InTraGas - A Stylized Model of the European Natural Gas Network

Anne Neumann and Norman Viehrig and Hannes Weigt

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Anne Neumann, Norman Viehrig, and Hannes Weigt

German Institute for Economic Research

Chair for Energy Economics and Public Sector Management

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Anne Neumann[2], Norman Viehrig[3], and Hannes Weigt[4]

Abstract:

We present an optimization model of the European natural gas market which is intended for the use within a regulatory approach providing incentives for efficient transmission investments. The stylized model is designed as welfare maximization taking into account production, pipeline, LNG, and storage constraints. We develop several scenarios to analyze the future development of the European natural gas market.

Key words: Natural gas, Europe, Network modeling

JEL-code: L95, D 43

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[2] DIW Berlin, Mohrenstr. 58, D-10117 Berlin, aneumann@diw.de

[3] Dresden University of Technology, Faculty of Business and Economics, Chair of Energy Economics and Public Sector Management

[4] Dresden University of Technology, Faculty of Business and Economics, Chair of Energy Economics and Public Sector Management, hannes.weigt@tu-dresden.de

1 Introduction

In order to develop a regulatory regime that provides incentives for pipeline owners/operators to invest in new pipeline infrastructure we need a simplified representation of the European natural gas market containing information on pipeline capacities, entry and exit points of the system, LNG landing facilities, and storage capacities. Whereas numerical modeling exercises regularly try to forecast market situations this paper describes a simplified representation of the main natural gas infrastructure in Europe. In later studies the model can be used as market representation to test a proposed regulatory model which removes existing cross-border bottlenecks in the European long-distance natural gas pipeline system.

We are interested in identifying existing transportation bottlenecks and the impact of **In**vestments into **Tra**nsmission facilities of natural **Gas** on the market outcome (InTraGas-Model). Therefore, we design a welfare maximization approach subject to constraints of natural gas infrastructure facilities. The focus is on optimization of the long-distance transport neglecting influences of strategic company behavior on the exporter side, interaction of traders in Europe, or market power concerns on the intra-European transmission network level.

The literature on natural gas transportation models mainly distinguishes three approaches. The system dynamic approach has been applied by two studies so far (Stäcker, 2004; Hallouche and Tamvaski, 2005). EWI Cologne has produced a series of linear optimization models (EUGAS, TIGER, MAGELAN), of which the TIGER model provides the most detailed dispatch model for Europe and is suited for identifying congestion (Perner and Seeliger, 2004; Lochner and Bothe, 2007). The dynamic model optimizes long-term European natural gas supply taking into account production and transportation facilities. Model outputs are mainly flows and supply costs. In order to allow for strategic behavior, market power and other market imperfections of the (European) natural gas market recent literature dominantly relies on the complementarity framework. In a first application Mathiessen et al. (1987) show that the European natural gas market is best described by a Cournot duopoly. The following works by Golombek et al. (1995, 1998) distinguish between up- and downstream players in the natural gas market and show the positive impact of market restructuring on upstream competition and welfare. Several streams within this literature evolved, which focus on (and study) different issues such as multi-period modeling and supply disruptions, double marginalization, or the cartel creation of exporters settings. The World Gas Model (WGM) provides a high level of granularity in a game-theoretic context while still covering 95% of world natural gas production (Egging et al., 2009). Holz (2009) discusses these different model families in more detail.

Investment in infrastructure in all of these models is best described as a net present value calculation optimization. Hence, even if the complementarity framework so far has attracted the largest share of researchers and literature it has yet not been able to include a convincing regulatory investment mechanism. The next section provides the model formulation and specifies the data sources. Section 3 applies the model to a set of stylized scenarios and discusses the results. We conclude with an outlook on further research in this area.

2 Model Formulations and Data

The InTraGas model represents a stylized representation of the existing European natural gas network including the major non-European exporting countries, i.e. Russia or Algeria, and the transit countries. The model takes into account storage, pipeline and LNG restrictions and can be utilized to obtain a competitive benchmark including congestion mark-ups. This section provides the mathematical formulation and the underlying dataset.

2.1 Model formulation

The market model[5] is formulated as non-linear optimization program maximizing social welfare under the assumption of perfect competition taking into account technical constraints:

$$\begin{aligned} \max_{d,g,flow,LNGflow} \quad W = & \sum_{n,t} \int_0^{d^*_{n,t}} p(d_{n,t})\,\mathrm{d}d_{n,t} - \sum_{n,t} c_{n,t} g_{n,t} \\ & - \sum_{n,m,t} tc_{n,m}\, flow_{n,m,t} - \sum_{n,m,t} LNGtc_{n,m}\, LNGflow_{n,m,t} \end{aligned} \qquad (1)$$

s.t.

$g_{n,t} \le g_n^{\max}$	Production constraint	(2)
$flow_{n,m,t} \le flow_{n,m}^{\max}$	Pipeline constraint	(3)
$LNGflow_{n,m,t} \le LNGflow_{n,m}^{\max}$	LNG route constraint	(4)
$\sum_m LNGflow_{n,m,t} \le Liquefaction_n^{\max}$	Liquefaction constraint	(5)

[5] The model is dynamic in the sense that it covers 12 months, but static as it does not take into account investments over the same time period.

$$\sum_m LNGflow_{m,n,t} \leq Regasification_n^{\max} \qquad \text{Regasification constraint} \qquad (6)$$

$$store_{n,t} = store_{n,t-1} + s_{n,t-1}^{in} - s_{n,t-1}^{out} \qquad \text{Storage balance} \qquad (7)$$

$$\begin{aligned} & store_{n,t} \leq store_n^{\max} \\ & s_{n,t}^{in} \leq sin_n^{\max} \\ & s_{n,t}^{out} \leq sout_n^{\max} \end{aligned} \qquad \text{Storage constraints} \qquad (8)$$

$$\begin{aligned} & g_{n,t} + s_{n,t-1}^{out} + \sum_m flow_{m,n,t} + \eta \sum_m LNGflow_{m,n,t} \\ & \geq d_{n,t} + s_{n,t-1}^{in} - \sum_m flow_{n,m,t} - \frac{1}{\mu} \sum_m LNGflow_{n,m,t} \end{aligned} \qquad \text{Energy balance} \qquad (9)$$

The objective of our market model is a welfare maximization (equation 1): We derive the gross consumer surplus assuming a linear demand function *p(d)* for each country and subtract the accumulated costs for production (*g*), pipeline transport (*flow*), and LNG transport (*LNGflow*). Production costs c_n are differentiated by production site, pipeline costs $tc_{n,m}$ depend on transport distance between starting node *n* and end node *m*; LNG cost $LNGtc_{n,m}$ include shipping costs and are differentiated according to the shipping route from *n* to *m*. Liquefaction and regasification costs are included as losses in the energy balance.

The welfare maximization is subject to several technical restrictions representing the underlying production, storage, and transportation limitations. First, production $g_{n,t}$ at site *n* in any period *t* can not exceed the maximum available production capacity g^{max} (equation 2). The flow $flow_{n,m,t}$ on a pipeline connecting *n* and *m* can not exceed the pipeline's capacity $flow^{max}$ (equation 3). LNG transport routes are not limited in the available transport capacity. Equation 4 therefore only represents the available sea routes connecting specific nodes *n* and *m* that have the necessary LNG facilities. The capacity limit $LNGflow^{max}$ is chosen such that no restrictions occur on those available sea routes whereas non available connections have no LNG transport capacity. The actual amount of LNG transport initiated at a node *n* is therefore limited by the installed liquefaction capacities $Liquefaction^{max}$ (equation 5) and the incoming LNG transport is limited by the installed regasification capacities $Regasification^{max}$ (equation 6).

To take account of the dynamic nature of the natural gas market the model consists of 12 periods *t* that represent one month each. Storage plays an important role in natural gas markets to manage demand and production variation during seasons.[6] The storage level $store_{n,t}$ at a site in period *t* is defined by the previous periods storage level $store_{n,t-1}$ and injections to (s^{in}) and withdrawals from (s^{out}) storage (equation 7). We assume that over one year the injected and withdrawn amounts sum to zero. The previous periods storage level $store_{n,t-1}$ in the first period $t=1$ is therefore set equal to the resulting storage level in the last period $t=12$. The storage level as well as injections and withdrawals are further limited in their maximum capacities (equation 8).

The market is cleared via a nodal energy balance constraint (equation 9). All injections at a node n (left hand side of equation 9) have to be at least as big as all withdrawals at that node (right hand side of equation 9). LNG injection and withdrawals take account of losses during liquefaction and regasification processes. Incoming LNG flows ($LNGflow_{m,n}$) are reduced by the factor η to account for energy needed for regasification reducing the amount of available natural gas for demand (d_n) or pipeline transport ($flow_{n,m}$). Outgoing LNG flows ($LNGflow_{n,m}$) are increased by the factor $1/\mu$ to take into account energy needed for the liquefaction process. Thus, the required amount of produced natural gas (g_n) increases in order to balance the constraint. The nodal market price is derived via the obtained optimal demand d^* and the linear demand function $p(d)$. The model is incorporated into GAMS using Conopt as solver.

2.2 Data

The underlying dataset is based on publicly available sources. The reference data is calibrated to represent 2005 values and is provided on a monthly basis covering a representative year. Seasonal fluctuations in demand and supply of natural gas as well as storage patterns can thus be captured. The network is a stylized representation of the existing gas pipeline system aggregating all facilities within one country into one node. Cross border connections between countries are summed up within one pipeline connecting the respective country nodes. The market includes the Western and Central European countries with a surrounding system of major natural gas exporting regions for both pipeline and LNG (Figure 1).

[6] Due to the monthly time level storage utilization due to short term variations is not taken into account.

Figure 1: Stylized network of the EU natural gas market

Source: Own presentation

Production data (g_t^{max}) are taken from IEA (2006) and BP (2006). For non-exporting countries indigenous production is defined as maximum production capacity. For the European natural gas exporting regions Norway, the Netherlands and the UK we consider December production as maximum capacity constraint. The production constraint for non-European natural gas exporting countries is determined by dividing the yearly production values using Norway's monthly production schedule as reference and the December value as maximum capacity constraint.

Production costs (c_n) are taken from OME (2005). For most of the non-European exporting countries these figures were readily available. For Norway and Russia we use the average of production costs from different sites[7]; for Ireland the costs of the UK are used. For the continental European countries we use costs of the Norway-North Sea pipe as reference. Production costs range from as little as 0,45€/MBtu in Algeria to more than 1,70€/MBtu in the UK. However, the majority of exporters produce in a cost range of about 0,30-0,60€/MBtu.

Reference demand is taken from the same sources as production data (IEA, 2006; and BP, 2006). The coverage includes all Western and Central European countries up to Poland, Slovakia, Hungary, and Slovenia as eastern boundary (see Figure 1). Demand of other

[7] Russia-Yamal, Russia-Nadym-Pur-Taz, Russia-Volga-Ural and Russia-Barent Sea - Baltic Sea.

countries as well as global interactions with the American and Asian natural gas market are not regarded in our model. For countries were only yearly demand values are available Poland is used as reference for the demand curve. Given the reference demand levels a linear demand function (*p(d)*) is derived assuming a reference price of 2.75 €/MBTU and a demand elasticity of -0.3 at that point.

Natural gas pipeline capacities ($flow^{max}$) between the nodes of the model are gathered from Gas Infrastructure Europe (GIE, 2005). The capacities of all connections between two nodes are added and transformed into mcm per month. Interconnection capacities between exporting countries like Russia and Ukraine are not available. We assume that these pipeline capacities are not limiting the exports towards Europe and thus do not display any bottleneck.[8] Transportation costs for pipeline transmission are derived from OME (2005) and transposed into a transport price per km and transported volume ($tc_{n,m}$). Given the representation of a country as a node we define the length of a pipeline as the distance between the two country centers.

Natural gas underground storage capacities per country are characterized by three parameters: working gas volume ($store^{max}$), peak withdrawal ($sout^{max}$) and peak injection capacity (sin^{max}).[9] The values for the different storage facilities of each country are taken from GIE (GIE, 2009a) and the storage operators' websites and aggregated into single values for each country.

The basic model setting also includes all liquefaction and regasification terminals in operation in 2005. Aggregated data on a monthly basis is available from GIE (GIE, 2009b). Losses generated during liquefaction (about 12% of the total intake of natural gas) and regasification (1%) are captured in the energy balance constraint of the model (IEA, 1994, pp. 50-51).

Even though LNG transportation capacity ($LNGflow^{max}$) is considered a constraint in the maximization problem, we argue that there exists no real limit to this parameter. It solely represents existing LNG trade links between nodes in our model. We restrict this capacity to 10.000 mcm/month for trade between nodes where LNG is already shipped under long-term contracts in 2005. Transportation costs for LNG are approximated by a shipping cost value (*LNGscr*) of 0.67 € per seamile and mcm. This is based on monthly LNG import prices into Europe (IEA, 2008), average speed of the world fleet of LNG carriers and 0.25% of cargo tank capacity used to fuel the vessel (IEA, 1994). We then derive the distances between LNG ex- and importing nodes, calculate averages if there are multiple connection possibilities and multiply this with the cost value to obtain a route specific cost value ($LNGtc_{n,m}$).

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[8] This assumption then translates into a transport capacity of 15.000 mcm/ month.

[9] Peak withdrawal and injection capacities were transformed from mcm/day to mcm/month.

Table 1: Dataset for calibration

Country	Average Production Capacity (mcm/month)	Average Reference demand (mcm/month)	Working gas volume (mcm)	Peak withdrawal capacity (mcm/month)	Peak injection capacity (mcm/month)	Lique faction (mcm/month)	Regasifi cation (mcm/month)
Austria	136	795	2820	952	851		
Belgium	0	1200					
Czech Republic	15	793	2255	1041	768		
Denmark	871	415	810	402	201		
France	160	3875	14303	7199	4121		1208
Germany	1654	8480	17584	13132	5962		
Hungary	243	1238	3460	1425	1088		
Ireland	45	335					
Italy	1002	7175	13290	7596	3987		292
Netherlands	6567	4124					
Norway	7387	560				483	
Poland	507	1354					
Portugal	0	358	150	210	75		433
Slovakia	12	541	2320	986	806		
Slovenia	0	97					
Spain	14	2686	3742	4488	288		2092
Sweden	0	78					
Switzerland	0	283					
UK	7733	8340	3589	3458	783		375
Russia	58532						
Turkmenistan	5755						
Azerbaijan	519						
Iran	8516						
Qatar	4258					1587	
Egypt	3396					932	
Libya	1145					104	
Algeria	8594					2588	
Nigeria	2134					1001	
T&T	2839					1104	

Source: As described in this section.

3 Scenarios and Results

We simulate several future developments for the European natural gas market to identify possible congestion problems and price developments. The model resembles a competitive environment thus market power concerns are neglected and the obtained prices represent a lower boundary.

3.1 Scenarios

We first derive a *2005 reference case* with the above described dataset as benchmark (see Table 1). The remaining scenarios represent developments up to 2015. All cases rely on a basic extension of the reference case including additional pipelines, LNG terminals, production sites and demand adaptation (IEA, 2008; GSE, 2009). To keep our model simple and tractable production costs and the reference price of 2.75 €/MBTU are kept constant across all scenarios. We assume that demand will increase by an average of 1.5% per year until 2015 (IEA, 2008). Production in Europe will decline by about 7% whereas production in the exporting countries will increase by 10% to 94% (IEA, 2008). Several pipeline projects are expected to become operational by 2015. The most important ones are the North- and South-Stream connecting Russia directly with European import countries avoiding transit through Belarus or the Ukraine, and the Nabucco pipeline connecting the Caspian gas fields with Europe mitigating the dependence on deliveries from Russia.

Regarding LNG facilities we include all projects that are under construction according to IEA (2008) and scheduled until 2015. On the exporting side in particular Qatar will extend its capacities significantly. On the importing side the UK currently expands its capacities significantly, but also Belgium and the Netherlands are going to diversify their supplies by adding regasification facilities. Spain, Italy, and France are extending their existing capacities to a similar level of import capacity by 2015. Among the major natural gas importing countries only Germany will have no opportunity to import LNG in 2015.

Regarding gas storage nearly all European countries are planning extensions of their existing capacities (GSE, 2009). The basic extension set represents the *2015 base case* (i.e. the expected market development until 2015). This case is adjusted subsequently to test the impact of several possible future developments in three further cases. First, a significant decline of indigenous production within Europe is modeled (*EU case*). We assume that the Netherlands and Norway face a 20% lower production level and the UK faces a sharp decline to 30% of its 2005 production capacity (Gabriel et al., 2008). The reduced local production will increase import dependence of Europe and most likely lead to a higher price level. Second, we assume that Russia has a conflict with its transit countries and cuts its supplies via Belarus and the Ukraine (*Russian case*). As we assume that the North- and South-Stream pipelines are finished by 2015, Russia can still rely on those for its exports to Europe. Nevertheless, the reduced transmission capacity will lead both to quantity and price movements in Europe. Finally, we assume a further extension of LNG facilities in Europe and exporting countries which could reduce import dependency of Europe on natural gas from Russian (*LNG case*). An overview of the adjusted dataset for the scenarios is presented in Table 2.

Table 2: Scenario overview

<table>
<tr><th></th><th>Reference case</th><th>EU case</th><th>Russian case</th><th>LNG case</th></tr>
<tr><td>Year</td><td>2005</td><td colspan="3">2015</td></tr>
<tr><td>Demand level*</td><td>100%</td><td colspan="3">116%</td></tr>
<tr><td>Production*</td><td>100%</td><td>UK: 20%
Norway, NL: 80%
Otherwise similar to Russian and LNG case</td><td colspan="2">- EU: 93%
- Transition Countries: 116%
- Russia: 110%
- Africa: 150%
- Middle East: 194%
- Other: 130%</td></tr>
<tr><td>New pipelines*</td><td>na</td><td colspan="3">- Russia - Germany (55 bcm/y)
- Russia - Bulgaria (30 bcm/y)
- Azerbaijan - Austria via Turkey (31 bcm/y)
- Turkey - Italy via Greece (8 bcm/y)
- Algeria - Italy (8 bcm/y)
- Algeria - Spain (8 bcm/y)
- Norway - Denmark (7 bcm/y)</td></tr>
<tr><td>Unavailable pipelines</td><td>na</td><td>none</td><td>All pipelines from Russia to EU via Belarus / Ukraine</td><td>none</td></tr>
<tr><td rowspan="2">New LNG facilities*</td><td rowspan="2">na</td><td colspan="3">Liquefaction
- Qatar: 83 bcm/y
- Algeria: 6.1 bcm/y
- Egypt: 6.5 bcm/y
- Nigeria: 12.3 bcm/y
- Norway: 5.6 bcm/y
- Trinidad: 7.1 bcm/y
Regasification
- France: 8.25 bcm/y
- Belgium: 4.5 bcm/y
- NL: 9 bcm/y
- Italy: 11.75 bcm/y
- Spain: 8 bcm/y
- UK: 43 bcm/y</td></tr>
<tr><td></td><td></td><td>Liquefaction
- Iran: 80 bcm/y
- Algeria: 5.4 bcm/y
- Lybia: 3.3 bcm/y
- Egypt: 7.2 bcm/y
- Nigeria: 40 bcm/y
- Trinidad: 7.1 bcm/y
Regasification
- France: 32 bcm/y
- NL: 16 bcm/y
- Germany: 14 bcm/y
- Italy: 17.5 bcm/y
- Spain: 14.4 bcm/y
- Portugal: 3 bcm/y
- UK: 3 bcm/y
- Ireland: 4.1 bcm/y</td></tr>
<tr><td>New storage facilities#</td><td>na</td><td colspan="3">- Austria: 1200 mcm/month
- Belgium: 100 mcm/month
- France: 540 mcm/month
- Germany: 1381 mcm/month
- Hungary: 2300 mcm/month
- Italy: 4152 mcm/month
- NL: 180 mcm/month
- Poland: 30 mcm/month
- UK: 640 mcm/month</td></tr>
</table>

Sources: * IEA (2008), #GIE (2009a)

3.2 Scenario results

In the *2005 reference case* we observe a separation of Europe into several price zones:[10] Portugal and Spain constitute a separate market from the rest of Continental Europe due to the limited interconnection capacities between the Iberian Peninsula and the rest of Europe. The same applies to the UK and Ireland. Germany, Austria and Eastern Europe are located in a more or less common price zone defined by natural gas imports from Russia. Finally, France, Italy and Switzerland are in a high price area due to their limited import capacities and existing congestion along the route from Russia. The average price level in the EU is about 2.32 €/MBTU. Existing LNG capacities in Europe are fully utilized and most of the available import capacities from Russia and Africa are congested. Within Europe we observe congestion between the producing countries (the Netherlands and Norway) and the connected importing countries (Belgium, France, and Germany).

The expected development of new infrastructure by 2015 (*base case*) leads to a small price reduction across Europe (Figure 2). The average price drops by 3% to 2.26 €/MBTU with Europe split into similar price areas as compared to 2005. However, the physical flow situation does change. Declining production within Europe combined with simultaneously increasing import capacities results in increasing import dependency (Figure 3). The increased LNG capacity is again fully utilized in particular with substantially increased exports from Qatar. In contrast, new build and existing pipelines from Russia to Europe are not fully utilized. The North-Stream pipeline shows a utilization of less than 50% with major supplies towards Germany transiting via Poland. Natural gas from the Caspian region plays only a minor role and is mainly used to supply Italy.

In the first scenario (*EU case*) we assume a significant decline in North Sea production until 2015. The UK and Ireland face the highest price increase due to the assumed reduction of UK production to 30% of its 2005 level. Other countries depending on North Sea natural gas (France, Benelux, and Germany) also face price increases whereas prices in the remaining European countries are not affected. The price level increases to 2.58 €/MBTU on average. LNG import facilities remain to be fully utilized. The lack of indigenous production is compensated by increasing imports from Russia and consequently the pipeline system in Eastern Europe is operating at a higher load level.

In the second scenario we assume that Russia cuts its transports to Europe via transition countries (*Russian case*). This shutdown of a significant share of Europe's imports has a significant price impact particularly on Central and Eastern European countries that heavily rely on Russian natural gas. The average price level rises to 3.25 €/MBTU. Germany acts as a transmission platform due to its still intact connection to Russia via the North-Stream pipeline and provides natural gas to Poland and the Czech Republic. Similar, the South-Stream pipeline is utilized to supply the South-Eastern region and the Nabucco pipeline is used to

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[10] A graphical representation of all cases is provided in the Appendix. The prices reported are annual averages; monthly prices are available from the authors upon request.

transport Caspian gas to Europe. However, the available capacities are too small to cancel out the effect of the Russian export reduction.

In a last scenario we extend the available LNG importing facilities in Europe and the exporting facilities in producing countries. This provides the European market with an increased diversification potential (*LNG case*). Consequently the price level in Europe is more equalized and significantly lower than in all other cases. The average price level is about 2.06 €/MBTU. In particular, the Iberian Peninsula profits from the increased LNG availability, but also Central Europe faces lower prices and less pipeline congestion. The import dependency of Europe from Russian natural gas is even below the *Russian case*. Overall, in this case Europe has four large import countries with equal share of supplies (Figure 3).

Figure 2: Average prices

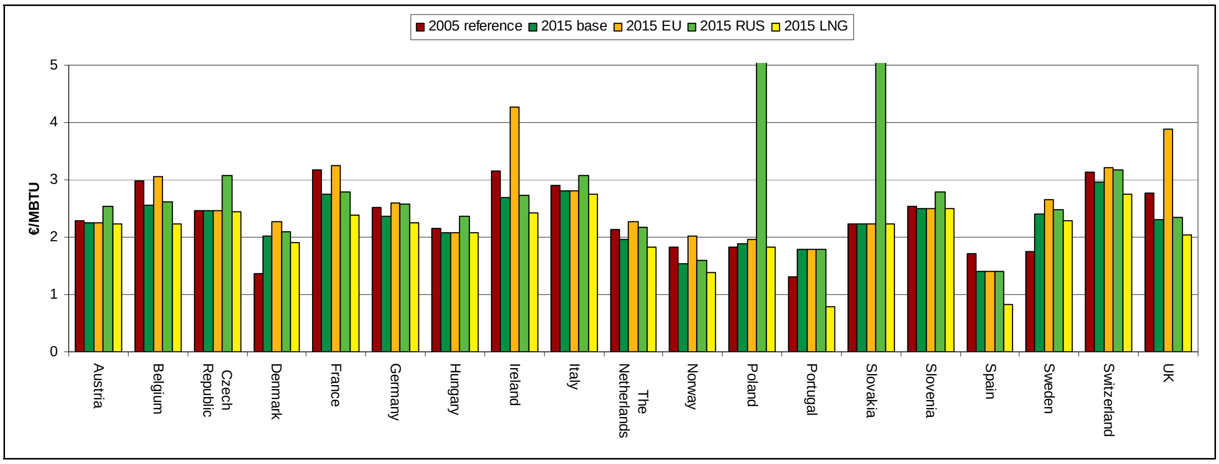
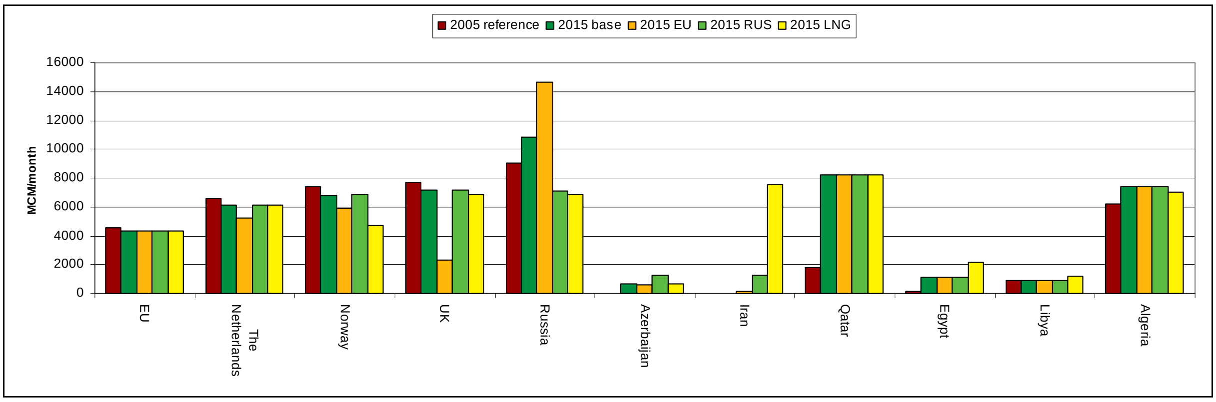


Figure 3: Average production



3.3 Discussion

The modeled cases show the possible impact of future developments of the European natural gas transmission infrastructure. European import dependency is to increase given the expected rise of demand for and a simultaneous decrease in indigenous production of natural gas. For a faster decrease in production than expected this dependency will increase even further (*EU case*). As major pipeline projects allow Russia to export more natural gas to Europe, the major share of future imports is still coming from there. Under the 2015 base case the full extent of export capacities is not even utilized as particularly the North-Stream pipeline seems to be oversized (Table 3).

Increased LNG export capacities provide a source of diversification for European countries. Within the model particularly Qatar directs a large share of its exports to Europe given its relative low production costs. The Nabucco pipeline only plays a minor role in our model as the availability of Russian natural gas is sufficient to meet European demand. Only in the case of an interruption of Russian exports does the availability of Caspian gas provide a hedge for European customers. LNG facilities will have the largest impact on the future development since they provide an optimal diversification opportunity and thus allow a range of export countries to supply Europe (Table 3).

The obtained results have to be evaluated against the background of assumptions and simplification of our model. First of all, the model does neglect a large part of the world natural gas market and thus misses possible impacts of international developments on the European market. This holds in particular for our LNG results since other importing countries are not included and consequently the full export capacity is available to European countries only within our model. Second, only the Central and Western European countries are included with a demand schedule. East and South East European countries are only transit points and thus their demand for natural gas is not part of our model allowing the natural gas transmission pipeline system to be exclusively used for exports to the modeled countries.

The network furthermore represents a stylized system of the real world network. All pipelines connected to a country are connected with one another. Thus, the pipeline from the Caspian region is connected with the Russian South-Stream within Hungary. Also, the pipelines are mostly directed and a reverse of natural gas flows (e.g. in case of a Russian boycott) is not possible within the model.

Finally, the model neglects any strategic behavior of market participants. Thus the obtained results provide the lower boundary for expected price developments. Given the market imperfections and the integration of the European natural gas market into a worldwide framework with competing regions for limited supplies (US, Asia) the real world developments are likely to result in a higher price level and a tighter congestion situation.

Table 3: Result overview

	Reference case	2015 base case	EU case	Russian case	LNG case
Average price [€/MBTU]	2,33	2,26	2,58	3,25	2,06
LNG-regasification utilization	100%	100%	100%	100%	98%
Pipeline utilization:					
Russia-EU	65%	51%	69%	33%	32%
Africa-EU	100%	87%	87%	87%	71%
Caspian-EU	-	26%	26%	55%	26%

4 Conclusion

In this paper we present a stylized model of the European natural gas market with a focus on gas transmission. The model is intended to be used as market representation within a regulatory model approach which provides incentives for pipeline owners/operators to invest in new pipeline infrastructure. Consequently the model setting is simplified and only covers the main natural gas infrastructure in Europe.

We simulate several scenarios to estimate the future development of the European natural gas market. Despite its simplified structure the obtained results highlight the existing bottlenecks in Europe, the importance of natural gas from the North Sea for the Central European region, the import dependency of Europe from Russian natural gas, and the price decreasing impact of LNG facilities. Further research will focus on the introduction of regulatory mechanism that encourages investment in cross-border long-distance natural gas transportation pipelines. In particular, the European grid will be considered to be operated by a European regulatory authority which then faces the difficulty to provide investment incentives in this capital-intensive industry.

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Appendix

Figure 4: 2005 reference case, average market prices and congestion

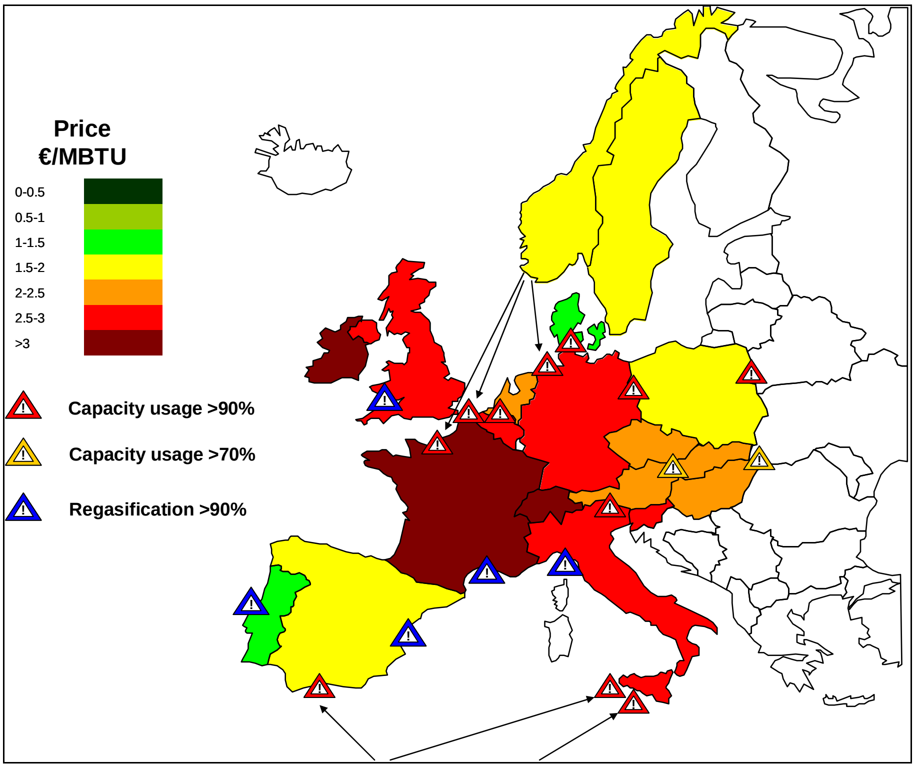

Figure 5: 2015 base case, average market prices and congestion

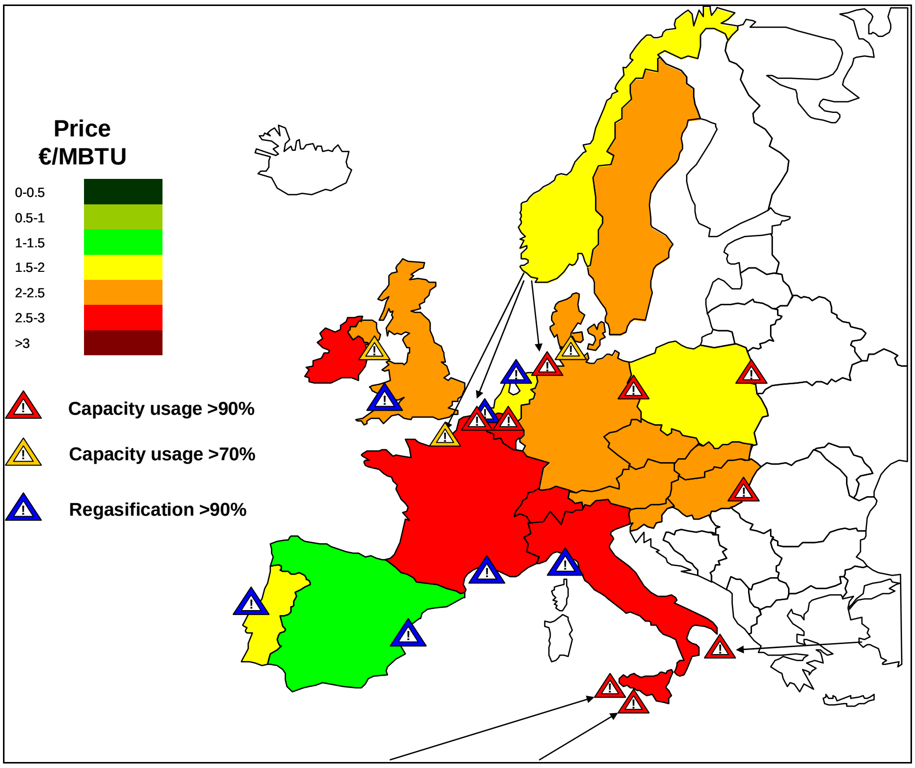

Figure 6: 2015 EU case, average market prices and congestion

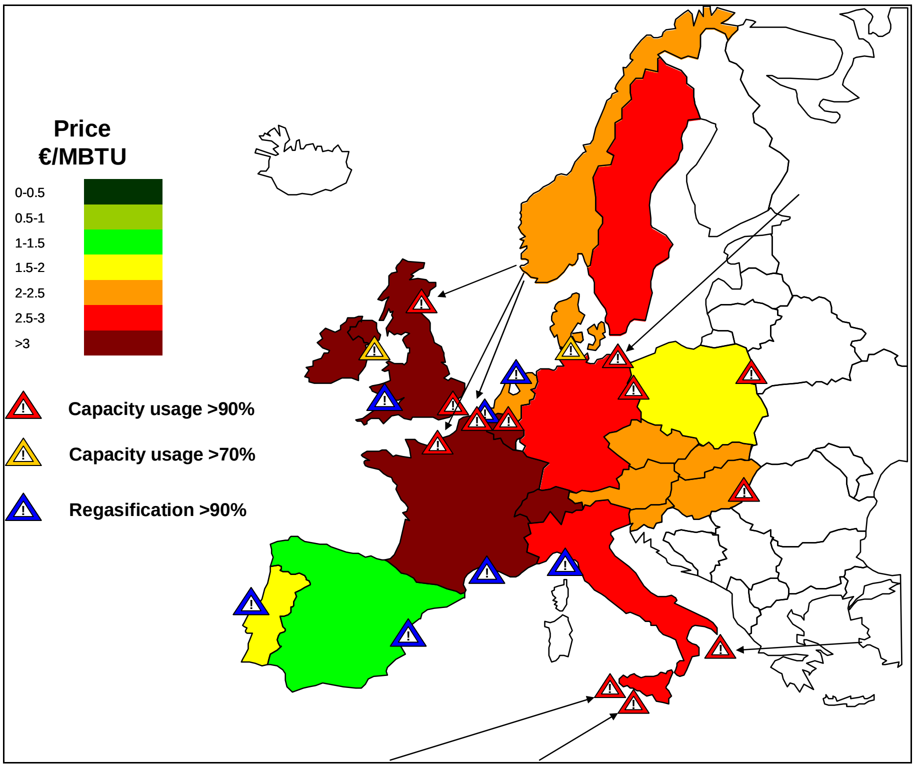

Figure 7: 2015 Russian case, average market prices and congestion

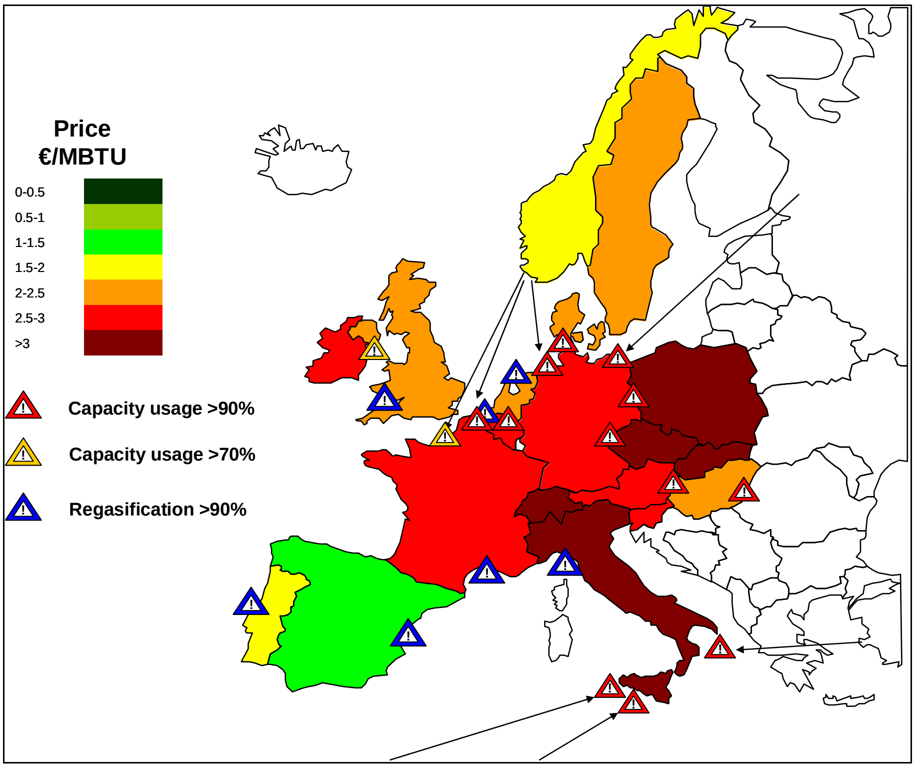

Figure 8: 2015 LNG case, average market prices and congestion