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European natural gas infrastructure: The impact of market developments on gas flows and physical market integration

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HIGHLIGHTS

- ▶ Application of a highly resoluted natural gas infrastructure and dispatch model.
- ▶ Analysis of integration of the European natural gas market in 2019.
- ▶ Simulation of gas flows in Europe for different infrastructure scenarios.
- ▶ Identification of location-specific marginal supply costs and congestions in gas network.
- ▶ Integrated gas market but bottleneck between Germany and Denmark and in Eastern Europe.

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ABSTRACT

Increasing European natural gas import dependency and risks of natural gas supply disruptions support the need for additional natural gas infrastructure. Demand developments and major import pipeline commissionings have a major impact on the level of market integration and the secure supply of final consumers. We analyze a variety of scenarios with a highly granulated European natural gas infrastructure model to analyze gas flows and identify where and when congestions occur in the European natural gas transmission network. In addition to daily and scenario specific demand variations, major pipeline scenarios are analyzed for 2019 as well as an LNG glut scenario. Based on the assumptions of planned intra-European interconnector projects being implemented by that time, we find that the level of market integration is high especially in Western Europe, except for a bottleneck between Denmark and Germany, and some countries in Eastern Europe.

1. Introduction and background

The European gas market is confronted with significant challenges over the next years: Within the borders of the European Union (EU), natural gas production is declining due to limited reserves. This especially affects today's largest gas producing countries in the EU, the United Kingdom (UK) and the Netherlands. In order to import increasing natural gas volumes – which may amount to up to an additional 150 billion cubic meter (bcm) per year in 2020 compared to 2005[1] – an increase in import capacity for natural gas into the EU will be necessary. The arrival of additional gas volumes at the EU border – either by pipeline or as LNG (Liquefied Natural Gas) – will in turn also affect gas flows within the EU as the volumes have to be transported to consumers. With domestic production declining and imports rising, transport distances will increase. To accommodate additional gas flows, expansions of cross-border capacities in the EU may become necessary. Furthermore, as pipeline imports over large distances are generally less structured (i.e. same volumes in summer and winter despite demand seasonality) and less flexible than domestic production, investments in additional natural gas storages might be required. Another potential challenge for the European natural gas market is the danger of short-term supply disruptions as observed during the Russian–Ukrainian gas conflict in January 2009 or the Libya crisis of 2011. The former crisis showed that especially south-eastern European countries were severely affected by disruptions of gas supply to consumers [with some observers speaking of humanitarian disasters as people were not able to heat their homes in the cold winter days of early January, see 2]. Western and central Europe avoided disruptions due to diversified supply portfolios and transport routes, sufficient natural gas stockage and high physical market integration. This even allowed the transportation of gas volumes against the normally prevailing flow directions in pipelines - and, hence, to supply some countries, which under usual conditions are highly dependent on

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[1] Own calculation based on Capros et al. [1].

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the Ukraine import route and do not have large storage capacities (e.g. Hungary), via alternative routes from west to east. Thus, the two lessons of the crisis were (i) that natural gas security of supply is regionally very unequal across Europe, and (ii) that an increased physical market integration through appropriate transport infrastructure can significantly improve security of supply (in addition to increasing storages and diversification) and mitigate the danger of supply disruptions.[2]

Hence, a high degree of physical natural gas market integration is of importance not only to enhance competition and implement a European internal market, but also to support the secure supply of natural gas. In the Third Energy Package of EU legislation on the internal electricity and gas markets the facilitation of cross-border trade in energy, the promotion of cross-border collaboration and investment, and the enhancement of increased solidarity among the EU countries are addressed. According to this Third Energy Package, the association of natural gas network operators in Europe, European Network of Transmission System Operators (ENTSOG), has to publish a Ten Year Network Development Plan (TYNDP) every two years. This plan should contain the European TSOs' perspective on the potential development of demand, supply and transport capacity. The first plan for the period 2010–2019 was published in December 2009.

In this context, a number of infrastructure projects increasing import capacity into Europe and physical interconnection between EU members are being discussed in order to master the different challenges and developments on the European gas market. This article offers an analysis of the impact of these infrastructure developments and potential natural gas demand pathes on gas flows and European market integration for 2019, when all important projects of the TYNDP should be realized. The model-based analysis applied thereby accounts for interdependencies in the European gas market due to the interconnection of grids, transit flows across several countries and intertemporal effects by demand seasonality and gas storages.[3] In the next section natural gas infrastructure models in the literature are indicated briefly, and our own modeling approach is summarized. Section 3 introduces the infrastructure and demand scenario combinations that are simulated. The results of the scenarios focusing on gas flows and physical market integration depending on infrastructure projects realized in 2019 are presented in Section 4. Section 5 offers some concluding remarks and policy implications.

2. Natural gas infrastructure models and methodological approach

2.1. Natural gas infrastructure models

Several natural gas infrastructure models are presented in the literature. Models focusing on long-term developments such as Seeliger [7], Lochner and Bothe [8] and Möost and Perlwitz [9] analyze investments in gas production and cross-border transportation assets (and the electricity sector in the case of Möst and Perlwitz [9]). They define a whole country as a node and model aggregated gas flows between countries implying that there are no bottlenecks within each country's national grid. In this context, it appears appropriate to assume that sufficient infrastructure expansions within each country take place. The same holds true for the models by Holz et al. [10] and Lise and Hobbs [11], which focus on the implication of upstream market power. Lise and Hobbs [11] aggregate Europe to five regions. Thus, they abstract from potential congestion between countries on the continent. The mixed-complementarity models presented by Gabriel and Smeers [12,13] and Holz et al. [14] focus mainly on different economic issues such as modeling competition and agents. These modeling approaches also consider aggregated gas trade flows without a pipeline-specific analysis of gas transports or bottlenecks.

Short-term considerations of the European gas grid with higher temporal and spatial granularity are provided by Lochner and Bothe [15], Neumann et al. [16] and Monforti and Szikszaia [17]. Lochner and Bothe [15] develop the TIGER model, an enhanced version of which is used in this paper. They present a network flow model of the European gas market with over 500 nodes covering all major long-distance transmission pipelines individually. A similar linear optimization approach is provided by Neumann et al. [16]. Instead of a minimization of commodity and dispatch costs, they maximize social welfare by including an estimated demand elasticity. Bottlenecks between nodes are then identified by analyzing the utilization of assets and applying congestion mark-ups. However, again countries are aggregated to one node. This does not allow to consider specific infrastructure assets individually. In addition, the temporal granularity of one month does not account for the system stress of peak demand days. The model by Monforti and Szikszaia [17] allows for the investigation of system resilience in the light of security of supply stress situations. Physical market integration is not in the focus of their model. It abstracts from storage operations explicitly but alters the amount of gas available from storages through Monte-Carlo simulations. Monforti and Szikszaia [17] cover a wider geographical area (EU-27 plus Norway and Switzerland) than Neumann and von Hirschhausen [18] but apply the the same regional resolution.

2.2. Methodological approach

The results presented in this paper are based on simulations with the TIGER model for the year 2019. The TIGER model is a European gas infrastructure and dispatch model specifically developed for the evaluation of existing assets and proposed projects, physical market integration and security of supply scenarios. It was originally developed by Lochner and Bothe [15] and enhanced with respect to temporal granularity by Lochner [19]. The model is capable of simulating the utilization of high pressure transport pipelines, LNG import terminals, and natural gas storages) and location-specific marginal gas supply costs under different assumptions on supply and demand.

Objective of the linear optimization of the TIGER model is the minimization of the total costs of the gas supply and transport system while meeting regionalized demand. Costs include commodity, transportation and, if utilized, regasification and storage costs. Thereby, the three later cost factors represent variable costs of the model's dispatch. The respective assumptions are based on different studies such as OME [20] (for pipeline transport and regasification) and United Nations [21] (for storages).

The model approach assumes that the transport of natural gas in the European Union is organized efficiently and that all possible swaps of natural gas are realized by transmission system operators. The approach presumes that the (regulated) natural monopoly transport segment, access to LNG import capacities and the storage market are organized efficiently. Furthermore, the total system perspective optimizes Europe as one market area. Hence, the model inherently presumes that capacity allocation and congestion management are implemented efficiently and that the regimes enable an efficient allocation of resources across market areas and grid "boundaries". With respect to the results, this implies that any congestion or supply–demand gap identified within the model

[2] Infrastructure sufficiency during security of supply crisis is not at the focus of this article, for a discussion see for instance Bettzöuge and Lochner [3], Dieckhöoner [4] and Lochner and Dieckhöoner [5].

[3] This paper is based on a study commissioned by the European Regulators' Group for Electricity and Gas (ERGEG) and prepared by the Institute of Energy Economics at the University of Cologne (see EWI [6]).

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framework would occur despite a perfectly efficient system operation. Further issues that arise from potential market inefficiencies would not be reproduced by the model.

Results include monthly gas flows on all pipelines, storage levels and injections/withdrawals. In addition, the location-specific marginal costs of gas supply can be evaluated for each node in the system and time period. These represent the shadow prices of each node's balance constraint in the model, which indicate marginal system costs for supplying one additional cubic meter of natural gas at this respective node at this time.[4]

The approach applied to investigate market integration in this study is based on price convergence in integrated markets[5]: The location- and time-specific marginal supply costs computed by the model can be interpreted as price indicators under the given assumptions. Selecting representative nodes provides a price estimator for each country and each model time period and, thus, the differences of marginal supply costs between countries. In a competitive market, as simulated by the model, this price (represented by marginal supply cost) difference should always be lower than the transport costs between the considered countries. Hence, in the simulated competitive market, any price differences exceeding transport costs imply a physical infrastructure bottleneck, otherwise arbitrage opportunities would be exploited.

3. Numerical assumptions and scenarios

3.1. Numerical assumptions

Natural gas supply: In Fig. 1 all major pipeline gas volumes additionally available by assumption to the European market in 2019 are presented. They are derived from a number of well-known forecasts including the World Energy Outlook [24] and the International Energy Outlook [25]. The specific assumptions made are discussed in more detail in EWI [6].

Regarding *European domestic gas production*, we use the assumptions of ENTSOG [26] which are displayed in Table A.1. According to these assumptions, the Netherlands are the largest EU gas producer in 2019 with an output of 57 bcm. The UK, which was still the largest gas producer in 2008 ([27]) sees the largest decline to a production level of below 30 bcm/year. Generally, output in the EU is expected to decline from 211 bcm in 2008 ([27]) to 126 bcm in 2019, which equals a 40% fall.

Import pipeline projects included in the simulations are depicted with their capacities and start-up dates in Fig. 1. The marked ones (*), South Stream, Nabucco, and the second line of the Baltic Sea pipeline Nord Stream, are only included in some scenario variations (see next subsection). The other lines are included in all simulations. Start-up dates are indicative only – for the simulations in 2019 it is merely relevant that the infrastructure enters operation by then. All (smaller) intra-European pipeline expansions until 2019 are included according to ENTSOG [26]; for a detailed list see ENTSOG [[6], p. 122].

With respect to total annual *LNG import capacity* in Europe (including Turkey), we assume an increase by almost 70% from 165 bcm in 2009/2010 to 279 bcm in 2019 [28]. With annual import capacities of more than 80 and 50 bcm respectively, Spain and the UK remain the countries with the larges LNG import capabilities. For a full list of the assumed projects, see [EWI [6], pages 125–126].

Storage working gas volumes (WGV) in Europe is presumed to increase from about 85 bcm in 2009 to 140 bcm in 2019. The distribution of existing capacities and projects ([6], pp. 123–124) reveals that Germany and Italy continue to be the countries with the largest absolute storage capacities.

3.2. Gas demand scenarios

The following two demand scenarios are used as assumptions in our study:

- EWI/ERGEG demand scenario based on Capros et al. [1,29],
- ENTSOG demand scenario based on ENTSOG [26]

of which the latter is the higher scenario on aggregate with a demand difference 49 bcm in 2019 between the two scenarios.[6]

In order to evaluate congestion in the European gas market, it is however not only relevant to consider these annual demand scenarios (broken down to monthly demand). Especially on a day with high demand, security of supply issues or bottlenecks, which do not appear to be of concern or relevance on an average winter day, may emerge. Hence, in addition to the aforementioned demand scenarios, we also explicitly consider the peak demand day according to ENTSOG [26]. It is also displayed in Table A.1. On average over all considered countries, the demand on the peak day is 106 percent above the average demand daily demand. To construct a worst case with respect to peak demand, we presume that it occurs simultaneously in all considered countries. This assumption of the concurrent peak day is in line with the assumptions by ENTSOG [26].

3.3. Infrastructure and supply variations

Results in terms of regionally disaggregated gas flows and congestions within the European grid are discussed for six infrastructure and supply variations. These are combined with the two aforementioned demand scenarios. As a whole year is modeled for each of these scenarios, results with respect to the occurrence of congestion thus further differ with respect to the time of the year. Therefore the focus of analysis is on the winter days of both demand scenarios, a summer day and a peak demand day in winter (EWI/ERGEG and ENTSOG winter day, the EWI/ERGEG summer day, and the ENTSOG peak demand day). Thus, we consider the combination of four different daily demand versions (of the two demand scenarios) and six infrastructure variations. In total there are, hence, 24 variations.

The six infrastructure and supply variations in the scenarios are as follows:

The *Reference Scenario* serves as a baseline scenario. It includes all of the LNG and storage projects that are presented in Section 3.1, but none of the pipeline projects marked with an asterisk in Fig. 1 (i.e. only one line of the Nord Stream pipeline with 27.5 bcm annual capacity is considered).

In addition, the *Nord Stream II Scenario* also covers a second line of Nord Stream with additional 27.5 bcm/year (and the onshore connection NEL with 20 bcm/year capacity).

The *Nabucco Scenario* adds the Nabucco pipeline (31 bcm annual capacity) to the Reference Scenario. Additionally, extra gas volumes that are available for the transport via Nabucco are added to the Reference supply assumptions (see supply assumptions).

The *South Stream Scenario* includes the South Stream pipeline (60 bcm annual capacity), but is otherwise identical to the Reference Scenario.

The *DG TREN Scenario*[7] covers the European Commission's TEN-E projects, i.e. Nord Stream (both lines) and Nabucco. Additional

[4] For a mathematical description of the model and the computation of the location-specific marginal costs of gas supply, see Lochner [19].

[5] See Baulch [22] and De Vany and Walls [23] for discussions on price convergence and market integration, also in the context of natural gas markets ([23]).

[6] The aggregated countries are the EU-27 plus the Balkan countries, Turkey, Norway and Switzerland.

[7] At the time EWI [6] was compiled, the respective Directorate General at the European Commission was still responsible for Transport and Energy.

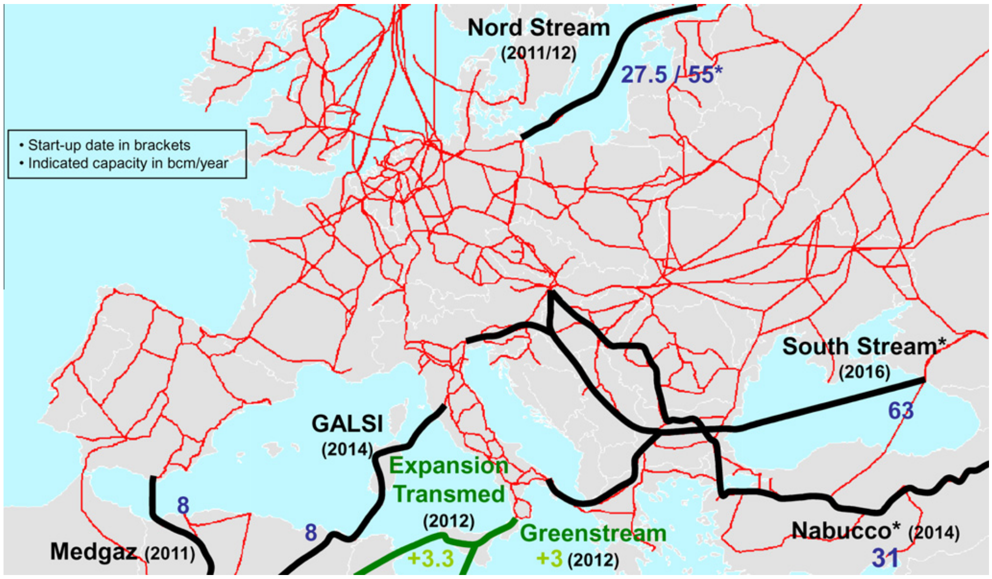

Fig. 1. Import pipeline projects.

Southern Corridor Supplies are assumed to be available for the latter pipeline.

In the scenario *LNG Glut*, we assume relative LNG prices to be low and large volumes consequently arriving in the European market. Otherwise, it is identical to the DG TREN Scenario. The motivation for this relative cost variation is to specifically see the effects on market integration or congestion in the infrastructure system caused by temporarily low LNG prices. Although relatively lower LNG costs (compared to pipeline gas) may not be a long-term equilibrium for the European market, such an LNG oversupply situation could arise temporarily in the global gas market (as it did in 2009). To ensure competition, physical market integration plays an important role – especially in times of oversupply which usually is a chance for new market entrants to procure gas at low prices. In such a situation, bottlenecks in the system could hamper market entry and block consumers from accessing cheaper gas supplies (imported as LNG).

4. Results

4.1. Changing gas flows in the European gas grid

The investigation of gas flows in 2019 in a comparison between the scenarios and relative to 2009 illustrates the consequence of the outlined supply, demand, and infrastructure developments:

Even with only few additional import pipeline projects (Nord Stream I, GALSI) according to the Reference Scenario, the increased European import dependency becomes evident through a general increase of gas flows on all new and existing pipeline import routes and a decrease of flows on pipelines originating in the UK and the Netherlands. As illustrated in Fig. 2, Russian gas largely supplies eastern and central Europe via (now) three large pipelines, Algerian and Libyan pipeline gas supplies the south and Norwegian gas the northwest of the continent. The overall transport costs are a major driver of the model's optimal dispatch and enhance the supply of gas volumes from suppliers with proximity to the respective demand regions.

Introducing a second line of Nord Stream in the Nord Stream II Scenario leads to a cannibalization of imports on the other Russian gas import pipeline routes and has significant effects on gas flows in central Europe (Germany, Austria, Italy, Benelux). The Nabucco project as the Nabucco Scenario demonstrates significantly increases the availability of non-Russian gas volumes in south-eastern Europe. However, these volumes are also to a large extent consumed in this region and not transported to central Europe physically. As these volumes partially replace Russian gas there, Russia could increase its exports to central and western Europe which, again, has a significant impact on gas flows there.

If more than one of the projects is assumed to be in place (DG TREN Scenario), the results combine the effects of the observations from the individual projects and are illustrated in Fig. 3. Interdependencies between Nord Stream and Nabucco seem, however, low as both serve different regions in Europe. The illustration in Fig. 3 shows how, on the one hand, Russian gas imported via Nord Stream is increasingly pushing into northwestern Europe while flows on the Transgas route via Ukraine and Slovakia decline. Transportation via Nord Stream, which is a significantly shorter route than the Transgas route, minimizes the total supply costs. Norwegian gas volumes are also pushed further west because of the additional lower cost Russian volumes in central Europe. Southern Corridor volumes via Nabucco, on the other hand, largely supply southeastern Europe and do not make it to central Europe under the assumptions of the model simulations.

In times of temporarily low LNG prices, as observed in 2009, the European LNG import capacities in 2019 would theoretically allow importing more than 200 bcm of natural gas annually. Then, the main direction of gas flows in Western and Central Europe is turning eastwards, see Fig. 4. E.g. LNG imported in Spain is exported to France and LNG from UK is transported to the continent. In addition, Norwegian gas is routed further towards the continent and less to UK. Flow directions from France also turn to the east enabling the transport for imported LNG volumes to Germany. Thus, the low LNG prices and the proximity to the demand regions of the LNG import terminals that imply supply cost reductions have a significant impact on the optimal dispatch of the model. The flexibility of the infrastructure already allows many European consumers to theoretically gain access to LNG if its price in the global market is low. Imports at the terminals at the coast can be transported to many consumers on the continent. However, not all terminals can be fully utilized as there are also some restrictions in the pipeline infrastructure (see next subsection).

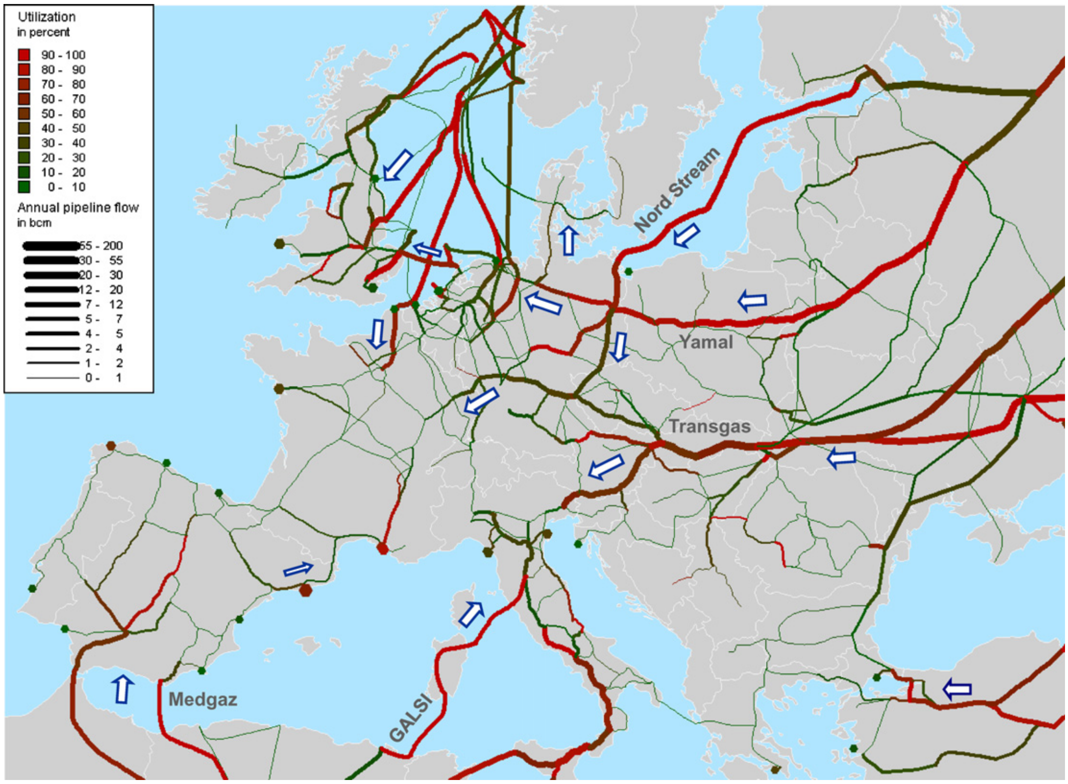

Fig. 2. Gas flows in 2019 in Reference Scenario (EWI/ERGEG demand).

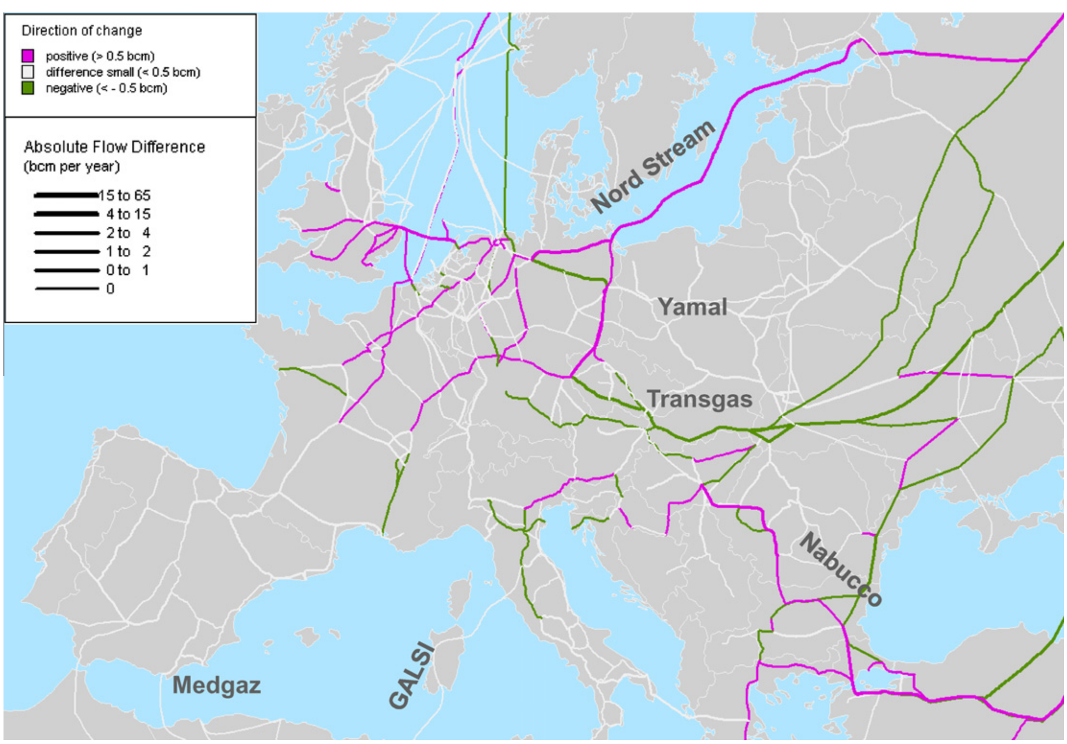

Fig. 3. Difference in gas flows – DG TREN vs. Reference Scenario (EWI/ERGEG demand).

In the South Stream Scenario, it is assumed that Russia cannot increase its exports relative to the other scenarios. Nord Stream and all existing routes through central Europe offer enough capacity for these exports and routes to western Europe that allow for natural gas supplies at lower costs. Hence, South Stream mainly serves as a pipeline allowing the diversification of export routes

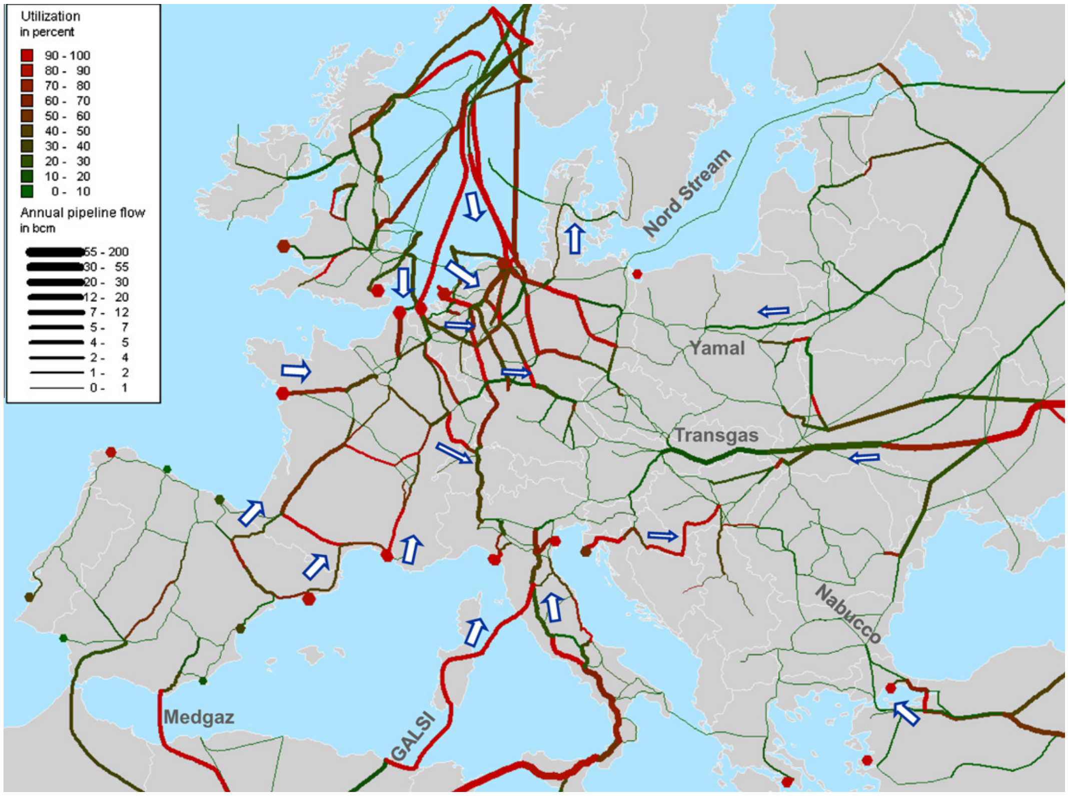

Fig. 4. Gas flows in 2019 in LNG Glut Scenario (EWI/ERGEG demand).

Table 1
Assumed probabilities of scenarios.

$\tau_{day,infr}$	Infrastructure					
Demand	Reference $\tau_{Ref} = 0.1$	Nord Stream II $\tau_{NordII} = 0.25$	Nabucco $\tau_{Nab} = 0.05$	South Stream $\tau_{South} = 0.25$	DG TREN $\tau_{DG} = 0.25$	LNG Glut $\tau_{LNG} = 0.1$
EWI/ERGEG						
summer $\tau_s = 0.25$	0.025	0.0625	0.0125	0.0625	0.0625	0.025
winter $\tau_w = 0.35$	0.035	0.0875	0.0175	0.0875	0.0875	0.035
ENTSOG						
winter $\tau_{w'} = 0.35$	0.035	0.0875	0.0175	0.0875	0.0875	0.035
peak day $\tau_p = 0.05$	0.005	0.0125	0.0025	0.0125	0.0125	0.005

away from Ukraine as a transit country. This rerouting of gas in eastern Europe of course affects the utilization of assets in the region, but has only limited effects in countries further in western Europe (see Table 1).

4.2. Physical market integration

Identifying market integration as outlined in Section 2 in twelve scenarios on various representative days in 2019 for all interconnections between countries yields a comprehensive picture of the congestion situation. Table 2 summarizes these information. For all country interconnections and all infrastructure and supply scenarios, different typical days are considered: an average winter day (w) and an average summer day (s) in the EWI/ERGEG demand scenario, an average winter days in the ENTSOG demand scenario (w') and the concurrent peak demand day (p) according to ENTSOG [26]. An 'x' indicates when the respective interconnection is congested, i.e. the price difference between the nodes exceeds transport costs, on that day. Additionally, we indicate on which of these four investigated days this congestion leads to demand curtailment[8] in one of the countries (see 'xx' in Table 2).

In order to enhance comparability between the different interconnection points i and to rank the bottlenecks, we develop a simple index. It is calculated as

$$Index_i = \sum_{day,infr} \tau_{day,infr}(0.5 * \mathrm{CONGESTION}_i + 0.5 * \mathrm{CURTAILMENT}_i) \quad (1)$$

[8] Demand curtailment in the context of the modeling exercise does not necessarily refer to a forced cut-off of supply to consumers. The reduction on demand might also be achieved by more market-based measures, e.g. the disruption of consumers supplied with interruptible contracts or the reduction of gas consumption in the industry and power sector caused by natural gas price spikes in the short-term wholesale market.

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Table 2
Bottlenecks between countries in 2019.

Border	Reference				Nord Stream II				Nabucco				South Stream				DG TREN				LNG Glut				Index
	w	s	w'	p	w	s	w'	p	w	s	w'	p	w	s	w'	p	w	s	w'	p	w	s	w'	p	
(1) DE and DK	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	xx	1.0000
(2) BG and MK	xx		xx	xx	xx		xx	xx	xx		xx	xx	x		x	x	xx		xx	xx	xx		xx	xx	0.6563
(3) HU and SK	x		xx	xx	x		xx	xx			x	x							x	x				x	0.2638
(4) HU and RO	x		xx	xx	x		xx	xx			x	x								x					0.2175
(5) HR and SI				xx				xx	x		x		x		x				x		x	x	x		0.2138
(6) CZ and DE-E[a]					x		x	x									x		x	x			x	x	0.2075
(7) CZ and SK	x		x	x				x	x		x	x	x		x	x	x			x					0.2063
(8) AT and HU	x		xx	xx	x		xx	xx																x	0.2038
(9) AT and SK	x		x	x			x	x	x		x	x							x	x					0.1563
(10) AT and SI			x				x				x	x							x						0.1150
(11) AT and IT											x				x				x						0.0963
(12) HR and HU			x				x																x		0.0788
(13) IT and SI														x	x										0.0750
(14) DE and NL				x				x				x				x		x		x	x			x	0.0738
(15) BG and TR				x				x					x			x									0.0588
(16) GB and NL				x				x				x				x				x		x	x	x	0.0550
(17) DE and FR				x				x				x				x				x	x	x			0.0525
(18) FR and CH																					x	x	x		0.0475
(19) AT and DE													x												0.0438
(20) BG and GR				xx				xx								xx						x			0.0425
(21) GB and BE				x				x				x				x				x			x	x	0.0425
(22) FR and BE																					x		x		0.0350
(23) GR and IT				xx				xx								xx									0.0300
(24) HU and RS				x				x				xx								xx				xx	0.0288
(25) DE and BE				x				x				x				x				x				x	0.0250
(26) CH and DE				x								x											x		0.0213
(27) CZ and DE-S[a]				x				x				x								x					0.0163
(28) ES and FR																								x	0.0025
(29) ES and PT																									0.0000
(30) GB and IE																									0.0000
(31) BE and NL																									0.0000
(32) CH and IT																									0.0000
(33) DE and PL																									0.0000
(34) BG and RO																									0.0000
(35) GR and TR																									0.0000

Congestion and curtailment on EWI/ERGEG demand winter (w) and summer (s) day, ENTSOG demand winter day (w'), and peak demand day (p). 'x' refers to type days when congestion occurs. 'xx' refers to type days when congestion even leads to demand curtailment.

[a] Southern (S) and Eastern (E) Germany respectively.

where τ is the probability of the scenario respective to $day \in \{w, s, w', p\}$ the representative day and $infr \in \{Ref, NordII, Nab, South, DG, LNG\}$ the considered infrastructure assumptions (Reference, Nord Stream II, Nabucco, South Stream, DG TREN and LNG Glut). CONGESTION and CURTAILMENT are dummy variables ($\in\{0,1\}$) which become 1 when congestion exists and demand curtailment in one of the countries becomes necessary as a consequence. The CURTAILMENT and the CONGESTION dummies are weighted by the infrastructure probabilities τ_{infr} and the probabilities τ_{day} for the type of day. For the purpose of this comparison, we assign the following probabilities τ_{infr} and τ_{day}: As we deem another large infrastructure project from Russia (in addition the already existing Nord Stream I) likely, the Nord Stream II, South Stream and DG TREN scenarios are each assigned a probability of 0.25. The Reference Scenario is assigned 0.1 and a scenario with Nabucco only and no second line of Nord Stream seems unlikely ($\tau_{Nab.} = 0.05$). For the LNG Glut Scenario, we also set the probability to 0.1.[9] The peak winter day has a probability of $\tau_p = 0.05$ – a one in twenty winter. The EWI/ERGEG and ENTSOG winter have a weight of $\tau_w + \tau_{w'} = 0.7$ together and the summer day's weight is $\tau_s = 0.25$ reflecting that the larger proportion of annual supply is provided in winter.

The idea behind the index is to aggregate the very detailed information on inter-country bottlenecks in the pipeline system provided in Table 2 and to give an indication of the frequency and severity of a bottleneck in the model results.

According to Table 2, the congestion between Germany and Denmark seems to be the bottleneck first warranting investment. Because of declining domestic production in Denmark, the country (which used to export gas to Germany in the past) is becoming a net-importer in the next years with imports increasing in the following years. Hence, additional import infrastructure may be required. The issue is known and TSO are planning to increase capacities on the route from Germany although no specific investment project was launched by the time this study was compiled.

The other major bottlenecks largely concern Eastern Europe (Nos. 2–5 and 8). There is insufficient import capacity into Macedonia (from Bulgaria) if ambitious Macedonian consumption growth projects are to materialize. Hungary seems to experience a supply–demand gap if import capacities into the country are not upgraded. This causes a number of bottlenecks from the neighboring countries (Austria, Slovakia, Romania, Croatia) into Hungary and illustrates the importance of interdependencies: It is unlikely to be efficient to remove all these economic bottlenecks. Increasing capacity at one of the interconnections would allow sufficient gas to be imported in Hungary. Price spikes there would disappear, thus, reducing the cost of congestion from all neighboring countries. Another point of congestion is the German–Czech border (No. 6 in Table 2) where gas flows from Germany to the Czech

[9] Note that this assignment of probabilities for the purpose of ranking the bottlenecks exceeds the EWI [6] study. It is, however, useful in the context of this paper as not all of the congestion issues can be discussed individually here.

Republic (gas flows are in the reverse direction at the other interconnection point in Waidhaus in Southern Germany). Here, the emergence of Nord Stream as a new supply route into Northeastern Germany provides additional volumes there. This new supply in the region needs to be transported to consumers in other markets, increasing the requirements for capacities from Germany to the south. Again, there are projects being discussed providing capacities in exactly that place and direction.

The distribution of 'x's in Table 2 also gives a general overview where physical market integration in the pipeline grid could still be improved. In the first five scenarios (from the left), the majority of congestion appears to be in Eastern Europe as described before. However, considering the third, fourth and fifth column, Table 2 also illustrates a decrease in the number of congested interconnection points implying that the additional interconnection provided by either the South Stream or Nabucco pipeline projects alleviates some congestion and reduces the number of bottlenecks. Due to the large capacity each of the pipelines establishes between various different markets, this is not surprising.

These two southern corridor pipelines also reduce curtailments to consumers significantly compared to the Reference Scenario (see reduced number of 'xx's in the Scenarios Nabucco, South Stream and DG TREN).

With respect to the LNG Glut scenario, most additional bottlenecks (compared to the DG TREN scenario with the same infrastructure endowment) show up in the upper part of the table, i.e. in Western Europe where most of the LNG import terminals are. Especially between UK and the continent (interconnection Nos. 16 and 21 in Table 2), the Benelux countries and Germany (Nos. 14 and 25), and France and Germany and Switzerland (Nos. 17 and 18), there appear to be bottlenecks in west to east direction. These may hamper access of consumers in Central Europe to "cheap" natural gas imported in Northwestern Europe if such an LNG glut in the global market were to occur again in 2019.

Another finding concerns the peak demand day (p). Some interconnections are only congested in this specific configuration of the peak demand in each country being on the same day; see specifically the interconnections 14–27 in Table 2. On this day of high demand in each country, the infrastructure system would generally be highly utilized with more congestion than on normal days. In Western Europe, the strain on the system is especially large in countries with relatively low storage capacities, for instance the UK. Hence, locational marginal supply costs in the UK would increase gas flows from the continent to the UK until all capacities are congested. As storage endowment is much higher in some central European countries (e.g. Germany), bottlenecks emerge at the interconnection from there to the west as not all available gas can physically be transported to the north west. However, this congestion occurs only on the hypothetical concurrent peak demand day.

For some interconnections, those numbered 29 or higher in Table 2, congestion is not an issue at any time or in any infrastructure. There, physical market integration seems to be rather high already when all announced infrastructure projects are implemented. Examples of such highly integrated markets include the UK and Ireland, Spain and Portugal, Switzerland and Italy or Belgium and the Netherlands.

5. Conclusion

Applying a highly granulated natural gas infrastructure model, gas flows and market integration of the European market have been analyzed for a variety of demand and major pipeline scenarios. Our analysis thereby accounts for dynamic spatial and temporal interactions of infrastructure components in the European natural gas market. The model approach allows for a detailed investigation of congestions in the pipeline system and location-specific marginal supply costs. Based on these results conclusions can be drawn on European market integration in the next decade. With the underlying assumptions and the planned intra-European pipeline expansions being implemented by 2019, we find that the European natural gas market is well integrated. However, there are some exemptions. There is a significant bottleneck between Germany and Denmark in all our scenarios and some further bottlenecks in Eastern Europe which would even lead to curtailment of natural gas supplies on cold winter days if demand develops as assumed and no further interconnection expansions take place. Addressing to resolve these bottlenecks with the most severe consequences should be at the focus of TSOs and regulators.

When interpreting the presented results, four important points need to be kept in mind: First, while a bottleneck may hamper competition and limit physical market integration, it is not necessarily efficient from an economic point of view to eliminate each bottleneck as the costs of the required investments might exceed the cost of the restriction.[10] Second, due to the interdependencies between all elements in the gas infrastructure, a seasonal bottleneck in transportation might not be most efficiently removed by investment in transport capacity; it might be more efficient to invest in storage or LNG regasification terminals instead. Third, there might be other reasons to consider an investment necessary such as enhancing security of supply or fostering competition by providing sufficient capacities. Fourth, the analysis of congestion in this paper focused on bottlenecks between countries. Although the applied model allows an investigation of bottlenecks within countries, for a parameterization in 2019 this would require an elaborate specification of natural gas demand developments on a regional level, which was not at the focus of this study. Therefore, potential bottlenecks which may arise between balancing areas inside a single country under certain scenarios were not discussed. With respect to conclusions on potential investment requirements, this implies that further bottlenecks, which do not cause supply–demand gaps but which may be needed to ensure high physical market integration within market areas or individual TSO networks, might additionally arise and warrant investment.

Hence, the bottlenecks identified in this study indicate (temporary) impediments to price convergence (and physical market integration) between countries; they do not imply that additional investments to remove these bottlenecks are necessarily efficient from an economic perspective. Results further refer to the congestion which occurs in an efficiently working market; potential additional congestion as a consequence of market inefficiencies is not detected by the model approach. To derive a conclusion on whether a bottleneck should be removed by additional investment or not, it would be necessary to compare the benefits from such an investment (reduction of system costs due to bottleneck elimination) with the additional (local) costs of the investment. Such comparisons could be tackled on the basis of the employed methodology, but are beyond the scope of this paper.

Appendix A

See Table A.1.

[10] In the context our analysis, we consider marginal congestion costs. Adding a marginal unit of capacity would, hence, be efficient if marginal capacity costs would not exceed marginal congestion costs. For determining the full size of investment, endogenous modeling of investment decisions would be required to capture interdependencies between investments and the lumpiness of investments. An approach to do so is provided by [30].

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Table A.1
European supply and demand assumptions in the model for 2019.

Country	Supply (bcm/year)	Demand (by scenario)		Peak day
		EWI/ERGEG[a](bcm/year)	ENTSOG[a] (bcm/year)	Demand (mcm/day)
Austria	2.0	9.6	13.0	86
Belgium		17.1	26.0	182
Bosnia and Herzegovina		0.5	0.6	2
Bulgaria		3.4	3.0	15
Croatia	2.0	4.3	6.0	37
Czech Republic		9.1	13.0	71
Denmark	2.0	2.8	3.0	26
Estonia		0.7	1.0	3
Finland		4.9	5.0	24
France		43.0	53.0	421
Germany	14.0	93.4	81.0	500
Greece		5.1	7.0	35
Hungary	0.5	14.8	21.0	132
Ireland	0.6	4.9	6.0	28
Italy	5.0	80.8	102.0	433
Latvia		1.9	2.0	8
Lithuania		2.9	3.0	14
Luxembourg		1.4	1.0	7
Macedonia, FYRo		0.2	0.8	3
Netherlands	57.0	46.3	46.0	431
Norway		7.5	7.9	48
Poland	4.0	20.7	19.0	85
Portugal		3.9	8.0	32
Romania	10.0	16.6	12.0	90
Serbia		2.8	4.0	20
Slovak Republic		7.2	6.0	40
Slovenia		1.2	2.0	9
Spain		36.6	56.0	294
Sweden		1.6	2.0	9
Switzerland		3.3	3.3	23
United Kingdom	29.0	98.9	90.0	483
Turkey		50.2	50.2	199
Total	126	597	654	3790

[a] Own assumptions for those countries where no ENTSOG [26] data available.

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