed of price revisions; and finally,
3) Not claim damages from Bulgaria for cancellation of the South Stream pipeline.

In March 2017, the EC opened Gazprom's proposed commitments to a market test, inviting stakeholder comments on the proposal. Most parties whose comments were made public seemed to have had a positive opinion of the proposed 'commitments decision', with the notable exception of Poland. The state-owned Polish supplier PGNiG expressed grave concerns that Gazprom's proposal did not ensure an end to its strategy of market segmentation in CEE and argued for a formal infringement decision under Article 7 of Regulation 1/2003 EC (PGNiG, 2018). The Industry, Trade, Research and Energy (ITRE) Committee of the European Parliament, headed at the time by the Polish MEP Jerzy Buzek, expressed disappointment in the EC's decision not to impose fines on Gazprom to compensate the victims of its anticompetitive strategy in CEE (Stern and Yafimava, 2017a).

Lithuania took a softer stance, proposing an alternative mechanism for pricing from that proposed by Gazprom and reiterating that the proposal lacked compensation for damages incurred, but fell short of calling for a 'prohibition decision' (Sytas, 2017). Bulgaria saw the proposal in a more positive light but sought clarifications on certain aspects, such as the exact benchmarks to be used in future price reviews (Tsolova, 2017), which were subsequently added to Gazprom's revised commitments (Gazprom, 2017). The Latvian position was also positive (Collins, 2016), while the Hungarian and Czech governments concluded new contracts with Gazprom shortly after the proposals were made, without making public comments on the commitments themselves (Stern and Yafimava, 2017b), implying a positive stance. Ultimately, following the market test and some minor changes, the revised commitments proposed by Gazprom in March 2018 were made legally binding on Gazprom in a 'commitments decision' passed on 24 May 2018 (EC, 2018).

[7] Article 9 allows for prospective resolution of competition problems in markets, without either a formal admission of guilt or a finding of infringement, whereas Article 7 leads to a formal prohibition case of infringement with the possibility of significant fines (Dunne 2014).

[8] Average weighted import border prices in Germany, France and Italy and/or the development of the prices at the relevant generally accepted liquid hubs in Continental Europe (paragraph 19(1) in Gazprom's commitments, Case AT 39816: http://ec.europa.eu/competition/antitrust/cases/g2/gazprom_commitments.pdf)

Table A. 1: Antitrust and cartel cases investigated by the DG COMP in gas markets

Year	Case number	Complainant/Violator (Country)	Policy area: Particulars	Settlement Details (Year of settlement)
1999	COMP/E-4/36.559	EdF Trading (UK) / WINGAS (Germany)	**Antitrust:** Contract clauses allowing WINGAS to reduce volumes bought from EdF if EdF sells gas to WINGAS's competitors in Germany, reducing EdF's incentive to directly supply to customers in Germany	Removal of reduction clauses from existing contracts between EdF and WINGAS, allowing EdF to sell gas directly to German suppliers (2002)
2000	COMP/37.542	Endesa / GasNatural (Spain)	**Antitrust:** Clauses in GasNatural's contract preventing Endesa from using gas for purposes other than electricity generation, foreclosure in gas market due to long-term contract between GasNatural and Endesa	Removal of use-restriction clauses, reduction of duration of GasNatural's supply contracts and volumes bought by Endesa (2000)
2000	COMP/E-3/36.246	Marathon (Norway) / Thyssengas (Germany), Gasunie (Netherlands), BEB (Germany), GdF (France)	**Antitrust:** Refusal of Thyssengas, Gasunie, BEB, GdF GmbH to grant network access to third parties	Commitments by Thyssengas (2001), Gasunie (2003), BEB (2003), GdF (2004) to effectively allow third parties access to its pipeline network
2000	COMP/E-4/37.732	ESB (Ireland), Statoil (Norway) joint venture Synergen	**Antitrust:** Construction of 400MW gas fired plant in Ireland by incumbent ESB and potential new entrant Statoil	Commitments by incumbent ESB to conduct auctions until new independent producers enter the market (2002)
2001	COMP/E-3/37.708	EU / Enterprise Oil, Statoil, Marathon (Norway)	**Cartel:** Application by Norwegian companies to jointly market the gas produced at Corrib oilfield	Withdrawal of application by the companies (2001)
2001	COMP/E-4/38.075	UK / Belgian interconnector	**Antitrust:** Rigidities in responsiveness of the Zeebrugge interconnector to respond to supply and demand, and flows against price differentials	Conclusion of new contracts between shippers provisioning for swifter flow transitions, less stringent sublease conditions (2002)
2001	COMP/E-1/36.072	EU / Gas Negotiating Committee (GFU) (Norway)	**Antitrust:** Fixing of gas prices and quantities through joint sale under the Gas Negotiating Committee (GFU)	Discontinuation of joint marketing and sales, commitment by Norwegian sellers to make volumes available to new buyers (2002)

2001	COMP/E-3/38.187	DUC / DONG (Denmark)	**Antitrust:** Joint marketing activities by DUC partners Shell, Maersk and ChevronTexaco, and reduction and use-restriction clauses in supply contracts with DONG	Removal of reduction and use-restriction clauses in contracts and commitment by companies to sell gas independently (2003)
2001	COMP/E-3/37.811	ENI (Italy) / Gazprom (Russia)	**Antitrust:** Territorial restrictions in contracts between ENI and Gazprom	Removal of territorial restrictions from ENI and Gazprom contracts (2003)
2001	COMP/38.085	OMV (Austria) / Gazprom (Russia)	**Antitrust:** Territorial restrictions on re-sale of gas purchased from Gazprom by OMV, right of first refusal to OMV on Gazprom's available gas	Removal of territorial restrictions and right of first refusal clauses in OMV and Gazprom contracts (2005)
2001	COMP/38.307	E.ON Ruhrgas (Germany) / Gazprom (Russia)	**Antitrust:** Territorial sales restrictions in contracts between Ruhrgas and Gazprom	Removal of territorial restrictions from Ruhrgas and Gazprom contracts (2005)
2001	COMP/37.811	European importers / Sonatrach (Algeria)	**Antitrust:** Territorial restrictions in existing supply contracts between Sonatrach and EU importers, and inclusion of profit-sharing mechanisms in new contracts	Removal of territorial restrictions Sonatrach and EU import contracts, agreement to add profit-sharing clauses only on DES LNG supplies (2007)
2002	COMP/E-4/37.811	European importers / NLNG (Nigeria)	**Antitrust:** Territorial restrictions and profit-sharing mechanisms in LNG import contracts between NLNG and EU importers	Removal of territorial restrictions and profit-sharing mechanisms from NLNG and EU import contracts (2002)
2004	COMP/38.662	ENI, ENEL / GdF (France)	**Antitrust:** Prevention of re-sale of gas by ENI and ENEL transported by GdF using contract clauses	Removal of re-sale restriction clauses (2004)
2006	COMP/39.401	E.ON (Germany), GdF (France)	**Cartel:** Market-sharing agreement to not sell gas in each other's markets, long-term capacity reservation	€553 million fine imposed on each company (2009)
2007	COMP/39.966	Large downstream consumers / Distrigas (Belgium)	**Antitrust:** Long term contracts between Distrigas and downstream industrial consumers causing foreclosure in downstream markets	Commitment by Distrigas to make 70% of supplied gas to be open to new competitors, contract duration limited to 5 years (2008)
2007	COMP/39.402	EU / RWE (Germany)	**Antitrust:** Abuse of market position by RWE in gas transport and wholesale supply by increasing new entrants' costs and preventing access	Divestiture by RWE from existing transmission network (2009)
2007	COMP/39.315	EU / ENI (Italy)	**Antitrust:** Capacity hoarding, capacity degradation and strategic underinvestment by ENI in gas transport infrastructure	Divestiture by ENI in companies related to international gas pipelines; Decision (2010)

2008	COMP/39.316	EU / GdF Suez (France)	**Antitrust:** GdF causing foreclosure in French gas markets through long-term reservation of import capacity and underinvestment	Commitment by GdF to release import capacity (2009)
2009	COMP/39.317	EU / E.ON (Germany)	**Antitrust:** E.ON causing foreclosure in German gas markets through long-term reservation of import capacity and underinvestment	Commitment by E.ON to release import capacity (2010)
2012	COMP/39.816	EU / Gazprom (Russia)	**Antitrust:** Territorial restrictions in LTCs between Gazprom and CEE countries	Commitments by Gazprom to remove territorial restrictions in contracts (2018)
2013	COMP/39.849	EU / Bulgarian Energy Holding (Bulgaria)	**Antitrust:** Refusal of BEH to grant third party access to its gas transmission network, storage facilities and import pipelines	€77 million fine imposed on BEH (2018)
2017	COMP/40.335	EU / Transgaz (Romania)	**Antitrust:** Restriction of imports to EU through Romanian interconnector by Transgaz using fees, underinvestment and delaying exports	Investigation on-going; market test opened in September 2018; proposed commitments to increase export capacity and use non-discriminatory tariffs
2018	AT.40416	EU / Qatar Petroleum (Qatar)	**Antitrust:** Territorial restrictions in LNG supply contracts between Qatar Petroleum and European importers	Investigation on-going (as of mid-2019)

Source: EC Competition case search, data extracted on 27 June 2019; EC Reports on Competition Policy 2000-2017; DG COMP Press Releases

NOTE 3: MAIN DATA INPUTS AND ASSUMPTIONS FOR MODELLING

A.3.1. The Gas Market Model - Formulation

The global gas market model used in this analysis is a static, deterministic, perfect foresight optimization model formulated as a nonlinear programming problem (NLP). A detailed formulation of the model using mixed complementarity framework (MCP) can be found in Chyong and Hobbs (2014). The model, formulated as a MCP, was originally developed to analyse the economics of large-scale gas pipeline projects (e.g., Nord Stream and South Stream) and their impacts on the evolution of the European gas market, energy policy and geopolitics. A version of this model was then used by the UK's Department for Business, Energy & Industrial Strategy (BEIS) to model GB's gas security of supply to 2035 (CEPA, 2017) the results of which informed BEIS's strategic policy review in this area (BEIS, 2017). Here, we outline the formulation of our gas market model using a NLP formulation. Let us consider quadratic gross surplus of the following form $S_i = a_i d_i - \frac{b_i}{2} d_i^2$. Since demand equal supplies at every demand nodes (i.e., $d_i = \sum_j s_{ji}$), we can write a general social welfare maximization problem as follows:

$$\max_{s_{ji} \geq 0} \omega = \sum_i \left[a_i \sum_j s_{ji} - \frac{b_i}{2} \left(\sum_j s_{ji} \right)^2 \right] - \sum_i \left[\frac{b_i}{2} \left(\sum_j s_{ji} \right)^2 \right] - \sum_j \left[\sum_i t_{ji} s_{ji} + C_j \left(\sum_i s_{ji} \right) \right] \quad \text{(A1)}$$

s.t.

$$s_{ji} \leq T_{ji} \qquad (\lambda_{ji}) \quad \text{(A2)}$$

$$\sum_i s_{ji} \leq Q_j \qquad (\gamma_j) \quad \text{(A3)}$$

where s_{ji} is gas supply from j to i, $C_j(\cdot)$ is total production cost and t_{ji} is transport cost; we assume constant marginal cost of production at i or $C_i'(\cdot) = c_i$; T_{ij} is upper transport capacity limit while Q_j is upper production capacity;

One can see that except for the middle square bracketed term, the objective function (eq. 1) of this non-linear maximization problem is similar to the standard 'social welfare' maximization problem used to calculate perfectly competitive equilibria in spatial commodity markets (Samuelson 1952; Harker, 1986; Labys and Yang, 1991) and, specifically, natural gas markets (e.g., Boucher and Smeers, 1985; Beltramo et al., 1986; Boucher and Smeers, 1987; Boots et al., 2004; Kiss et al., 2016). For example, the term in the first square bracket is gross consumer surplus generated at all consumption nodes i by consuming d_i while the term in the last square bracket is total supply cost of all producing nodes j; The middle term allows transformation of the standard perfect competition condition '*price equals marginal cost'* to *'marginal revenue equal marginal cost'.* In the latter case, the marginal revenue is for any

Cournot producer *j* that we assume behave strategically; removing this middle term turns the problem into a welfare maximization under perfect competition[9].

A.3.2. Key Modelling Assumptions

The distinctive feature of this global model is the ability to analyse the interaction of supply and demand at daily resolution and at global scale. On the supply side, the model includes all the main gas producing countries, such as Russia, Norway, Qatar, Australia, Algeria and other producing regions such as North America, Central and South America, Middle East, Central Asia and so on. On the demand side, the model covers all existing consuming countries and regions, such as Great Britain, Continental European markets, Russia and other countries of the Former Soviet Union, China, India, North America, Middle East and so on. Further, the model considers all existing cross-border interconnection points in Europe as well as disaggregating European demand regions into individual national markets (for all of the EU-27+UK).

To match demand with supply, the model also covers the key stages of the gas value chain: from production regions down to the transmission level. It captures various gas infrastructure assets: pipelines, LNG and gas storage facilities. It is an economic and optimization model and therefore does not include some real-world characteristics of gas infrastructure (such as pressure drop in gas pipelines, management of linepack, gas quality limits etc.).

Given the assumptions about costs and capacities for these infrastructure assets, the objective of the model is to find a least cost solution to meet global demand taking into account various physical constraints, such as gas production capacities, transmission network capacities, LNG liquefaction and regasification/send-out capacities, storage injection, withdrawal and maximum working volume capacities as well as minimum and maximum daily demand profiles and contractual obligations (e.g. annual contract quantity and minimum take-or-pay). The outputs from the model are projections of supply, demand, equilibrium prices, pipeline and LNG flows, storage injection and withdrawal at daily resolution.

This analysis was calibrated to 2020 and 2021 using gas demand and supply capacities from IEA (2020b) WEO 2020 and from IEA's most recent (2020) short-term gas market report (see details below). Marginal supply cost curves are taken from the MIT (2011) report on the future of natural gas[10]. All other assumptions related to physical capacities of existing infrastructure assets were obtained from IEA WEO 2020, or from the owners of those infrastructure assets.

It is important also to note that the entry and exit charges that were used for the European network in the model are annual tariffs (taken from ACER reports), hence flow patterns from the model should be treated as annual contracted flows adjusted for daily fluctuations in supply and demand conditions, whereas in reality there are different transportation products (e.g. daily, monthly) with corresponding tariff structures which may (or may not) result in additional flows for some entry and exit points in Europe.

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[9] This formulation is applicable if we have affine demand functions (Hashimoto 1985).

[10] MIT (2011). "The Future of natural gas: An interdisciplinary MIT study," MIT multidisciplinary report (published online 6 June 2011). http://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

Also, it is worth mentioning that the European pipeline network in the model does not take into account the differences between high- and low-calorific gas and therefore some of the physical constraints resulting from such differences might not be captured in the network flow results. However, it is understood that conversion facilities between high and low-calorific gas are in place at the majority of the interconnection points of the two systems (e.g. in the Netherlands[11]) so these differences would have a limited impact on the flows from the model.

Finally, daily gas demand profiles[12] are the average of daily gas demand in the last 5 years and hence the impact of weather on gas demand in the modelling time horizon (2021-2026) is assumed to be an average impact witnessed in that 5-year period.

A.3.3. Global Supply and Demand Balance Modelled

Our central case demand projections to 2026 includes estimated negative impacts of covid-19, which is based on IEA (2020a) short-term gas market analysis. In particular, post-covid demand projection for 2026 for all key regional gas market is based on the following set of assumptions:

1. IEA (2020a) expects covid-19 will have a permanent negative impact on global demand of 75 bcm in 2025 relative to pre-covid demand but without detailing this impact by regions;
2. However, IEA (2020a) expects most of this permanent reduction in demand to be in the developed countries; hence, to allocate this demand reduction to our modelled regions, we assume that this reduction is proportion to the reduction in 2020 (relative to 2019), which IEA (2020a) did publish (see **Figure A. *5***).

Thus, Table A. 2 below summarises our reference demand projections for key regional gas markets under our central case (IEA short-term demand forecast) and two sensitivities: IEA SPS and SDS scenarios from 2020 World Energy Outlook (IEA, 2020b). One can see that these scenarios cover a wide range of potential demand variations by 2025.

[11] See https://www.gasterra.nl/en/news/from-l-gas-to-h-gas

[12] Most of data needed to estimated demand profiles for EU countries were obtained from https://transparency.entsog.eu/ and from IEA monthly gas statistics: https://www.iea.org/data-and-statistics/data-product/monthly-gas-statistics#data-sets

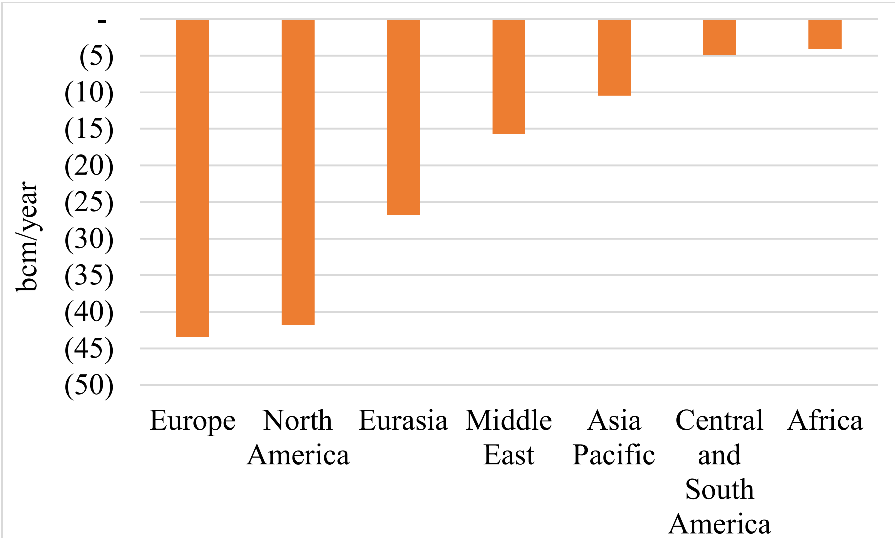

Figure A. 5: Demand reduction in 2020 relative to 2019

Source: IEA (2020a)

Table A. 2: Expected gas demand (bcm/year) in key regional gas markets in 2025

	IEA short-term demand forecast	IEA SPS demand sensitivity	IEA SDS demand sensitivity
Asia Pacific	**891**	**858**	**844**
China	*437*	*401*	*376*
India	*91*	*94*	*99*
Central and South America	**164**	**167**	**151**
Eurasia	**536**	**536**	**520**
Europe	**527**	**512**	**461**
EU27	*401*	*391*	*354*
Middle East	**655**	**613**	**545**
North America	**1116**	**1126**	**986**

Source: IEA (2020a; 2020b)

A.3.4. Delivery points for "gas swaps" and service fee

In Gazprom's proposed commitments (2017) there was a limited set of original gas delivery points from which wholesalers could ask Gazprom to change gas flows. Subsequently after the market test feedback, in its Final Commitments Gazprom (2018) has expanded on the number of delivery points eligible for swap flows; it also revised the minimum service fees and other revisions. Thus, the following delivery points available for European wholesalers to change gas flows:

1. Estonia: Varska delivery point located at the Estonian/Russian border
2. Latvia: Izborsk delivery point located at the Estonian/Russian border
3. Lithuania: Kotlovka delivery point located at the Lithuanian/Belarussian border
4. Poland: Kondratki and Wysokoje delivery points located at the Polish/Belarussian border
5. Slovakia: Velke Kapusany delivery point located at the Slovak/Ukrainian border
6. Hungary: Beregovo delivery point located at the Hungarian/Ukrainian border

7. Bulgaria: Negru Voda delivery point located at the Bulgarian/Romanian border

Table A.3 outlines the committed service fees charged by Gazprom for changing the delivery points for the wholesalers. Note that in the final commitments, Gazprom offered that the flows between the original and new delivery points could be on bidirectional basis, unlike in the proposed commitments where swap flows was only on unidirectional basis.

Table A.3: Service fee for swaps flows between original and new delivery points

Original point	**New delivery point**	**Service fee** €/MWh	$/tcm
Kondratki (PL)	Kotlovka (LT)	0.76	10.3989
Kondratki (PL)	Varska (EE)	0.76	10.3989
Kondratki (PL)	Izborsk (EE/LV)	0.76	10.3989
Wysokoje (PL)	Kotlovka (LT)	0.76	10.3989
Wysokoje (PL)	Varska (EE)	0.76	10.3989
Wysokoje (PL)	Izborsk (EE/LV)	0.76	10.3989
Velke Kapusany (SK)	Kotlovka (LT)	1.52	20.7979
Velke Kapusany (SK)	Varska (EE)	1.52	20.7979
Velke Kapusany (SK)	Izborsk (EE/LV)	1.52	20.7979
Beregovo (HU)	Negru Voda (BG)	1.52	20.7979
Velke Kapusany (SK)	Negru voda (BG)	1.52	20.7979

Notes: EUR to USD exchange rate was based on the average spot rate on the 9th of Feb-21

NOTE 4: DETAILED RESULTS FROM THE MODEL

A.4.1. Social welfare, Gazprom profit and wholesale prices under alternative market scenarios

Table A.4: Simulated social welfare for all markets under various scenarios, $ bn (%, relative to Scenario A)

	STO case	SPS case	SDS case
Scenario A	20,634 (100%)	21,706 (100.0%)	16,675 (100.0%)
Scenario B1	20,594 (99.8%)	21,661 (99.8%)	16,642 (99.8%)
Scenario B2	20,595 (99.8%)	21,663 (99.8%)	16,643 (99.8%)

Table A.5: Gazprom's simulated profit ($ bn) under various scenarios

	STO case			SPS case			SDS case		
Year	Scenario A	Scenario B1	Scenario B2	Scenario A	Scenario B1	Scenario B2	Scenario A	Scenario B1	Scenario B2
2021	43.59	42.18	42.02	42.23	41.27	40.86	28.90	31.19	30.49
2022	38.04	38.97	38.42	37.31	38.28	37.65	23.17	25.07	24.27
2023	33.04	34.80	34.19	33.03	34.50	33.62	20.44	22.09	21.52
2024	29.92	31.44	30.61	29.09	30.99	30.04	18.49	19.93	19.41
2025	26.60	28.31	27.62	24.83	27.01	26.30	14.89	16.39	16.03
2026	25.86	26.87	26.88	24.74	26.01	26.04	10.73	11.63	11.67

Table A.6: Simulated wholesale gas prices in $/mmbtu (% TTF) under IEA's SPS scenario

		Competitive benchmark		Gazprom's monopolistic behaviour in MS5			
		Scenario A		**Scenario B1**		**Scenario B2**	
Demand weighted-average price ($/mmbtu)	BG	7.82	187%	16.14	385%	7.79	186%
	EE	3.65	87%	5.45	130%	4.08	98%
	LT	3.75	90%	4.90	117%	4.22	101%
	LV	3.43	82%	4.87	116%	3.86	92%
	PL	4.11	99%	4.99	119%	4.79	115%
	TTF*	4.17	100%	4.19	100%	4.18	100%
	DE, FR, IT**	4.06	97%	4.06	97%	4.05	97%
Minimum price ($/mmbtu)	BG	7.20	269%	7.20	268%	7.20	269%
	EE	2.82	106%	3.70	138%	2.60	97%
	LT	2.86	107%	3.04	113%	2.63	98%
	LV	2.74	102%	3.12	116%	2.36	88%
	PL	2.95	110%	3.06	114%	2.98	111%
	TTF*	2.67	100%	2.69	100%	2.68	100%
	DE, FR, IT**	2.73	102%	2.74	102%	2.74	102%
Maximum price ($/mmbtu)	BG	8.65	167%	19.55	378%	8.65	167%
	EE	4.81	93%	6.21	120%	5.12	99%
	LT	6.74	130%	7.58	147%	5.61	108%
	LV	4.23	82%	5.63	109%	4.54	88%
	PL	6.26	121%	5.91	114%	5.74	111%
	TTF*	5.17	100%	5.17	100%	5.19	100%
	DE, FR, IT**	5.04	98%	5.00	97%	5.03	97%
	BG	5.74	32%	24.57	139%	5.74	32%

	EE	19.05	107%	12.04	68%	16.92	94%
	LT	21.00	118%	15.25	86%	18.60	104%
Coefficient of variation, %	LV	14.76	83%	13.51	76%	13.26	74%
	PL	19.30	108%	16.62	94%	18.20	101%
	TTF*	17.79	100%	17.68	100%	17.96	100%
	DE, FR, IT**	16.72	94%	16.15	91%	16.47	92%

*Notes: * TTF is taken to be a demand weighted-average wholesale prices in the Netherlands, Belgium, France and Germany; ** demand weighted-average wholesale prices in Germany, France and Italy*

Table A. 7: Simulated wholesale gas prices in $/mmbtu (% TTF) under IEA's SDS scenario

		Competitive benchmark		**Gazprom's monopolistic behaviour in MS5**			
		Scenario A		**Scenario B1**		**Scenario B2**	
Demand weighted-average price ($/mmbtu)	BG	5.51	155%	10.61	293%	5.22	145%
	EE	3.31	93%	4.77	132%	3.73	103%
	LT	3.36	94%	4.20	116%	3.77	104%
	LV	3.17	89%	4.19	116%	3.58	99%
	PL	3.60	101%	4.33	120%	4.20	116%
	TTF*	3.56	100%	3.62	100%	3.61	100%
	DE, FR, IT**	3.45	97%	3.47	96%	3.46	96%
Minimum price ($/mmbtu)	BG	3.02	160%	3.02	151%	3.02	154%
	EE	2.82	150%	3.14	157%	2.00	102%
	LT	2.48	132%	2.48	124%	2.04	104%
	LV	2.56	136%	2.56	128%	1.92	98%
	PL	2.39	127%	2.52	126%	2.46	126%
	TTF*	1.88	100%	2.00	100%	1.95	100%
	DE, FR, IT**	1.98	105%	2.03	101%	2.03	104%
Maximum price ($/mmbtu)	BG	8.42	185%	15.64	337%	8.42	181%
	EE	4.30	94%	5.44	117%	4.84	104%
	LT	6.40	140%	6.58	142%	4.94	106%
	LV	3.72	82%	4.86	105%	4.26	92%
	PL	5.74	126%	5.36	115%	5.29	114%
	TTF*	4.56	100%	4.65	100%	4.64	100%
	DE, FR, IT**	4.33	95%	4.37	94%	4.37	94%
Coefficient of variation, %	BG	26.61	147%	39.11	220%	24.46	138%
	EE	14.41	80%	13.52	76%	16.42	93%
	LT	16.15	89%	17.09	96%	17.64	100%
	LV	12.74	71%	15.45	87%	15.32	86%
	PL	16.30	90%	18.85	106%	18.83	106%
	TTF*	18.05	100%	17.78	100%	17.72	100%
	DE, FR, IT**	15.55	86%	15.41	87%	15.35	87%

*Notes: * TTF is taken to be a demand weighted-average wholesale prices in the Netherlands, Belgium, France and Germany; ** demand weighted-average wholesale prices in Germany, France and Italy*

A.4.2. Results from comparing prices under Scenario B1 with average NWE prices under the competitive benchmark case (Scenario A)

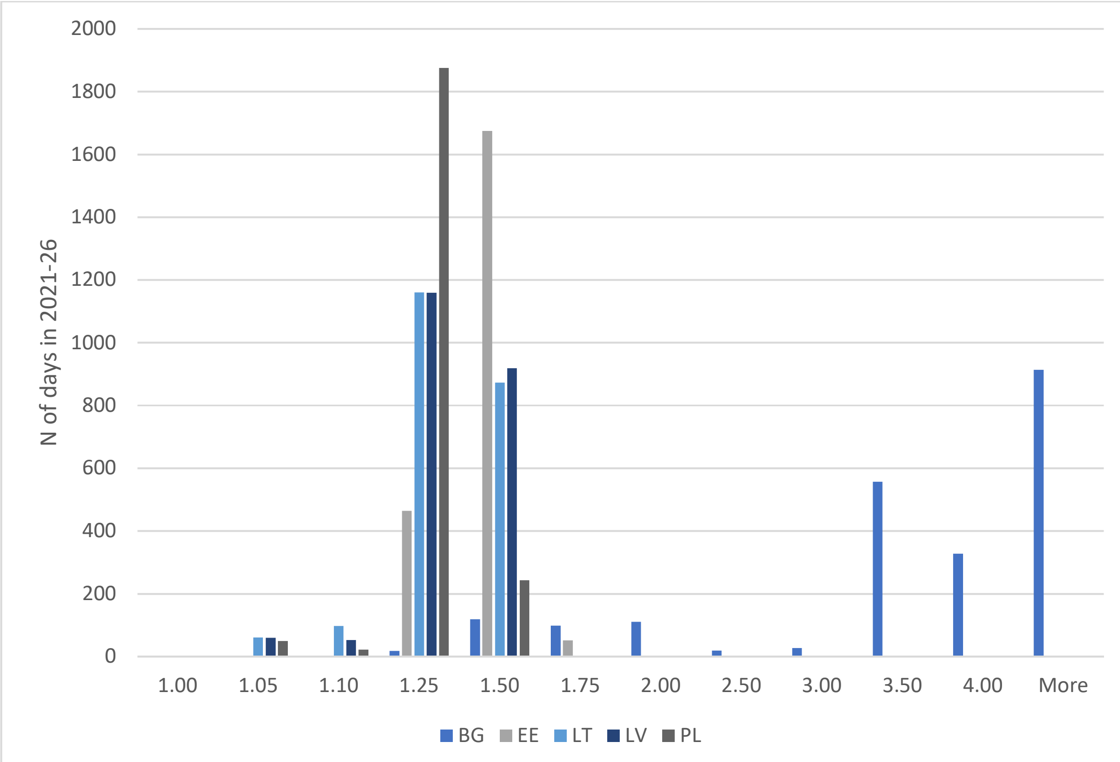

Figure A. 6: Frequency of simulated price mark-ups for the five CEE MS under market power case (Scenario B1) relative to average prices of North Western European (NWE) markets in 2021-26 under the competitive benchmark case (Scenario A)

Note: The x-axis shows the relative price index under market power compared to the average NWE prices under a competitive benchmark (competitive benchmark = 1). The y-axis shows the total number of days that prices under market power are higher (>1) or lower (<1) than under the competitive benchmark case. For example, in Bulgaria, there are 328 days over the period 2021-26 when prices under market power exceed competitive NWE prices by a factor of 4.

Table A. 8: Relative price index under market power case (Scenario B1) (relative to calculated TTF price).

	2021	2022	2023	2024	2025	2026
			BG			
Jan	3.946	3.941	4.423	4.665	4.852	1.896
Feb	3.392	3.415	3.597	3.786	3.835	1.524
Mar	3.384	3.381	3.562	3.732	3.731	1.447
Apr	3.372	3.271	3.36	3.409	3.309	1.312
May	3.334	3.145	3.233	3.189	3.154	1.256
Jun	3.316	3.113	3.062	3.144	3.132	1.327
Jul	3.799	4.07	3.764	4.014	3.883	1.629
Aug	4.003	4.189	4.123	4.289	4.033	1.71
Sep	4.077	4.169	4.383	4.525	4.127	1.757
Oct	4.176	4.454	4.491	4.688	4.251	1.798
Nov	4.309	4.744	4.829	4.924	4.482	1.947
Dec	4.299	4.891	4.863	5.122	4.563	1.895

			EE			
Jan	1.352	1.329	1.387	1.4	1.431	1.448
Feb	1.229	1.266	1.266	1.268	1.26	1.325
Mar	1.226	1.253	1.253	1.254	1.234	1.28
Apr	1.226	1.253	1.252	1.252	1.233	1.276
May	1.225	1.252	1.251	1.251	1.23	1.273
Jun	1.244	1.273	1.283	1.293	1.287	1.358
Jul	1.471	1.442	1.443	1.481	1.485	1.467
Aug	1.426	1.453	1.456	1.494	1.494	1.374
Sep	1.378	1.454	1.456	1.494	1.495	1.294
Oct	1.377	1.454	1.456	1.494	1.496	1.231
Nov	1.378	1.454	1.461	1.494	1.495	1.281
Dec	1.376	1.452	1.455	1.494	1.495	1.307
			LT			
Jan	1.203	1.184	1.224	1.233	1.259	1.269
Feb	1.101	1.16	1.156	1.161	1.165	1.207
Mar	1.15	1.169	1.163	1.163	1.164	1.183
Apr	1.103	1.141	1.136	1.143	1.143	1.173
May	1.098	1.14	1.133	1.14	1.141	1.169
Jun	1.114	1.149	1.153	1.163	1.167	1.207
Jul	1.317	1.264	1.257	1.28	1.281	1.259
Aug	1.262	1.267	1.26	1.28	1.283	1.156
Sep	1.213	1.267	1.261	1.28	1.284	1.074
Oct	1.213	1.267	1.26	1.28	1.284	1.011
Nov	1.214	1.267	1.264	1.28	1.284	1.051
Dec	1.214	1.266	1.259	1.28	1.284	1.086
			LV			
Jan	1.22	1.198	1.239	1.245	1.265	1.277
Feb	1.116	1.152	1.146	1.142	1.126	1.184
Mar	1.113	1.141	1.134	1.129	1.103	1.144
Apr	1.113	1.14	1.134	1.128	1.102	1.14
May	1.112	1.14	1.132	1.126	1.1	1.138
Jun	1.13	1.156	1.16	1.162	1.149	1.21
Jul	1.336	1.285	1.279	1.305	1.305	1.284
Aug	1.283	1.289	1.283	1.308	1.308	1.182
Sep	1.234	1.29	1.284	1.309	1.309	1.1
Oct	1.234	1.289	1.283	1.309	1.31	1.037
Nov	1.234	1.289	1.288	1.308	1.309	1.078
Dec	1.233	1.288	1.282	1.308	1.309	1.113
			PL			
Jan	1.171	1.172	1.211	1.22	1.247	1.255
Feb	1.161	1.165	1.167	1.177	1.188	1.218
Mar	1.166	1.165	1.159	1.168	1.17	1.201

Apr	1.165	1.164	1.158	1.166	1.169	1.2
May	1.165	1.163	1.157	1.165	1.167	1.196
Jun	1.158	1.156	1.161	1.173	1.18	1.217
Jul	1.204	1.235	1.238	1.256	1.252	1.235
Aug	1.183	1.236	1.228	1.246	1.249	1.181
Sep	1.182	1.236	1.229	1.246	1.25	1.106
Oct	1.181	1.236	1.228	1.246	1.25	1.044
Nov	1.182	1.236	1.232	1.246	1.25	1.084
Dec	1.181	1.235	1.227	1.246	1.25	1.12

Notes: price indices were calculated by dividing the projected prices of the corresponding MS5 by the by calculated TTF prices; these indices show by how much prices in MS5 differ from TTF prices over time.

A.4.3. Results from comparing prices under Scenario B1 with marginal cost of supply in MS5 (Scenario A)

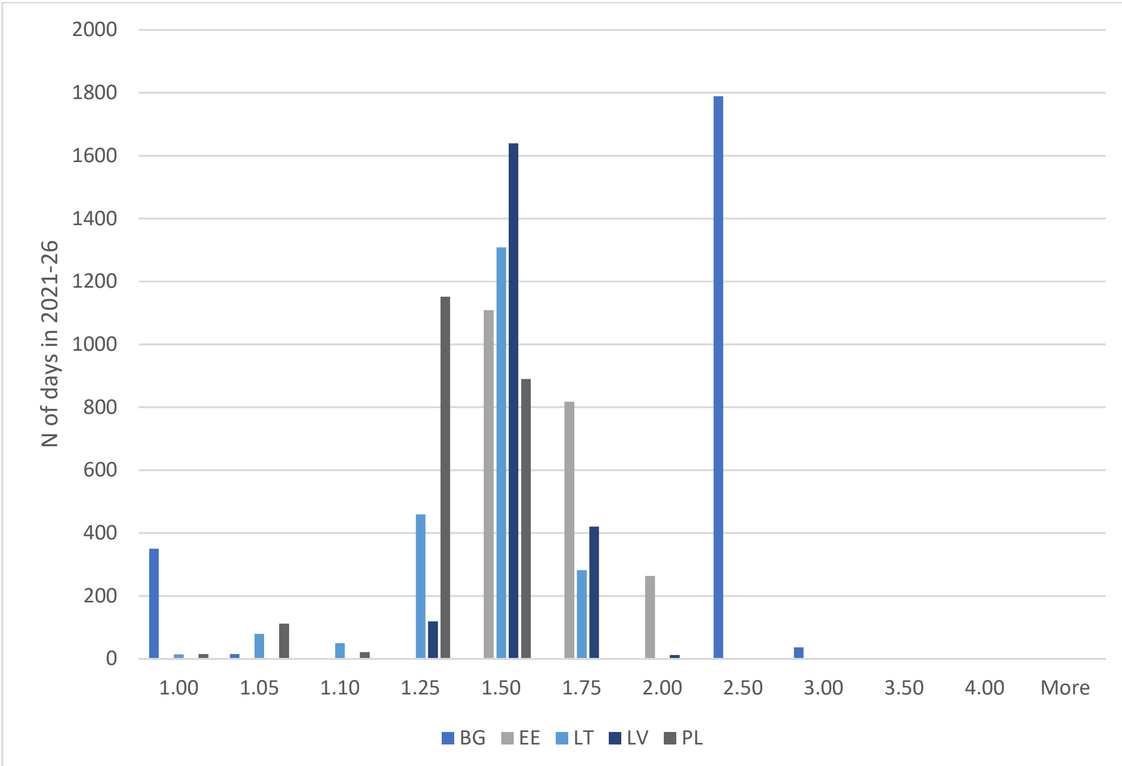

Figure A. 7: Frequency of simulated price mark-ups for the MS5 under market power case (Scenario B1) relative to their marginal cost of supply in 2021-26.

Note: x-axis shows the relative price index under market power compared to day-ahead average NWE prices under competitive benchmark (competitive benchmark = 1). Y-axis shows the total number of days that prices under market power are higher (>1) or lower (<1) than marginal cost of supply.

Table A. 9: Relative price index under market power case (Scenario B1) (relative to marginal cost of supply in MS5).

	2021	2022	2023	2024	2025	2026
			BG			
Jan	2.057	2.169	2.300	2.404	2.462	1.000
Feb	2.226	2.164	2.290	2.436	2.481	1.000
Mar	2.203	2.204	2.327	2.483	2.506	1.000
Apr	2.349	2.384	2.422	2.459	2.437	1.000
May	2.369	2.371	2.408	2.426	2.412	1.000
Jun	2.327	2.312	2.321	2.363	2.361	1.000
Jul	2.253	2.223	2.206	2.268	2.272	1.000
Aug	2.232	2.200	2.222	2.271	2.269	1.000
Sep	2.242	2.197	2.259	2.302	2.282	1.000
Oct	2.257	2.238	2.274	2.323	2.300	1.000
Nov	2.221	2.277	2.315	2.351	2.331	1.000
Dec	2.186	2.295	2.322	2.373	2.341	1.000
			EE			

Jan	1.581	1.526	1.588	1.548	1.546	1.558
Feb	1.431	1.477	1.494	1.450	1.431	1.488
Mar	1.363	1.428	1.447	1.394	1.360	1.397
Apr	1.357	1.426	1.443	1.390	1.359	1.389
May	1.320	1.405	1.423	1.365	1.327	1.364
Jun	1.415	1.458	1.487	1.443	1.424	1.466
Jul	1.742	1.697	1.668	1.628	1.626	1.599
Aug	1.758	1.805	1.727	1.650	1.644	1.465
Sep	1.703	1.806	1.727	1.650	1.644	1.365
Oct	1.724	1.806	1.727	1.650	1.644	1.296
Nov	1.705	1.806	1.727	1.650	1.644	1.295
Dec	1.669	1.787	1.720	1.649	1.644	1.377
			LT			
Jan	1.393	1.340	1.377	1.348	1.345	1.350
Feb	1.269	1.333	1.341	1.313	1.309	1.342
Mar	1.215	1.264	1.262	1.246	1.243	1.253
Apr	1.178	1.232	1.231	1.226	1.224	1.238
May	1.135	1.195	1.192	1.199	1.195	1.217
Jun	1.254	1.287	1.305	1.285	1.279	1.290
Jul	1.545	1.471	1.437	1.391	1.386	1.356
Aug	1.539	1.555	1.478	1.397	1.395	1.219
Sep	1.483	1.556	1.478	1.397	1.395	1.120
Oct	1.502	1.556	1.478	1.397	1.395	1.051
Nov	1.486	1.556	1.478	1.397	1.395	1.051
Dec	1.456	1.540	1.472	1.397	1.395	1.131
			LV			
Jan	1.458	1.449	1.477	1.428	1.397	1.428
Feb	1.343	1.457	1.486	1.413	1.340	1.391
Mar	1.331	1.446	1.478	1.403	1.326	1.368
Apr	1.331	1.446	1.478	1.403	1.326	1.368
May	1.331	1.446	1.478	1.403	1.326	1.368
Jun	1.350	1.447	1.478	1.405	1.342	1.374
Jul	1.618	1.510	1.472	1.434	1.466	1.441
Aug	1.587	1.544	1.465	1.416	1.473	1.300
Sep	1.526	1.544	1.465	1.416	1.473	1.197
Oct	1.526	1.544	1.465	1.416	1.473	1.125
Nov	1.526	1.544	1.465	1.416	1.473	1.125
Dec	1.524	1.538	1.464	1.416	1.473	1.208
			PL			
Jan	1.210	1.221	1.248	1.256	1.268	1.270
Feb	1.181	1.193	1.203	1.223	1.232	1.257
Mar	1.168	1.177	1.174	1.187	1.186	1.211
Apr	1.157	1.170	1.169	1.183	1.182	1.204
May	1.157	1.166	1.165	1.179	1.177	1.200

Jun	1.174	1.182	1.197	1.206	1.220	1.234
Jul	1.214	1.262	1.280	1.280	1.282	1.262
Aug	1.226	1.274	1.299	1.290	1.288	1.186
Sep	1.232	1.275	1.301	1.290	1.288	1.104
Oct	1.233	1.275	1.301	1.290	1.288	1.040
Nov	1.231	1.275	1.301	1.290	1.288	1.040
Dec	1.233	1.274	1.299	1.289	1.288	1.117

Notes: price indices were calculated by dividing the projected prices of the corresponding MS5 by the by calculated marginal supply costs in MS5; these indices shows by how much prices in MS5 differ from their marginal supply costs.

A.4.4. Results from comparing prices under Scenario B2 with average NWE prices under the competitive benchmark case (Scenario A)

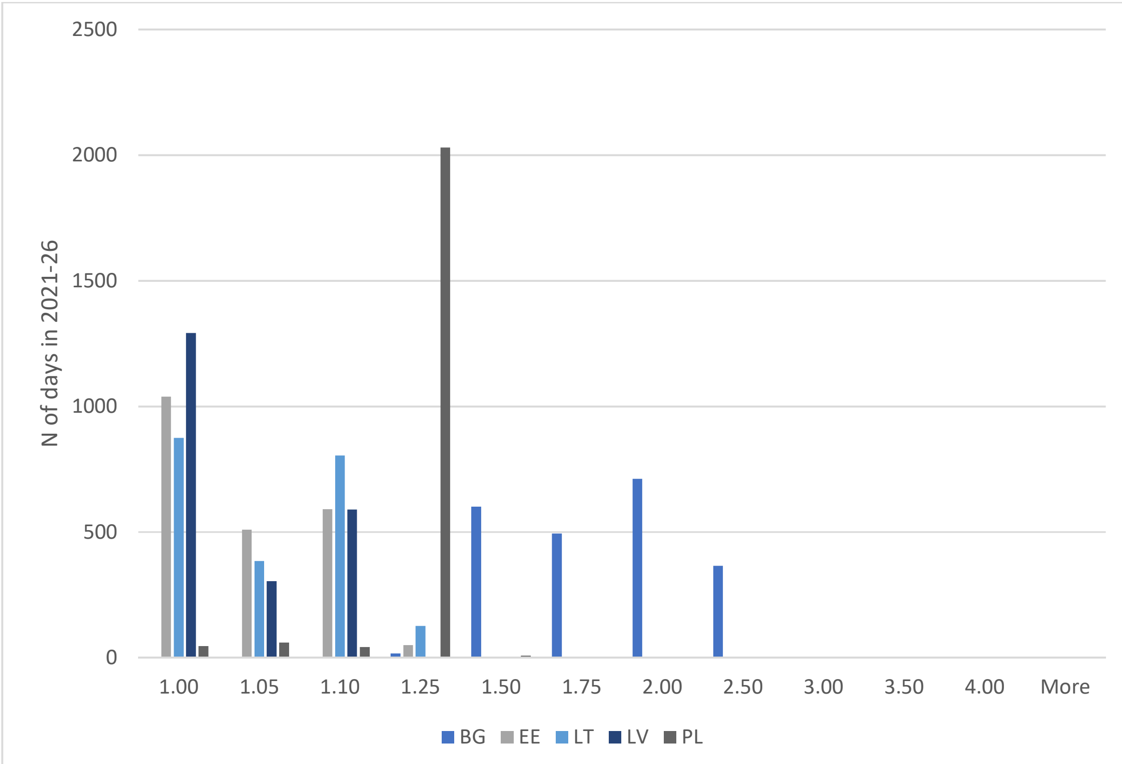

Figure A. 8: Frequency of simulated price mark-ups for the MS5 under market power with swap deals case (Scenario B2) relative to the NWE competitive benchmark case (Scenario A) in 2021-26.

Note: X-axis shows relative price index under market power compared to prices under competitive benchmark (competitive benchmark = 1). Y-axis shows the total number of days that prices under market power are higher (>1) or lower (<1) than under the competitive benchmark case.

Table A. 10: Relative price index under market power with swap deals (Scenario B2) (relative to calculated TTF price).

	2021	2022	2023	2024	2025	2026
			BG			
Jan	1.922	1.814	1.936	1.967	1.970	1.896
Feb	1.525	1.569	1.571	1.562	1.550	1.525
Mar	1.537	1.527	1.533	1.508	1.489	1.447
Apr	1.437	1.366	1.389	1.391	1.357	1.314
May	1.408	1.319	1.342	1.324	1.322	1.258
Jun	1.425	1.348	1.329	1.341	1.343	1.328
Jul	1.682	1.855	1.737	1.774	1.710	1.629
Aug	1.793	1.930	1.902	1.889	1.778	1.706
Sep	1.818	1.924	1.988	1.965	1.808	1.744
Oct	1.849	2.018	2.025	2.018	1.849	1.788
Nov	1.940	2.113	2.133	2.094	1.923	1.945
Dec	1.965	2.160	2.147	2.158	1.949	1.890
			EE			

Jan	0.944	0.962	1.007	1.052	1.071	1.082
Feb	0.935	0.936	0.949	0.968	0.987	1.016
Mar	0.921	0.935	0.952	0.981	0.992	1.008
Apr	0.935	0.944	0.963	0.992	1.004	1.019
May	0.944	0.955	0.974	1.014	1.024	1.033
Jun	0.946	0.959	0.978	1.001	1.018	1.057
Jul	0.908	0.977	1.015	1.060	1.067	1.082
Aug	0.891	0.970	1.029	1.078	1.083	1.057
Sep	0.888	0.970	1.029	1.079	1.083	0.980
Oct	0.889	0.970	1.029	1.079	1.084	0.949
Nov	0.892	0.970	1.030	1.078	1.083	0.931
Dec	0.903	0.969	1.028	1.078	1.083	1.014
			LT			
Jan	0.958	0.978	1.023	1.062	1.081	1.092
Feb	0.949	0.949	0.963	0.978	0.996	1.026
Mar	1.006	1.007	1.025	1.035	1.041	1.055
Apr	1.008	1.007	1.029	1.038	1.046	1.059
May	1.035	1.035	1.055	1.069	1.073	1.077
Jun	0.968	0.980	0.998	1.012	1.028	1.066
Jul	0.916	0.986	1.025	1.070	1.078	1.093
Aug	0.900	0.980	1.039	1.089	1.093	1.065
Sep	0.896	0.980	1.039	1.089	1.094	0.956
Oct	0.898	0.980	1.039	1.089	1.094	0.950
Nov	0.900	0.980	1.040	1.089	1.094	0.942
Dec	0.911	0.979	1.038	1.089	1.094	1.012
			LV			
Jan	0.915	0.935	0.977	1.022	1.031	1.043
Feb	0.883	0.888	0.888	0.924	0.942	0.976
Mar	0.836	0.852	0.859	0.893	0.902	0.926
Apr	0.847	0.856	0.868	0.902	0.911	0.933
May	0.838	0.850	0.861	0.897	0.905	0.928
Jun	0.886	0.903	0.912	0.946	0.962	1.009
Jul	0.913	0.987	1.028	1.043	1.044	1.055
Aug	0.929	1.002	1.061	1.066	1.059	1.029
Sep	0.930	1.002	1.061	1.066	1.060	0.947
Oct	0.929	1.002	1.061	1.066	1.060	0.919
Nov	0.930	1.002	1.061	1.066	1.059	0.901
Dec	0.927	1.001	1.059	1.066	1.059	0.985
			PL			
Jan	1.111	1.123	1.133	1.169	1.192	1.195
Feb	1.130	1.111	1.127	1.137	1.140	1.154
Mar	1.134	1.119	1.132	1.142	1.141	1.152
Apr	1.134	1.118	1.132	1.142	1.142	1.153
May	1.133	1.118	1.131	1.141	1.140	1.155

Jun	1.132	1.119	1.134	1.142	1.147	1.165
Jul	1.161	1.156	1.190	1.199	1.195	1.206
Aug	1.138	1.110	1.178	1.190	1.195	1.147
Sep	1.129	1.103	1.177	1.190	1.195	1.000
Oct	1.126	1.103	1.177	1.190	1.196	0.999
Nov	1.128	1.103	1.177	1.190	1.195	1.044
Dec	1.126	1.102	1.176	1.190	1.195	1.057

Notes: price indices were calculated by dividing the projected prices of the corresponding MS5 by the by calculated TTF prices; these indices show by how much prices in MS5 differ from TTF prices over time.

A.4.5. Results from comparing prices under Scenario B2 with marginal cost of supply in MS5 (Scenario A)

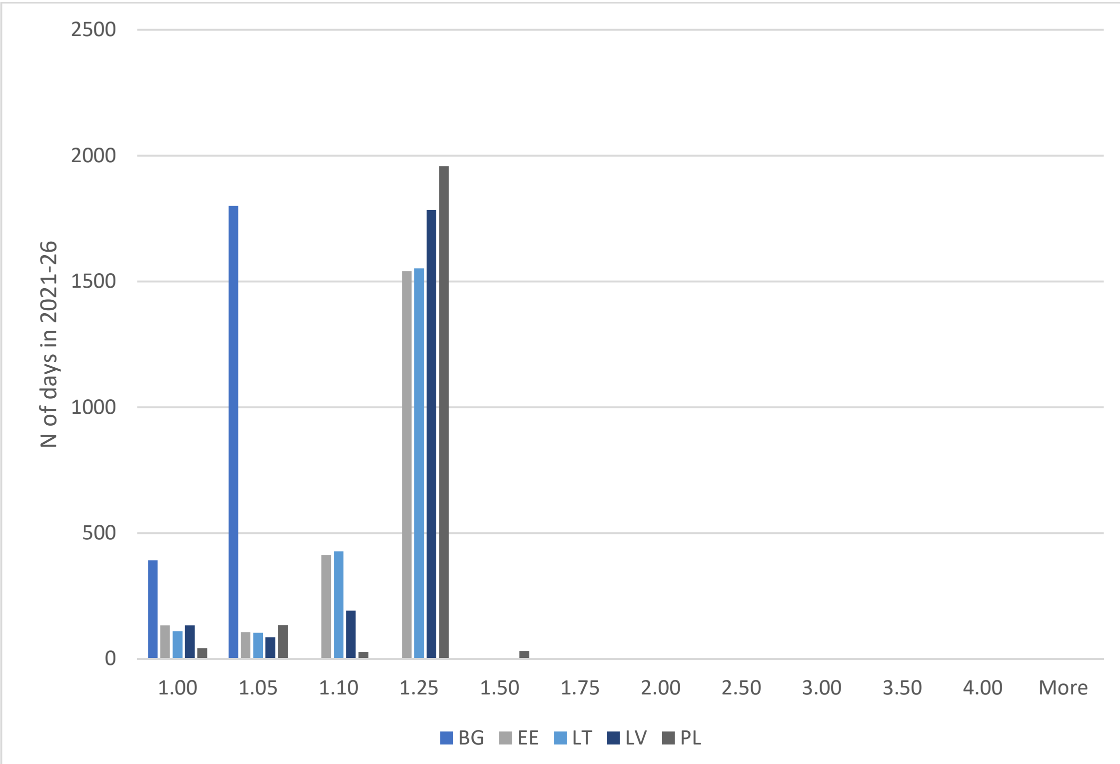

Figure A. 9: Frequency of simulated price mark-ups for the MS5 under market power with swap deals case (Scenario B2) relative to their marginal cost of supply in 2021-26.

Note: X-axis shows the relative price index under market power compared to day-ahead average NWE prices under competitive benchmark (competitive benchmark = 1). Y-axis shows the total number of days that prices under market power are higher (>1) or lower (<1) than under the competitive benchmark case.

Table A. 11: Relative price index under market power with swap deals case (Scenario B2) (relative to marginal cost of supply in MS5).

	2021	2022	2023	2024	2025	2026
			BG			
Jan	1.000	1.000	1.000	1.000	1.000	1.000
Feb	1.000	1.000	1.000	1.000	1.000	1.000
Mar	1.000	1.000	1.000	1.000	1.000	1.000
Apr	1.000	1.000	1.000	1.000	1.000	1.000
May	0.999	0.998	0.998	1.003	1.011	1.000
Jun	1.000	1.000	1.001	1.005	1.012	1.000
Jul	1.000	1.000	1.000	1.000	1.000	1.000
Aug	1.000	1.000	1.000	1.000	1.000	1.000
Sep	1.000	1.000	1.000	1.000	1.000	1.000
Oct	1.000	1.000	1.000	1.000	1.000	1.000

Nov	1.000	1.000	1.000	1.000	1.000	1.000
Dec	1.000	1.000	1.000	1.000	1.000	1.000
			EE			
Jan	1.095	1.102	1.142	1.145	1.159	1.164
Feb	1.086	1.096	1.118	1.099	1.116	1.138
Mar	1.025	1.070	1.098	1.086	1.093	1.100
Apr	1.035	1.079	1.108	1.096	1.106	1.108
May	1.017	1.076	1.106	1.102	1.104	1.105
Jun	1.074	1.097	1.126	1.113	1.125	1.139
Jul	1.077	1.133	1.152	1.161	1.168	1.178
Aug	1.098	1.188	1.191	1.191	1.191	1.130
Sep	1.096	1.189	1.191	1.191	1.191	1.041
Oct	1.112	1.189	1.191	1.191	1.191	1.005
Nov	1.102	1.189	1.191	1.191	1.191	0.943
Dec	1.095	1.176	1.186	1.190	1.191	1.071
			LT			
Jan	1.101	1.104	1.139	1.144	1.157	1.162
Feb	1.091	1.094	1.114	1.099	1.114	1.137
Mar	1.065	1.090	1.107	1.102	1.110	1.115
Apr	1.073	1.088	1.109	1.106	1.116	1.114
May	1.067	1.088	1.107	1.118	1.122	1.118
Jun	1.085	1.095	1.121	1.113	1.124	1.138
Jul	1.075	1.132	1.150	1.159	1.166	1.176
Aug	1.097	1.186	1.189	1.189	1.189	1.125
Sep	1.095	1.187	1.189	1.189	1.189	1.004
Oct	1.111	1.187	1.189	1.189	1.189	0.994
Nov	1.101	1.187	1.189	1.189	1.189	0.943
Dec	1.094	1.174	1.184	1.188	1.189	1.057
			LV			
Jan	1.090	1.131	1.157	1.157	1.142	1.167
Feb	1.061	1.129	1.151	1.137	1.117	1.145
Mar	0.998	1.084	1.117	1.106	1.084	1.106
Apr	1.011	1.090	1.130	1.118	1.096	1.117
May	1.001	1.083	1.122	1.113	1.091	1.114
Jun	1.058	1.130	1.156	1.141	1.124	1.144
Jul	1.107	1.146	1.161	1.143	1.171	1.184
Aug	1.150	1.184	1.181	1.153	1.192	1.134
Sep	1.150	1.184	1.181	1.153	1.192	1.038
Oct	1.150	1.184	1.181	1.153	1.192	1.003
Nov	1.150	1.184	1.181	1.153	1.192	0.941
Dec	1.147	1.179	1.180	1.153	1.192	1.073
			PL			
sJan	1.147	1.172	1.161	1.188	1.215	1.211

Feb	1.148	1.145	1.162	1.176	1.179	1.190
Mar	1.135	1.135	1.145	1.156	1.156	1.161
Apr	1.125	1.128	1.141	1.153	1.154	1.156
May	1.125	1.126	1.137	1.150	1.149	1.157
Jun	1.148	1.146	1.165	1.172	1.185	1.180
Jul	1.175	1.166	1.209	1.219	1.223	1.232
Aug	1.180	1.129	1.215	1.232	1.232	1.154
Sep	1.176	1.121	1.216	1.232	1.232	1.006
Oct	1.176	1.121	1.216	1.232	1.232	1.001
Nov	1.175	1.121	1.216	1.232	1.232	1.002
Dec	1.176	1.121	1.214	1.231	1.232	1.056

Notes: price indices were calculated by dividing the projected prices of the corresponding MS5 by the by calculated marginal supply costs in MS5; these indices shows by how much prices in MS5 differ from their marginal supply costs.

A.4.6. Detailed results of the assessment of the impact of swap deals on MS5 import dependency

Table A. 12: Sources of gas in MS5 under market power scenarios with swaps (Scenario B2) and without swaps (Scenario B1)

	BG				
	Scenario B2			Scenario B1	
	Gazprom	Net Swaps	Other sources	Gazprom	Other sources
2021	73%	23%	4%	96%	4%
2022	73%	23%	4%	96%	4%
2023	73%	27%	1%	98%	2%
2024	73%	27%	0%	99%	1%
2025	73%	27%	0%	100%	0%
2026	73%	-68%	94%	73%	27%
	LT				
	Scenario B2			Scenario B1	
	Gazprom	Net Swaps	Other sources	Gazprom	Other sources
2021	59%	-2%	44%	60%	40%
2022	59%	41%	0%	60%	40%
2023	59%	40%	1%	60%	40%
2024	59%	39%	1%	60%	40%
2025	60%	38%	2%	61%	39%
2026	60%	36%	4%	61%	39%
	PL				
	Scenario B2			Scenario B1	
	Gazprom	Net Swaps	Other sources	Gazprom	Other sources
2021	31%	12%	57%	31%	69%
2022	31%	9%	60%	31%	69%
2023	31%	10%	59%	31%	69%
2024	31%	3%	66%	31%	69%
2025	31%	2%	67%	32%	68%
2026	32%	4%	64%	32%	68%
	EE				
	Scenario B2			Scenario B1	
	Gazprom	Net Swaps	Other sources	Gazprom	Other sources
2021	65%	34%	1%	67%	33%
2022	65%	35%	0%	68%	32%
2023	65%	35%	0%	68%	32%
2024	66%	34%	0%	68%	32%
2025	66%	34%	0%	68%	32%
2026	66%	34%	0%	69%	31%
	LV				
	Scenario B2			Scenario B1	
	Gazprom	Net Swaps	Other sources	Gazprom	Other sources
2021	57%	39%	5%	59%	41%
2022	57%	43%	0%	59%	41%

2023	57%	43%	0%	59%	41%
2024	57%	43%	0%	59%	41%
2025	58%	42%	0%	59%	41%
2026	58%	41%	1%	60%	40%

Note: Note that net swap volumes are the sum of all swap volume into a country less the sum of all swap volume out that country

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