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Model-based Analysis of Infrastructure Projects and Market Integration in Europe with Special Focus on Security of Supply Scenarios

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Study

"Model-based Analysis of Infrastructure Projects and Market Integration in Europe with Special Focus on Security of Supply Scenarios"

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Office of Gas and Electricity Markets (Ofgem, UK)

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
bcm	billion cubic metre
CO_2	Carbon Dioxide
DG TREN	Directorate-General for Transport and Energy
EC	European Commission
EIA	Energy Information Administration
ENTSOG	European Network of Transmission System Operators for Gas
ERGEG	European Regulator's Group for Electricity and Gas
EU	European Union
EUR	Euro
EWI	Institute of Energy Economics (University of Cologne)
GIE	Gas Infrastructure Europe
GSE	Gas Storage Europe
GTE	Gas Transmission Europe
IEA	International Energy Agency
mcm	million cubic metre
mmbtu	million British thermal units
MWh	Mega Watt-hour
LNG	Liquefied Natural Gas
OME	Observatoire Méditerranéen de l'Energie
SoS	Security of Supply
TEN-E	Trans-European Energy Networks
TIGER	Transport Infrastructure for Gas with Enhanced Resolution-Model
TSO	Transmission System Operator

TYNDP	Ten Year Network Development Plan
UGS	Underground gas storage
WGV	Working Gas Volume

Country and pipeline (project) abbreviations can be found in Table 8 and Table 9 in the Appendix.

1 Executive Summary

The European Regulators' Group for Electricity and Gas (ERGEG) has initiated the compilation of a study analysing infrastructure projects, market integration and security of supply in Europe. The findings of the model-based analysis, which was performed by the Institute of Energy Economics at the University of Cologne (EWI), are presented in this report.

The study is structured as follows. After an introduction to the issue within the regulatory and legislative context, the modelling framework used for the analysis and all the assumptions regarding the investigated scenarios are described. The results are then presented with respect to gas flows in the European market, physical market integration between the different countries, and the resilience of the system in the context of two security of supply stress simulations in 2019. Finally, the study is put into the context of other European gas infrastructure analyses.

This Executive Summary is structured as follows: Section 1.1 introduces the model and the scenarios. The results are then presented with a focus on gas flows (Section 1.2), physical market integration (Section 1.3) and security of supply (Section 1.4). Section 1.5 offers some concluding remarks.

1.1 Modelling Framework and Scenarios

The results of the study are based on simulations with the EWI TIGER model. TIGER is a natural gas infrastructure and dispatch model of the European gas market which allows for the desired analyses with a high temporal and regional granularity taking published technical capacities into account. Hence, grid characteristics like pipeline length, capacity, location and interconnection with other pipelines are considered; the contractual availability of capacities or pipeline-operational issues such as compressor stations or pressure levels are not. The model minimises the total cost of gas dispatch in the investigated year (2019) given the restriction provided by the infrastructure and by gas supply. The modelling approach, hence, assumes that the European downstream market is working efficiently and that all efficient and possible gas swaps are realised by TSOs. Technically available capacity is, thus, presumed to be made available to shippers efficiently according to market needs.

The analysis is based on six different infrastructure and supply scenarios with a variation of the major import pipeline projects Nord Stream, Nabucco, South Stream and two demand scenarios. One demand scenario, with an average annual growth of 0.8 percent per year until 2019, is based on the baseline scenario of the European Commission (adapted to the economic downturn); the other assumes 1.4 percent demand growth per year and is retained from the European Network of Transmission System Operators for Gas' (ENTSOG) Ten Year Network Development Plan.

Combined with a decline in indigenous gas production, these demand scenarios imply an increasing European import demand, which is largely met by additional supplies from Russia, Algeria and Norway and by LNG imports. Gas production from unconventional sources in the EU is not assumed to contribute significantly to domestic production until 2019; however, global production from unconventionals may increase the availability of LNG to the European market and is reflected in an "LNG glut" scenario.

Hence, the infrastructure and supply scenarios assume different realisations with respect to the announced major import pipeline projects and relative LNG prices:

- Reference Scenario with the first line of Nord Stream only,
- Nord Stream II Scenario also including the second line of Nord Stream,
- Nabucco Scenario: Nord Stream I plus Nabucco pipeline,
- South Stream Scenario with Nord Stream I and South Stream,
- DG TREN Scenario including both lines of the Nord Stream pipeline and Nabucco,
- LNG Glut Scenario: DG TREN Scenario with the assumption of temporarily low LNG prices.

For other infrastructures (other pipeline projects, storages, LNG terminals), supply (with the exception of relative LNG prices), assumption between the scenarios are not varied to enable deriving the individual effects of each of the major projects. The assumptions on intra-European pipeline infrastructures for 2019 thereby include a number of projects under construction or as planned by the different TSOs (and outlined in the individual or in ENTSOG's European ten year network development plan). Investment obligations potentially arising from the new EU Security of Supply guideline are, however, not included.

In addition to monthly simulations, the six different scenarios are simulated on a daily basis to investigate the stress on the system of a concurrent peak demand day (based on ENTSOG data) and for two different security of supply scenarios: a four week disruption of transits via Ukraine and a four week halt of Algerian exports (LNG and pipeline gas).

The evaluation of the scenarios focuses on the year 2019.

With respect to the modelling approach's assumptions, which impact the results, it needs to be noted that the model presumes that the (regulated) natural monopoly transport segment, access to LNG import facilities, and the storage market are organised efficiently. With the total system perspective, it is not only assumed that capacity allocation and congestion management are implemented efficiently in each country, but that the regimes are harmonised and enable an efficient allocation of resources across market areas and TSO grid "boundaries". With respect to the results, this implies that any congestion or supply-demand gap identified within the model framework would occur despite a perfectly efficient system operation (capacity allocation and congestion management).

1.2 Gas Flows in 2019

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

Even with only few additional import pipeline projects (Nord Stream I, GALSI), 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. Introducing a second line of Nord Stream shows 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 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.

In the South Stream Scenario, it is assumed that Russia cannot increase its exports relative to the other scenarios. Hence, South Stream mainly serves as a pipeline allowing the diversification of export routes away from Ukraine as a transit country. This rerouting of gas in eastern Europe of course affects the utilisation of assets in the region, but has only limited effects in countries further in western Europe.

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. Interdependencies between Nord Stream and Nabucco seem, however, low as both serve different regions in Europe.

In times of temporarily low LNG prices, as observed in 2009, the 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. 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.

1.3 Physical Market Integration

Physical market integration is investigated by the analysis of the locational marginal supply costs to each country. Large differences between these marginal costs in the framework of a competitive market indicate that arbitrage is prohibited by congestion. However, the absence of bottlenecks is a necessary condition for having an integrated EU market. The presence of congestion, on the other hand, implies the need to analyse the cost-benefit for investing in order to remove a bottleneck. Furthermore, it needs to be noted that the normative modelling approach only identifies congestion which would even occur in an efficiently working market. Additional (contractual) bottlenecks potentially arising from market inefficiencies would not be identified by the model.

As infrastructures designated in the context of the ten year network development plans are already included in the simulations, any bottlenecks identified are further limited to those not already addressed in these network expansion plans.

With these grid expansions, most European countries are generally found to be well integrated based on the simulation results. However, there are a number of exceptions. These include severe bottlenecks which can cause supply-demand gaps as well as congestion which mainly hampers physical market integration (but does not cause security of supply concerns).

Supply-demand gaps are caused by the following bottlenecks:

- There is a structural bottleneck between Germany and the region of Sweden and Denmark, if demand and supply in these two countries evolves as assumed. In this case, there is a definite need for investment.
- In eastern Europe, some bottlenecks are identified in the winter months. These mainly concern Hungary and the countries in the Balkans with a gas sector. However, the realisation of one of the new major import pipeline projects (Nabucco and South Stream) helps to increase market integration in the region and to eliminate some of these bottlenecks.
- In addition, it is found that high demand in south-eastern Europe (including Turkey) might limit gas flows between Turkey and Greece opening a supply-demand gap in Greece (but only on days with very high demand in both countries).

As these bottlenecks are simulated to potentially cause supply disruptions to consumers, there may be a high need for investment.

The findings, however, show further congestion which does not result in supply disruptions to consumers, but which may cause large price differences between markets and hamper competition in an integrated European gas market. These include:

- In western Europe, congestion is found to arise on the concurrent peak demand day (coldest winter day if it happens to be in each country on the same day) and in times of low LNG prices. While physical market integration amongst western European countries and between western and central Europe is found to be fairly advanced in general, these bottlenecks might temporarily limit market integration and hamper competition.
- The peak demand day bottleneck seems to be due to a relatively high availability of storages in central Europe and the UK relative to France, Belgium and the Netherlands. The latter group of countries also sees a relatively high peak day demand as a percentage of average daily demand compared to the EU average. Hence, congestion on such a peak day may be significant between Germany and France, Belgium and the Netherlands, and on the Interconnector between the UK and Belgium.
- In the case of temporarily low LNG prices, the model finds that more LNG could be transported from the LNG import capacities in the west further to the east if more capacity were available. Congestion, for instance, arises between the UK and the continent, France and Germany and Switzerland, the Netherlands and Germany and between Spain and France on peak demand days.

While this congestion does not cause supply disruptions to consumers, it might nevertheless be economically beneficial to remove it. In order to evaluate the costs of the individual bottlenecks, it is necessary to compare the costs of possible projects to remove the respective congestion with the economic costs caused by it. This is beyond the scope of this study. However, the case for investment and the removal of such a bottleneck are also strengthened by positive external effects of a physically larger and better integrated market such as increased competition.

1.4 Security of Supply Stress Scenarios

The stress scenarios are investigated with respect to the consequences for consumers (demand reduction and price effects) and the gas flow diversions and additional storage withdrawals necessary to mitigate the consequences. As in the market integration analysis, the model characteristics have to be kept in mind implying that only supply disruptions which would occur despite the best possible response of the market to the respective crisis are identified. Furthermore, pipeline operational issues or insufficient storage fill levels – despite the availability of working gas volumes – might lead to additional disruptions which are also not modelled explicitly. However, the approach applied in this study has been previously tested to simulate the effects of the January 2009 Russia-Ukraine crisis and was found to provide a good estimation of actual events.

In this study, two stress scenarios are modelled:

Four week disruption of Ukraine transits

This stress scenario assumes that all transits of natural gas via Ukraine are halted for a duration of 28 days. In the model simulations, the disrupted transits via Ukraine in January 2019 range from 186 to 345 million cubic metres per day depending on which alternative infrastructure projects for Russian gas exports to Europe are available which has different impacts on consumers. The findings in this case are the following:

Amongst EU member states, the one most severely affected country is Hungary if neither the South Stream nor the Nabucco pipeline is in place. Then, almost 20 percent of demand cannot be met on an average day.

The simulations further yield supply-demand gaps in Greece, Romania and Bulgaria between one and eight percent of demand depending on the scenario. (This is also true for the Balkan countries where bottlenecks were identified.)

Generally, in the scenarios with one of the new major import pipeline projects in south-eastern Europe, either Nabucco or South Stream, the consequences of the crisis to consumers are smaller.

The only country experiencing very minor disruptions to consumers in all scenarios is Romania whose import, production and storage capacities are sufficient for coping with short, temporary disruptions of imports from Ukraine, but not with a disruption of four weeks.

Apart from these countries, severe effects for consumers in the rest of Europe are not projected by the simulations. For the countries, where demand can be met during a crisis, the changes in marginal supply costs are relatively small.

Despite the reverse flow projects realised after the 2009 Russia-Ukraine conflict bottlenecks are found to still exist between central and eastern Europe preventing even higher west-to-east gas flows, namely between eastern Germany and the Czech Republic, the Czech and Slovak Republics and Austria and Hungary. With respect to Greece and Italy, the results show that a reverse flow on the proposed pipeline link between the two countries would be beneficial in times of a disruption of Ukraine transits.

As was the case in the 2009 crisis, the largest volumes to compensate the disrupted transit flows from Ukraine have to come from natural gas storages in eastern Europe, Germany and Italy.

Four week disruption of Algerian exports in 2019

Like the Ukraine transit disruption, this stress scenario assumes that all exports of natural gas from Algeria via pipeline are halted for a duration of 28 days. To include an impact of an Algerian export stop on LNG supplies, it is assumed that 25 percent of all LNG cargos to Europe in this time period do not arrive. The main findings can be summed up as follows:

Generally, it can be concluded that the resilience of the European gas market to such a crisis depends on the flexibility of the LNG market and the interconnection within Europe. A flexible (competitive) LNG spot-market contributes significantly to mitigate the consequences of such an assumed crisis by enabling efficient diversions of LNG within Europe (as assumed by the model). If possible, this helps to spread the missing gas volumes over a larger number of countries by sending LNG cargos which would have gone to less affected countries (UK, Belgium) to those also dependent on Algerian pipelines gas (Spain, Italy).

Of course, such diversions would take a number of days implying that the initial consequences of an Algerian export stop would be more damaging to consumers in southern Europe. (Also, further disruptions to consumers arising from system operational issues in the case of the loss of one or two major entry points, which could only be identified with detailed pipeline operation models, could be possible.)

With respect to interconnection, it is found that security of supply in such a crisis scenario is improved by significant additional capacity between Spain and France (MidCat pipeline) which would allow more gas flows from France to Spain.

If there is sufficient interconnection and a flexible LNG market are in place, the results show that actual supply disruptions to consumers could be reduced significantly. The evaluation of the short-run marginal supply costs, however, shows that price effects in most European countries are very likely. The impact is strongest in the countries that are most dependent on Algerian pipeline (Spain, Italy) or LNG imports (Portugal, France), but a large number (higher than in the Ukraine stress scenario) is affected due to the efficient LNG diversions. However, this LNG diversions also implies that gas volumes in other countries (additional storage withdrawals in the UK, Netherlands, Germany, France) can indirectly help to compensate the lost imports from Algeria.

Additional congestion during such a crisis scenarios is identified in the countries where marginal supply costs rise due to the shortage of LNG volumes, i.e. from Austria to Slovenia to Croatia (Krk terminal), from Bulgaria to Greece and Turkey, and from Austria to Italy. However, the bottlenecks are not evident in all scenarios and depend on which of the different large-scale infrastructure projects is implemented.

1.5 Conclusions

The analysis shows that interdependencies in the gas market between different countries and regions require an encompassing and integrated consideration of all elements in the market in order to investigate gas flows, market integration and security of supply issues.

The results confirm the findings of other studies and provide additional insights by considering the whole European gas market (instead of selected countries) and by taking into account gas volumes in addition to capacities: The severe bottlenecks leading to demand-capacity gaps identified by the ENTSOG Ten Year Network Development Plan are confirmed by this study. Additionally, this study highlights congestion which does not cause demand disruptions but which hampers physical market integration and competition.

Generally, apart from the aforementioned exceptions, the European gas market is found to be well integrated once the projects outlined in the ten year network developments by ENTSOG and the TSO are implemented. The findings on the changing gas flows in the European market, identified bottlenecks and outlined potential supply-demand gaps provide regulators and the industry with indications regarding potential investments needs. As the approach identifies physical congestion which would occur despite a (presumed) completely efficient market organisation – potential bottlenecks arising from contractual congestion are not addressed –, the importance of regulatory success with respect to the implementation and harmonisation of capacity allocation and congestion management regimes is evident: If this is not accomplished, additional bottlenecks may arise and might hamper competition (limited pipeline access for shippers) and possibly lead to inefficient (unnecessary) network expansions. The same also holds true for the efficient allocation of the available LNG import capacities.

The scenario approach shows the impacts of the major import pipeline projects, different demand growth paths, a temporary LNG glut, and potential stress scenarios on these issues. However, a full economic evaluation of each bottleneck including investment costs, which would allow detailed recommendations with respect to which investment is necessary and which is not, is neither the purpose nor within the scope of this study.

2 Introduction and Background of the Study

2.1 Background

European Gas Market Developments

Generally, the European gas market is believed to be confronted with significant challenges over the next years: Within the borders of the European Union, natural gas production is declining due to limited natural gas reserves. This especially affects today's largest gas producing countries in the EU, the United Kingdom (UK) and the Netherlands. On the other hand, natural gas demand in most EU countries is projected to rise. This is mainly driven by the EU's emission reduction targets within the sectors covered by the European Emission Trading Scheme. A significant reduction will thereby have to come from electricity generation, 33 percent of which in the EU in 2006 took place in relatively emission-intensive coal-fuelled power plants.[1] As electricity demand is projected to increase and some countries, notably Germany, might phase-out zero-emission nuclear generation, emission reductions will have to come from renewable energy sources as well as a switch towards less CO_2-intensive conventional generation. Natural gas as the least CO_2-intensive fossil fuel is expected to gain importance significantly. Hence, this possibly increasing overall gas demand in combination with declining domestic production will significantly increase import dependency.

In order to import additional natural gas volumes – which may amount to up to 150 billion cubic metres per year in 2020 compared to 2005[2] –, 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.

[1] See IEA (2008).
[2] Own calculation based on EC (2008).

The crisis showed that while large parts of Europe escaped the severe consequences of supply disruptions, other countries, especially in south-eastern Europe, 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).[3] 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 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.

European Gas Market Legislation

Being aware of these developments in and challenges for the European gas market, the introduction of legislative acts as well as further enhancements are being addressed by the EU. Therefore, the most important legislative developments regarding the European gas market that are relevant to consider in the context of infrastructure (investments) are summed up briefly in the following paragraphs.

Third Energy Package

The third package of EU legislation on the internal electricity and gas markets provides a new framework for competition in the energy sector. Especially, the separation of production and supply from transmission networks, the facilitation of cross-border trade in energy, more impact and cooperation of national regulators, the promotion of cross-border collaboration and investment, and the enhancement of increased solidarity among the EU countries are addressed.

[3] See Pirani, S.; J. Stern and K. Yafimava (2009).

The central points of this legislation concerning the European gas market are the three following legislative acts:

- Directive concerning common rules for the internal market in natural gas[4]
- Regulation on conditions for access to the natural gas transmission networks[5]
- Regulation establishing an Agency for the Cooperation of Energy Regulators (ACER)[6]

of which the regulation and directive repeal the previous ones which came into force in 2003 and 2005.

ACER is already established with its seat in Ljubljana, Slovenia, and will take up its duties from March 2011 onwards. It will help to ensure the free flow of electricity and gas in Europe through the review of appropriate infrastructure across national borders in order to support the integration of national energy markets towards one single European market. In addition, issues of security of energy supply in Europe will be addressed.

Ten Year Network Development Plan

Within the regulatory framework of ACER, the adoption and publication of a European community wide ten year network development plan (TYNDP) by the European Network for Transmission System Operators for Gas (ENTSOG) every two years is constituted.[7]

One of ACER's tasks in this context is to provide an opinion on the TYNDP and monitor its implementation.[8] In addition, the Agency should review the "national ten year network development plans" by the single TSOs to assess their consistency with the EU TYNDP.[9]

"The Community-wide network development plan shall include the modelling of the integrated network, scenario development, a European supply adequacy outlook and an assessment of the resilience of the system."[10]

Concerning the TYNDP, ENTSOG's task is to conduct an extensive consultation process, at an early stage, involving all relevant market participants.[11]

[4] See Directive 2009/73/EC.
[5] See Regulation (EC) No 715/2009.
[6] See Regulation (EC) No 713/2009.
[7] See Article 8 of Regulation (EC) No 715/2009. The recent TYNDP has just been published by ENTSOG (2009).
[8] See Article 6 of Regulation (EC) No 713/2009.
[9] See Article 8 of Regulation (EC) No 715/2009.
[10] Article 8 of Regulation (EC) No 715/2009.

Security of Supply

In July 2009, after the Russia-Ukraine crisis of January 2009, the European Commission published its proposal for a regulation to improve security of supply of the European gas market.[12] The intention of the proposal was to establish common standards for all EU countries and to ensure that consumers would benefit from high gas supply security. Member states should be prepared and cooperate in case of gas supply disruptions through a strengthened Gas Coordination Group and through shared access to data and information on supply. The new regulation calls for member states to have emergency plans involving all stakeholders and incorporating the EU dimension of a significant disruption. The member states are required to have a competent authority to monitor gas supply developments, appraise the risk of supply disruptions and establish preventive action and emergency plans. The regulation should improve the framework for investment in new European gas transport infrastructure supported by the European Economic Recovery Plan. These are investments in cross-border interconnections, new import corridors, reverse flows capacities and storage.

Notification of Investment Projects

Furthermore, last year, the European Commission adopted a proposal for a regulation to establish a common framework for the notification to the Commission of data and information on investment projects into energy infrastructure within the EU to establish greater transparency on the likely evolution of energy infrastructure in the main energy sectors oil, electricity and gas, but also in related areas such as the transport and storage of carbon related to energy production.[13] As a significant proportion of ageing capacities have to be renewed or new capacities have to be built in order to fulfil environmental policies and to enhance a low carbon energy mix, transparency on planned and ongoing investment projects will help to assess whether there is a risk of infrastructure gaps over the coming years. Every two years, member states or the entity they appoint for this task would be required to collect and notify data and information on investment projects concerning production, transport and storage to the European Commission.

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[11] See Article 10 of Regulation (EC) No 715/2009.

[12] See COM (2009) 363. The regulation should replace the Directive 2004/67/EC. The proposal is still in the European legislation process.
(See decision COM (2009) 363 on PreLex http://ec.europa.eu/prelex/apcnet.cfm?CL=en.)

[13] See COM (2009) 361.

Initiator of the Study

In the context of the third energy legislation package, the proposal of an Security of Supply (SoS) regulation[14] and of an investment notification system[15] and in preparation for the future role of ACER, the European Regulators' Group for Electricity and Gas (ERGEG)[16] as the advisory body on internal energy market issues in Europe, is seeking to enhance coordination and cooperation of national energy regulators and to support a consistent implementation of EU energy legislation in all Member States.

ERGEG commissioned this study to gain an understanding on and providing a basis for the discussion of the impact of infrastructure projects on (cross-border) gas flows, physical market integration (i.e. bottlenecks) and the potential security of supply stress scenarios.

Supporting Model-Based Analysis

In order to master the different challenges and developments on the European gas market, a number of infrastructure projects increasing import capacity into Europe and physical interconnection between EU members are being discussed. To obtain an in-depth understanding of the impact of each new project on existing assets, market integration, security of supply, and gas flows in the European gas supply infrastructure, a broad system perspective is useful: Interdependencies in the European gas market are significant due to the interconnection of grids, transit flows across several countries and the intertemporal element constituted by demand seasonality and gas storages. Hence, new projects can impact all other infrastructure elements and need to be considered within the context of the whole European gas infrastructure. A model-based approach ensures that those interdependencies between investigated projects and the existing infrastructure as well as supply, demand and other potential projects are taken into account.

Before this background, a European gas infrastructure and flow (dispatch) model taking the whole European natural gas infrastructure into account should serve as a supporting tool for analysing different future infrastructure developments.

[14] See COM (2009) 363.
[15] See COM (2009) 361.
[16] ERGEG was set up by the European Commission (see 2003/796/EC) as an advisory body on internal energy market issues in Europe through which the energy regulators of Europe advise the European Commission.

The TIGER model of the Institute of Energy Economics is able to simulate the utilisation of existing and proposed infrastructure assets in the gas sector (pipelines, LNG terminals, storages, production facilities) and compute location-specific marginal gas supply costs under various supply, demand and infrastructure scenarios.

Based on the model simulations, a Europe-wide top-down perspective on infrastructure needs with respect to import infrastructure, physical integration of national markets – under normal situations and short term supply disruptions – and the identification of bottlenecks is developed. Projects already set out as Trans-European Network for Energy (TEN-E)[17] priority interconnections are considered; the ENTSOG's Ten Year Network Development Plan (TYNDP) is taken into account during the study set-up.

2.2 Structure of Study

This study is structured as follows:

The TIGER infrastructure and dispatch model of the European gas market, which is applied for all simulations in the context of this study, is presented in the next chapter. This includes the underlying model assumptions and the database of the European gas infrastructure.

Chapter 4 presents the study's assumptions with respect to supply, demand and infrastructure developments. Based on these assumptions, the scenarios which are at the focus of the analyses are introduced.

After a comparison of modelled and actual gas flows for 2008 and some general results regarding supply diversification and LNG imports in Chapter 5, the major findings on the study are presented in the following sections:

- Chapter 7 presents the results with respect to gas flows in the European market depending on the scenarios and the implemented infrastructure projects.
- Physical market integration between countries and identified (temporary) bottlenecks are outlined in Chapter 8.
- Chapter 9 investigates the European infrastructure system's resilience regarding two selected security of supply stress tests with respect to supply disruptions to consumers and increases in marginal supply costs by country. Furthermore, the optimal measures

[17] See Decision No 1364/2006/EC.

necessary to reduce the impact to consumers in case of the respective stress situation as calculated by the model are outlined.

Chapter 10 offers some concluding remarks and sets the study at hand into the context of other studies and investigations of the European natural gas infrastructure system.

3 Model Description

This section provides a description of the European infrastructure model TIGER and the database which is the basis for the model simulations.[18]

3.1 TIGER Natural Gas Infrastructure Model

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 within the framework of the complex system of the European gas infrastructure. The model is capable of simulating the utilisation of all major European gas-infrastructure (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.

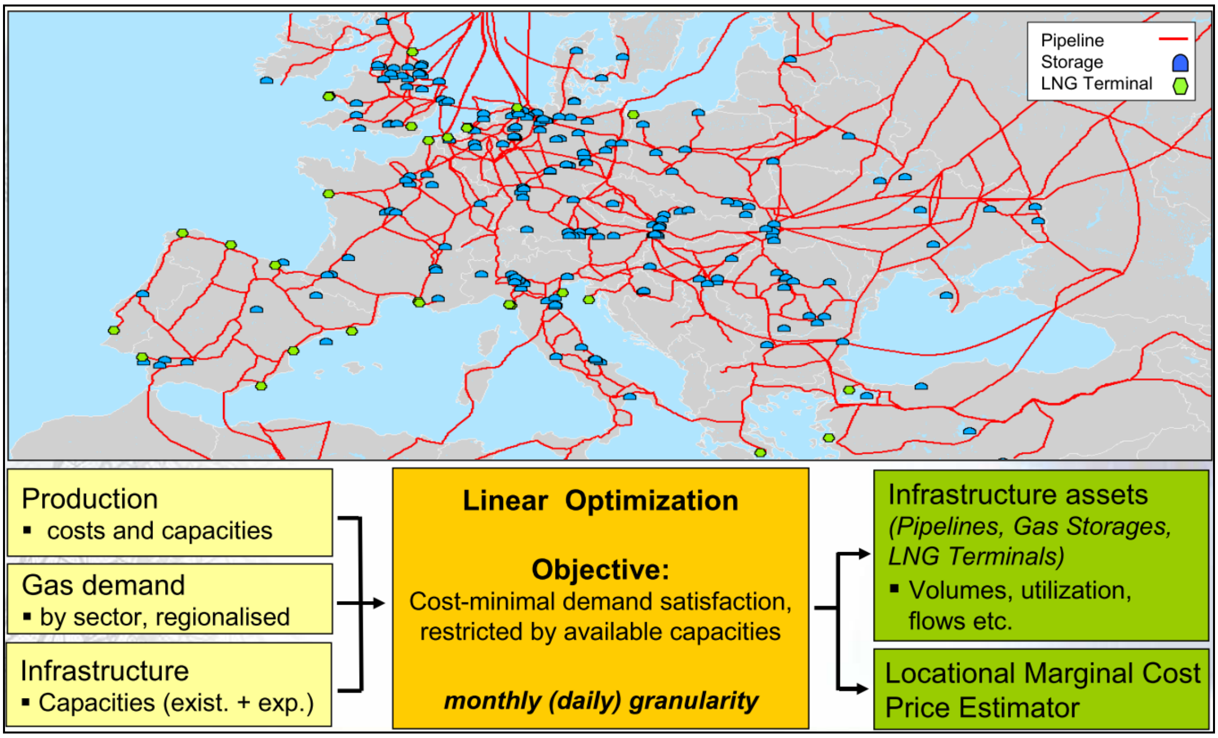
Methodologically, TIGER is essentially a linear network flow model consisting of nodes and edges. Nodes represent locations in the European gas supply infrastructure where there are connections between pipelines, connections to storages, gas injections into the grid from gas production or LNG regasification facilities and withdrawals from consumers (locations of demand or exits to local distribution networks). The edges represent the pipelines in the European gas grid. The individual characteristics of each pipeline like geographic location, connection with specific nodes, technical capacity, length, directionality, availability (in case of a new project entering operation at some point in the future) are attached to the respective edge within the detailed database of the model. Similarly, the individual characteristics of storages (working gas volumes, storage type, maximum injection and withdrawal rates and respective profiles) and LNG terminals (import, LNG storage and regasification capacity) are likewise included and assigned to the respective element located at the nearest geographic node.

On the input side, the model is exogenously provided with assumptions on natural gas demand, supply and future infrastructure (see the next chapter for the specific parameterisation in this study). Based on historic data, country and sector specific demand projections are broken down into monthly, regionalised demand profiles to ensure a realistic distribution of natural gas demand over area and time. In addition, assumptions about the future gas supply of the

[18] For a more detailed model description, see EWI (2010).

European Union can be specified (domestic production, import volumes and commodity prices or supply costs at the border). Apart from the existing infrastructure, model inputs include assumptions on new projects regarding LNG import terminals, pipelines and natural gas storages which become available for the optimisation at the respective future points in time.

Figure 1: TIGER-Model Overview



Source: EWI (2010).

Objective of the linear optimisation is the minimisation of the total costs of the gas supply and transport system, while meeting the regionalised demand. Costs include commodity, transportation and, where applicable, regasification and storage costs. With the model's focus on the dispatch of natural gas, the latter three cost factors essentially represent variable costs, the assumptions of which are based on different studies such as OME (2001) (for pipeline transport and regasification) and United Nations (1999) (for storages). The optimisation, with a monthly or daily granularity, takes place subject to the restrictions of the maximum available supply, demand which has to be satisfied and the technical constraints of available transport, LNG and storage infrastructure. Decision variables for the model are the natural gas flows on each pipeline and the utilisation of storages and LNG terminals. The linear cost minimisation approach assumes that the transport of natural gas in the European Union is organised efficiently and that all possible swaps of natural gas are realised by transmission system operators. It needs to be noted that a fully competitive natural gas market including the upstream and sales side of the industry is not an underlying assumption of the model. However, it presumes that the (regulated) natural monopoly transport segment, access to LNG import capacities and the storage market (which is not regulated in all countries) are organised efficiently. Furthermore, the total system perspective optimises Europe as one market area (as opposed to optimising individual TSO grids). Hence, the model inherently presumes that capacity allocation and congestion management are not only implemented efficiently in each country, but that the regimes are harmonised and enable an efficient allocation of resources across market areas and TSO grid "boundaries". With respect to the results, this implies that any congestion or supply-demand gap identified within the model framework would occur despite a perfectly efficient system operation (capacity allocation and congestion management). Further issues that arise from potential market inefficiencies would not be reproduced by the model. Thus, if intransparencies, inefficient allocation of capacities or not working competition in the European market distort the optimised dispatch yielded by this normative approach, additional bottlenecks or supply-demand gaps (or disruptions to consumers in the security of supply scenarios) might be the consequence. However, the ongoing work by European and national legislatives and regulators is supposed to enhance competition and improve efficiency in the next decade so that the European gas market may approximate a competitive market.

Apart from the endogenously optimised variables (monthly gas flows on all pipelines, storage levels and injections/withdrawals), the location-specific marginal costs of gas supply can be evaluated for each node (i.e. point in the system) and time period. These represent the shadow costs on each node's balance constraint in the model (for each time period), which indicate marginal system costs for supplying one additional cubic metre of natural gas at this respective node (at this time). Generally, these location-specific marginal costs can be applied to analyse supply interruptions in security of supply scenarios and physical market integration. In the former case, marginal supply costs would increase to infinity if demand cannot be met. A large difference in marginal supply costs within close geographic proximity, on the other hand, would indicate a lack of transmission capacity and, thus, implies a bottleneck in the transportation infrastructure. (For a more detailed description of the TIGER model see EWI's extensive model description (EWI, 2010).)

3.2 European Infrastructure Database

In order to accurately represent the European natural gas supply infrastructure, the model is based on a comprehensive database containing all major infrastructure elements in the market. ("Europe" in this case includes the EU-27 plus Norway, Switzerland, the Balkans, and Turkey.) Specifically, encompassed data includes:

- more than 750 high-pressure natural gas transmission pipelines with data on location, technical capacity, directionality based on TSO information, Gas Infrastructure Europe (GIE),
- more than 200 gas storages with data on location (grid connection), working gas volumes, maximum injection/withdrawal rates, storage type-specific injection and withdrawal profiles, based on IGU (2006), EGM (2007), Gas Storage Europe (GSE), storage operators,
- more than 30 LNG import terminals (projects and existing ones) with data on location (grid connection), import, storage and regasification capacities based on terminal operators, GLE, commercial databases (platts, Gas Matters),
- all border points and border capacities according to GIE,
- the major European gas production sites aggregated to twelve production regions,
- non-European pipeline import capacities (from Russia, Algeria, Libya, Azerbaijan, Middle East) at the respective border points,
- 57 demand regions with country-specific seasonal demand profiles for the power and non-power sector (based on historical data from IEA, Eurostat).

One noteworthy feature of the model and the database is the geographic information assigned to all infrastructure elements. This enables a visualisation of results with geographic-information-system (GIS) software such as MapInfo Professional. Hence, model results are not only provided in numerical format, but also as geo-coded maps illustrating physical gas flows, location-specific marginal costs, and supply disruption effects. This supports the presentation and interpretation of results significantly.

Hence, with the TIGER natural gas model, the underlying database and the visual evaluation tools, a suitable tool as a starting point for a model-based analysis of gas infrastructure projects and market integration with a special focus on security of supply scenarios is applied. The tool's benefit has been proven in both academic and commercial projects.

4 Assumptions and Scenario Descriptions

Within the TIGER modelling framework, assumptions with respect to supply, demand and the natural gas infrastructure consisting of pipeline, gas storages and LNG terminals need to be specified. This chapter presents the main assumptions with respect to those parameters.

Section 4.4 points out how these assumptions are combined for the different scenarios which are at the focus of this study.

4.1 Supply Assumptions

In Figure 2 all pipeline gas volumes available to the European market are presented. They are derived from a number of well-known forecasts including the IEA's World Energy Outlook (2008), EIA's International Energy Outlook (2009) and publications from the Observatoire Méditerranéan de l'Energie (2007).

Norwegian Supplies:

The production forecast for Norway is based on IEA (2008), where a production increase of 21 percent from 2008 to 2019 to 112 bcm is projected. Barents Sea production, which is liquefied and exported as LNG[19], and domestic consumption[20] are subtracted to obtain the volumes available to the European market.

Algerian Supplies:

Algeria's production capacity significantly exceeds its pipeline export capacity, as the country can also export LNG (in much larger quantities than Norway). Regarding production available for pipeline exports to Europe, we, hence, assume that it is determined by pipeline capacity to Europe. For pipelines, we assume a maximum average utilisation of 90 percent.

Libyan Supplies:

Libya is also an LNG and pipeline gas exporter and is therefore be treated like Algeria. I.e. the maximum gas export capability via pipeline equals 90 percent of pipeline capacity.

[19] 5.75 bcm/year, see http://www.offshore-technology.com/projects/snohvit/.
[20] 4.4 bcm in 2008 (BP, 2009), assumed to be constant until 2019.

Russian Supplies:

According to BP (2009), Russia exported 154 bcm to the countries considered in this study in 2008. We assume that exports do not increase until 2011 due to the economic crisis in Europe. Afterwards, i.e. for the 2011 to 2019 time period, exports are assumed to be able to grow by 3 percent a year until 2019 leading to an upper limit for imports from Russia of about 195.2 bcm/year in 2019.[21]

Middle Eastern Supplies:

Contracted Iranian exports currently include 10 bcm/year to Turkey[22] and, as of 2010, 5.5 bcm/year to Switzerland-based utility EGL (volumes are formally destined to power plants in Italy)[23]. Hence, Iran has contracted exports slightly in excess of the pipeline export capacity to Turkey (14.6 bcm/year). Therefore, it is assumed that these volumes can actually be exported to Europe (including the Turkish market) up to that limit over the next decade.

Supplies from Caspian Countries[24]:

For the simulations up to 2019, we only deem pipeline exports via Azerbaijan towards Turkey to be realistic as new pipelines bypassing Russia from the Caspian region may not be built until 2019. Hence, the only direct import route for Caspian gas to Europe is the South Caucasus Pipeline from Azerbaijan via Georgia to Turkey with a capacity of 8.8 bcm/year and a likely expansion up to 20 bcm/year (scheduled for 2012)[25]. Contracted flows were 2.95 bcm in 2008, 6.6 bcm in 2009 and 6.3 bcm/year from 2010 onwards.[26] Due to the growing Turkish market and existing and potential transit routes through Turkey to the EU-27, we assume that the South Caucasus Pipeline will be expanded to 20 bcm/year in 2012. Hence, we assume Azerbaijani gas flows to Turkey can increase up to 90 percent (pipeline utilisation) of this limit by 2019.

Further Southern Corridor Supplies:

Some uncertainty is associated with further potential pipeline gas imports from the regions of the Middle East or the Caspian Countries. However, these volumes are especially relevant for pipeline projects in the region. In the context of this study, this is especially true for the

[21] This implies an average growth factor for 2.1 % annually between 2008 and 2019.
[22] http://www.iea.org/Textbase/work/2002/caspian/Skagen.pdf
[23] http://www.payvand.com/news/08/jun/1206.html
[24] Note that this only refers to pipeline exports which are not routed via Russia.
[25] http://www.upstreamonline.com/live/article119108.ece
[26] http://www.eia.doe.gov/cabs/Azerbaijan/NaturalGas.html

Nabucco pipeline project (see Section 4.3). A number of countries could provide the gas to fill the pipeline, and it seems realistic that the pipeline is only going to be built if the respective volumes can be contracted. Therefore, in the scenarios which include this pipeline project, it is assumed that additional supplies for this Southern Corridor are available. We do not specify where these volumes come from as this is beyond the scope of this study and not relevant for the gas flows in Europe. Possible sources include (in alphabetical order):

Azerbaijan: The country is already exporting gas to Turkey. Major production increases in the future are expected to come from the Shah Deniz offshore natural gas and condensate field. Due to the existing pipeline connection to Turkey (which can be expanded), the country is one of the most-likely contributors to gas volumes for Nabucco. However, upstream investments in the aforementioned field will be required to expand production capability.

Egpyt: The Arab Gas Pipeline currently connects Egypt to Jordan and Syria. A proposed connection of the Arab Gas Pipeline to the Turkish and European grid could be filled with additional volumes from Egypt (provided capacities along the existing route are expanded). With 2.17 trillion cubic meters of reserves and 59 bcm of production in 2008, the potential does exist (BP (2009)).

Iran: With relatively low gas production cost and the world's second largest gas reserves, Iran seems to be the most viable supplier of Nabucco gas based on fundamental costs. A pipeline connection to Turkey exists and gas production (mainly for domestic use) is also already the fourth largest in the world (116 bcm in 2008). However, the Iranian investment climate in general and the lack of foreign direct investment due to the political situation in particular hamper an increase in production output.

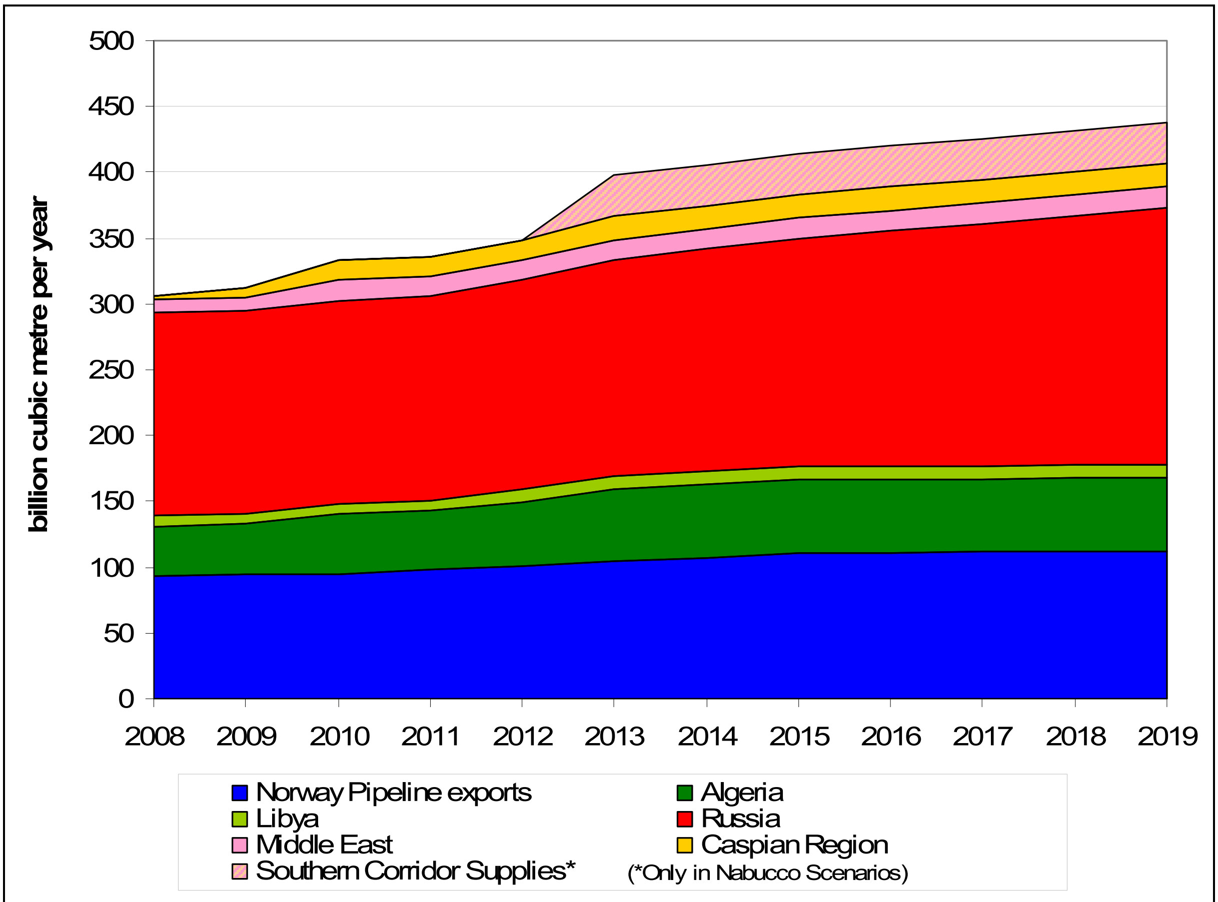
Iraq: With estimated reserves of more than 29 trillion cubic meters (BP, 2009) and due to its geographic location, Iraq is a potential pipeline supplier of natural gas to the European market (most resources are actually closer to the European market distance-wise than those in Iran). However, production was only 3 bcm in 2006 and significant investments are required to increase production capacity. "Plans to export natural gas remain controversial due to the amount of idle and sub-optimally-fired electricity generation capacity in Iraq - much a result of a lack of adequate gas feedstock."[27] Nevertheless, exports to Europe are an option and the proposed Arab Gas Pipeline could deliver gas from Iraq's Akkas field to Syria and then on to

[27] See EIA (http://www.eia.doe.gov/cabs/Iraq/NaturalGas.html).

Lebanon and the Turkish border at some time during the next decade. Whether that will happen and which volumes would be exported remains, however, uncertain.

Turkmenistan: Similar to Azerbaijan, Turkmenistan has significant gas reserves and seems politically more stable than Iran. However, Turkmenistan is not yet connected to the Turkish grid due to its geographic location to the east of the Caspian Sea. Hence, apart from significant upstream investments, Turkmenistan gas for Nabucco would require a pipeline through the Caspian Sea or around the Caspian Sea via Iranian territory. As Turkmenistan is selling natural gas to Russia, Iran and China and these countries appear to be willing to pay prices near the European net-back price, the amount of gas the country can supply via Nabucco during the next ten years remains uncertain.

Figure 2: Supply Assumptions: Pipeline Imports

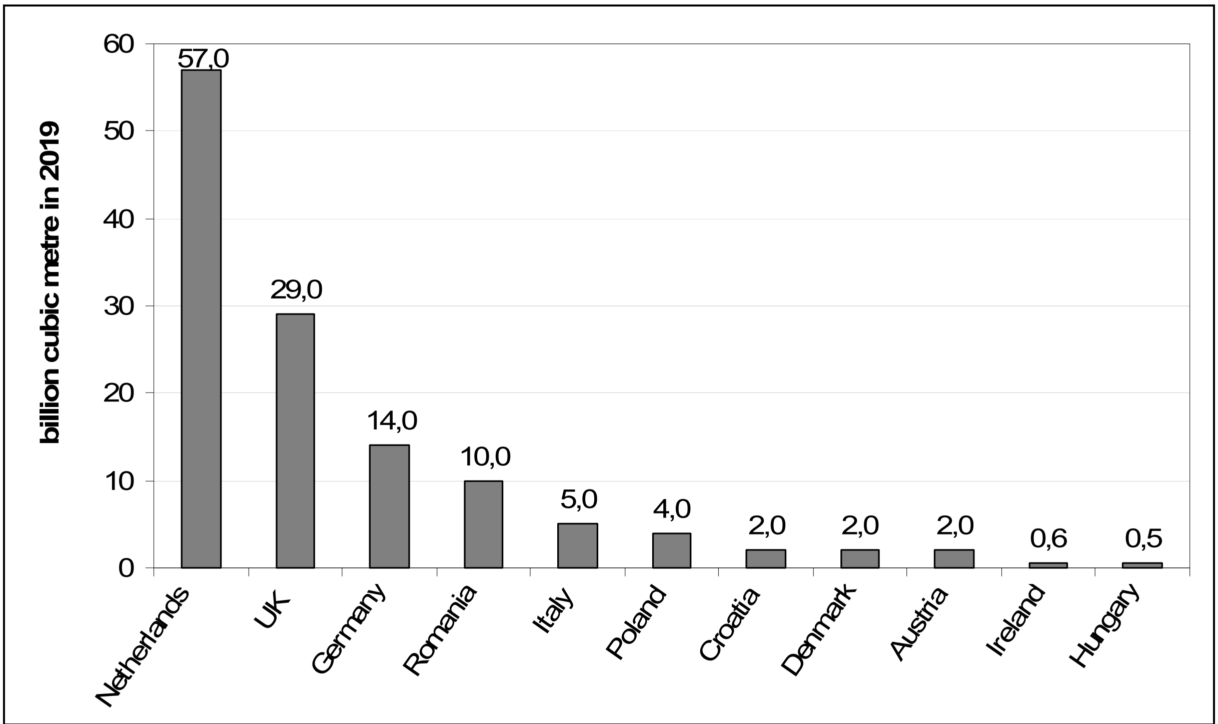


Source: EWI.

Assumptions with respect to the EU's indigenous production are based on ENTSOG (2009). Although they differ slightly compared to other forecasts (e.g. EC (2008)), ENTSOG offers one of the most up-to-date projections on EU gas production at the time of the compilation of this study. Furthermore, the application of this projection allows a high comparability of results with the ENTSOG (2009) study.

According to the applied 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 (BP, 2009) sees the largest decline to a production level of below 30 bcm/year. (For the data for all countries, see Figure 3.) Generally, output in the EU is expected to decline from 211 bcm in 2008[28] to 126 bcm in 2019, which equals a 40 percent fall, according to these supply assumptions.

Figure 3: Supply: EU Indigenous Production



Source: Own illustration based on ENTSOG (2009).

With respect to supply, a specification of supply costs is necessary in addition to which volumes are available. These were calculated with EWI's global gas supply model MAGELAN, a description of which can be found in Lochner and Bothe (2009) and Appendix E of this study. The resulting supply costs at the EU border (Turkish border in case of Southern Corridor volumes) are depicted in Table 1.[29]

[28] Own calculation based on Eurostat (2009) and EC (2008).

[29] There are slight differences to Lochner and Bothe (2009) due to an updated parameterisation for the purpose of this study. Further results of this updated simulation are published in Lochner and Richter (2010). Supply costs

The interesting case thereby is the cost of LNG. As depicted in Table 1, the marginal LNG supply in the global market is significantly higher than the marginal cost of pipeline supplies to the European market which is quite intuitive considering that Europe is in a geographical advantageous position in close proximity to a number of gas producing and LNG exporting countries.

However, if Europe wants to import LNG, it has to compete with other potential LNG importers (and all studies indicate that LNG cargos will be necessary for supplying the European market, see also Lochner and Bothe (2009)). The price of LNG is determined by its value in other markets as LNG suppliers, especially in an increasing global market with more short-term trade, always have the opportunity to sell LNG in a different downstream market, e.g. North America, Japan, South Korea, Taiwan, India, China and others. (European importers will likewise also be prepared to redirect their LNG cargos to other destinations if the LNG has a higher value there, which of course implies that they are able to meet their European supply obligations through other means.)

Table 1: Supply Cost Assumptions

Supply Source	Supply Cost at EU border [EUR / MWh]
Pipeline supplies:	
Norway*	6.24
Russia	8.73
Azerbajian**	8.26
Iran**	8.06
Algeria	7.13
Lybia	7.51
LNG (cif to Europe):	
Global Marginal Supplier	19.78
LNG to Europe	6.21

*Supply Cost at field; **Supply Cost at Turkish border.

Source: Own calculations based on Lochner and Bothe (2009).

Hence, in long-term equilibrium pipeline gas supplies may have a cost advantage compared to LNG imports in the European gas market (due to the high opportunity costs of LNG arising from its value in other downstream markets).

However, situations may arise when the marginal global LNG supplier is not price setting. Such a situation was observed in the gas market in 2009: On the LNG upstream side, liquefaction capacities increased quickly. At the same time, global demand for LNG fell due

for the EU indigenous supply were set to zero as these volumes are projected to come into the market as specified in the previous paragraph anyway.

to the economic crisis, and the extraction of unconventional gas reserves in the United States, which led to significantly smaller LNG import demand in North America. Hence, the LNG market became a buyer's market where sellers were looking for the best prices globally.

Looking at prices in 2009, net-backing the United States wholesale price to Europe indicates it was profitable to redirect LNG cargos from the US to Europe as long as European wholesale prices exceeded 6.94 EUR/MWh (which was the case during the whole year).[30]

At the same time, the price for natural gas imported by pipeline via long-term contracts remained well above this threshold and the wholesale prices: e.g. the import price for Russian gas to Germany at the German border was 17.12 EUR/MWh in August 2009 (EGM, 2009, p. 16).

Consequently, importers reduced their pipeline gas imports as much as was contractually possible and additional LNG cargos arrived in Europe.

While this is certainly not a long-term equilibrium (global LNG supplies might decline leading to higher LNG prices or long-term pipeline contracts may be renegotiated leading to lower pipeline gas prices, or, more likely, both), it may, thus, happen that the global gas demand-supply balance leads to relatively low-priced LNG coming to Europe in large quantities. Such an oversupply situation is typically a time when new players in the gas market can easily procure gas volumes and enter in competition with incumbent firms. Hence, it may be relevant to investigate if such a changed price structure in the European gas market (which certainly leads to changes in gas flows as more LNG is imported) causes additional bottlenecks to occur in 2019 which might hamper market integration and competition in a time of temporarily low LNG prices. Therefore, a separate scenario is conceived (see Section 4.4) with low LNG prices. Methodologically, we set the cost of LNG in this scenario equal to those of the average LNG supplier to the European market according to Lochner and Bothe (2009).

Another recently often debated potential source of gas is unconventional gas resources. Such unconventional resources come in different forms with the most promising ones being coal-bed methane (CBM; gas extracted from coal beds), shale gas (extracted from shale

[30] Averages for August: Henry Hub wholesale price 3.39 US-Dollar/mmbtu = 8.14 EUR/MWh minus transport cost differential 1.20 EUR/MWh (EGM, 2009, p. 8) and assuming equal regasification tariffs in US and Europe. EIA's natural gas database reports that LNG imports took place at these prices with significant quantities coming from the European side of the Atlantic Basin", mainly Egypt and Norway.

formations), and tight gas (extracted from other low permeable rock formations, e.g. sandstone). While the extraction of such resources used to be unprofitable in the past, technological progress in recent years and economies of scale (spurred by the high gas prices up to 2008), approximately halved production costs and made drilling in these formations in the United States economically viable (Economist, 2010). Thanks to production from unconventional gas resources, the United States passed Russia as the world's largest gas producing country in 2009. With the IEA estimating global unconventional gas resources to total 921 trillion cubic metres (and, thus, more than five times proven conventional reserves), there appears to be a huge potential for this production to significantly shape global gas supply during the coming decades.

The prospects of unconventional gas production on the European continent, however, remain to be seen. Firstly, less than five percent of the global resources are estimated to be in Europe. Secondly, the geological and political difficulties facing unconventional production in Europe may be much larger than in the United States. Geologically, the shale gas formations in Texas are found between 1,500 and 2,500 metres below ground. Austrian energy company OMV, on the other hand, estimates the promising rock formations in a basin near Vienna to be as low as 4,000 to 6,000 metres below ground making drilling significantly more expensive than in the United States (DowJones, 2010). Politically, the new technologies applied to extract unconventional gas resources may also raise environmental concerns. Compared to conventional gas production, the extraction involves significantly more drilling (as deposits are smaller) and the injection of chemicals and other materials into the ground to increase permeability. The application of such technologies may prove to be much easier in the United States than in densely populated Europe with stricter environment protection laws (although these are also changing in the United States to limit the pollution by unconventional gas production).

Apart from these challenges, it also has to be noted that the exploration of possible basins in Europe, e.g. in Germany, Austria, Poland and Hungary, only began recently; shale gas production in the United States, on the other hand, already started 15 years ago.

Hence, within the 10 year horizon of this study, European production from unconventional gas resources is not expected to play a major role.[31]

[31] Data and facts on unconventional resources reported in this section are largely based on articles in Economist (2010) and DowJones (2010).

However, this does not mean that unconventional gas production does not have an impact on the European gas market, even today. The significant unconventional gas production in the United States means the country's import demand is much lower than was expected just a few years ago. Many of the LNG upstream facilities entering operation around the world between 2009 and 2012 were meant to cater this demand when they were planned. With lower demand for LNG in North America, these volumes are, thus, to a larger extend available to other markets including Europe. In combination with the economic crisis in 2008 to 2010, this already caused the LNG glut with record numbers of LNG cargos coming to Europe in 2009 and 2010.

In the future, a global natural gas resource base broadened by unconventional resources may also benefit gas consumers in Europe as it enables larger supply diversification. This limits the dependency on individual gas sources or supply countries and the market power of countries with conventional gas reserves, which in turn enhances upstream competition and security of supply.

With respect to the supply assumptions presented in this section, it has to be noted that these have a significant impact on the results. Apart from supply volumes, the largest impact arises from relative supply costs, in particular of LNG relative to pipeline gas. This uncertainty is taken into account through scenario analysis as relative LNG prices are varied between scenarios, see Section 4.4.

4.2 Demand Assumptions

With respect to demand, two scenarios are applied in this study. Again, as the projection of the development of gas consumption itself is not at the focus of this study, these demand scenarios are based on publicly available studies by other institutions. With the aim of covering a wide range of possible demand developments and selecting projections based on data provided by both the gas industry and policy institutions, the following two demand scenarios are compiled:

- EWI/ERGEG demand scenario based on EC (2008) and EC (2009),
- ENTSOG demand scenario based on ENTSOG (2009).

Compared to other available studies, they have the advantage of being relatively up-to-date at the time of the compilation of this study and offering a relatively high granularity of data with respect to countries (and sectors in case of EC (2008)).

EWI/ERGEG demand scenario:

This scenario is based on the Baseline scenario published by the European Commission in its report "European Energy and Transport – Trends to 2030, 2007 Update" (EC, 2008). The original scenario assumes a gas demand growth rate of 0.9 percent annually between 2010 and 2020 of which the power sector growth amounts to 1.5 and the all other sectors together feature a growth rate of 0.6 percent per year. As an official EU Commission projection based on consistent assumptions regarding economic development, it is selected as the Reference – and therefore most-likely – demand scenario for this study. The detailed provision of data by country and sector (power- vs. non-power sector) and all EU member states by EC (2008) allow an application of country-specific seasonal demand profiles incorporated in the TIGER model (see Chapter 3).

However, one of the major disadvantages of the original EC (2008) Baseline scenario is that it is not up-to-date as it is based on 2007 data compiled in 2008. Therefore, the data is adjusted to the demand declines following the 2009 economic crisis as follows: A regression of non-power and power sector gas demand is performed (using the GDP and gas demand data from EC (2008) for the 2000 to 2010 time period) to establish the relationship between GDP and sectoral gas consumption on a country-level. Using current GDP data for 2009 and 2010 (forecast)[32] the estimators are then used to correct the original EC (2008) non-power and power sector demand projections for the two years and for each country respectively. After 2009, the demand data is projected to increase with the original EC (2008) growth rates. [33] The resulting average annual demand growth between 2009 and 2019 is 0.8 percent.

The Baseline Scenario in its original form (EC, 2008) and the adapted EWI/ERGEG version are displayed in Figure 4. (All numerical assumptions by country can also be found in Table 10 in the Appendix (page 121)).

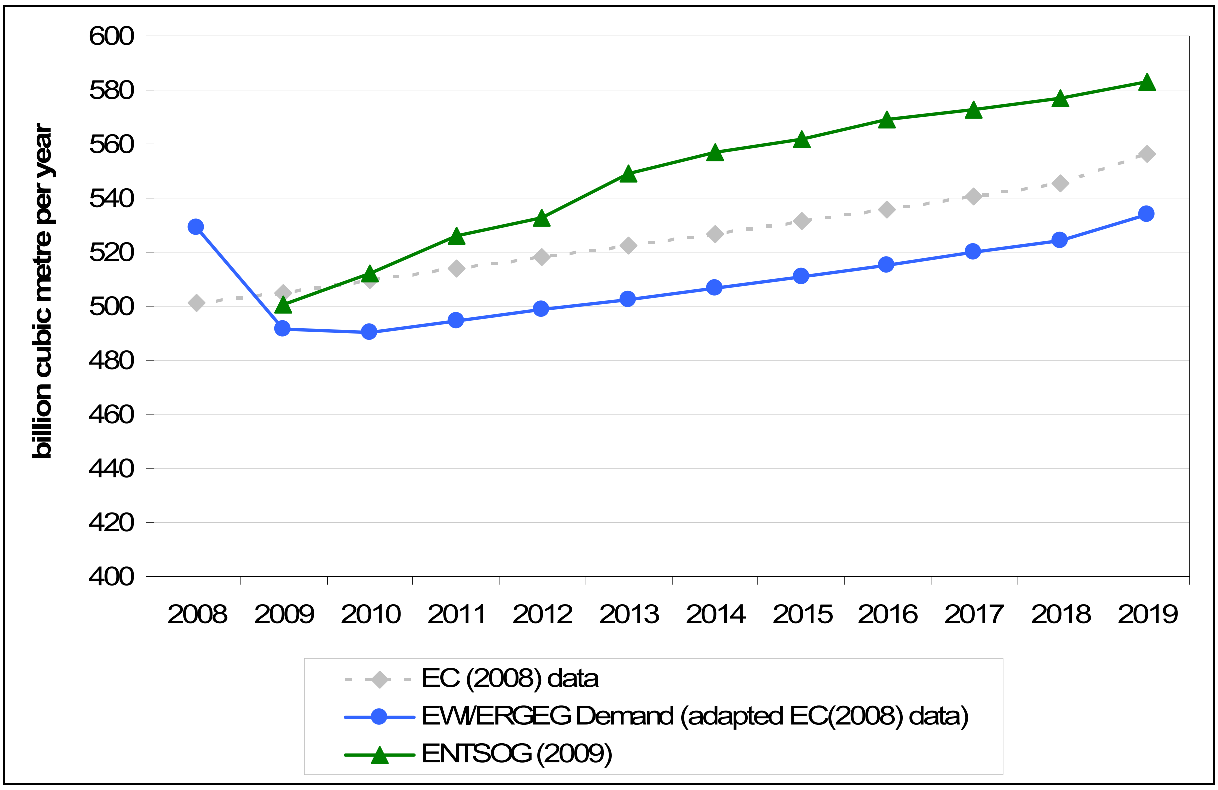
[32] GDP forecasts published by Eurostat data have been used.

[33] For more details on the underlying assumptions for future GDP growth during and after the financial crisis see EC (2009).

ENTSOG demand scenario:

Demand projections are associated with some degree of uncertainty. Therefore, we include a second demand scenario which equals the ENTSOG (2009) annual demand assumptions. This scenario is a suitable complement to the first demand scenario: Firstly, the EWI/ERGEG demand (especially after adjusting for the economic crisis) constitutes a rather conservative projection for the development of gas consumption (also in context of other studies, e.g. IEA (2008), EIA (2009)); the ENTSOG one presumes higher demand growth of 1.4 percent annually. Secondly, maintaining a high degree of comparability of this study with ENTSOG (2009) is in the interest of ERGEG and relevant stakeholders. This is ensured by applying a second demand scenario along the lines of ENTSOG (2009). Together with the EWI/ERGEG demand assumption, the ENTSOG scenario is depicted in Figure 4. The demand difference between the ENTSOG and EWI/ERGEG Scenario is about 49 bcm in 2019. Hence, the two scenarios cover a sufficient bandwidth of possible gas demand developments until 2019.

Figure 4: Demand Scenarios

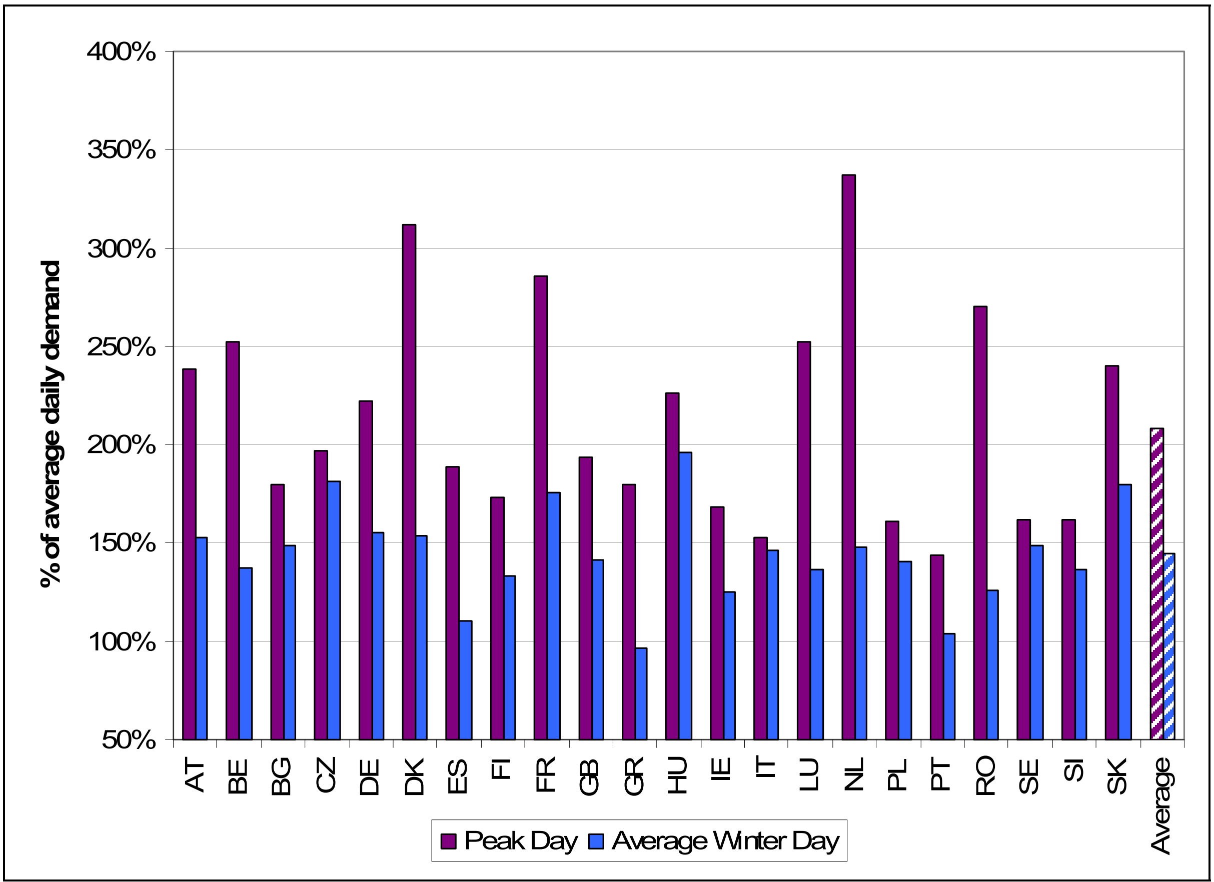


Source: Own calculation based on ENTSOG (2009), EC (2008) / IEA (2009) and EWI assumptions.

Peak Demand Day Sensitivity:

For analysing security of supply and bottlenecks 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 day.

Figure 5: Relative Demand on Peak Demand and Average Winter Day



Source: EWI.

Assumptions for demand on the peak day are fully consistent with data from ENTSOG (2009), see Table 10 in the Appendix (page 121). 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 (2009). Figure 5 presents demand on the peak demand day relative to the average winter day demand and the average daily demand in 2019 (100 percent). This illustrates the magnitude of the demand on this peak day. On average over all considered countries, the demand on the average winter day is about 48 percent higher than the average daily demand throughout the year. On the peak day, demand is another 40 percent higher (or plus 106 percent above the average demand day).[34]

(All numerical demand data for 2019 can be obtained from Table 10 in the Appendix.)

There are, however, significant differences between countries which might have implications on the results regarding the peak day simulations: According to these assumptions, the peak day has the relatively highest demand in the Netherlands, Denmark and France. In Poland and Italy, on the other hand, demand on the peak day barely exceeds demand on an average winter day.

4.3 Infrastructure Assumptions

The assumptions concerning the major infrastructure components of the model simulations are presented in this section.

This includes which new projects are commissioned and which existing once are expanded relative to the status quo (December 2009).

As the focus of the subsequent investigations is the year 2019, it has to be noted that the assumed commissioning date within the 2010 to 2018 period is not relevant for the model results. However, it is of course important if the project is commissioned by 2019 or not. For selected pipeline projects, this is varied between scenarios, i.e. some scenarios assume that a pipeline project is postponed to after 2019 or cancelled (see next section). In this section, all infrastructure projects included in at least one of the scenarios are presented with respect to assumptions concerning capacities, routes and start-up dates (for pipelines, LNG regasification terminals and storages).

Import Pipeline Projects

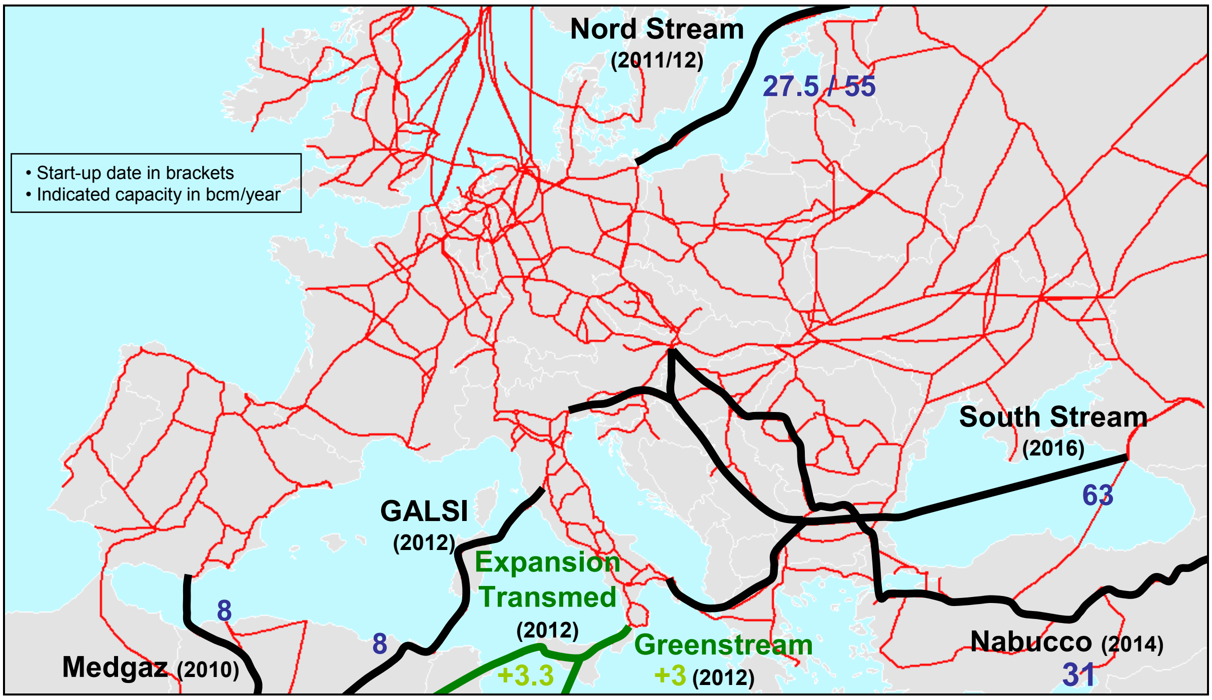
The major import pipeline projects (and their assumed routes) included in this study are depicted in Figure 6. These are:

[34] We assume the peak demand day to be in winter on the fourth Wednesday in January.

Nord Stream I and II:

The first line of Nord Stream is assumed to be commissioned in 2011 with 27.5 bcm/year and its onshore connection OPAL with 36 bcm/year. The second line provides additional 27.5 bcm/year capacity going on line in 2012 together with the onshore connection NEL with 20 bcm/year capacity.

Figure 6: Import Pipeline Projects



Source: EWI.

Nabucco:

The assumed route of Nabucco is shown in Figure 6 and is based on the website of Nabucco Gas Pipeline International GmbH (2010). Start-up dates and capacity assumptions are based on the same source. Being commissioned in 2014 Nabucco provides 8 bcm/year capacity between Ankara and Baumgarten and 8 bcm/year between the Iranian and Georgian border as of 2016. A capacity increase to 31 bcm/year between Iran and Georgia and Baumgarten is assumed to be realised in 2017 and 2018. Thus, for the evaluation of this study (and for the scenarios in which Nabucco is covered), Nabucco is included with 31 bcm/year in 2019. There are several connections to the national grids in Turkey, Bulgaria, Romania, Hungary and Austria which allow for a withdrawal (and consumption) of Nabucco gas on the way to central Europe, but also for additional injections of natural gas into the pipeline.

South Stream:

The assumptions for South Stream are the following according South Stream (2010): The pipeline provides a capacity of 63 bcm/year as of 2016. The route of the pipeline is directed from Russia via the Black Sea to Bulgaria with different onshore sections for transporting the gas further on. In the context of this study, we include two onshore sections: a route via Serbia, Hungary and Slovenia to Arnoldstein in southern Austria as well as the route via Serbia and Hungary to Baumgarten, Austria. [35]

GALSI:

The GALSI pipeline is included with a transport capacity of 8 bcm/year from Algeria via Sardinia to northern Italy and with a start-up date at the end of 2012.[36]

Interconnection of Greece and Italy:

Two projects are proposed to connect Greece and Italy within the next couple of years:

- The Interconnector Greece-Italy (IGI) with its offshore section known as Poseidon Pipeline as a connection of the Turkey-Greece pipeline in Komotini to Otranto in Italy's Apulia region. The pipeline has a capacity of 8 bcm/year as of 2012 when the start-up is expected.[37]
- The Trans Adriatic Pipeline (TAP) from near Thessaloniki in Greece via Albania to Italy's southern Puglia region with a capacity of 10 bcm/year (and the option to expand to 20 bcm/year).[38]

Within the context of this study, it does not appear to be likely that both pipeline projects are realized until 2019. Hence, it is assumed that a pipeline between Greece and Italy is in place in 2019. However, it is not specified which one this is going to be as this study does not include the Albanian gas market and both projects are similar with respect to their connection of the Greek and Italian gas transport systems. The capacity of the Turkey-Greece pipeline that is operational since 2007 is presumed to be expanded from 7 to 11 bcm/year by 2012.

[35] Another route via Greece to Brindisi in Italy does not seem likely if, as assumed in this study, the pipeline interconnector between Greece and Italy (IGI) is implemented. In this case there already exists a new transport route for gas from south-eastern Europe to southern Italy. Therefore, a South Stream onshore section into this region is omitted.

[36] http://www.forbes.com/feeds/afx/2007/11/14/afx4338467.html

[37] http://www.igi-poseidon.com/english/project.asp

[38] http://www.trans-adriatic-pipeline.com

Intra-European Pipeline Projects

With respect to intra-European pipeline projects and expansions of interconnector capacities between countries, these are included in the simulations according to their actual planning status and capacities published in ENTSOG (2009) with adjustments made by EWI in consultation with ERGEG. An overview of these projects is depicted in Table 11 in the Appendix (page 121). Apart from numerous expansions of existing pipelines, the largest included new projects (in terms of annual capacity) are the OPAL and NEL pipelines in Germany (the onshore connections of Nord Stream), the TGL as bi-directional pipeline link between southern Germany, Austria and northern Italy and the MidCat pipeline (bi-directional between Spain and France). Investment obligations potentially arising from the new EU Security of Supply guideline are, however, not included.

Storage Projects

The data for and the selection of the included storage projects is based on the current planning status published by storage operators, the Gas Storage Europe (GSE) database, assumptions derived from GTE+ (2009) and in consultations between EWI and ERGEG.

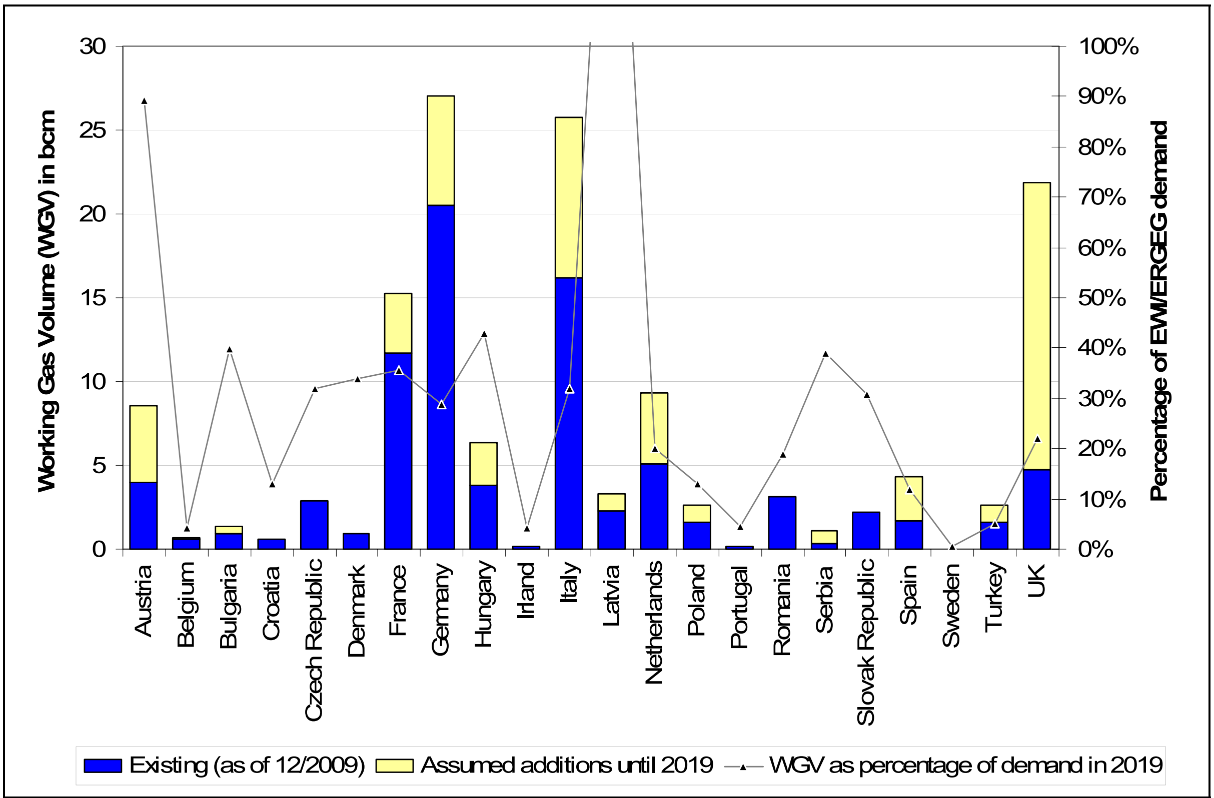
The resulting expansions of storage working gas volumes in Europe are depicted in Figure 7 including aggregated existing capacities, assumed expansions and the resulting storage capacity relative to demand in 2019 (EWI/ERGEG demand assumption). A table providing details on each of the included projects individually is attached in the Appendix (Table 12, page 123).

The distribution of existing capacities and projects reveals that Germany and Italy continue to be the countries with the largest absolute storage capacities. The largest capacities additions are presumed to take place in the UK and in Italy; (with the exception of Latvia[39]) the highest percentage of working gas volume relative to demand is presumed for Austria (90 percent).

For all considered countries, total working gas volume (WGV) increases from about 85 bcm in 2009 to 140 bcm in 2019 according to these assumptions. As a percentage of (EWI/ERGEG) demand, this implies an increase from about 15 percent in 2009 to 23.4 percent for all countries included in the model simulations.

[39] Latvia has high storage capacities as it used to serve as a main provider of storage capacities for the surrounding regions when they were part of the Soviet Union.

Figure 7: Storage Working Gas Volumes in Europe

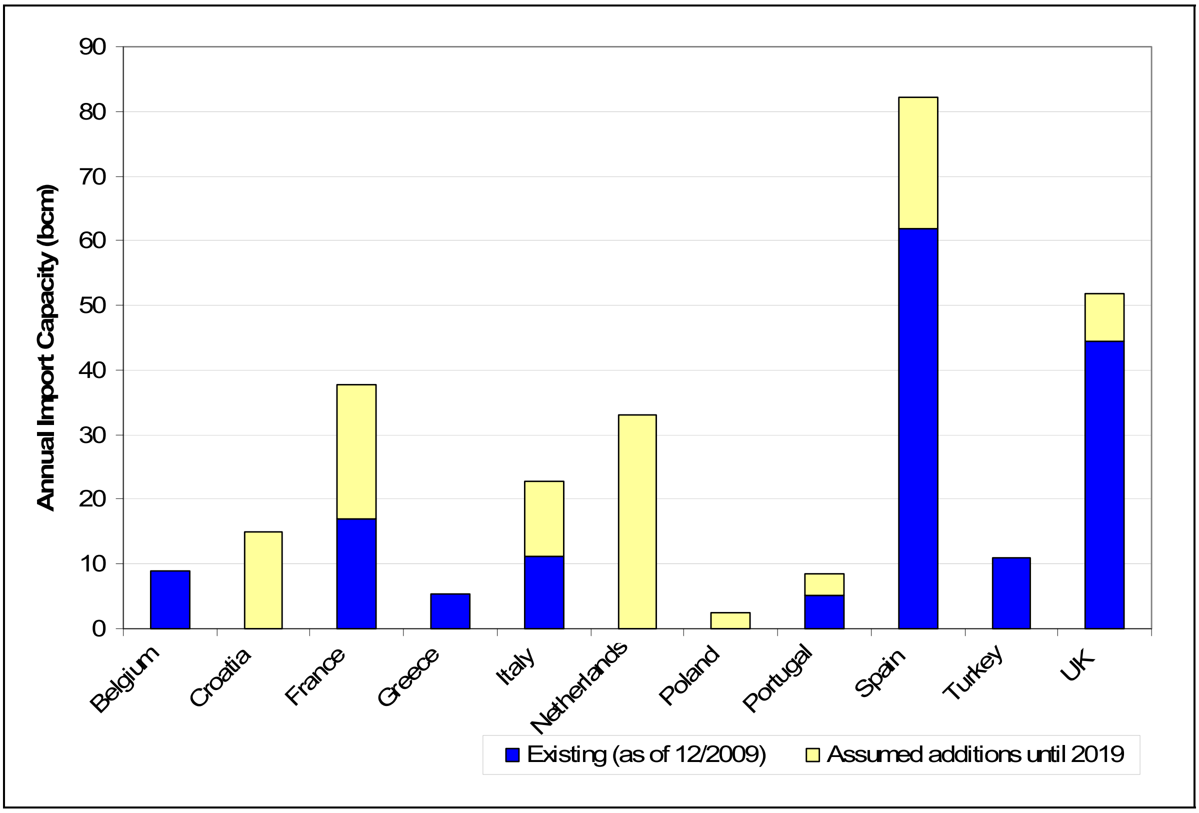


Source: EWI.

LNG Import (Regasification) Terminal Projects

The data assumptions for the regasification terminals included in the simulation are based on official publications of the terminal operators and databases as for example provided by GLE. Similar to storage, they have been adapted in coordination with ERGEG to obtain a realistic picture of LNG import capacity expansions in Europe until 2019. A list of all terminals and expansion stages is displayed in Table 13 on page 125. (The table is also accompanied by a map showing the location of terminals (Figure 57).) Figure 8 illustrates existing capacities and presumed capacity additions by country. Thereby, Spain remains the country with the largest nominal import capacities. Large increases are also expected for the Netherlands and France (but less so for the UK after 2010 as the country's capacity has already significantly increased in 2009). Total annual LNG import capacity in Europe (including Turkey) increases by almost 70 percent from 165 bcm in 2009/2010 to 279 bcm in 2009.

Figure 8: LNG Import Capacities in Europe



Source: EWI.

4.4 Scenario Definitions

The simulation of scenarios is at the core of this study. Changes between the scenarios therefore have to incorporate the issues at the focus of interest to derive the specific influences of these assumptions on the gas market.

Different import pipeline projects have a significant impact on gas flows, physical market integration and security of supply in the European gas market. Thus, possible developments need to be reflected in sufficient scenario variations. To see the influence of the introduction of different combinations of major import pipelines, five different scenarios are simulated on the infrastructure side of the model inputs; one is reserved for a change in the pipeline-LNG cost ratio to reflect the impact of temporarily rising LNG imports.

In addition, the study covers two demand variations: the EWI/ERGEG Demand Scenario and the ENTSOG Demand Scenario, which have been described in Section 4.2. This leads to twelve scenario variations – each of the five infrastructure plus one supply scenarios being combined with each demand scenario – which are analysed on a monthly basis. Table 2 sums up all these scenario variations and the long-distance transmission pipelines that are included in the different scenarios.

The **Reference Scenario** should serve as a baseline scenario to compare the effects of the variations in the other scenarios with the results of this scenario. It includes all of the aforementioned LNG and storage projects. This is also true for all the intra-European pipeline projects except for the NEL. Furthermore, the scenario includes only one line of the Nord Stream pipeline with 27.5 bcm annual capacity (which is the reason why the onshore connection for the second line, NEL, is not incorporated).

Table 2: Scenario Variations

Scenario	Pipeline Project included				"LNG price"
	Nord Stream II	Nabucco	South Stream	Midcat	
Reference				YES	cost-based
Nord Stream II	YES			YES	cost-based
Nabucco		YES*		YES	cost-based
South Stream			YES		cost-based
DG TREN	YES	YES*		YES	cost-based
LNG Glut	YES	YES*		YES	low

*Additional Southern Corridor gas supplies are assumed to be available.
Source: EWI.

In addition to the Reference Scenario 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 to the Reference Scenario. Additionally, extra gas volumes that are available for the transport via Nabucco are added to the Reference supply assumptions (see Section 4.1).

The **South Stream Scenario** then includes the South Stream pipeline and excludes the Mid-Cat pipeline in Spain, but is otherwise identical to the Reference Scenario.[40]

The **DG TREN** Scenario covers the European Commission's TEN-E projects[41], i.e. Nord Stream (both lines) and Nabucco. Additional Southern Corridor Supplies are assumed to be available for the latter pipeline.

[40] For a more detailed description of the capacities and routes assumed for both South Stream and Nabucco see Section 4.3.
[41] See Decision No 1364/2006/EC.

The influence of an exclusion of the inner European MidCat pipeline between north-eastern Spain and southern France is also analysed in addition to the major import pipelines. Therefore it has only been excluded in the South Stream Scenario as South Stream should not have any significant effect on the Spanish gas market.

In the scenario **LNG Glut**, the relative LNG costs are assumed to be lower (see Section 4.1). 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 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).

Furthermore, six sensitivities (one per infrastructure scenario) covering a peak day analysis (based on the higher ENTSOG demand) are implemented. Moreover, five security of supply sensitivities simulating a disruption of the Russian pipeline gas supplies through Ukraine, and another five sensitivities simulating a disruption of Algerian exports are analysed. (The LNG Glut scenario is not considered in the SoS simulations as in such a stress situation, infrastructure is the most relevant assumption. In this respect, the LNG Glut Scenario is identical to the DG TREN scenario.) The duration of the stress situations is presumed to last one month; however, both are modelled in simulations of the whole year 2019 with a daily granularity.

The twelve scenarios cover a wide range of potential demand, upstream (relative LNG) price and infrastructure developments (with respect to the major projects). They allow an encompassing investigation of these major projects, physical market integration and security of supply stress scenarios. The interpretation of results thereby focuses on the year 2019.

5 Model Validation

This chapter provides a comparisons of model results with actual gas flows in the European gas market for the year 2008 is presented. In Table 3 and Figure 9, actual physical cross-border gas flows, which have been gathered from different gas pipeline operators, and the flows that result of the TIGER model simulation for the year 2008 are displayed.[42]

Table 3: Model Validation (2008) - Cross Border Gas Flows in bcm

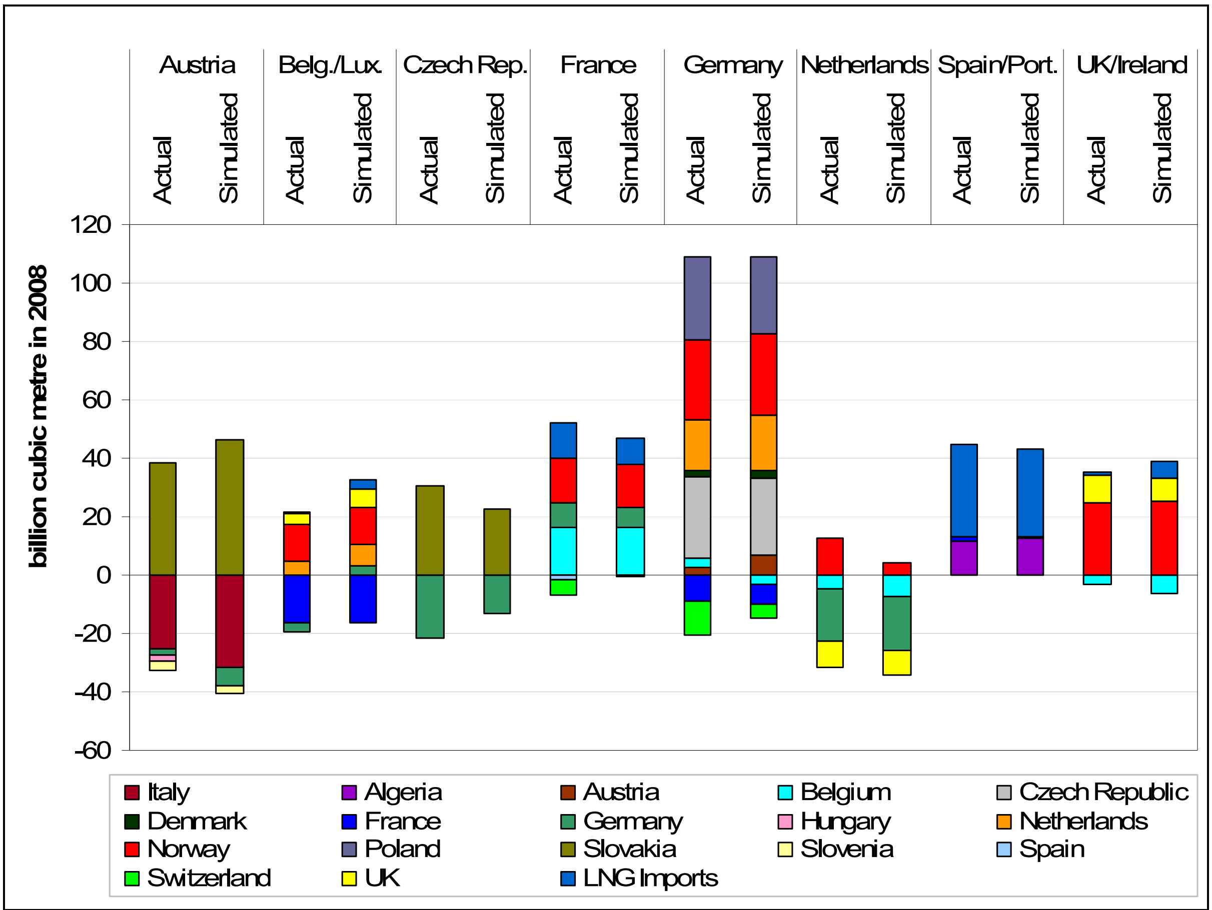
	Flows into country			Flows out of country		
	From	**Actual**	**Simulated**	**To**	**Actual**	**Simulated**
Austria	Slovakia	38.40	46.48	Germany	-2.44	-6.63
				Hungary	-2.28	0.00
				Italy	-25.00	-31.38
				Slovenia	-2.67	-2.37
Belgium	Netherlands	4.90	7.30	France	-16.30	-16.14
	Norway	12.70	12.70	Germany	-3.10	3.03
	UK	3.20	6.54			
	LNG Imports	0.90	2.86			
Czech Republic	Slovakia	30.70	22.79	Germany	-21.40	-13.34
France	Belgium	16.30	16.14	Spain	-1.76	-0.17
	Norway	15.00	15.00	Switzerland	-5.10	-0.52
	Germany	8.70	6.89			
	LNG Imports	11.90	8.55			
Germany	Austria	2.44	6.63	France	-8.70	-6.89
	Belgium	3.10	-3.03	Switzerland	-11.90	-4.76
	Czech Republic	21.40	13.34			
	Denmark	2.10	2.98			
	Netherlands	17.50	18.60			
	Norway	27.60	28.37			
	Poland	27.98	26.28			
Netherlands	Norway	12.70	4.40	Belgium	-4.90	-7.30
				Germany	-17.50	-18.60
				UK	-9.20	-8.16
Spain/Portugal	Algeria	11.50	12.79			
	France	1.76	0.17			
	LNG Imports	31.30	30.43			
UK/Ireland	Netherlands	9.20	8.16	Belgium	-3.20	-6.54
	Norway	25.00	25.20			
	LNG Imports	1.00	5.37			

Source: Data published by transmission system operators and EWI.

Although the model does not account for contracts but optimises the dispatch of the total system, gas flow volumes resulting from the simulation are close to real gas flows.

[42] Only physical gas flows, not contractual ones, are presented in the table.

Figure 9: Model Validation (2008) - Cross Border Gas Flows



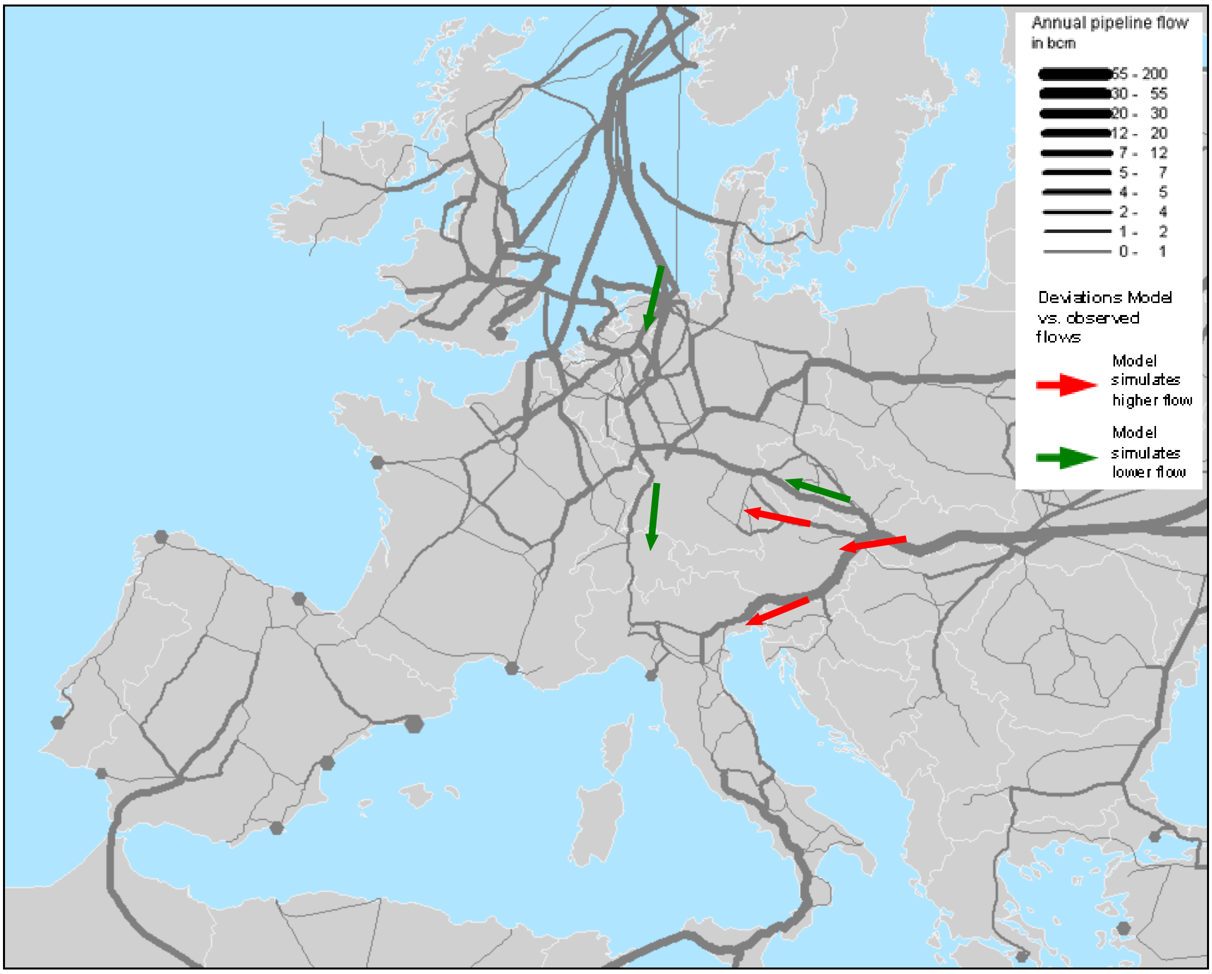
Source: EWI and data published by transmission system operators.

However, there are some differences between the actual and simulated gas figures that can be attributed to contract structures that are not covered by the model. These differences are mainly evident for gas flows between Slovakia and Austria, from there to Italy and Germany, between the Czech Republic and Germany, and Germany and Switzerland as well as for flows between Germany and Belgium. Figure 10 sums up these main differences which can be explained as follows:

In reality, more Russian gas volumes are transited via the Czech Republic to Germany and more Norwegian gas via Germany and Switzerland to Italy. Within the model framework, less gas is transported via the Czech grid and more Russian gas is transited via Slovakia and Austria to Germany and Italy. This is partially the shorter route to some consumers in southern Germany and implies a swap of Norwegian and Russian gas volumes. The former physically remain to a larger extent in Germany (instead of being transited to Italy via Switzerland) while the latter are transported to a larger extent to Italy than to Germany.

Additionally, there remain some uncertainties regarding actual physical gas flows which are only partially published. These concern Norwegian gas flows where BP (2009) had to be included as a source which does not fully distinguish between physical and contractual gas flows, and the Belgian gas balance, which, from the "Actual" column in Table 3 implies that domestic consumption would have been unrealistically low in 2008.

Figure 10: Deviation of Modelled to Real Gas Flows in 2008



Source: EWI.

The largest differences between simulated and actual gas flows are also illustrated in Figure 10. For all other country combinations evaluated in Table 3, the absolute differences between the model projection and the data for actual gas flows are relatively smaller.

The fact that some contractual gas flows are not replicated by the model simulation does not limit the suitability of the model for the purpose of this study. This is especially true when considering a time period nine years in the future (2019) as the reasons for the deviations between modelled and actual gas flows may be less relevant over time.

Firstly, with increasing separation (unbundling) of gas transport and trading and the efforts by national regulators to enhance efficiency and improve network access, one can expect European gas transportation to become more efficient. Hence, more of the efficient swaps presumed by the model might actually be implemented in reality.

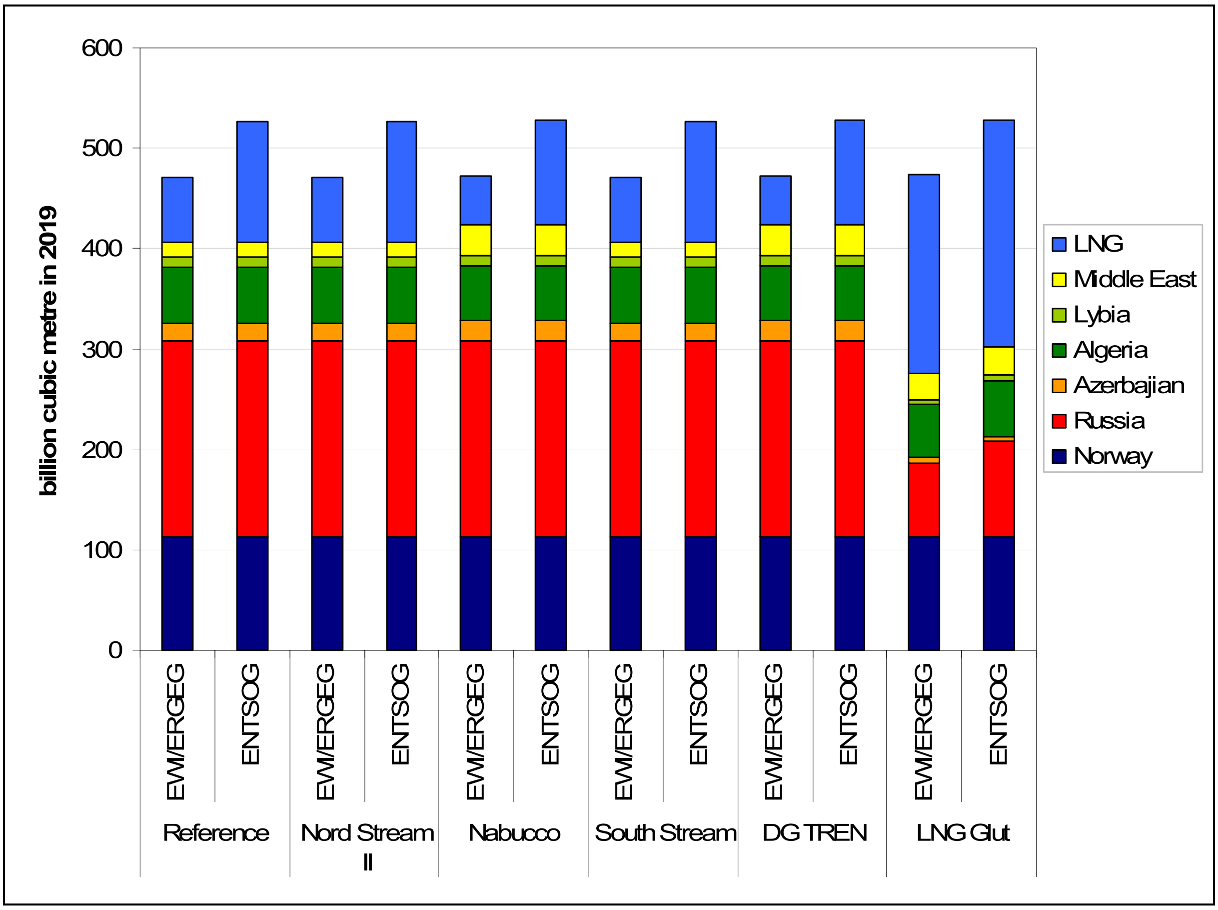
The second reason which causes the modelled flows to deviate from actual gas flows might be differences in gas qualities for natural gas from different sources: The applied TIGER Model only distinguishes between high (H) and low (L) calorific gas, but not between H gas from different sources (Norway vs. Russia in this case) which might hamper the implementation of gas swaps in the short-term. However, with the medium term view of this study, this is less of a constraint as consumers can adapt to changes in gas qualities. As indigenous European production declines, imports increase and new supply sources (LNG, Caspian region) are projected to be tapped for the European market, this may have to happen anyway.

Hence, the medium-term perspective applied in this study and the increasing efficiency in the European gas market may even further increase the overlap of model simulations and actual gas flows.

6 European Import Diversification in the Scenario Simulations

This section gives an overview of the model results concerning European gas import diversification. As the supply assumptions presented in Section 4.1 focus on potential supply, this, hence, enables an evaluation of the scenarios with respect to which gas volumes are procured for the European market from the different supply sources (i.e. supply diversification).

Figure 11: European Imports* 2019 – All Scenarios



* Pipeline and LNG imports. LNG imports in bright blue colour. Potential countries exporting LNG to Europe in 2019 could be Qatar, Algeria, Libya, Egypt, Nigeria, Norway, Russia, Trinidad and Tobago and Yemen. Europe here stands for EU-27 plus Norway, Switzerland and Turkey.

Source: EWI.

Imports from non-European countries are presented in Figure 11. All the different sources are listed for the two demand variations (EWI/ERGEG and ENTSOG demand) and the six different infrastructure scenarios. The depicted volumes by source only include imported pipeline volumes whereas LNG imports are displayed in bright blue colours.[43]

Within the TIGER modelling framework, the imported gas volumes are constrained by the assumptions on the maximum pipeline volumes that are available to the European gas market and the cost assumptions for the different gas sources (see Section 4.1).

The major source of pipeline imports for Europe is Russia with 195 bcm import volume in 2019 throughout all scenarios (except for the scenario with low LNG costs, which could only be a short-term situation in reality and does not represent a long-term equilibrium). Norway is the second largest supplier in every scenario with 112 bcm.

Algeria provides 55 bcm throughout all scenarios (except for the LNG Glut Scenario with EWI/ERGEG demand in which slightly less is provided) and is ranked the third biggest gas supply source (considering LNG supplies not as one but as multiple potential supply sources). Middle Eastern and Caspian pipeline imports also play an increasingly large role (even more so in the scenarios with Nabucco as a new Southern Corridor import route).

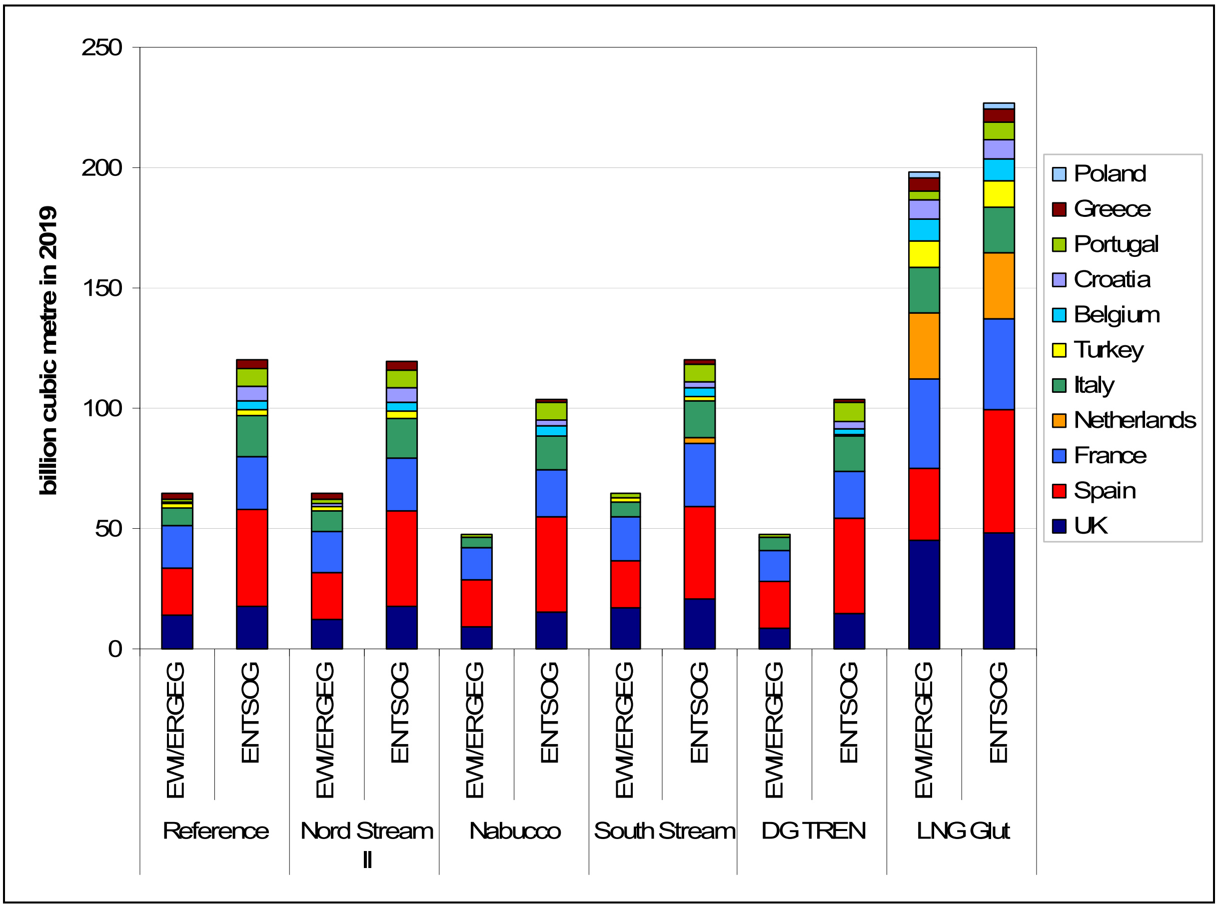
One of the findings from Figure 11 is that supply diversification partially depends on the scenario. Additional Southern Corridor volumes on Nabucco (+/- 31 bcm/year) are, from a European perspective, not significant enough to greatly reduce the dependency on Russian, Algerian and Norwegian gas; although this is different for individual countries, especially in south-eastern Europe and when only considering pipeline imports as these would be diversified by extra Southern Corridor volumes. However, additional Southern Corridor volumes also replace some LNG imports mitigating the overall diversification effect as LNG imports may also be diversified to a large extent due to an expected large number of LNG exporting countries in 2019. On the other hand, the small impact on the import mix is also true for South Stream: This pipeline largely cannibalises flows on other Russian export routes and does not lead to a significant overall increase in Russian imports (except from the increase happening anyway).

Figure 12 shows the aggregated annual LNG imports into the different European countries in 2019. As the assumptions on LNG costs presume that LNG is the marginal supplier, significant differences can be observed between the scenarios. In the first five scenarios, total European LNG imports thereby essentially depend on demand. Based on EWI/ERGEG

[43] A differentiation of LNG sources is not relevant for the scope of this study. Furthermore, this would require an incorporation or explicit modelling of LNG upstream supplies which is not part of the applied model.

demand assumptions, LNG imports amount between 48 and 64 bcm (about 48 bcm in the scenarios with Nabucco (Nabucco and DG TREN) and about 64 bcm without Nabucco).

Figure 12: LNG Imports per Country in 2019



Source: EWI.

With the higher ENTSOG demand, more LNG is imported: between 103 and 120 bcm depending on the scenario (with about 103 bcm in the scenarios with Nabucco and about 120 bcm without Nabucco).

Thus, it can be concluded that less LNG is needed with Nabucco bringing extra gas volumes to the European market. Hence, LNG acts as an implicit swing supplier in this medium term view: If more pipeline gas is contracted to come to Europe, less LNG is imported and vice versa.

In case of low LNG costs (Scenario LNG GLUT), pipeline gas is crowded out starting with the most expensive sources which is gas from Libya and Azerbaijan based on the modelling assumptions. However, Russian imports are also reduced by 62 percent to 74 bcm in the LNG Glut Scenario with EWI/ERGEG demand and by 51 percent to 95 bcm for the ENTSOG demand case (see Figure 12). With the assumed LNG capacities, it is hence theoretically possible to import more than 200 bcm of LNG annually in 2019 if LNG prices are low and contractual obligations (from Take-Or-Pay clauses) to import pipeline gas can be partly reduced. For all considered LNG terminals (see Section 4.3), this implies an average utilisation of 70 percent in the EWI/ERGEG demand scenario and of 80 percent with ENTSOG demand.

Spain, the UK and France are the countries with the highest LNG imports in 2019 throughout all scenarios. The Spanish LNG import volumes differ between 19 bcm (Reference Scenario with EWI/ERGEG demand) and 40 bcm (Reference and Nord Stream II scenarios with ENTSOG demand) for the scenarios in which LNG is cost-based. They even rise up to 52 bcm (LNG Glut Scenario with ENTSOG demand) if very low LNG prices are assumed. Relative to the total Spanish LNG import capacities, it is hence possible that a high availability of Algerian pipeline gas on the new import route (Medgaz) combined with low demand growth (EWI/ERGEG demand) leads to a relatively low utilisation of LNG terminals in Spain (on average).

The aggregated annual utilisation of the single terminals is shown in the gas flow maps in the next chapter and the Appendix and is described in Section 7.1. The French terminals in Fos-sur-Mer, and the two Spanish LNG import terminals in Barcelona and Bilbao are highly utilised in almost every scenario.

The Polish LNG regasification terminal in Swinouscie is only used in the LNG Glut Scenario importing 2.5 bcm. Almost the same holds for the terminals in Rotterdam, Netherlands, where almost no LNG is imported except for the LNG Glut Scenario with a volume of 27 bcm LNG imports. The Italian LNG imports vary between 4.4 bcm (Nabucco Scenario with EWI/ERGEG demand) and 19 bcm for the low-LNG-cost scenario LNG Glut.

7 Gas Flows and Utilisation of Infrastructure

The results of the simulations with the TIGER model under the assumptions mentioned above and for the different scenarios listed in Section 4.4 are presented in the following chapters. This chapter thereby focuses on gas flows in the scenarios in 2019 and the utilisation of selected major import pipeline projects.

7.1 Annual Gas Flows in 2019

This section gives an overview of gas flows and pipeline utilisations for the year 2019 displayed in maps for each of the six different infrastructure scenarios as well as for the two different demand scenarios which leads to twelve different gas flow maps. In addition, to highlight differences between the scenarios and underlying infrastructure assumptions, seven maps are added to indicate differences in flows between the specific scenarios. The flow maps with EWI/ERGEG demand are presented in this chapter. All flow maps based on the ENTSOG demand assumptions can be found in Appendix B.

For the analysis of the different scenario variations, the focus is on the differences between the scenarios. First, the flows in the scenario itself are considered, then the differences compared to another scenario, which is normally the Reference Scenario, and finally for each infrastructure scenario the flows that resulted with the higher ENTSOG demand are evaluated.

In the annual gas flow maps, the utilisation of the displayed pipelines is shown in different colours where red colour indicates a high and green colour a low utilisation of the pipelines. The thickness of the lines indicates the volume of annual gas flows in billion cubic metre (bcm). The arrows signify the main flow directions on the pipelines.

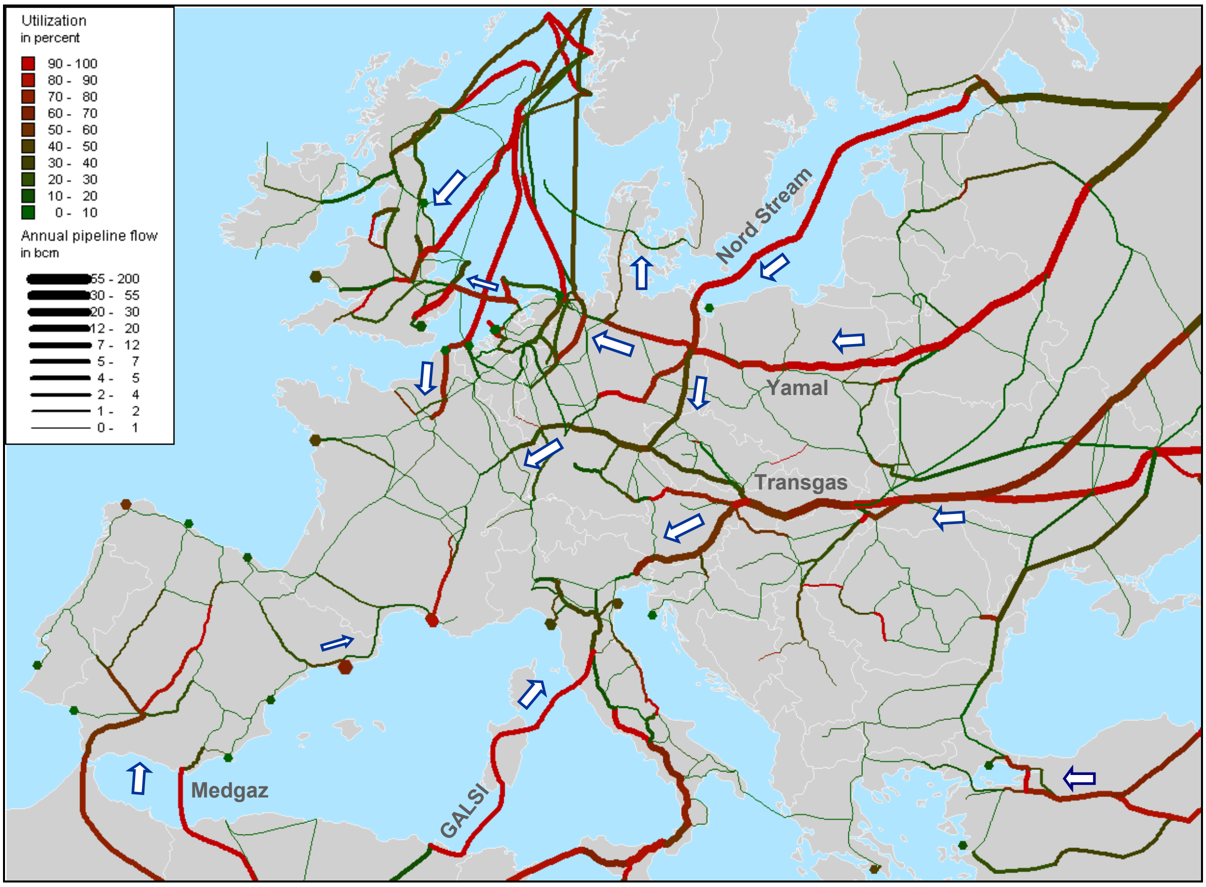
The absolute change of gas flow maps shows pipelines in pink and green colours where a pink line indicates that gas flows increased by more than 0.5 bcm; a green line presents a reduction of gas flows of at least 0.5 bcm and a white line denotes that there are no significant gas flow changes (less than 0.5 bcm increase or decrease) between the compared scenarios on an annual basis. The direction of these differences should be interpreted in such a way that the gas flows of the secondly stated scenario in the caption are subtracted from the flows of the firstly stated scenario in the caption of the respective figure. (For example Nord Stream II vs. Reference Scenario means that the change of flows is computed by Nord Stream II flows minus Reference Scenario flows.) Here, the thickness of the lines indicates the gas flow volume change in bcm per year. All these flow difference maps are based on the EWI/ERGEG demand assumptions.

In all gas flow maps the annual utilisations of the LNG regasification terminals in Europe are displayed for the respective scenario. (An overview of all LNG regasification terminal numbers and locations are displayed in Table 13 and Figure 57.)

Reference Scenario

Figure 13 shows the annual gas flows resulting from the simulation of the Reference Scenario.

Figure 13: Annual Gas Flows 2019 – Reference Scenario (EWI/ERGEG Demand)



Source: EWI.

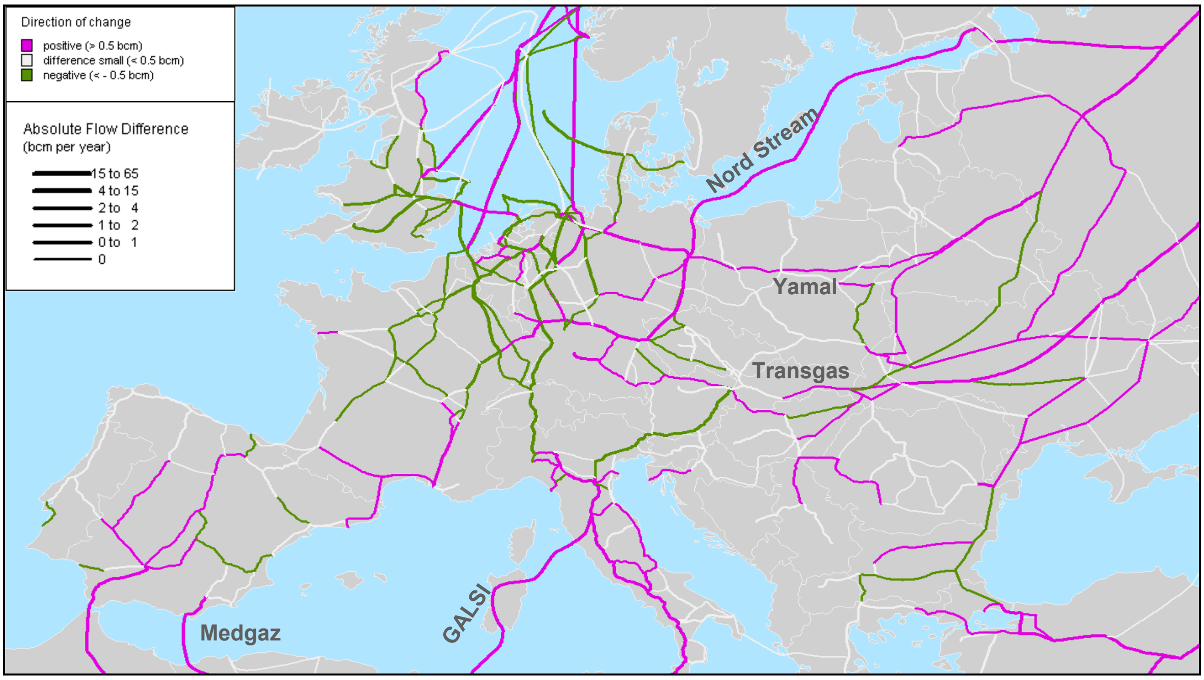
The main routes for Russian gas into the European gas market are Nord Stream (27.5 bcm per year), Yamal (about 32 bcm per year) and the Transgas route[44] via Ukraine and Slovakia to

[44] The term Transgas in this study refers to the pipeline route from Ukraine into the EU via Slovakia. This term is consistent with the pipeline maps for example provided by the Petroleum Economist (2008). Parts of this

Austria and the Czech Republic (about 70 bcm per year at the entry into the EU). Gas from Norway is transported to the United Kingdom, France, Belgium, Germany and the Netherlands and from there further on within western Europe. Gas from Algeria and Libya is directly imported by Italy and Spain, also via the two new direct routes from Algeria, Medgaz and GALSI.

The absolute change of gas flows between this Reference Scenario and the gas flows of a simulation for the year 2008 is presented in Figure 14.

Figure 14: Absolute Change of Annual Gas Flows – Reference Scenario 2019 vs. 2008



Source: EWI.

A general increase of gas flows on all new and existing pipeline import routes except Transgas can be observed. Thus, the increasing import dependency becomes obvious. Fewer inner European flows, especially originating from the UK or the Netherlands, also result from the decrease of European production.

The extra natural gas imports via Nord Stream in north-east Germany are transported south on the OPAL and JAGAL pipeline and west on the NETRA pipeline. The volumes on the OPAL pipeline are transported to the German-Czech border in Olbernhau and in the Czech Republic on the Gazelle pipeline to the Czech-German border in Waidhaus.

pipeline route are also known as the Brotherhood pipeline (historic Soviet era terminology) or Eustream (the Slovak TSO).

The volumes that are imported on the GALSI pipeline via Sardinia reach northern Italy whereas the volumes on the Transmed[45] (Algerian gas) and Greenstream pipeline (gas from Libya) via Sicily are supplying southern Italy.

Spain also imports pipeline gas (20.8 bcm in 2019) from Algeria via Medgaz and the Maghreb Europe pipelines. Assuming that there would be a liquid an competitive LNG market and that this gas could be free and instantaneously diverted between terminals, gas flows from Spain to France on the MidCat pipeline are only limited (see Section 8.8 for an extensive discussion). For the year 2019, only slightly more than 1 bcm are transported via MidCat and only in winter months. Applying the higher ENTSOG demand results in only minor changes: The main Russian import volumes do not change compared to the same infrastructure scenario based on the lower EWI/ERGEG demand, but more Russian gas is transported through Austria to Italy in this case. At the same time, less transit of Russian gas to France through the MEGAL pipeline takes place. Generally, the higher demand scenario mirrors the findings of Chaper 1 that an increase in consumption is largely met by additional LNG imports. Those mainly take place in western Europe. Imports from the north (Norway), south (Algeria), and east (Russia) are consumed closer to the respective import points in the EU. Transits of e.g. Russian gas do not reach as far west as in the EWI/ERGEG demand scenario. (For an illustration of gas flows in the Reference Scenario with ENTSOG demand, see Figure 58 in the Appendix.)

Nord Stream II Scenario

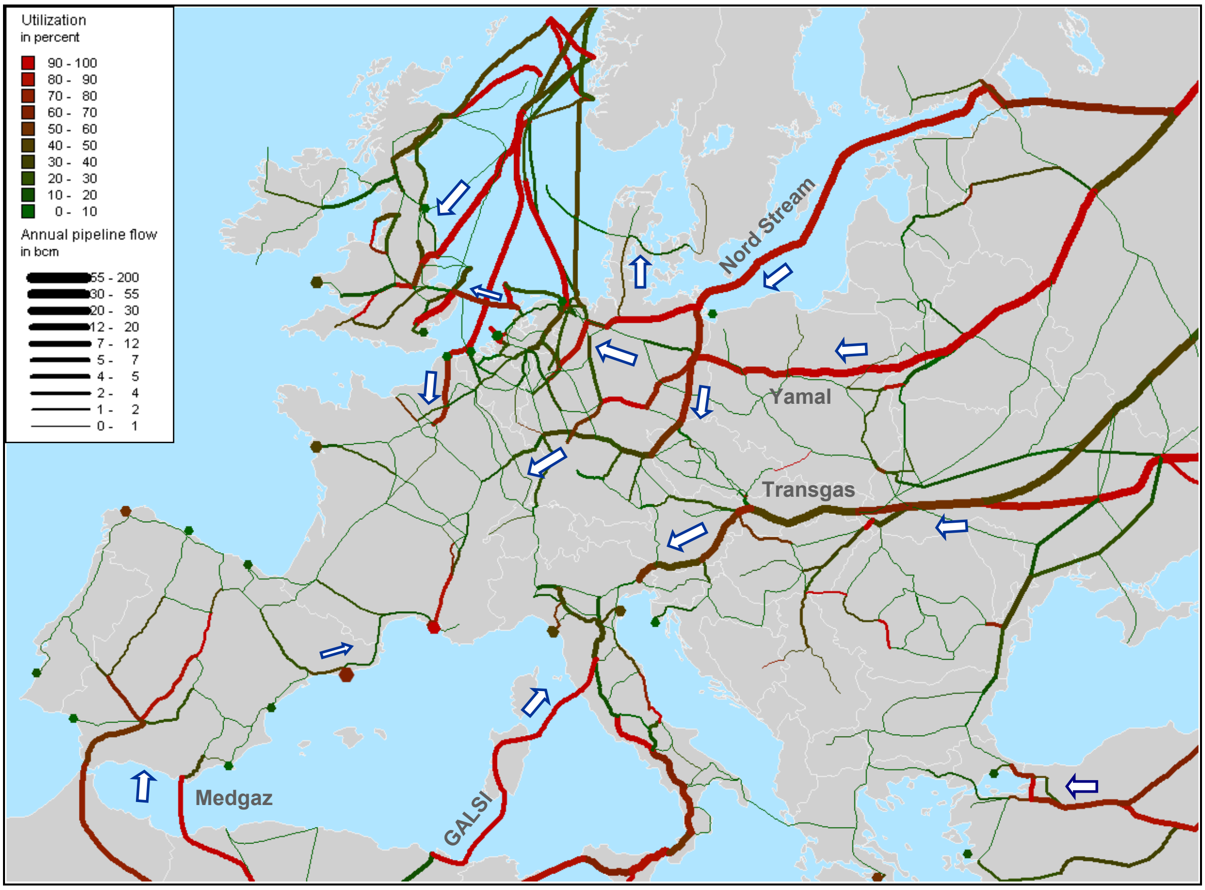
Implementing the Nord Stream II scenario, simulations with the TIGER model yield the gas flows shown in Figure 15, Figure 59 and Figure 60 (with the latter two in the Appendix, page 128).

In this scenario more gas is transported via Nord Stream as a second line is in use. After the Nord Stream landfall, these gas volumes are transported via the onshore connection NEL to north-west Germany. These volumes substitute gas on the Transgas pipeline where fewer volumes are transported compared to the Reference Scenario. Transits from Transgas via Czech Republic to Germany almost fully cease. In addition, less gas volumes are sent through

[45] The Transmed pipeline is also sometimes referred to as the Enrico Mattei gas pipeline.

the MEGAL pipeline (in southern Germany) due to the higher east-to-west transit capacity in northern Germany (provided by the onshore connection of the second Nord Stream line).

Figure 15: Annual Gas Flows 2019 – Nord Stream II Scenario (EWI/ERGEG Demand)



Source: EWI.

The major changes in absolute gas flows between the Reference and the Nord Stream II Scenarios are the following: Imports on Yamal and Transgas to Italy and Germany decrease. Nord Stream gas volumes are routed to the west from Germany and on to Belgium and the Netherlands and replace volumes imported via the Yamal and Transgas pipelines. Moreover, Switzerland is supplied increasingly from the north instead of via Italy. (These absolute changes of gas flows between the scenarios are depicted in Figure 59 in the Appendix.)

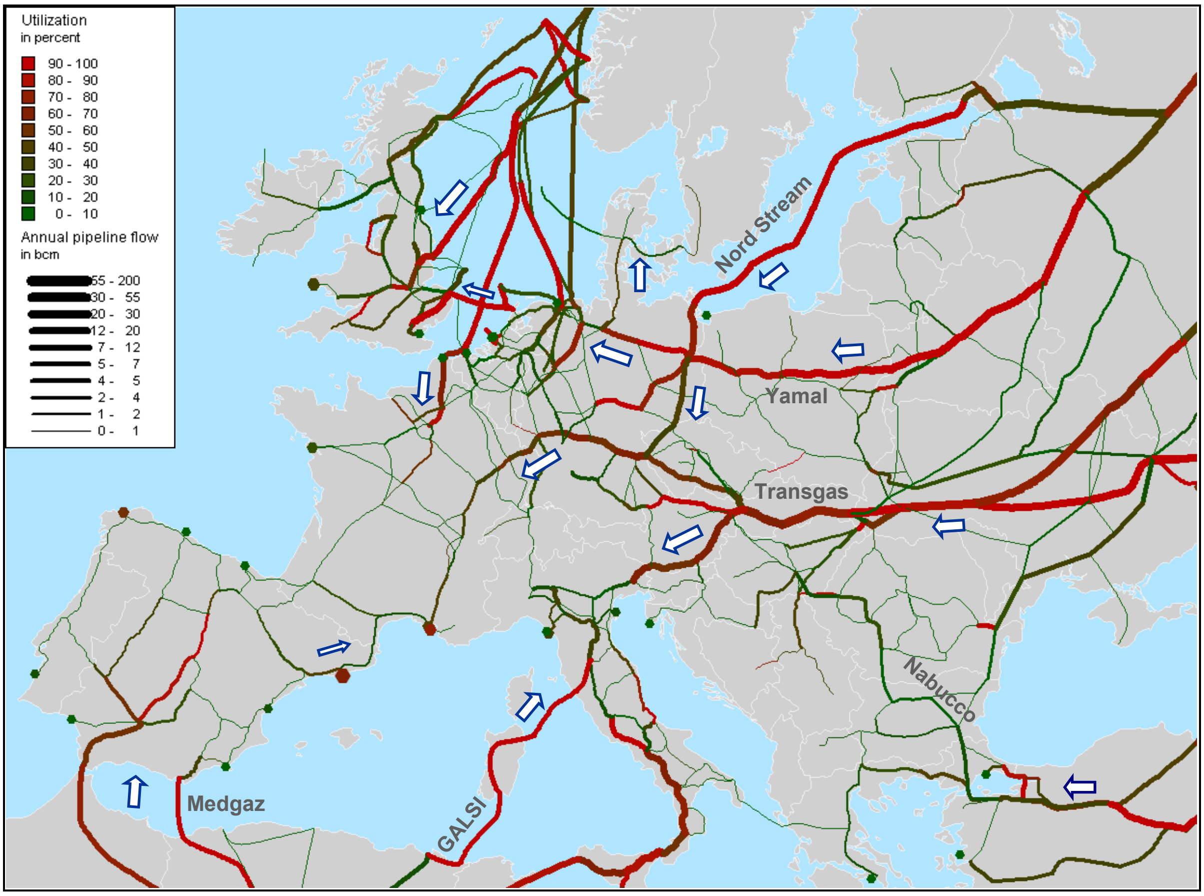
Thus, it can be summed up that a second line of Nord Stream with additional 27.5 bcm mainly affects central Europe (Germany, Austria, Italy, Benelux) where gas flows change significantly compared to the Reference Scenario.

With the higher ENTSOG demand, compared to the Reference Scenario with EWI/ERGEG demand assumptions, a lower utilisation of the Yamal pipeline can be observed. In addition, more Russian gas is transported through Austria to Italy and generally, there is less east-to-west transit of Russian gas in Germany. The same explanation as for the Reference Scenario applies: Higher demand induces more LNG imports in western Europe reducing the need for transits of other gas volumes in this direction. (For an illustration of gas flows in the Nord Stream II Scenario with ENTSOG demand, see Figure 60 in the Appendix.)

Nabucco Scenario

The Nabucco Scenario is based on the same infrastructure assumption as the Reference case except for the inclusion of Nabucco, which is assumed to go on line with a capacity of 31 bcm per year following the route depicted in Figure 6.

Figure 16: Annual Gas Flows 2019 – Nabucco (EWI/ERGEG Demand)



Source: EWI.

In this scenario it can be seen that most of the gas volumes transported via Nabucco are already consumed in Turkey and are not transported further towards central Europe. Thus, the Russian import routes do not lose their importance; their volumes are increasingly routed to central and western Europe. A general increase in east-to-west transits on various pipelines can be seen. The reasons are the following: Nabucco basically replaces Russian gas volumes in south-eastern Europe such as Blue Stream volumes and gas imports via Romania. This has indirect effects in western Europe as less Russian gas is transported to the south-east and more to central and western Europe. Therefore, Transgas flows increase towards Germany, Italy, and France. In general, it can be concluded that Nabucco causes Russian pipeline gas volumes being transported further to the west.

Although gas volumes on Nabucco to Hungary increase in the higher ENTSOG demand scenario, hardly any volumes from Nabucco would physically be delivered to Baumgarten (as they could be efficiently swapped with Russian gas along the way). Relative to EWI/ERGEG demand, Russian gas volumes remain further in the east so that east-to-west transits in central Europe are even slightly lower. (See Figure 62 in the Appendix for the gas flows based on ENTSOG demand.)

South Stream Scenario

For the South Stream Scenario, South Stream is included in the infrastructure assumption instead of Nabucco with a capacity of 63 bcm per year. Its route is presented in Figure 6. To see the effects of including and excluding the MidCat Pipeline going from Spain to France (Eastern Axis), and as it is assumed that the inclusion of South Stream has only minor or no effects on Spain, MidCat is included in all infrastructure scenarios except for the South Stream Scenario to allow a comparison relative to the Reference case.

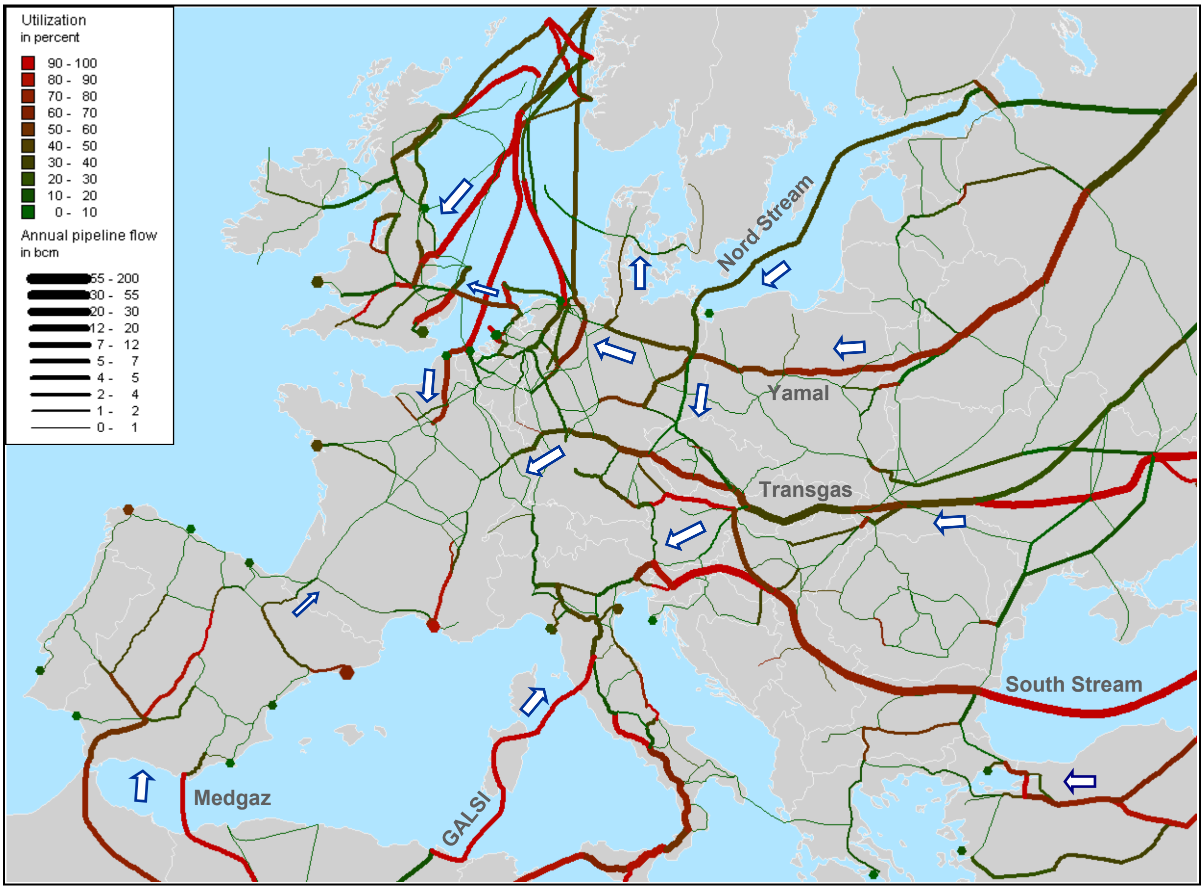
The gas flows for this scenario are presented in Figure 17 for the EWI/ERGEG demand (and in Figure 64 in the Appendix for the ENTSOG demand scenario). The absolute change of annual gas flows for the South Stream Scenario compared to the Reference Scenario is shown in Figure 61.

Significant gas volumes are imported on South Stream, of which a large share goes to Italy. Thus, less Russian gas volumes are transited via Slovakia to Austria and on to Italy.

Consequently, fewer volumes are transported to Europe via the Transgas pipeline compared to the Reference Scenario and less gas is imported via Nord Stream and the Yamal pipeline. Particularly, this happens due to the fact that South Stream replaces some of the volumes for Italy, Croatia and Slovenia which are sent through Transgas in the Reference Scenario.

Moreover, Switzerland is supplied to an increasing extent from the south (and less from the north) when South Stream increases the availability of Russian gas there.

Figure 17: Annual Gas Flows 2019 – South Stream Scenario (EWI/ERGEG Demand)



Source: EWI.

The analysis of the effect of the MidCat pipeline is supported by Figure 63. As the MidCat pipeline is excluded in this scenario, considering the difference of gas flows compared to the Reference Scenario depicts a reduction on the MidCat pipeline. However, without MidCat, physical gas flows between Spain and France increase on the Larrau pipeline on the Western Axis. Thus, these volumes are exported from Spain to France on the Larrau pipeline if the MidCat pipeline is not available.

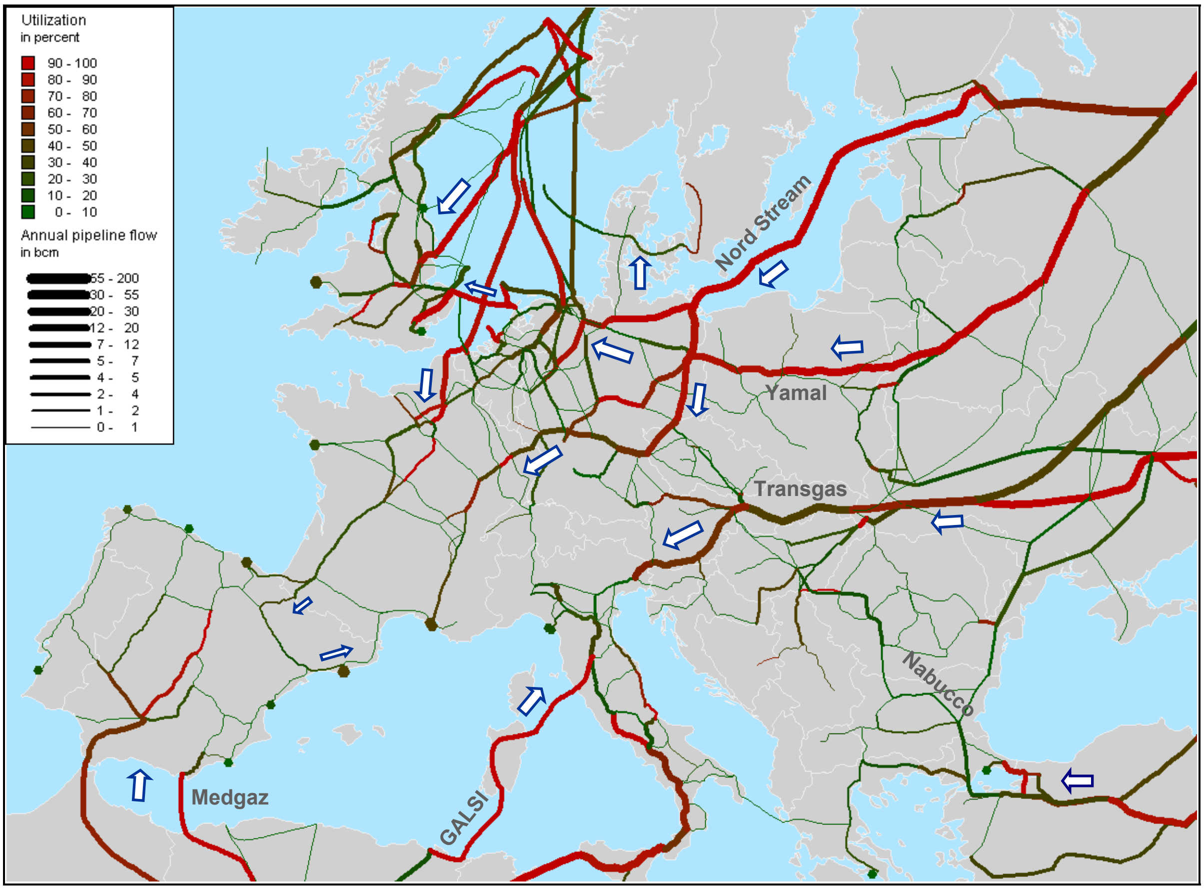
Considering the ENTSOG demand scenario and, again, comparing it to the Reference and EWI/ERGEG demand scenario (see Figure 64 in the Appendix) yields that even more Russian gas is transported via Austria to Italy. Consequently, less volumes are transported through the Transgas pipeline and slightly less gas is transported via Nord Stream as north-western Europe increases its LNG imports in the higher demand scenario.

DG TREN Scenario

The DG TREN Scenario covers all TEN-E infrastructure projects[46]. Thus, a second line of Nord Stream (with its onshore connection NEL) as well as the Nabucco pipeline is included in the infrastructure input for the model simulation.

Compared to the Reference Scenario, only slight changes can be identified which are a combination of the effects of the Nord Stream II and Nabucco Scenario. Russian gas volumes in central Europe increase but they are routed via Nord Stream II instead of via Transgas. Less gas is imported through Transgas to Germany and Russian gas loses market share in south-eastern Europe although only small volumes are transported through Nabucco all the way to Hungary. (See Figure 18 and Figure 65 in the Appendix.)

Figure 18: Annual Gas Flows 2019 – DG TREN Scenario (EWI/ERGEG Demand)



Source: EWI.

46 TEN-E projects can be found on http://ec.europa.eu/energy/infrastructure/tent_e/ten_e_en.htm.

Assuming the higher ENTSOG demand (see Figure 66 and Figure 67 in the Appendix) volumes through Nabucco are increasing (especially on the section from Bulgaria to Hungary) compared to the EWI/ERGEG demand scenario and more gas is transited via Austria to Italy.

Based on the higher ENTSOG demand, generally, fewer transits further to the (north-)west take place as demand is higher in eastern Europe in this scenario and gas is already consumed there. To supply the higher demand in the west, more LNG is imported in Spain, France, and UK. (The regasification terminals (colored spots) are much higher utilised in Figure 66 than in Figure 18.) The consequence of the increased LNG imports is a reduction of pipeline imports to the UK. In addition, more gas is exported from Spain to France. Another effect is that Norwegian is gas pushed further east from the UK and France to Belgium and Germany and replaces some Russian gas whereas Russian gas is routed to a larger extent towards Italy or it is consumed in eastern Europe. (See Figure 66 and Figure 67 in the Appendix.)

LNG Glut Scenario

The LNG Glut Scenario has the intention to analyse the effect of (temporary) low LNG prices on gas flows in Europe within the modelling framework of TIGER. Hence, LNG volumes are assumed to be available at very low costs in this scenario (see Section 4.1).

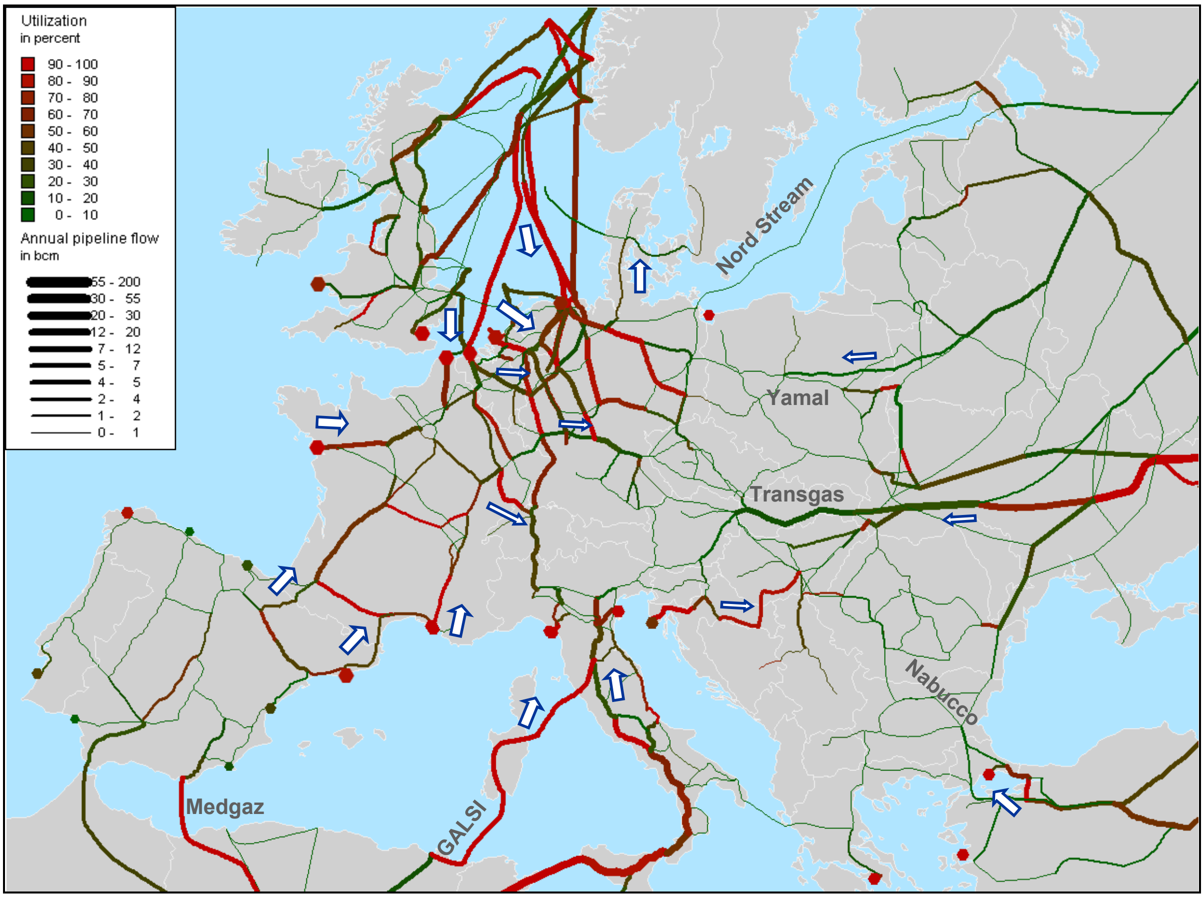
LNG imports rise significantly in every country and especially in the major LNG importing countries Spain, France and UK. (See Figure 12 for the LNG import volumes and Figure 19 and Figure 69 for the utilisation of the terminals.)

In comparison to the other scenarios, the terminals in northern France and the UK are much higher utilised as well as the pipelines from these terminals. Furthermore, a high utilisation of the pipeline from the Krk terminal in Croatia becomes evident. (See Figure 19 and Figure 69.)

In this case, no gas is transported via Nord Stream[47] and Yamal and Transgas are only utilised to a low degree. Pipelines in France and Spain are highly utilised. More gas is exported from Spain to France on the MidCat pipeline, especially in the winter months.

[47] In this specific LNG Glut scenario, all Nord Stream volumes are crowded-out. This is based on the assumption that all gas volumes in take-or-pay contracts can be reduced to zero, which is rather unrealistic to this extent. However, the intention of the LNG Glut simulation was to analyse the effects of this extreme scenario more in qualitative terms showing that low LNG costs in the LNG Glut Scenario might reduce pipeline imports as much as they can flexibly be withheld.

Figure 19: Annual Gas Flows 2019 – LNG Glut Scenario (EWI/ERGEG Demand)



Source: EWI.

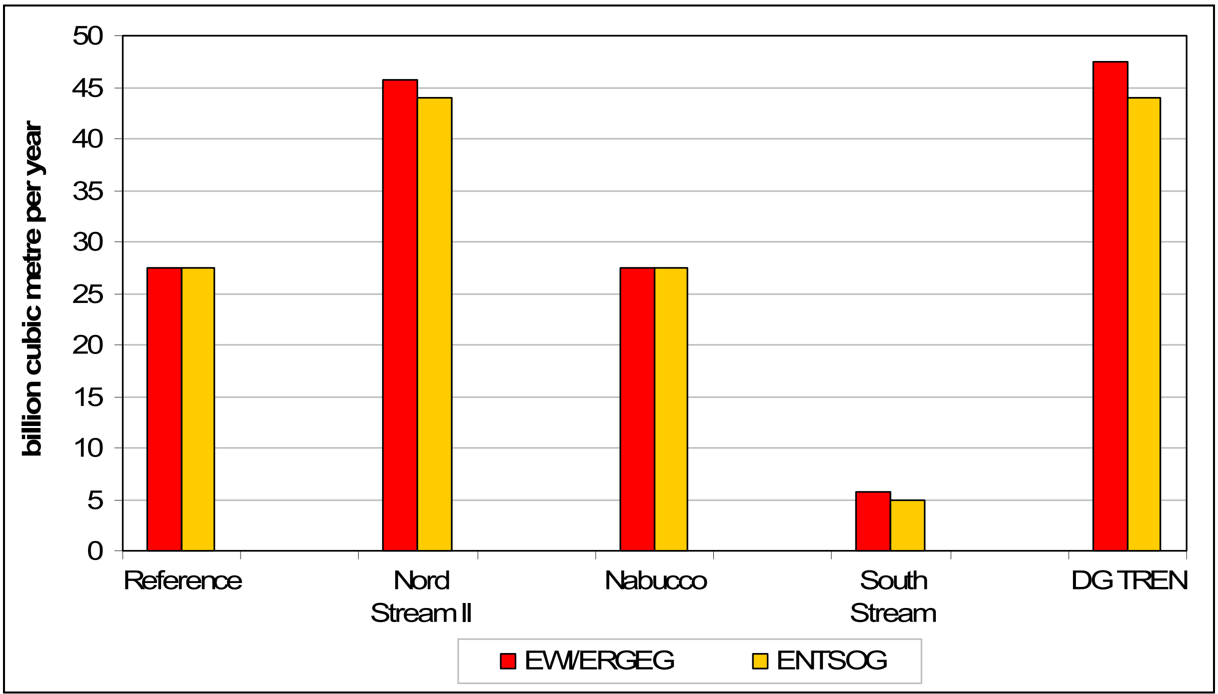
Generally, the main flow directions are turning eastwards, especially in western and central Europe. LNG imported in Spain is exported to France and LNG from UK to the continent. In addition, Norwegian gas is routed further towards the continent as there are less LNG import capacities than in the UK. A general decline of gas flows on all pipeline import routes results.

For the high ENTSOG demand scenario (see Figure 69), there are only minor changes, the most significant being that more Russian gas is transported to northern Italy compared to the EWI/ERGEG demand scenario.

7.2 Nord Stream, Nabucco, and South Stream Gas Flows

For the major new import pipeline projects, the pipeline utilisations already indicated in the previous section are quantified and compared for all scenarios in this section.

Figure 20: Nord Stream – Aggregated Gas Flows in 2019

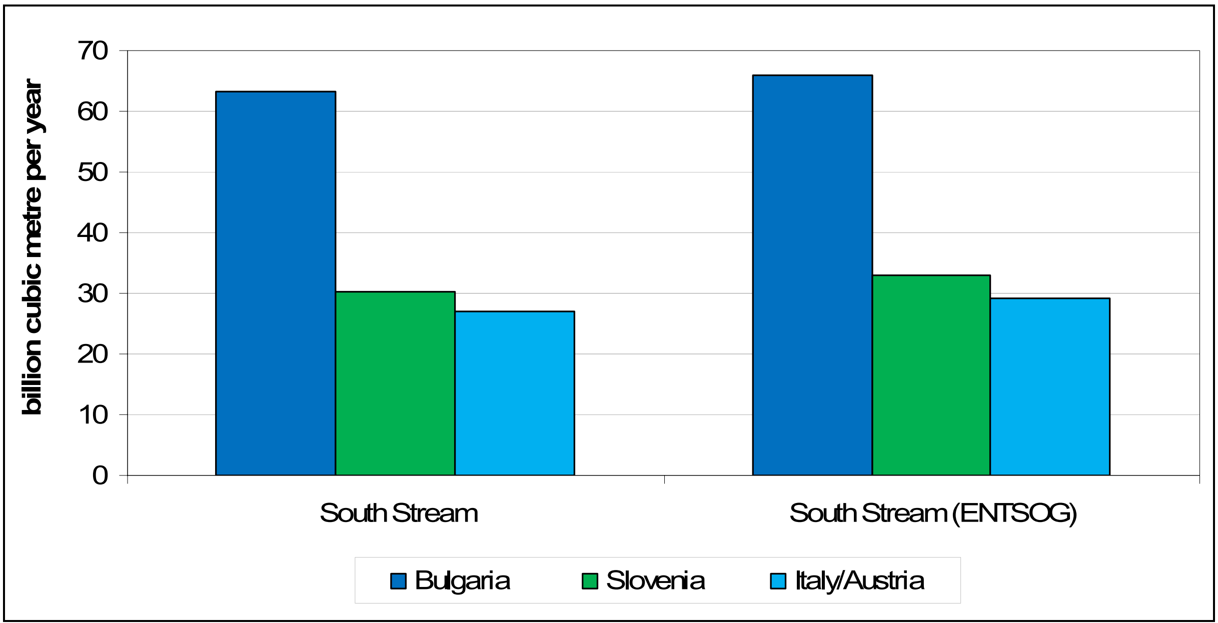


Source: EWI.

Figure 20 shows the aggregated Nord Stream gas flows for 2019 for the five different infrastructure and two different demand scenarios. It becomes evident that Nord Stream gas flows are partially cannibalized by South Stream volumes as in this scenario only approximately 5 bcm are routed via Nord Stream compared to 27.5 bcm in the Reference Scenario.[48] However, Nord Stream imports remain high in the Nabucco Scenario. Therefore, it can be concluded that these two pipelines are rather complements than substitutes. Despite the higher ENTSOG demand, in some of these scenarios, there are slightly less gas volumes imported via Nord Stream compared to the EWI/ERGEG demand scenarios as more LNG is imported (causing Russian gas to be consumed to a larger extend in eastern Europe).[49]

[48] This is due to the fact that Russian gas export volumes are restricted.
[49] The LNG Glut Scenario is not mentioned here as in the extreme case modelled in this simulation under the given assumptions, volumes transported via Nord Stream are even reduced to zero if no contractual flows are enforced. See Section 7.1.

Figure 21: South Stream – Aggregated Gas Flows in 2019

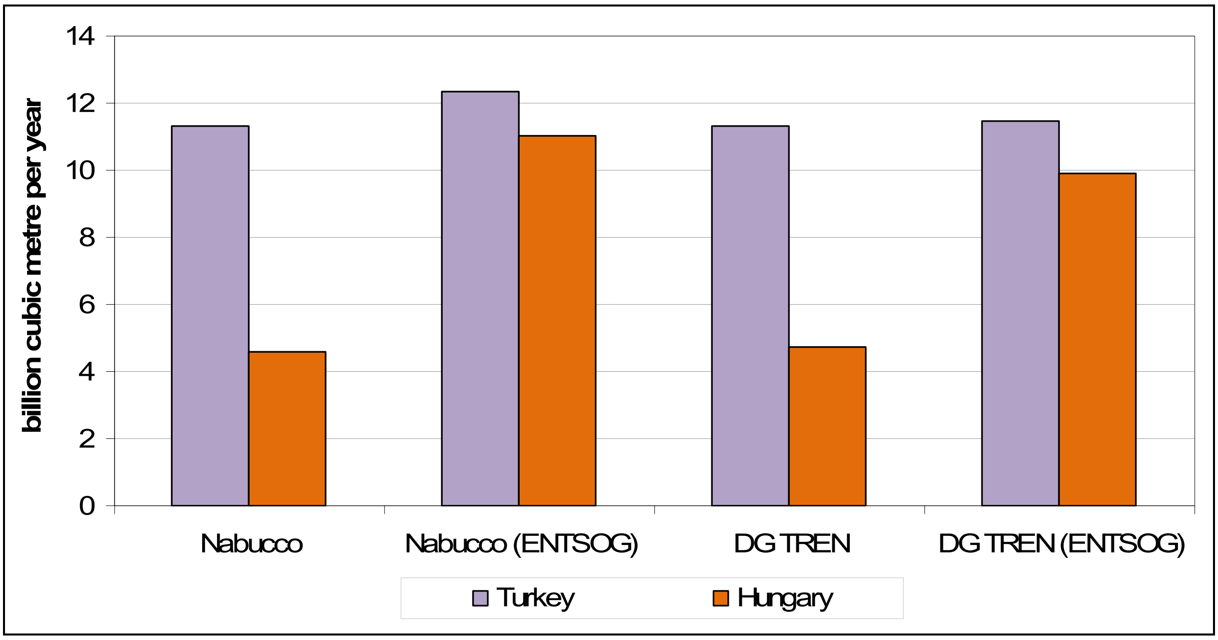


Source: EWI.

Figure 21 presents the aggregated gas flows on the different pipeline sections of South Stream for 2019 (only for the two demand variations in the South Stream Scenario as South Stream is only included in the other infrastructure scenario). Most of the South Stream volumes are already withdrawn and consumed in south-eastern Europe and only half of the volumes that are transported to Bulgaria get to Slovenia or Italy and Austria. The pipeline section to Baumgarten is not used but significant volumes (about 25 bcm) are transported to the Austrian/Italian border.

The aggregated Nabucco gas flows in 2019 on the pipeline sections through Turkey and through Hungary are presented in Figure 22 for the Nabucco and DG TREN infrastructure scenarios in which Nabucco is included (with the two demand variations for each). The utilisation of Nabucco is less than 50 percent on an annual level because a large share of volumes already remains in Turkey and south-eastern Europe (Bulgaria, Romania). Volumes to Hungary are only significant in the ENTSOG demand scenarios. Again there are almost no transits to Baumgarten, Austria, which is due to the cost-optimal dispatch of the TIGER model simulation causing Nabucco gas volumes to remain in eastern Europe as they are swapped with Russian gas which is transported to Baumgarten instead.

Figure 22: Nabucco – Aggregated Gas Flows in 2019



Source: EWI.

8 Market Integration

This chapter analyses physical market integration between the natural gas markets in the different EU member states with respect to the location of potential bottlenecks and their implications on security of supply in 2019. In order to assess the integration of the natural gas markets in the different countries, market integration is initially defined.

8.1 Specification of Market Integration

Generally, the economic literature considers an integrated market as one where there are no impediments to trade, where all arbitrage opportunities within the market can be exploited and where, consequently, the Law of One Price holds meaning there are no price differences within the market (provided the good can be supplied to all locations within the market at the same costs).[50] Hence, the possibility to trade is an important prerequisite. Barriers to trade can thereby stem from taxation (import or export duties), high transaction costs or physical limits to trade. If none of these impediments to trade is in place, prices in a market would correlate perfectly.

However, natural gas is not an example for such a market. It is a grid-bound commodity and transports costs are also a significant proportion of its price.[51] Even without any physical limits to trade, prices would, hence, differ between European countries in an efficient market. As natural gas is a grid-bound commodity, trade is also highly dependent on the availability of the infrastructure to transport it (from the market with low to the market with the higher price).

In the context of an analysis of the natural gas infrastructure, the model-based approach applied in this study is suitable to investigate this physical market integration, i.e. whether the gas infrastructure provides the prerequisites for an integrated European natural gas market.

Other dimensions of market integration, especially those concerning transaction costs, are not considered. High transaction costs might, for example, arise from non-harmonised market regimes, different capacity allocation methods or illiquid natural gas trading. If such issues complicate trading for market players and increase its costs, the European natural gas market

[50] See Baulch (1997) and De Vany and Walls (1996) for discussions on price convergence and market integration, also in the context of natural gas markets (De Vany and Walls, 1996).

[51] According to the assumptions applied in the model (see Section 3), transports costs are 1.36 EUR/MWh/1000 kilometres, which equals about 15 percent of the presumed border price for Russian gas imports (see Table 1).

may still not be integrated, even if the analysis in this study finds parts of the gas market to be well integrated physically.

The approach applied to investigate market integration in this study is based on price convergence in integrated markets: The location- and time-specific marginal supply costs computed by the model can be interpreted as price indicators under the assumptions of a competitive European gas market with an efficient capacity allocation method. 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, i.e. the price difference should lie within the parity bound determined by transport costs.[52] (Transport costs in the model are based on the assumed variable transport costs and length of the transportation route.) If it were not and physical transport capacity were still available, traders in a functioning market would always continue to move gas from the low to the high price location to profit from arbitrage. Hence, in the simulated competitive market, any price differences exceeding transport costs can only be a consequence of a physical infrastructure bottleneck which, at least temporarily, leads to a non-integrated market.

When interpreting the results presented in the next sections, 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. Second, due to the interdependencies between all elements in the gas supply 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.[53] In addition, 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 focuses on bottlenecks between countries. Although the applied model allows an investigation of bottlenecks within countries, for a parameterisation in 2019 this would require an elaborate specification of natural gas

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[52] Parity bound implies that a price difference below this threshold means the market is still integrated, see Baulch (1997).

[53] See Lochner (2009).

demand developments on a regional level, which is not the focus of this study. Therefore, potential bottlenecks which may arise between balancing areas inside a single country under certain scenarios are 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 merely 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. They are limited to the congestion which occurs in an efficiently working market; potential additional congestion as a consequence of 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 economic gains from such an investment (reduced economic cost of the bottleneck) with the monetary size of the investment necessary to do so (i.e. capital expenditure for new pipeline or interconnector). Only if the economic gains exceed the costs, it would be beneficial to make the investment. Analysing this is beyond the scope of this study.

Moreover, as explained in Section 3.1, the bottlenecks presented here do not cover potential congestion that might originate from inefficient capacity allocation or congestion management.

8.2 Overview of Bottlenecks

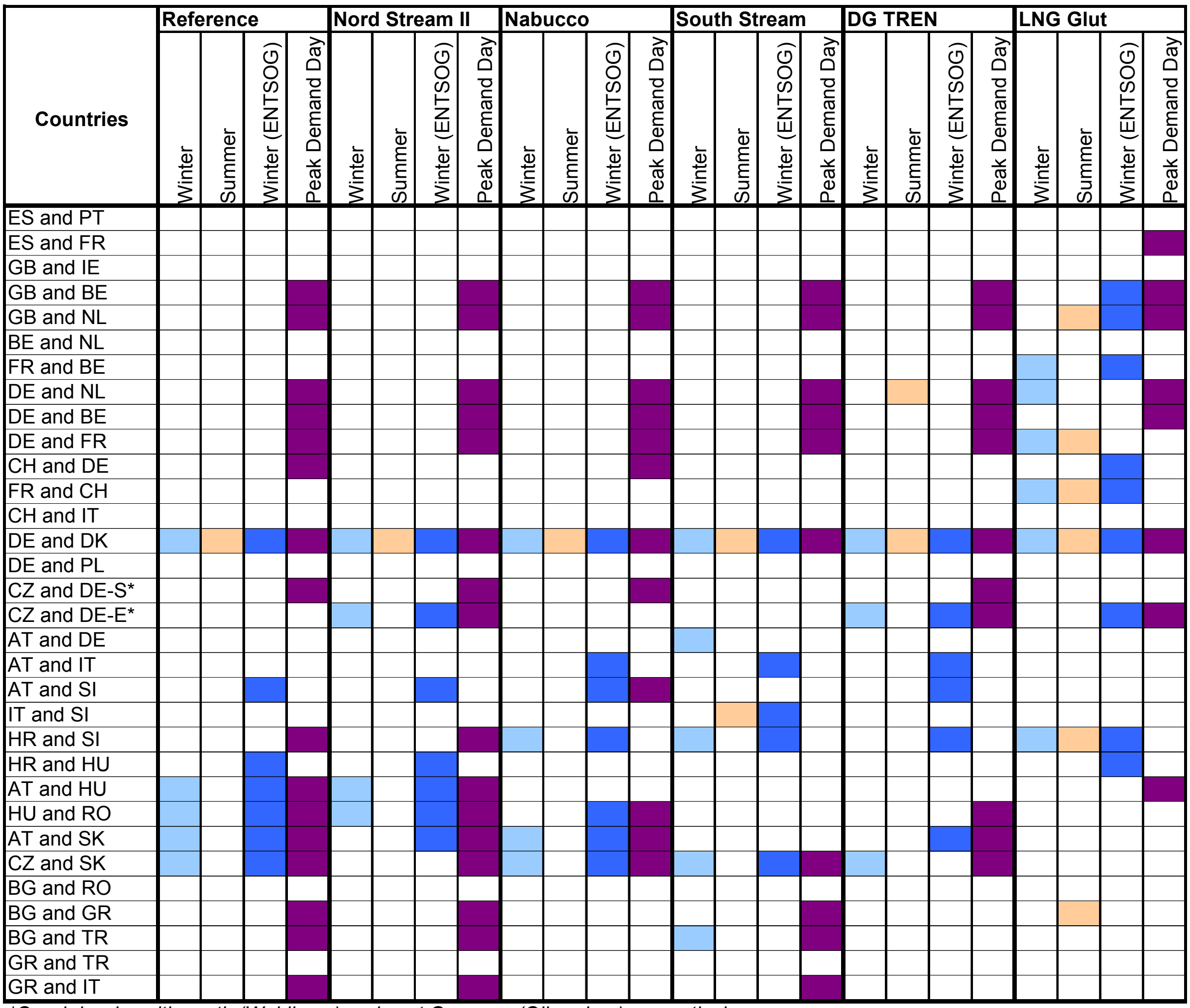
As the following sections provide an in-depth analysis of each identified bottleneck, we first consider an overview of all combinations of countries considered. Generally, each European country is investigated for market integration with all its neighbouring countries individually.[54] For each of the six scenarios, an average winter day with demand according to both, EWI/ERGEG and ENTSOG, an average summer day with EWI/ERGEG demand, and the peak demand day (ENTSOG assumption) are considered. The results are presented in Table 4.[55] White fields in the matrix imply no bottlenecks between the countries in the respective scenario on the respective day; a coloured field indicates there is one. The colours,

[54] Except for neighbouring countries where no pipeline link either exists or is being planned, e.g. Italy and France.

[55] See Table 8 (page 119) for an overview of the used ISO country codes.

thereby, indicate the type of day. Although it may be clear in most cases, it has to be noted that Table 4 does not indicate the direction of the bottleneck between the countries, as it may differ between scenarios and as there is no predominant flow direction for some combination of countries.

Table 4: Overview Market Integration (Location of Bottlenecks)



**Czech border with south (Waidhaus) and east Germany (Olbernhau) respectively*

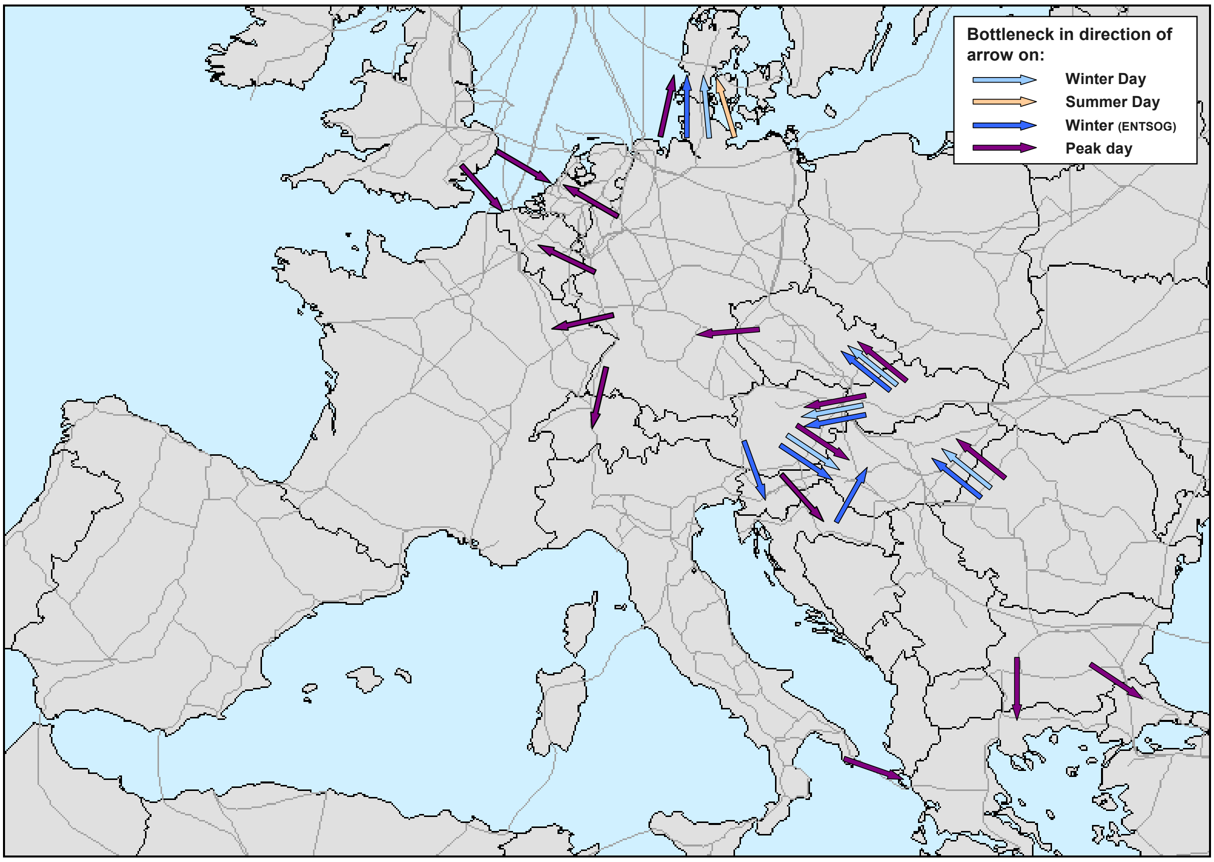
Note that table does not indicate direction of bottlenecks, see subsequent sections and figures.

No Bottleneck
Bottleneck on average winter day (EWI/ERGEG)
Bottleneck on average summer day (EWI/ERGEG)
Bottleneck on average winter day (ENTSOG)
Bottleneck on peak demand day (ENTSOG)

Source: EWI.

For the Reference and LNG Glut scenarios, Figure 23 and Figure 24 visualise the identified bottlenecks on the respective days with the arrows pointing into the direction of the bottleneck. (For the other four scenarios, these charts can be found in the Appendix.) Furthermore, details on all identified bottlenecks (including their direction) are discussed in the subsequent sections.

Figure 23: Bottlenecks Reference Scenario 2019

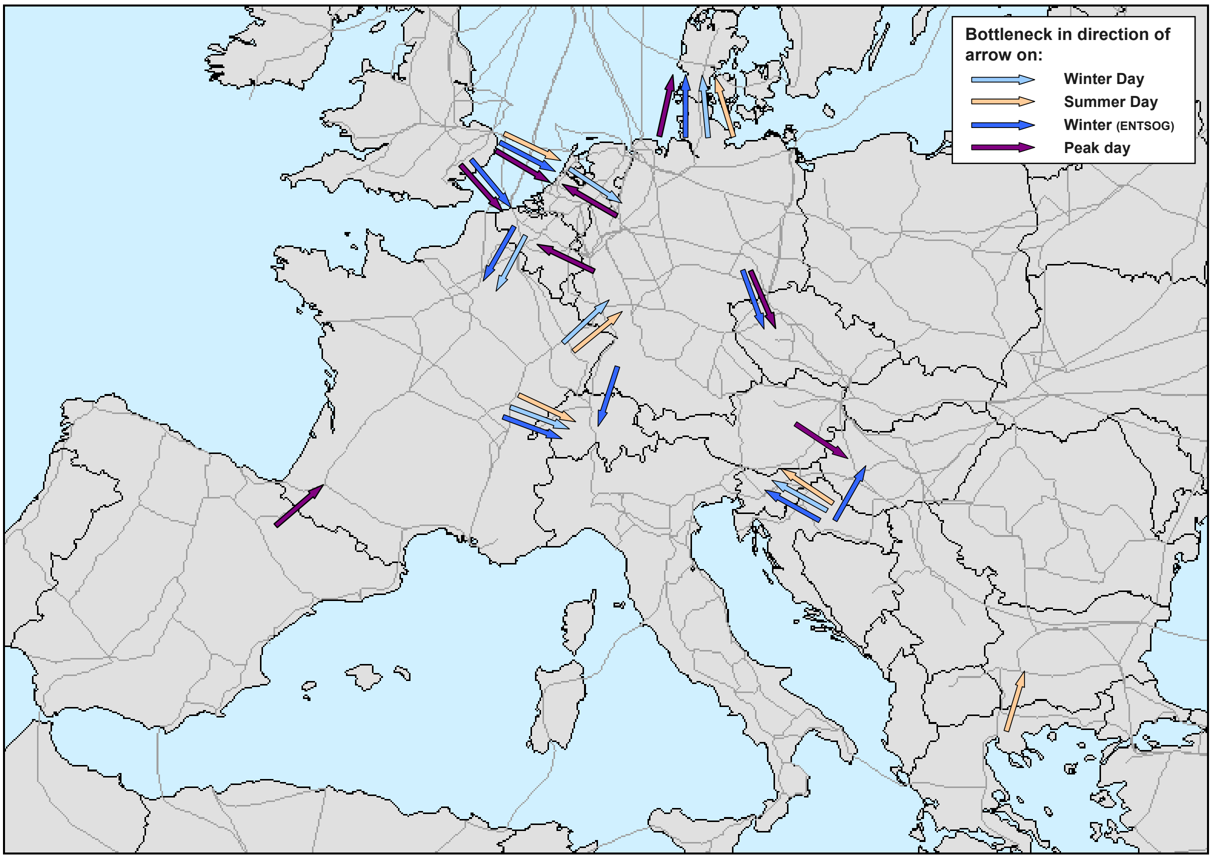


Source: EWI.

Generally, it can be noted that most European countries are well integrated on the average winter and summer days (in all scenarios and with both demand assumptions). The only persistent bottleneck is between Germany and Denmark. In 2019, according to the applied ENTSOG demand and supply scenarios, Danish (and Swedish) consumption cannot be met by the assumed existing import capacity and Danish production. Hence, large price increases in Denmark would be observed implying a large marginal supply cost difference to Germany and demand for additional capacity between the countries.

In eastern Europe, some bottlenecks are identified between Hungary, Slovenia and the Slovak Republic and some of their neighbouring countries. While the costs of these bottlenecks differ significantly (see Section 8.3), they can generally be observed in winter in both demand scenarios and on the peak days. However, it also has to be noted that the large-scale infrastructure projects in south-eastern Europe, Nabucco and South Stream, help to eliminate some of these bottlenecks.

Figure 24: Bottlenecks LNG Glut Scenario 2019



Source: EWI.

In the region of western Europe, bottlenecks between some of the countries arise in the simulation, but only on the concurrent peak day and in times of low LNG prices. On the concurrent peak demand day, there are bottlenecks between the region of France, Belgium and the Netherlands and all its surrounding neighbours. In between this group of countries, the market seems to be well integrated physically. In times of low LNG prices, the model finds that more LNG could be transported from the LNG import capacities in the west further to the east if more capacity were available. Specifically, bottlenecks between the UK and the continent, France and all its eastern neighbours and the Benelux countries and Germany are identified. (Similar issues arise from the Croatian Krk LNG terminal to neighbouring countries when LNG prices are low.)

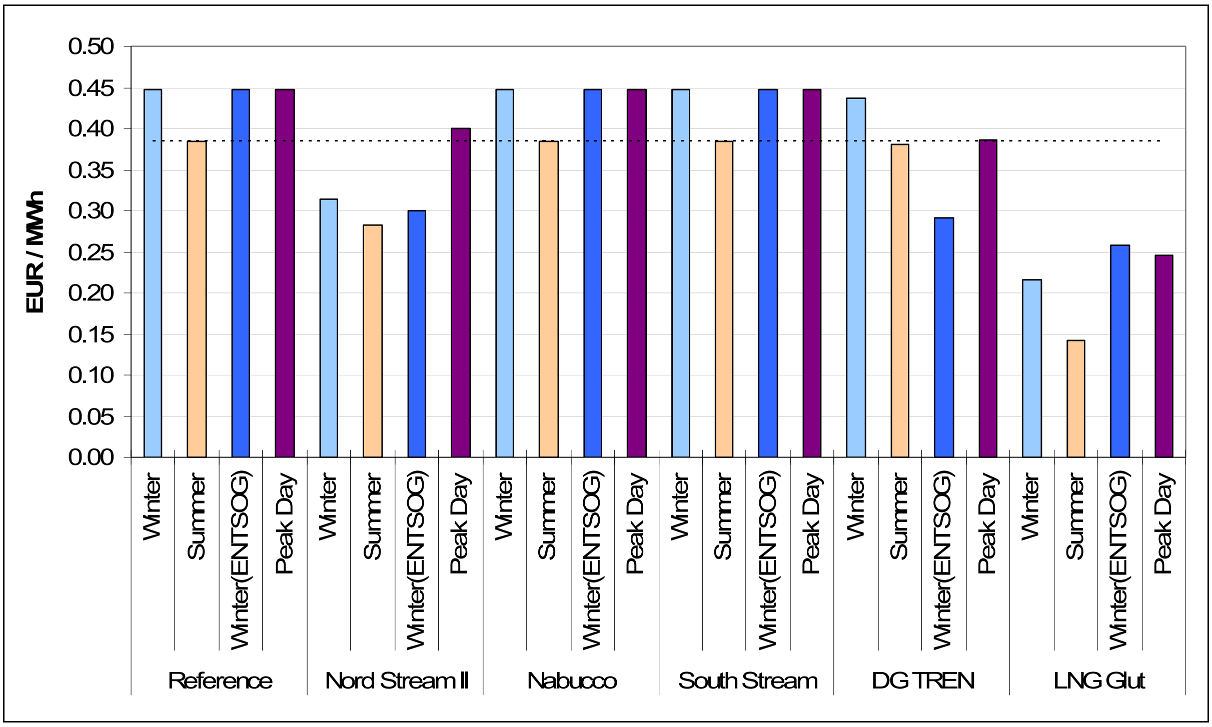
In the following sections, all these bottlenecks are discussed in detail. The detailed graphs of the country combinations without bottlenecks (see Table 4), which are omitted in the following sections, can be found in Appendix (starting page 136). An explanation of the graphs is also illustrated in Figure 70 (page 134).

8.3 Eastern Europe: Hungary, Slovak Republic and neighbouring countries

The bottlenecks regarding Hungary and the Slovak Republic indicated in Table 4 are found to differ significantly when investigated in detail.

Regarding the Slovak Republic, the costs of the bottleneck (difference in country-specific marginal supply costs in excess of transport costs[56]) to the Czech Republic is small, as can be seen in Figure 25 and can largely be explained by bottlenecks within the Czech grid.[57]

Figure 25: Marginal Supply Cost Difference between the Czech and Slovak Republics



Source: EWI.

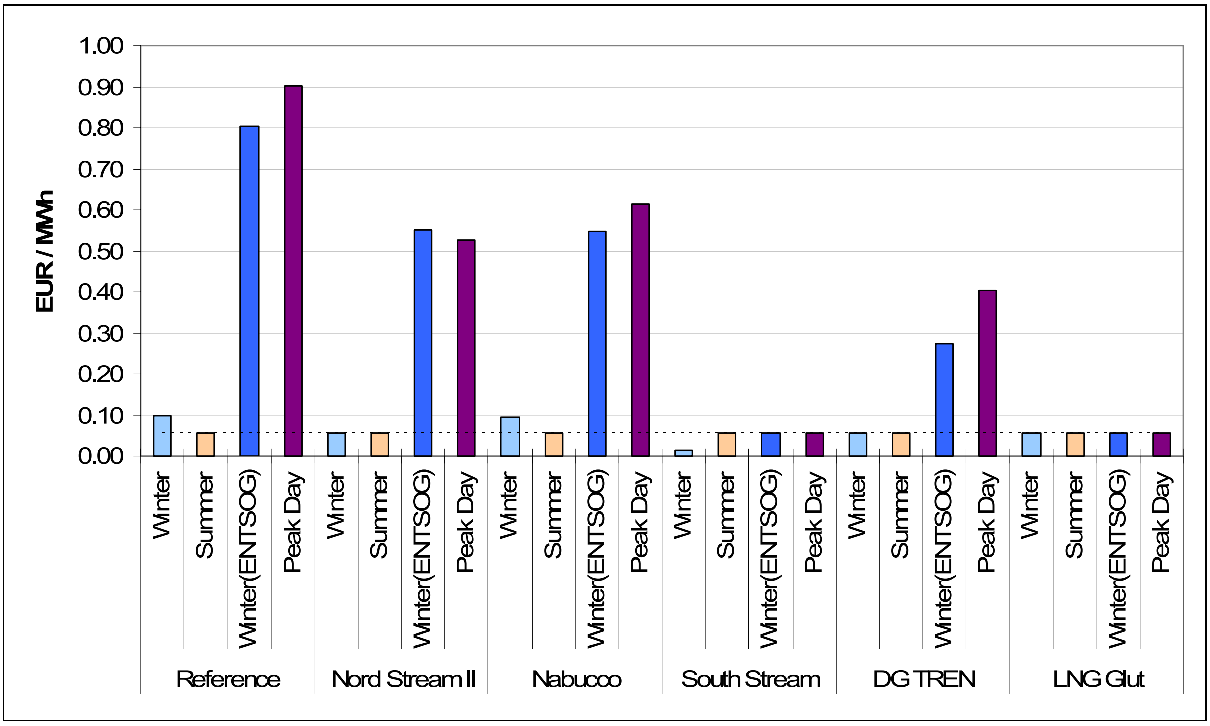
For the connection from the Slovak Republic to Baumgarten, Austria (Figure 26), the economic costs of the bottleneck are higher in times of high demand, i.e. on the peak demand day or in winter with the higher ENTSOG-demand. In these cases more Russian gas could be transported via Slovakia to Austria (and further west) if more capacity on the route were

[56] See Figure 70 (page 134) for an illustration of the interpretation of the following charts. Generally, the bars indicate the supply cost difference between the countries (first named country in caption minus second stated country); the dotted line represents the transport costs between those countries. If the cost difference exceeds the transport costs, further arbitrage would be beneficial but cannot take place (which would lead to a smaller cost difference) as there is not sufficient capacity available. Hence, there must be a physical bottleneck. The colours of the bars only indicate the type of day (corresponding to the colours in Table 4): Winter day EWI/ERGEG in light blue, summer day in Navajo white, winter day ENTSOG in blue, and peak demand day in dark magenta.

[57] A representative location in the centre of the Czech Republic was chosen as a reference.

available. This is generally possible in all scenarios after 2012 when the first line of Nord Stream is completed and, hence, less Russian gas via Slovakia is transported towards Germany freeing up capacity on this route for gas transports to Austria and Italy. While the interconnection between Slovakia and Austria is always highly utilised, it only constitutes a bottleneck in times of high demand (peak day or winter with ENTSOG demand). When South Stream is in place as a second transport route for Russian gas to Austria and Italy, this bottleneck disappears even in times of higher demand.

Figure 26: Marginal Supply Cost Difference between Austria and the Slovak Republic



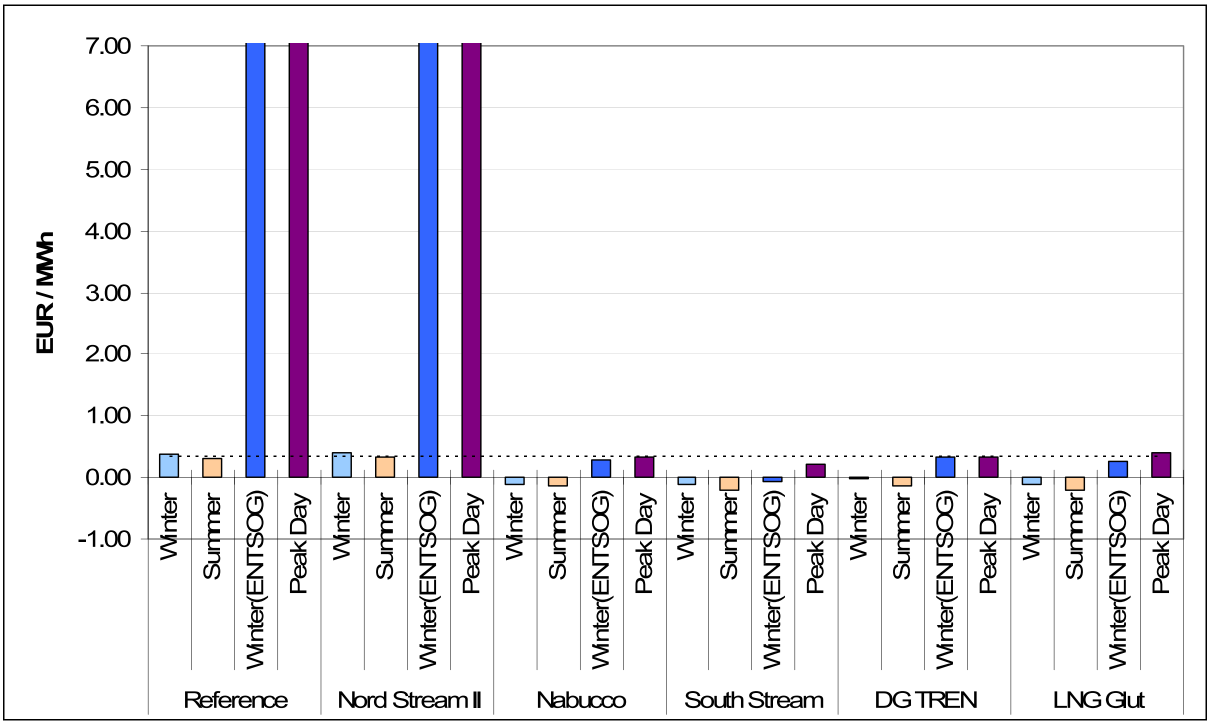
Source: EWI.

The case is generally different for the bottlenecks between Hungary and the surrounding countries, see Figure 27 and Figure 28. In the scenarios without South Stream or Nabucco, which both provide new import capacity to Hungary,[58] demand on peak days or on winter days with higher demand (ENTSOG demand scenario) cannot be met and the marginal supply costs increase significantly. (For a discussion of the supply-demand gaps and security of supply implications arising from the bottlenecks, see Section 8.10 on page 91.) Hence, the cost of the bottleneck, or the economic value of additional capacity, between Hungary and both, Austria (Figure 27) and Romania (Figure 28), increases significantly. In the summer

[58] Nabucco directly and South Stream has exit points in Serbia which is relatively well connected with the Hungarian grid.

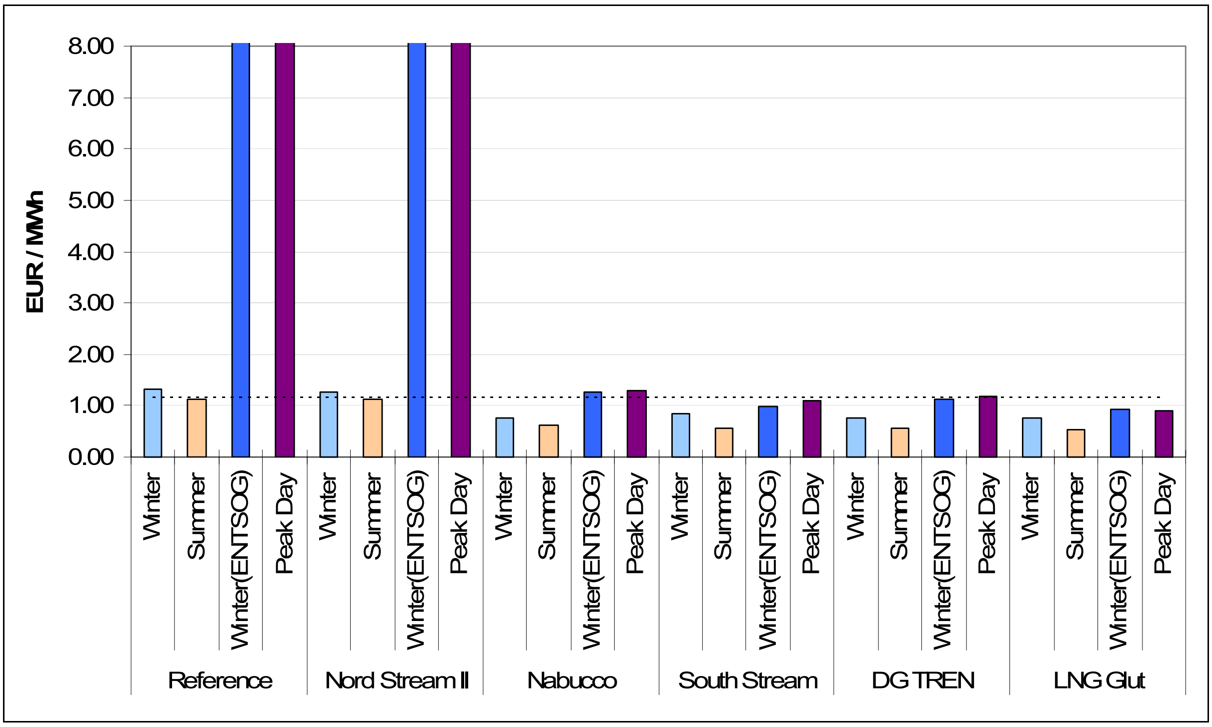
months, and in scenarios with either South Stream or Nabucco, market integration of Hungary and the neighbouring countries is, however, less of an issue.

Figure 27: Marginal Supply Cost Difference between Hungary and Austria



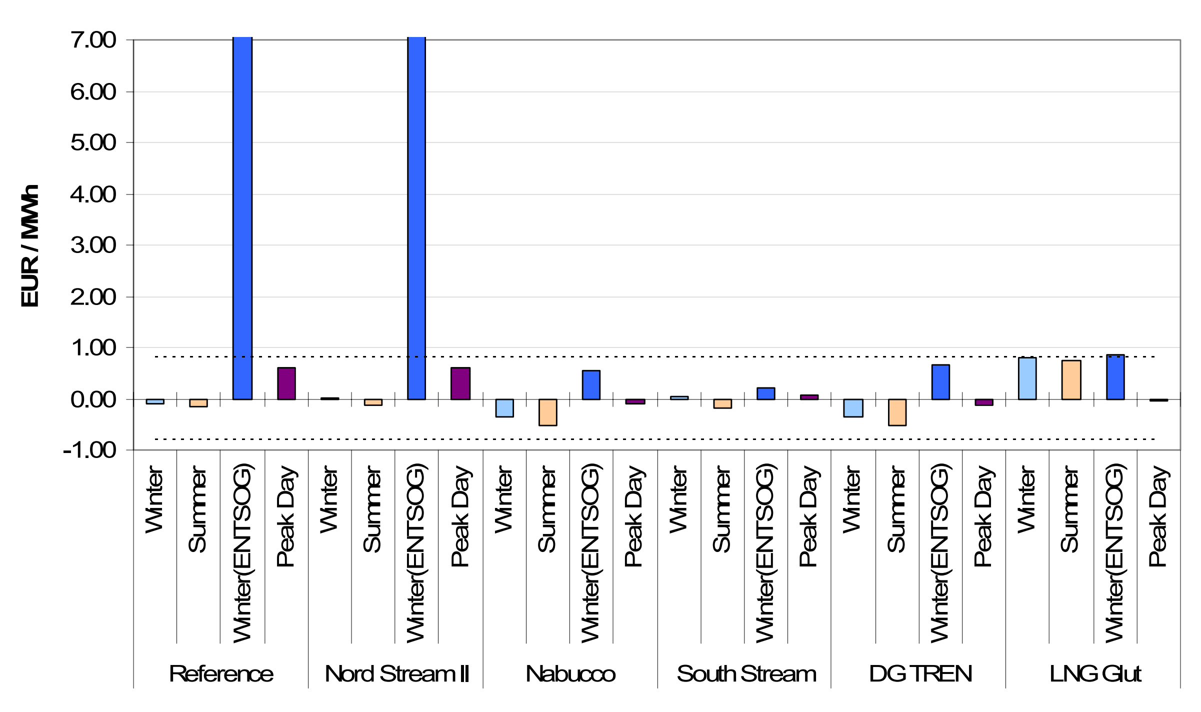
Source: EWI.

Figure 28: Marginal Supply Cost Difference between Hungary and Romania



Source: EWI.

Figure 29: Marginal Supply Cost Difference between Hungary to Croatia



Source: EWI.

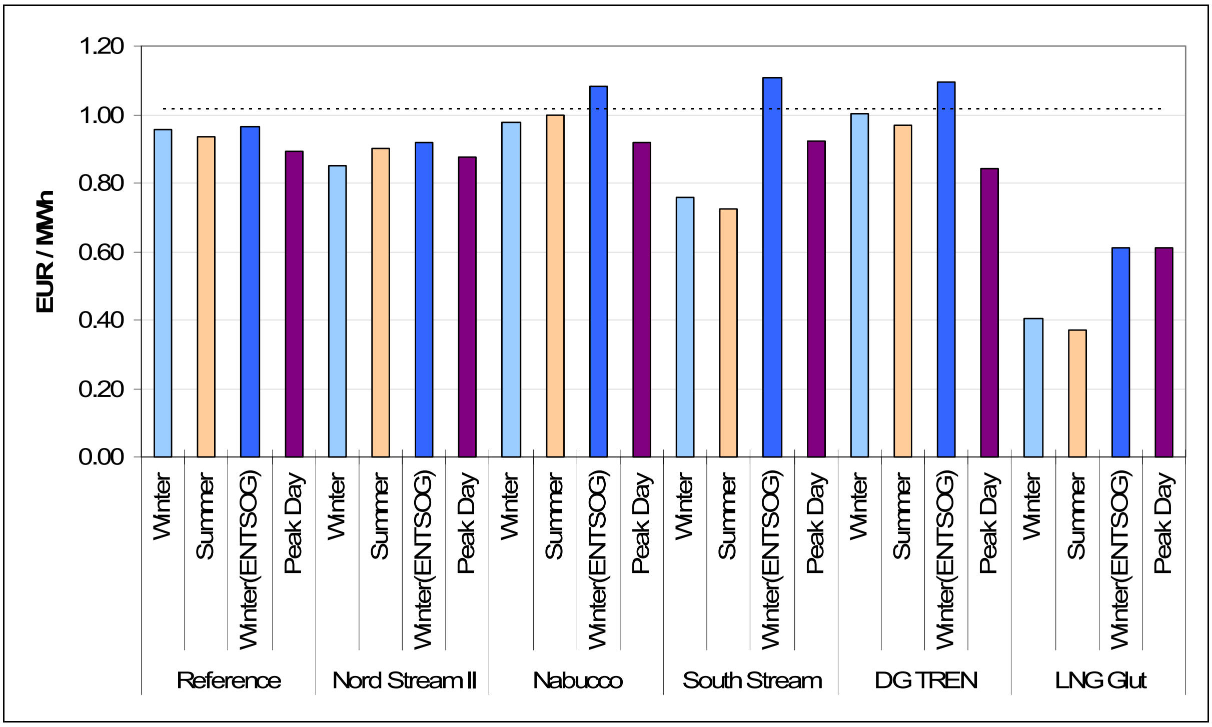
The same holds true for the (new) interconnection pipeline between Hungary and Croatia (see Figure 29). However, the marginal supply cost difference only increases to infinity on the average winter day in 2019 with the ENTSOG demand. With capacity being constant, this implies that it is fully utilised on an average winter day, but not the peak day. The reason for that is that with peak day demand, the potential for Croatian gas flows to Hungary is lower as domestic demand is also very high in Croatia. Thus, LNG imports, transits via Slovenia, and Croatian production do not allow utilising all the pipeline capacity to Hungary on such a day: On the peak day, capacity between Croatia and Hungary is sufficient. As there is not enough gas available in Croatia to fully supply the Hungarian market, the locational marginal supply costs increase in both countries. (See also next section regarding the integration of Slovenia and Croatia (Figure 33) which illustrates there is a bottleneck between these two countries similar to the ones between Hungary and Romania and Hungary and Austria on the concurrent peak day. This implies that Hungary and Croatia are well integrated with each other but not with all other neighbouring countries on this day. The supply-demand gaps, which only affect Hungary, are discussed in Section 8.10).

In the LNG Glut Scenario, additional gas transports from Croatia to Hungary would be economically feasible in winter if more capacity were available on the route. However, the marginal supply cost difference only slightly exceeds the cost of transportation, so the economic costs of this temporary bottleneck are rather small.

8.4 South-central Europe: Italy, Austria, Slovenia and Croatia

The gas markets of Italy and Austria are well integrated according to the simulation assumptions in 2019. The marginal supply cost difference between the two countries only slightly exceeds transport costs when additional gas volumes can be transported to Baumgarten in the scenarios with either South Stream or Nabucco being in place, see Figure 30. In theses cases, more gas could be transported on TAG if more capacity were available on a winter day with the higher ENTSOG demand. However, the cost of this temporary bottleneck is small and with the EWI/ERGEG demand assumptions, it entirely disappears. This is also true on the peak demand day when more gas is also consumed in eastern Europe making less gas available for transport from Austria to Italy.

Figure 30: Marginal Supply Cost Difference between Italy and Austria



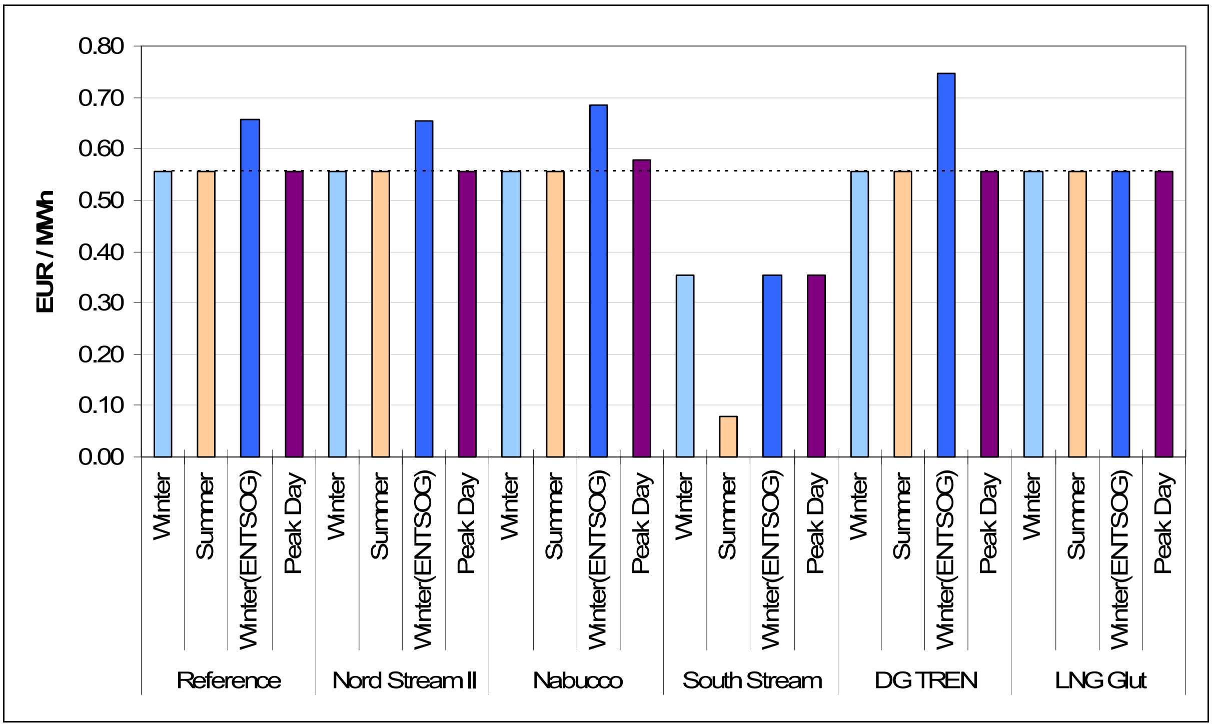
Source: EWI.

With all the assumed expansions of the interconnections of Slovenia with Italy and Austria, the country is similarly well connected with the gas markets in these two countries, see Figure

31 and Figure 32. Between Austria and Slovenia, larger gas transports would be economically feasible in winter 2019 (with ENTSOG demand) if more capacity were available between these two countries. However, the economic costs of this temporary physical bottleneck are rather small.

The results for both interconnection points (Austria to Slovenia and Austria to Italy) in selected scenarios show that there is congestion on the average winter but not on the peak demand day. This is explained similarly as the average winter day bottleneck between Croatia and Hungary (see previous section): On the average winter day, this congestion exists as more gas could be transport from Austria to these countries. However, with Austria having a relatively high peak day demand, the scope for gas flows to neighbouring countries is reduced on such a high demand day. More gas is consumed within Austria and cannot be transited further to the west or south. Hence, the congestion disappears.

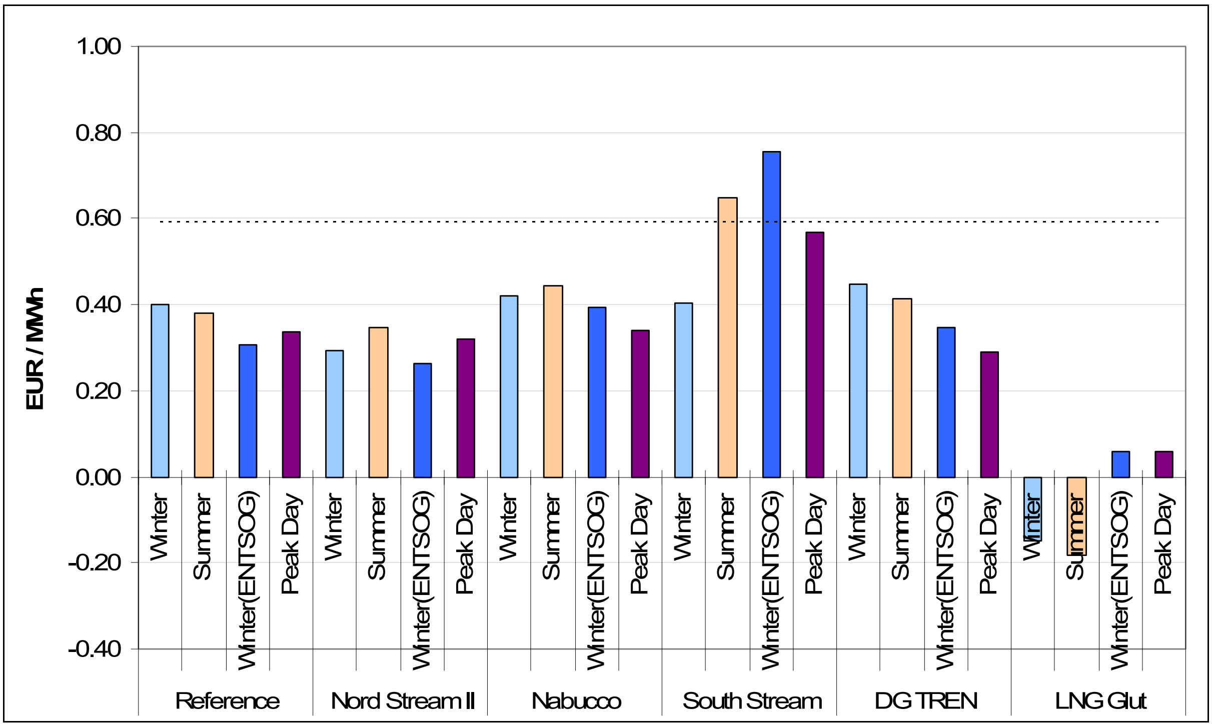
Figure 31: Marginal Supply Cost Difference between Slovenia and Austria



Source: EWI.

Regarding Italy and Slovenia, the model simulations do not yield any significant bottlenecks. (Note that the marginal supply cost difference is defined as Italy minus Slovenia in Figure 32 while it is Slovenia minus Austria in Figure 31!) A small and temporary bottleneck in the direction from Slovenia to Italy may only occur when South Stream provides additional volumes to Slovenia and Italy. Then, it may temporarily be more economic to withdraw more gas from South Stream in Slovenia and supply some parts of north-eastern Italy via the Italy-Slovenia pipeline than routing all gas volumes via the Austrian-Italian border (where South Stream "ends").[59] However, the overall economic savings would be small making the bottleneck less relevant.

Figure 32: Marginal Supply Cost Difference between Italy and Slovenia



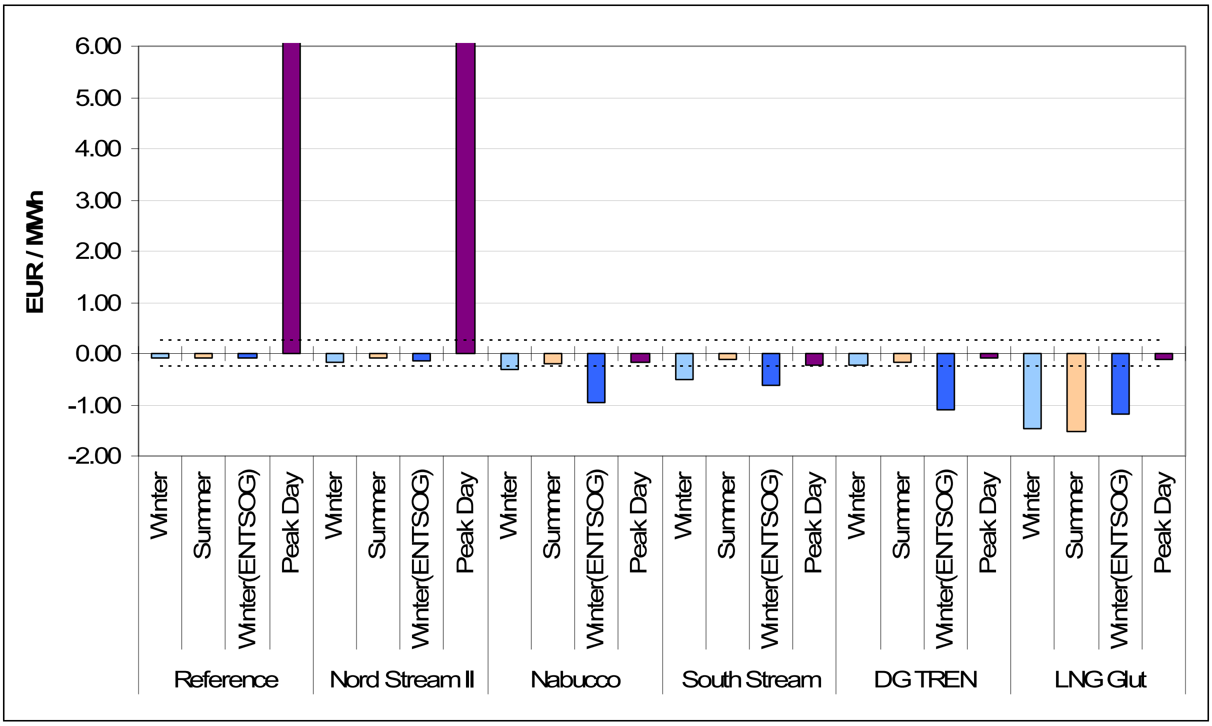
Source: EWI.

Considering the integration of the markets between Slovenia and Croatia (see Figure 33) unveils two relevant findings. First, the observation from the previous section that peak winter day demand in Hungary and Croatia causes an increase in supply costs in those countries, when neither Nabucco nor South Stream is built, is confirmed. Hence, this implies that all import infrastructures into these two countries are fully utilised and that additional infrastructure between Slovenia and Croatia would be of economic value. However, this is only true on the peak day. Second, there is a bottleneck in the reverse direction in some time periods when Nabucco or South Stream is in place (the negative marginal supply cost difference in Figure 33 with the absolute value exceeding transport costs). Both pipeline projects increase the general availability of gas in south-eastern Europe. Hence, more gas could be transported via or from Croatia (Krk LNG imports) to Slovenia if more capacity

[59] This is determined by the modelling approach which always prefers the shortest route.

were available in times of high demand. This is especially severe in times of temporarily low LNG prices (LNG Glut Scenario) when the limited capacity between Croatia and Slovenia prevents further LNG imports in Krk for the Slovenia market.

Figure 33: Marginal Supply Cost Difference between Croatia and Slovenia



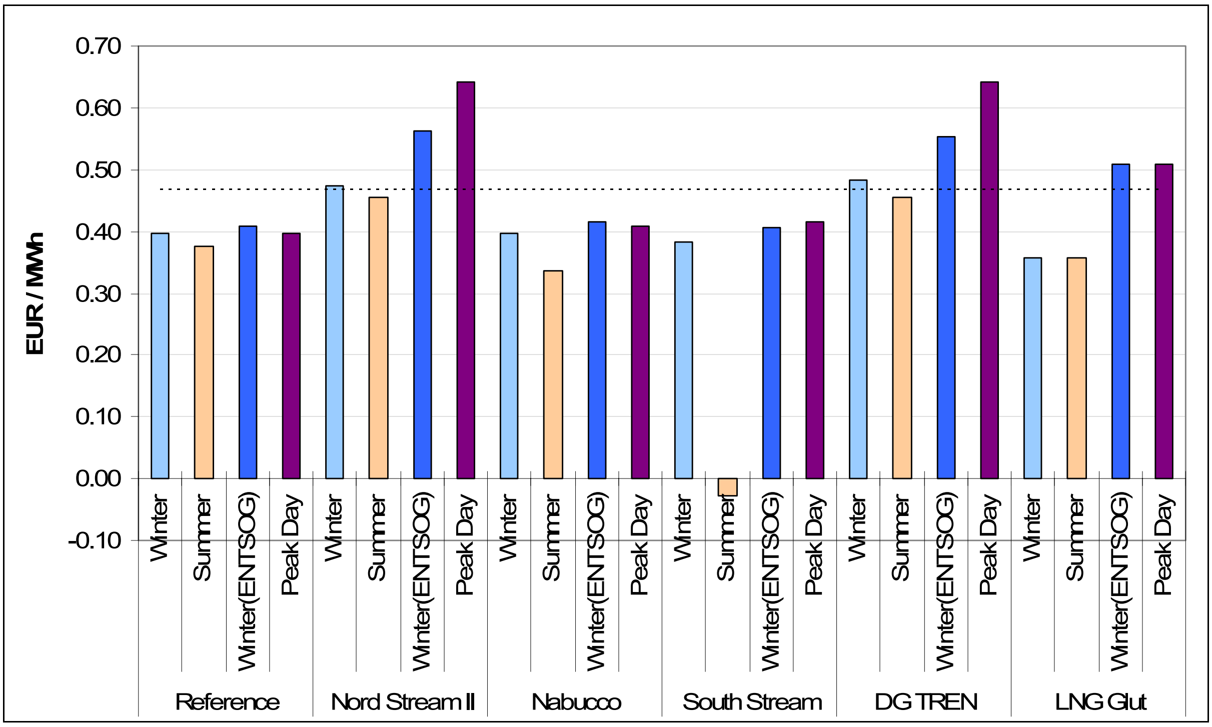
Source: EWI.

8.5 Central Europe: Germany and neighbouring countries

Regarding the market integration of Germany with its neighbouring countries, Table 4 illustrates that there is a persistent bottleneck to Denmark and some temporary bottlenecks with its western neighbours and the Czech Republic. The integration to the west is discussed in Section 8.7 and with Denmark in Section 8.6. For the countries where no bottlenecks to Germany exist, the respective charts can be retrieved in the Appendix: Austria (Figure 77), Switzerland (Figure 78) and Poland (Figure 80).

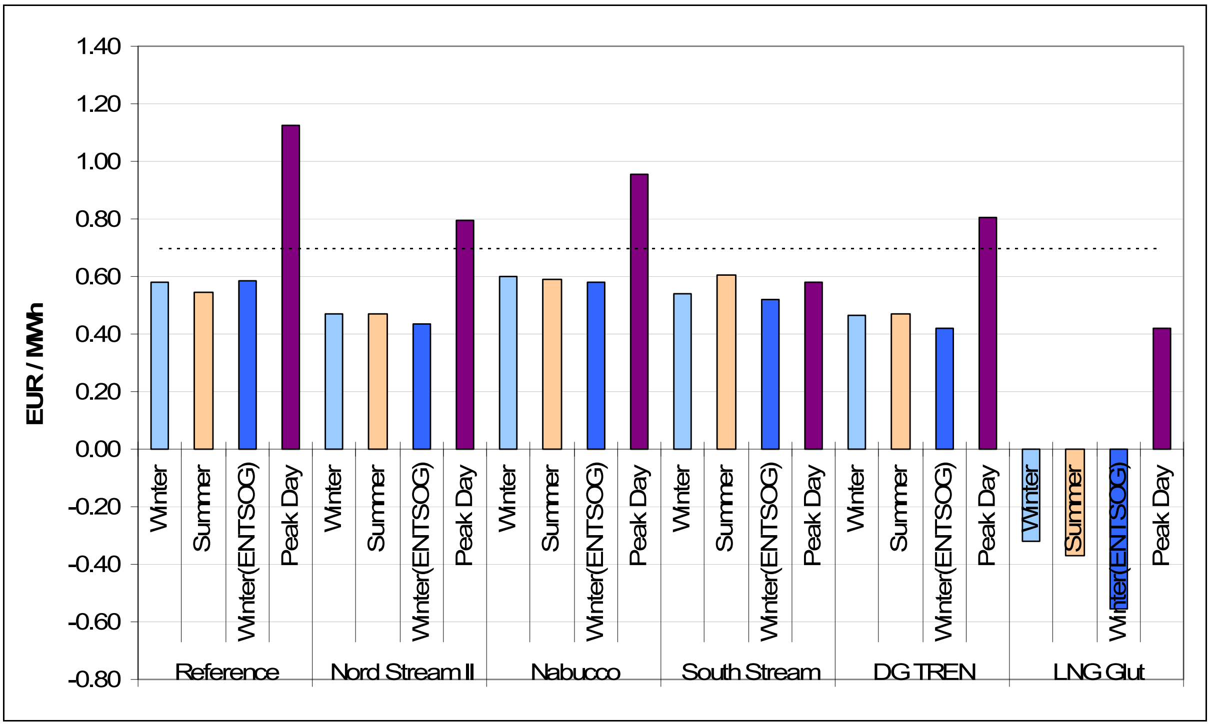
The gas flow analyses in Section 7.1 have shown that in 2019, natural gas imports on Nord Stream in north-eastern Germany are (partially) transported south on the OPAL pipeline to the German-Czech border in Olbernhau and in the Czech Republic on the Gazelle pipeline to the Czech-German border in Waidhaus. Hence, the gas volumes exit Germany to the Czech Republic in eastern Germany and re-enter southern Germany from the Czech Republic. This requires the analysis of two potential bottlenecks. The marginal supply cost differences between the Czech Republic and eastern Germany are displayed in Figure 34; the ones between southern Germany and the Czech market in Figure 35.

Figure 34: Marginal Supply Cost Difference between the Czech Republic and north-eastern Germany



Source: EWI.

Figure 35: Marginal Supply Cost Difference between southern Germany and the Czech Republic



Source: EWI.

For the connection from eastern Germany to the Czech Republic (OPAL pipeline), it becomes evident that capacity is sufficient for one line of the Nord Stream pipeline (scenarios Reference, Nabucco and South Stream). When a second line of Nord Stream doubles capacity to 55 bcm/year (scenarios Nord Stream II and DG TREN), there is a temporary bottleneck between eastern Germany and the Czech Republic in winter as even more gas from Nord Stream could be transported further to Czech consumers. However, apart from its temporary nature, the economic costs of the bottleneck are rather small.

Regarding the market integration of southern Germany and the Czech Republic (Figure 35), there is only a bottleneck on the peak demand day. For all other demand variations, the capacities in Waidhaus are sufficient to ensure an integration of the Czech and German markets. It is noteworthy, that the marginal supply cost difference between Germany and the Czech Republic is negative in the LNG Glut Scenario (except on peak days) implying that marginal supply costs are higher in the Czech Republic and that gas will actually flow from the west to the east in this case. However, the absolute marginal supply cost difference does not exceed transport costs implying that capacity in Waidhaus is sufficient for west-to-east transport on this route.

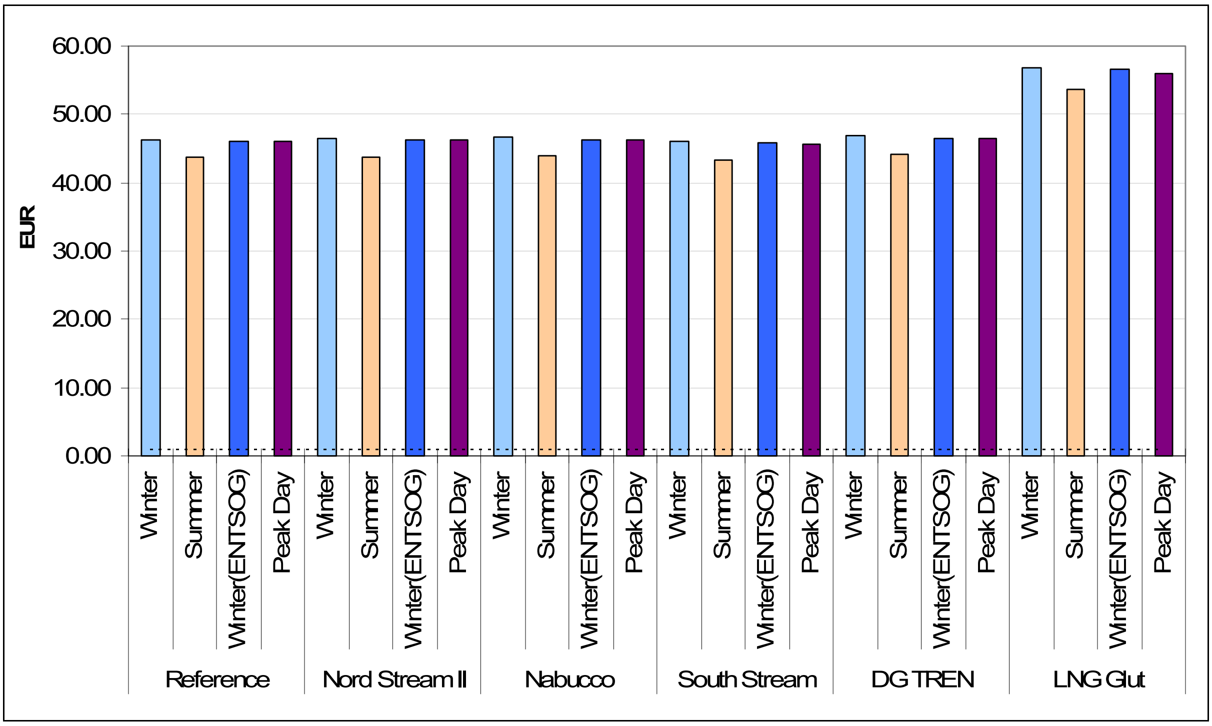
8.6 Scandinavia: Denmark and Germany

The case of Denmark is the only bottleneck found to be persistent in all scenarios and across the whole year 2019 according to our simulations in this study. This is, thereby, largely a consequence of the assumptions. According to ENTSOG (2009), Danish production declines to 1.8 bcm in 2019. With Danish and Swedish demand at 5 bcm in 2019,[60] the existing import capacity from Germany is not sufficient to meet demand in the two countries.[61] Hence, there is a significant bottleneck if no other import infrastructures to Denmark are realised. As potential pipeline projects between Denmark and Norway or across the Baltic Sea to Poland seem less likely at the moment, this implies a need for increased capacity between Germany and Denmark to enable gas imports to compensate for declines in Danish production. The costs of congestion are depicted in Figure 36 and indicate a need for investment.

As for the integration of Sweden and Denmark, this largely depends on natural gas demand growth in Sweden. If demand grows as projected, and expansion of pipeline link between the countries may also be required.

[60] ENTSOG (2009). Sweden is solely supplied via Denmark in our infrastructure assumptions.
[61] According to ENTSOG (2009), capacity is not expanded.

Figure 36: Marginal Supply Cost Difference between Denmark and Germany



Source: EWI.

8.7 Western and Central Europe

Generally, market integration amongst western European countries and between western and central Europe is fairly advanced. There are hardly any temporary bottlenecks. Nevertheless, two issues seem to be relevant when investigating these countries: First, there appears to be a bottleneck on peak days between the region of the Netherlands, Belgium and France and Great Britain on the one hand and Germany on the other. Second, the LNG Glut scenario is specially conceived to address issues of market integration in the case of temporarily low LNG prices, i.e. whether or not there are sufficient transport capacities to make full use of the LNG import capacities and supply LNG volumes to markets without direct access to LNG terminals. The analysis shows that some congestion may exist in this case.

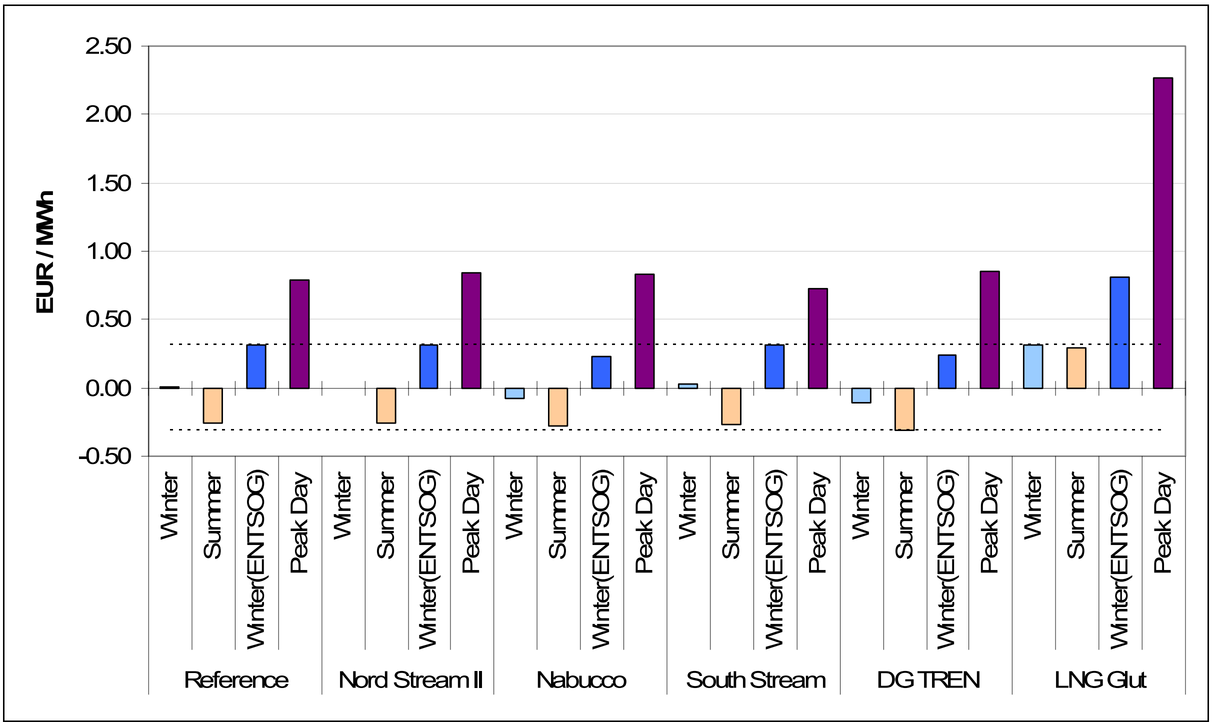
Considering the United Kingdom, physical market integration is found to be high in our model simulations:

- There is no bottleneck to the Irish market (see Figure 75 on page 115 in the Appendix).
- On the Interconnector to Belgium there is only a bottleneck on peak days. Generally, gas flows in winter (including peak days) go from Britain to the continent (as there are

relatively higher marginal supply costs on the continent), in the summer from the continent to Britain (which can be derived from the negative difference in Figure 37). In the LNG Glut Scenario (low LNG prices), the marginal supply cost difference also exceeds variable transport costs on the average ENTSOG winter day implying even higher exports to the continent would be feasible on the Interconnector if more export capacity on the Interconnector were available. This is a result of Britain's high LNG import capacities which would allow the country to import more LNG and export additional gas to the continent if there were additional export capacity.

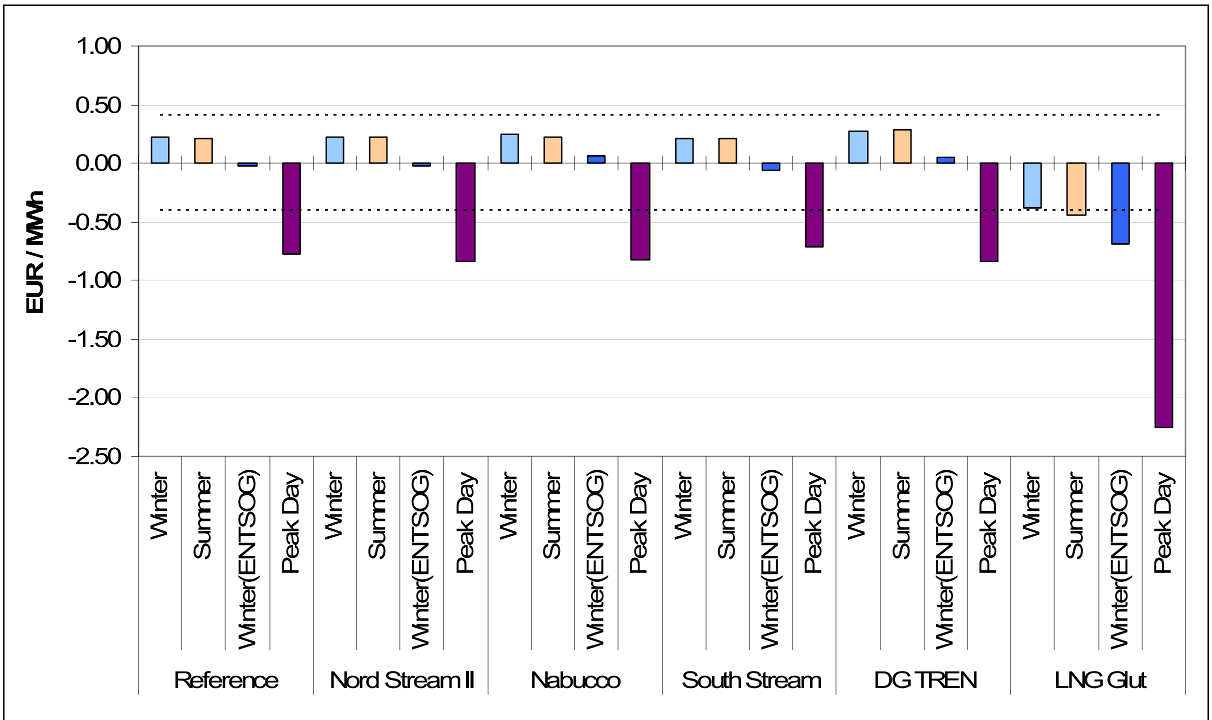
- This is also mirrored in the investigation of market integration between the Netherlands and Great Britain (Figure 38). The marginal supply cost difference on both ends of the BBL never exceeds its transport costs implying that its capacity is sufficient. However, on the concurrent peak day, marginal supply costs are relatively higher in the north-west of the continent than in the UK. (This may be due to relatively lower storage capacities and higher relative peak day demands, see discussion at the end of this section.) Hence, there would be demand for physical reverse flows on the BBL on such a concurrent peak day. Nevertheless, it needs to be stressed that this is a temporary bottleneck from the UK to the Netherlands which would only occur in this hypothetical case (concurrent peak day).
- A negative marginal supply cost difference between the UK and the Netherlands can also be observed in the LNG Glut Scenario (Figure 38). Hence, marginal supply costs in the Netherlands are higher than in the UK which would induce GB-to-NL flows on the BBL if reverse flow were available.

Figure 37: Marginal Supply Cost Difference between Belgium and Great Britain



Source: EWI.

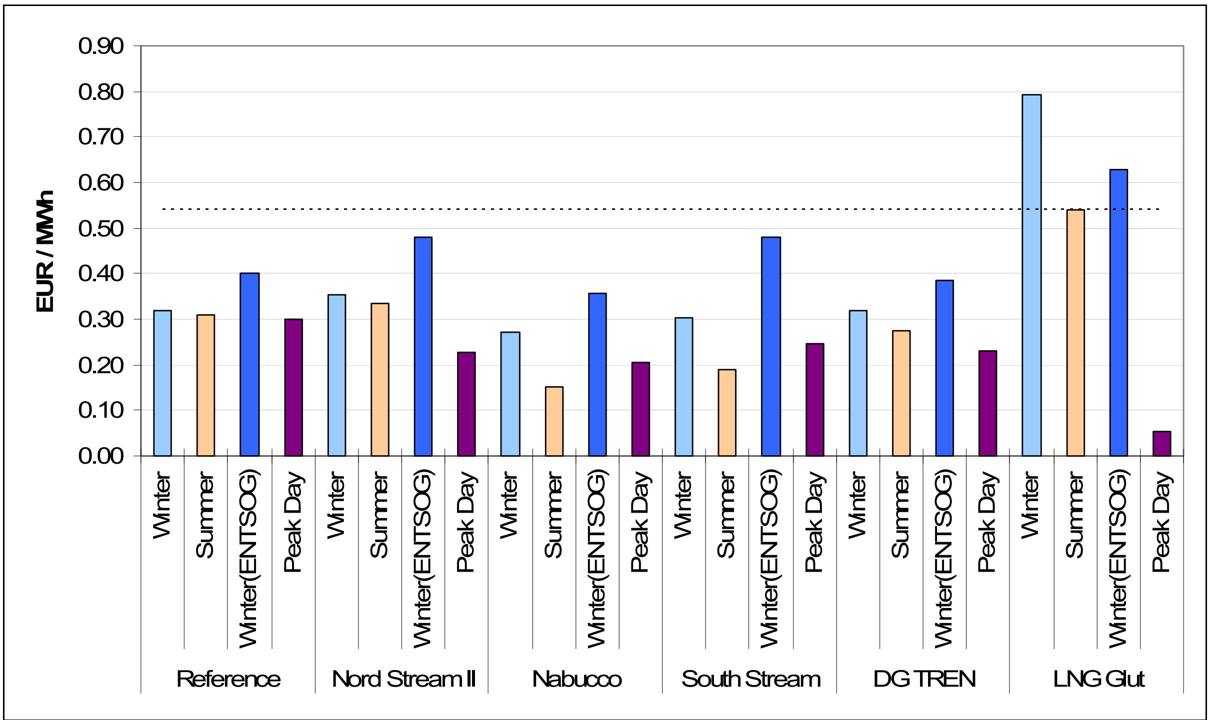
Figure 38: Marginal Supply Cost Difference between Great Britain and the Netherlands



Source: EWI.

For the identified region of the Netherlands, Belgium and France, market integration is high. There is a small bottleneck between Belgium and France in times of low LNG prices (LNG Glut Scenario) when more LNG could be transported to France from Belgium (these volumes would then be transported further on to Germany and Switzerland, see the following paragraphs). In all other scenarios, marginal supply cost differences never exceed variable transport cost (see Figure 39). This is also true for the markets of Belgium and the Netherlands in all scenarios (see Figure 76 in the Appendix).

Figure 39: Marginal Supply Cost Difference between France and Belgium



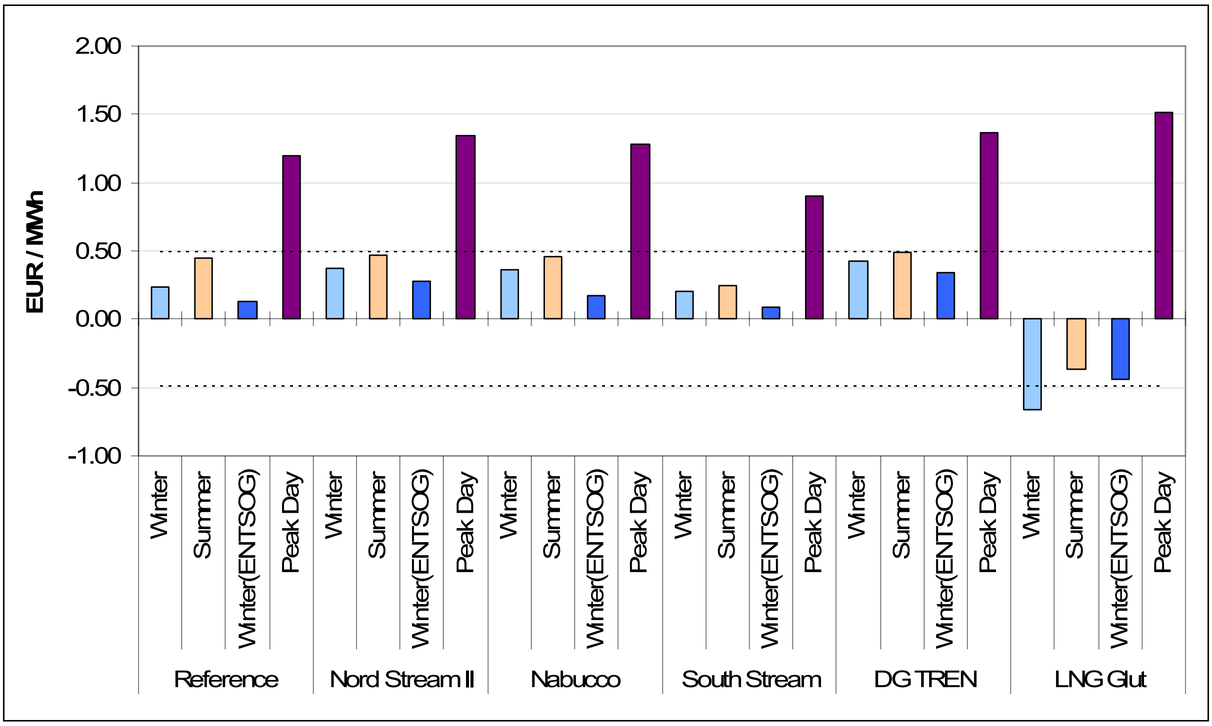
Source: EWI.

The three countries (Belgium, Netherlands, France) border on Germany in their east. The respective marginal supply cost differences to the German market are displayed in Figure 40 (Netherlands), Figure 41 (Belgium) and Figure 42 (France). The integration of these countries with Germany reveals a similar pattern for each one individually (supporting the finding of a well developed integration):

- On peak days, marginal supply cost differences between western and central Europe (Germany) significantly exceed variable transport costs (as is the case between continental western Europe and Great Britain). This is due to the relative abundance of storage volumes in Germany relative to western Europe. Hence, on peak demand days, gas is relatively cheaper in Germany than in Belgium, the Netherlands and France (see discussion in last paragraph of this section). If more transport capacity were available, more gas could be supplied from German storages to the west. However, the capacity is only a constraint on the concurrent peak demand day.

- On average winter days (or summer days), no such bottleneck exists and the markets in western Europe are well integrated with central Europe physically independent of which of the major import pipeline projects is implemented.
- In the LNG Glut Scenario, gas flows from the west to the east (negative marginal supply cost difference between the three aforementioned countries and Germany). (See also Section 7.1 on gas flows.) Generally, higher "reverse" capacities (west-to-east) between those countries would also warrant higher LNG imports. Small bottlenecks, hence, exist, especially between France and Germany and between the Netherlands and Germany in winter.[62]

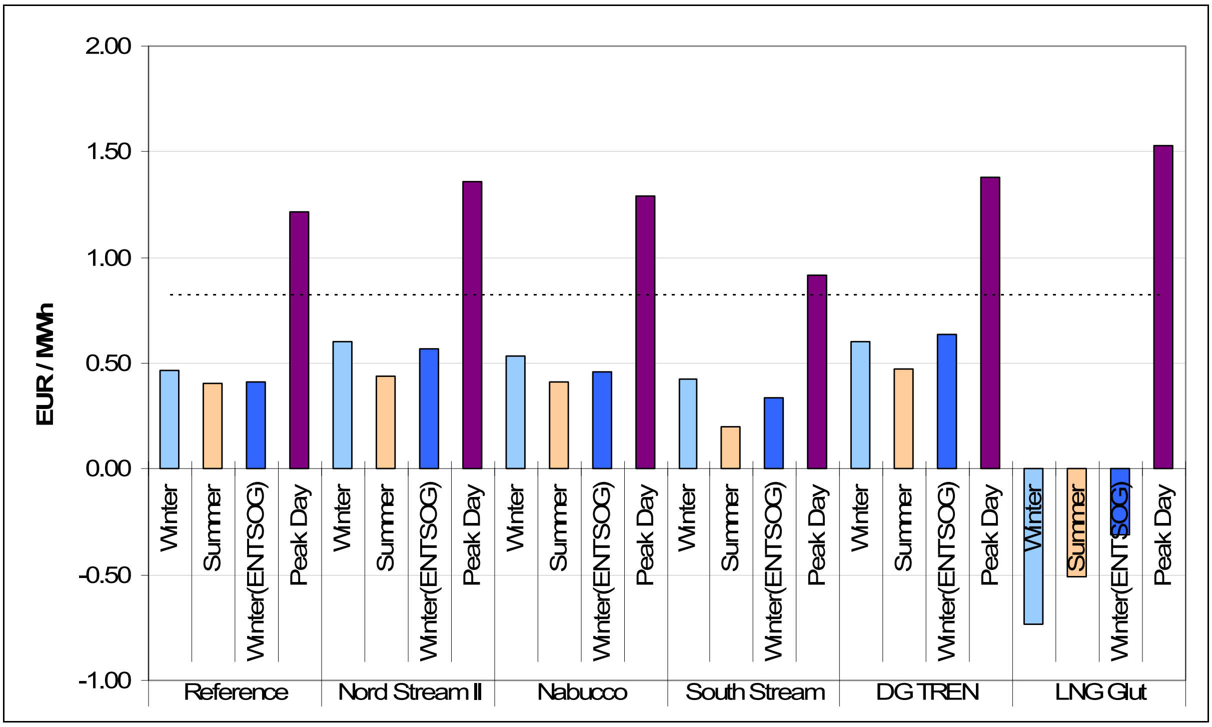
Figure 40: Marginal Supply Cost Difference between the Netherlands and Germany



Source: EWI.

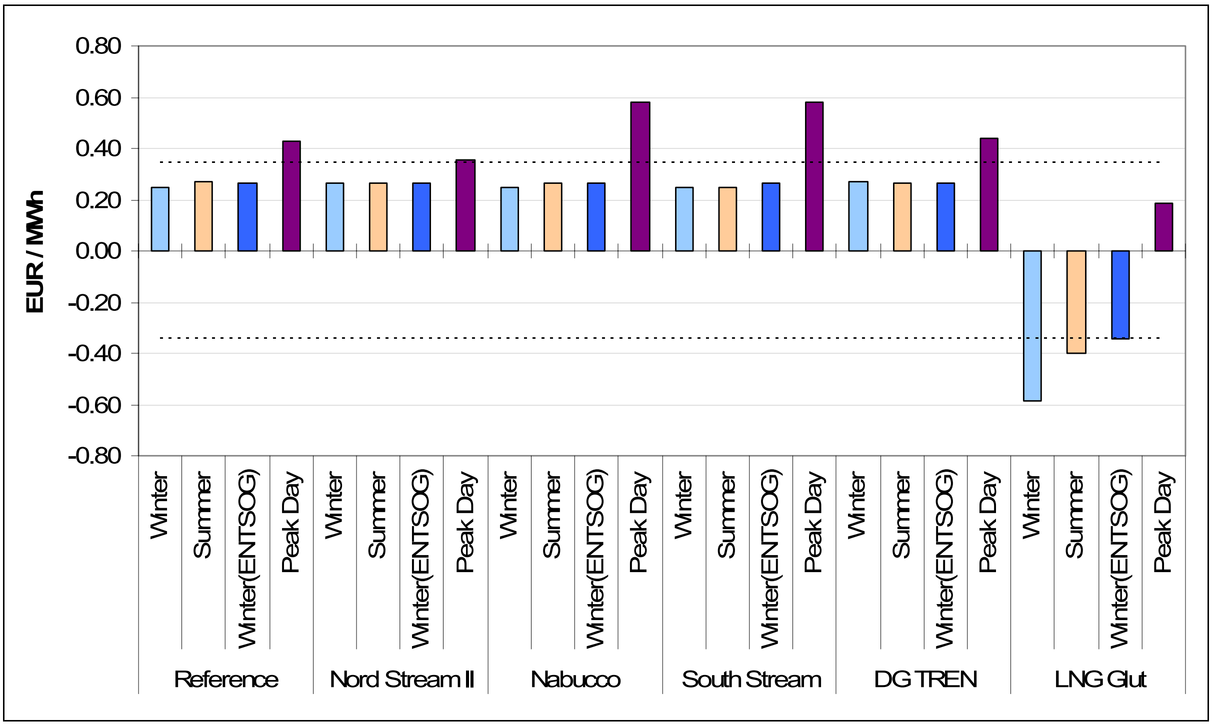
[62] This of course depends on the amount of LNG coming into Europe and, therefore, also on the assumed expansions of LNG import capacities and assumed LNG costs, see Sections 1, 4.3 and 4.1 respectively.

Figure 41: Marginal Supply Cost Difference between Belgium and Germany



Source: EWI.

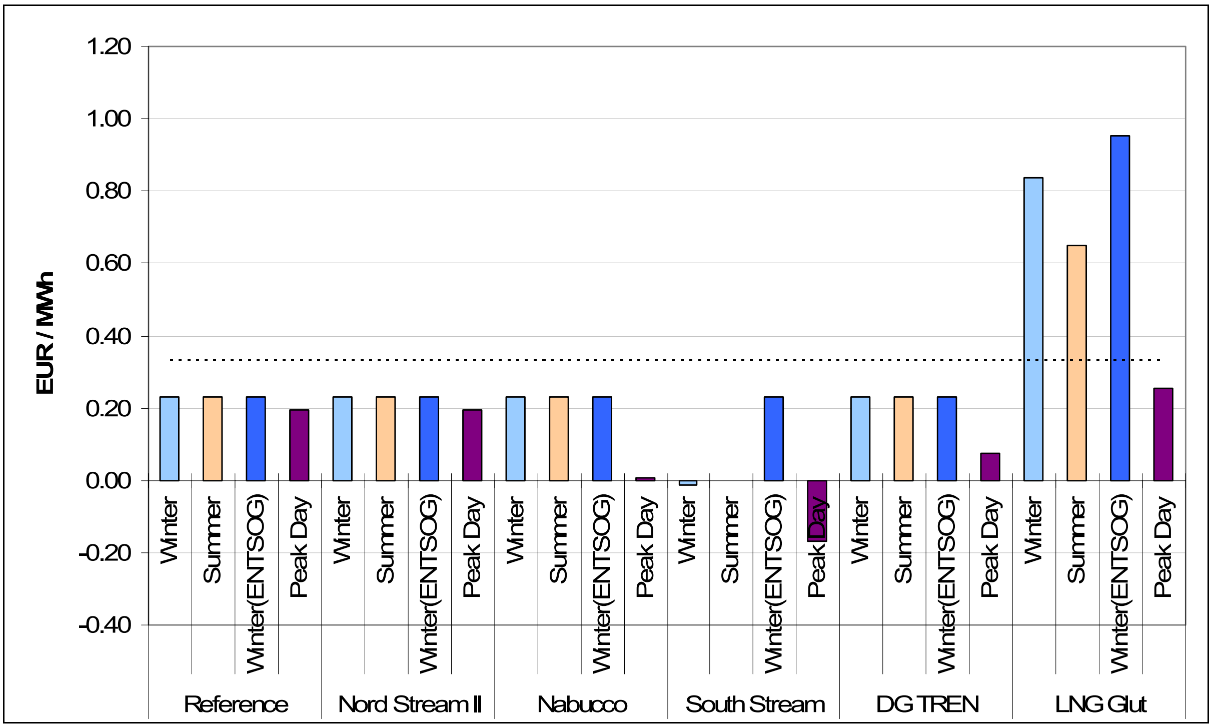
Figure 42: Marginal Supply Cost Difference between France and Germany



Source: EWI.

The bottlenecks between Switzerland and France (Figure 43) follow a similar pattern in the LNG scenarios than between Germany and France (Figure 42). When LNG prices are low, more natural gas could be transported from France to Switzerland if more capacity were available. In the reverse direction (where there is no capacity as the pipeline link from France to Switzerland is unidirectional), the model shows that gas flows in the reverse direction from Switzerland to France would be feasible in the South Stream Scenario on the peak day as marginal supply costs are then higher in France. However, even in this case the difference in marginal supply costs is small and would not warrant investment (difference is smaller than variable transport costs).

Figure 43: Marginal Supply Cost Difference between Switzerland and France



Source: EWI.

The bottlenecks regarding western and central Europe also become evident in the congestion overview maps Figure 23 and Figure 24 (pages 67 and 68). In the LNG Glut Scenario (Figure 24) they generally point from the LNG importing countries to the east. Especially between France and Germany and Switzerland, more capacity would allow more LNG imports and transports to these markets.

In all other scenarios, there are generally only issues on the peak day (Figure 23 for the Reference Scenario). These imply that (under the scenario assumptions) there seems to be a relative shortage of natural gas in Belgium, the Netherlands and France on the peak day indicating demand for additional import capacity from all neighbouring countries (except Spain). Reflecting on the assumptions confirms this: with respect to storages – which provide significant swing supply in times of exceptionally high demand –, capacity additions in the aforementioned countries are rather low compared to, for example, Germany, the UK or Italy (see Figure 7 in Section 4.3). Furthermore, the detailed storage data (Appendix Table 12) reveals that a large share of these additional storage capacities, especially in the Netherlands, comes from depleted gas fields converted into underground gas storages (e.g. Bergermeer storage). While depleted gas fields can generally store large volumes of gas, their withdrawal rates are limited. Hence, these storages are not able to release large volumes of gas in a short time period as required on a peak demand day. This effect is further amplified by the relative magnitude of the peak day in Belgium, France, the Netherlands and Luxembourg (which is supplied largely via Belgium): Figure 5 on page 32 shows that these four countries are amongst the six countries where the peak day demand exceeds 250 percent of average daily demand. (Only Denmark and Romania have similarly high relative peak day demands.)

These circumstances lead to relatively higher costs of providing the marginal (price setting) gas volumes to consumers in this group of countries (compared to their neighbours). Nevertheless, as stated previously, the resulting congestion is only relevant temporary (on a concurrent peak day).

8.8 Iberian Peninsula and France

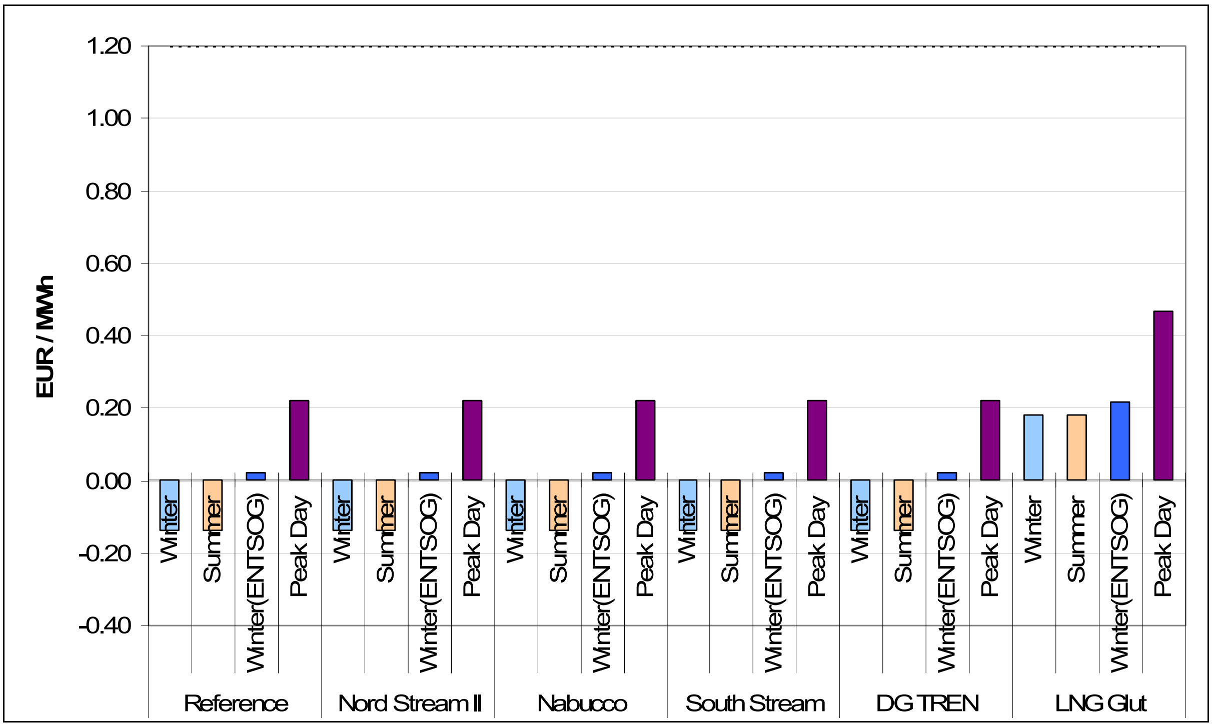
Again, with the assumed expansion of capacities between Spain and Portugal and Spain and France, physical market integration between these countries is well developed according to the model simulations in all scenarios.

Between Portugal and Spain, no bottlenecks can be identified (see Figure 44).

A differentiated consideration is required for the interconnection of the Spanish and French gas markets.

As described in Section 4.3, the South Stream Scenario does not contain the MidCat pipeline between Spain and France. Hence, capacity between the countries is smaller than in the other scenarios. However, the results show that in this scenario, the simulations do not find a significant differential in marginal supply costs between Spain and France (see Figure 45). These findings presume that the global LNG market is working efficiently in the sense that cargos can be delivered to the destination where they have the highest economic value (as long as LNG import capacities in this market are available).

Figure 44: Marginal Supply Cost Difference between Spain and Portugal



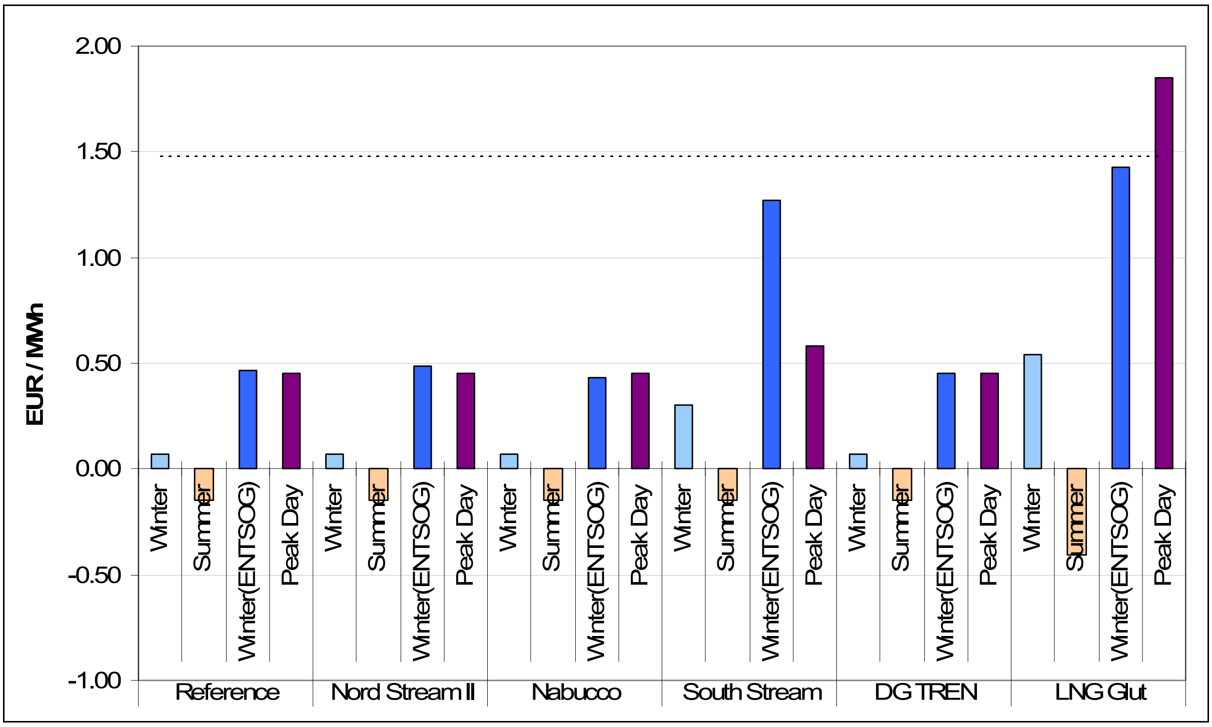
Source: EWI.

Although both, France and Spain, are supplied by pipeline gas volumes, they receive significant LNG imports which might be price-setting in the short-term. If short-term trade in LNG emerged and there were no shortages of LNG capacities in either Spain or France, the LNG cargos would be delivered to the destination market with the highest price leading to a convergence of prices (marginal supply costs in the model) limiting the potential for additional pipeline gas flows between the countries.[63] Thus, short term LNG trade would enhance market integration and lead to price convergence across markets. Thereby, it would contribute to reduce the need for additional pipeline connections onshore from this purely economic perspective. (Considerations of security of supply and enhancing competition might still increase the need for enhanced physical pipeline connections, see discussion in Chapters 3 and 9 (for security of supply)). Thus, presuming that access to LNG import facilities is efficiently granted (no capacity withholding), imports of LNG in Spain and the transportation of the gas to

[63] The direction of these gas flows can also be derived from Figure 45 as gas would flow from the low to the high price market. Hence, in the summer months, we see gas flows from France to Spain, in the winter from Spain to France.

France would not be economic unless all French LNG terminals are fully utilised. Nevertheless, on the peak demand day in the case of the LNG Glut Scenario, even with MidCat, higher gas flows from Spain to France would be economically viable as the price difference between these countries exceeds the transport costs in this case, as the LNG import capacity limit in France is reached.

Figure 45: Marginal Supply Cost Difference between France and Spain



Source: EWI.

8.9 South-South East: Romania, Bulgaria, Greece and Turkey

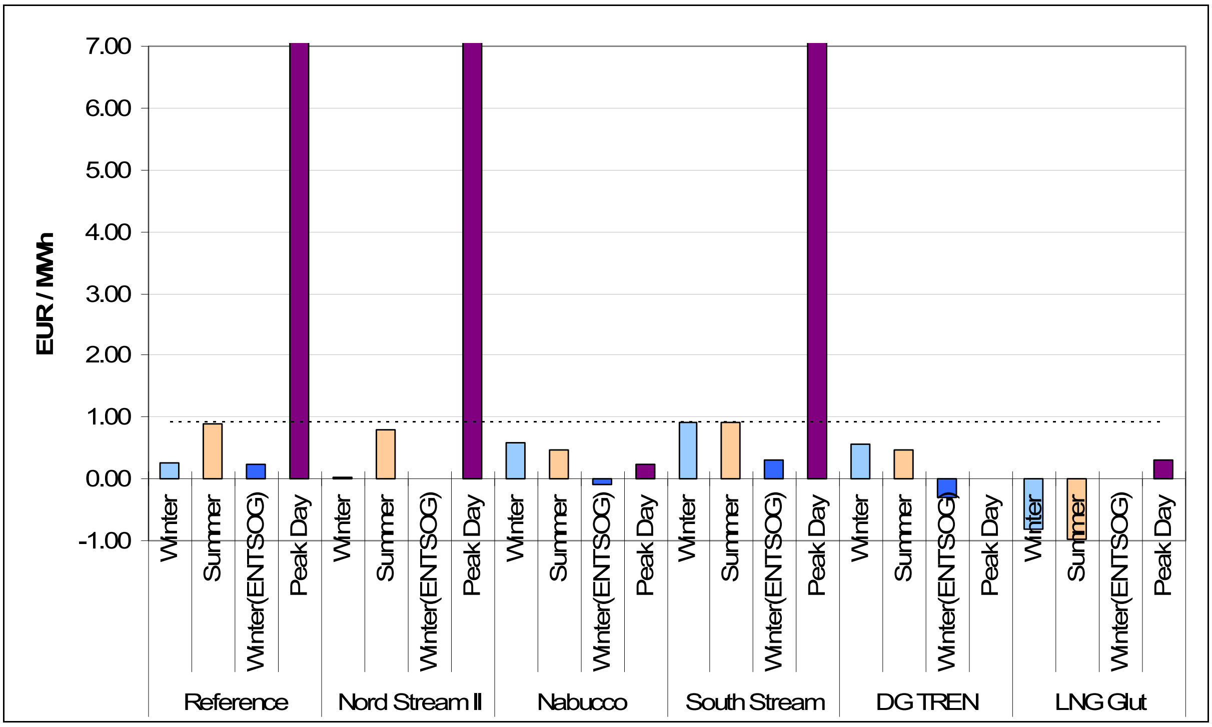
For the EU member states in south-eastern Europe, the model simulations also yield relatively high market integration – with the exception of Greece on the peak days in the non-Nabucco scenarios.[64] As the peak day sensitivity simulated concurrent peak days in all countries covered in the study, this also applies to Turkey which transits gas to Greece via the existing (and assumed to be expanded) pipeline links. However, our model simulations show that Turkey, which witnesses generally high demand growth, may not be able to transit large volumes of natural gas on days of high domestic demand. Hence, such high demand in Turkey can lead to a reduction of the gas flows from Turkey to Greece resulting in shortages in

[64] I.e. scenarios Reference, Nord Stream II and South Stream.

Greece (if the Greek peak demand day happens to take place on the same day).[65] Consequently, Figure 46 also reveals a bottleneck at the Greek-Bulgarian border: although flows are at the capacity limit, there would still be shortages in Greece on the peak day. This is the case in all scenarios without Nabucco. (It needs to be noted that these shortages in Greece are small relative to total consumption, see Section 8.10.)

When the Nabucco pipeline project is realised, the pipeline would also provide additional gas volumes to Turkey, alleviate the stress on the system on peak days there and allow a continuation of the gas flows from Turkey to Greece.

Figure 46: Marginal Supply Cost Difference between Greece and Bulgaria



Source: EWI.

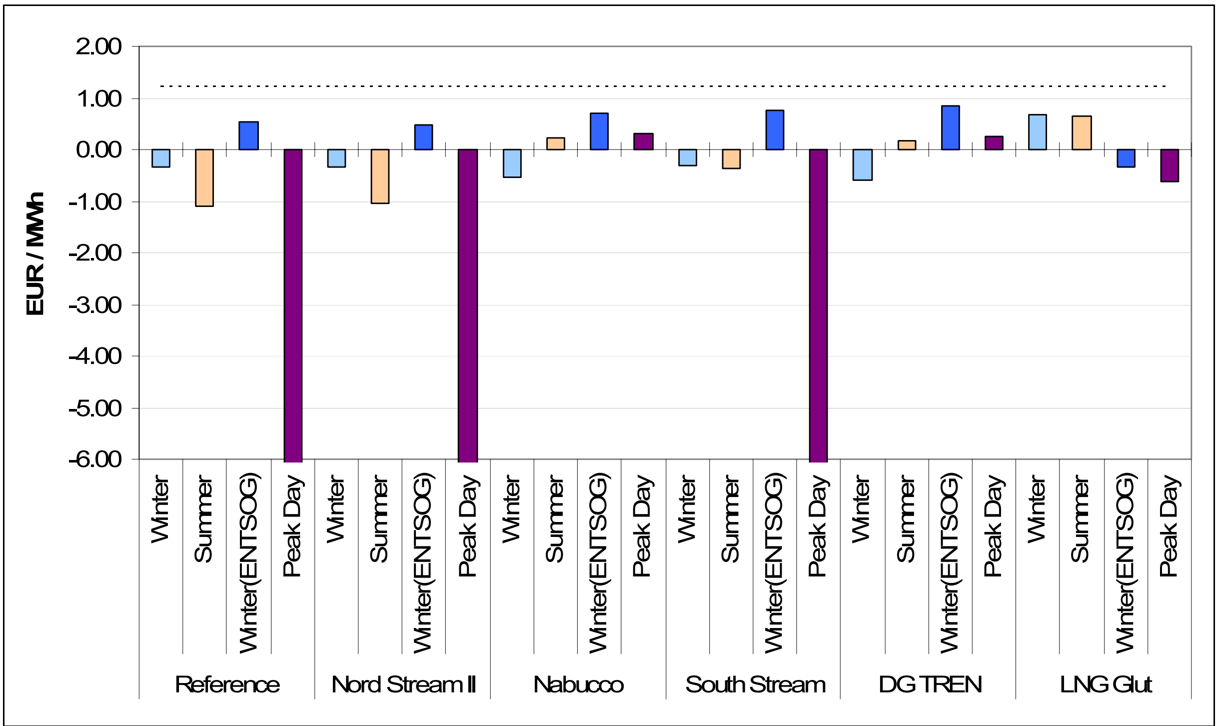
Apart from this effect on the concurrent peak days, the EU member states in the region are well integrated and there are no further bottlenecks. The graphs for Bulgaria and Romania (Figure 81), Greece and Turkey (Figure 83), and Bulgaria and Turkey (Figure 82) can be found in the Appendix, although it needs to be noted that the aforementioned bottleneck on the peak day can, of course, also be observed at the Bulgarian-Turkish interconnection (due to

[65] Our simulations imply that storage withdrawals and import pipelines reach the maximum technical capacities in Turkey on days of high demand in these scenarios. In the cost-minimization framework, the model then reduces transits to Greece as we do not consider contractual transit obligations. Turkey, could, however also maintain transports at the expense of a domestic supply-demand gap.

the high marginal supply costs in Turkey in the Reference, Nord Stream II and South Stream scenarios).

Between Greece and Italy, a new pipeline (either IGI Poseidon or TAP) constitutes a new direct pipeline link in the direction from Greece to Italy. Marginal supply cost differences between the countries are depicted in Figure 47. Gas flows on the pipeline can mainly be observed in the winter months with higher (i.e. ENTSOG) demand. Generally, with the expanded Transmed and the new GALSI pipeline from Algeria and additional LNG import capacities, Italy is relatively well supplied with natural gas. Hence, in summer or with lower demand (EWI/ERGEG), marginal supply costs in Italy are actually relatively lower than in Greece. However, the difference is low and would not warrant investment in reverse flows on the Greece-Italy pipeline link except on the concurrent peak demand days due to the aforementioned supply problems in Turkey and Greece in such a scenario.

Figure 47: Marginal Supply Cost Difference between Italy and Greece



Source: EWI.

8.10 Security of Supply Implications of the Identified Bottlenecks

The preceding sections identified a number of bottlenecks leading to marginal supply cost differences between countries and, hence, temporarily or permanently non-integrated markets. However, some of the bottlenecks also have more significant implications in the sense that the deliverability of natural gas in some countries is compromised severely. Hence, in some cases the assumed import capacities plus domestic output plus possible storage withdrawals are not sufficient to meet domestic demand on the peak day or on winter days in general leading to supply-demand gaps.

Figure 48 summarises the scope of these disruptions in all affected countries for all relevant scenarios[66] on an average winter day with ENTSOG demand and for the peak demand day as a percentage of the respective total consumption on that day. Four EU member states are affected. As discussed in Section 8.5, a permanent significant bottleneck between Denmark and Germany compromises the supply situation in Sweden and Denmark. Denmark is, thereby, only affected on the peak demand day. Due to the shortage of gas in the country, exports to Sweden, however, fully cease in winter. Demand disruptions in Hungary are smaller, only around 15 percent of consumption, and only in the scenarios without a new major import pipeline project in south-eastern Europe. The peak day issues regarding Greece are discussed in Section 8.9. Figure 48 illustrates, however, that the scope of the demand disruption on the concurrent peak day only amounts to around five percent of peak day consumption.

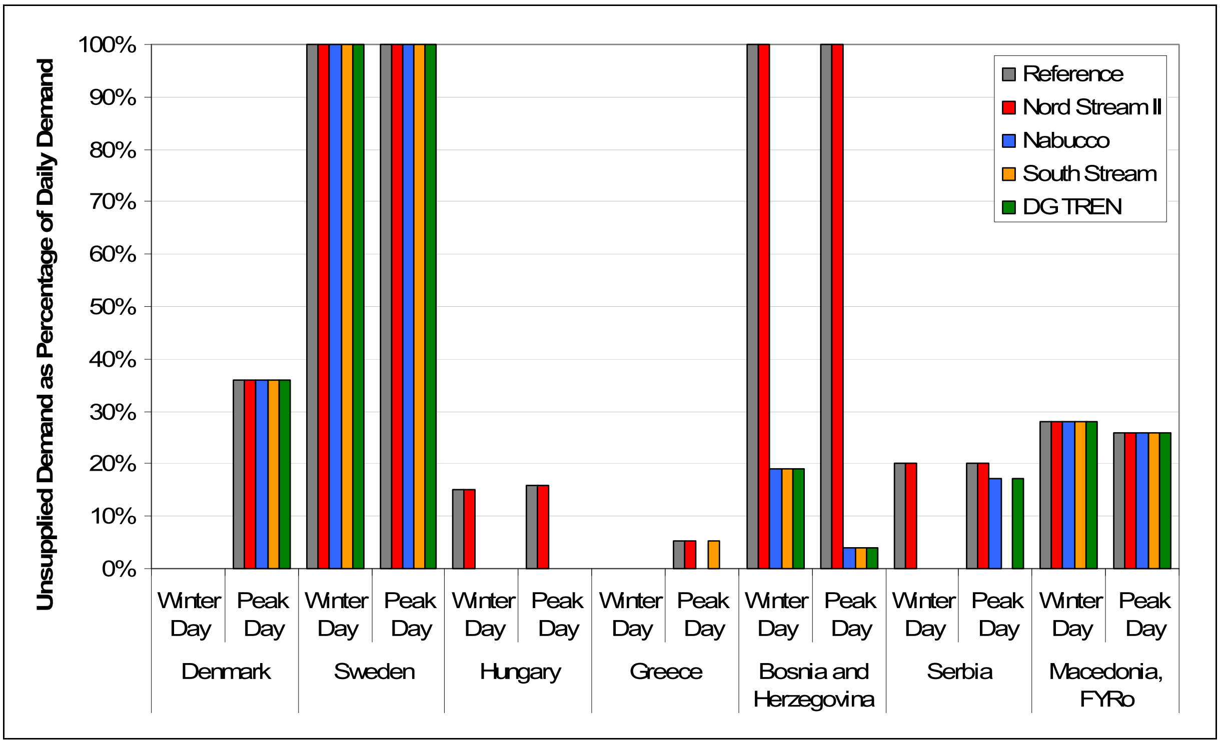
Apart from these EU member states, the three Balkan countries with a gas industry also suffer under insufficient import capacities given the assumed pipeline expansions and demand developments. This is especially severe in Bosnia and Herzegovina when there are shortages in Hungary as the country solely depends on gas imports via Hungary (Serbia at least has a storage facility). In the other scenarios, and the other two countries (Serbia and Macedonia), the supply shortages never exceed 30 percent of daily consumption. (It needs to be noted that gas demand projections for this region are associated with a very high degree of uncertainty. Furthermore, not all realistic pipeline expansion may be published clearly.[67] Hence, the model

[66] The LNG Glut Scenario is not considered in this section and in Chapter 9 (Security of Supply) as it is based on the same infrastructure assumptions as the DG TREN scenario and therefore does not yield any additional insights on security of supply or possible supply demand gaps.

[67] Apart from taking into account the ENTSOG (2009) assumptions (which yield similar results the respect to demand-capacity gaps in those countries), infrastructure data was also compared with publications of the Energy

results for the Balkans are a consequence of those assumptions. The results, however, clearly imply that without further infrastructure expansion, the ambitious demand growth projections cannot be realised and that further investment will be necessary to enhance security of supply in this region.)

Figure 48: Gas Consumption Disruptions without Crisis in 2019



Source: EWI.

Community representing the gas industry in the region. However, only committed projects were included, see Chapter 4.3.

9 Security of Supply Simulations

This chapter presents the results of the security of supply sensitivities. Both stress scenarios are discussed separately in the following two sections with respect to the consequences for consumers (demand reduction and price effects) and the simulated optimal gas flow diversions and additional storage withdrawals necessary to mitigate the consequences of the stress scenarios. Section 9.3 analyses the impacts of the two stress scenarios on market integration and specifically on the bottlenecks identified in Chapter 8.

Generally, it has to be noted that the model simulations take the demand assumptions as given and compute how demand is met during such a crisis – or what share of demand cannot be met. Hence, the results abstract from all possible demand side measures to mitigate supply disruptions. Furthermore, it needs to be stressed that the model simulations are non-technical. I.e. pipeline operations including pressures are not simulated. Hence, it is not possible to compute supply disruptions which might be caused by pressure declines as a consequence of stopped gas flows at one import point into a TSO network. Instead, it is assumed that if the gas volumes can be replaced from other sources in such a case, the underlying technical components of the system ensure that the pipeline network can continue to operate and supply gas. This approach might, thereby, miss to highlight some supply disruptions caused by technical issues in pipeline grids.

However, previous analysis with the applied model, for instance of the 2009 Russia-Ukraine crisis, have shown that model is able to match actual supply disruptions in case of a crisis situation quite well (see Bettzüge and Lochner (2009) and Bettzüge (2009)).

9.1 Four Week Disruption of Ukraine Transits in 2019

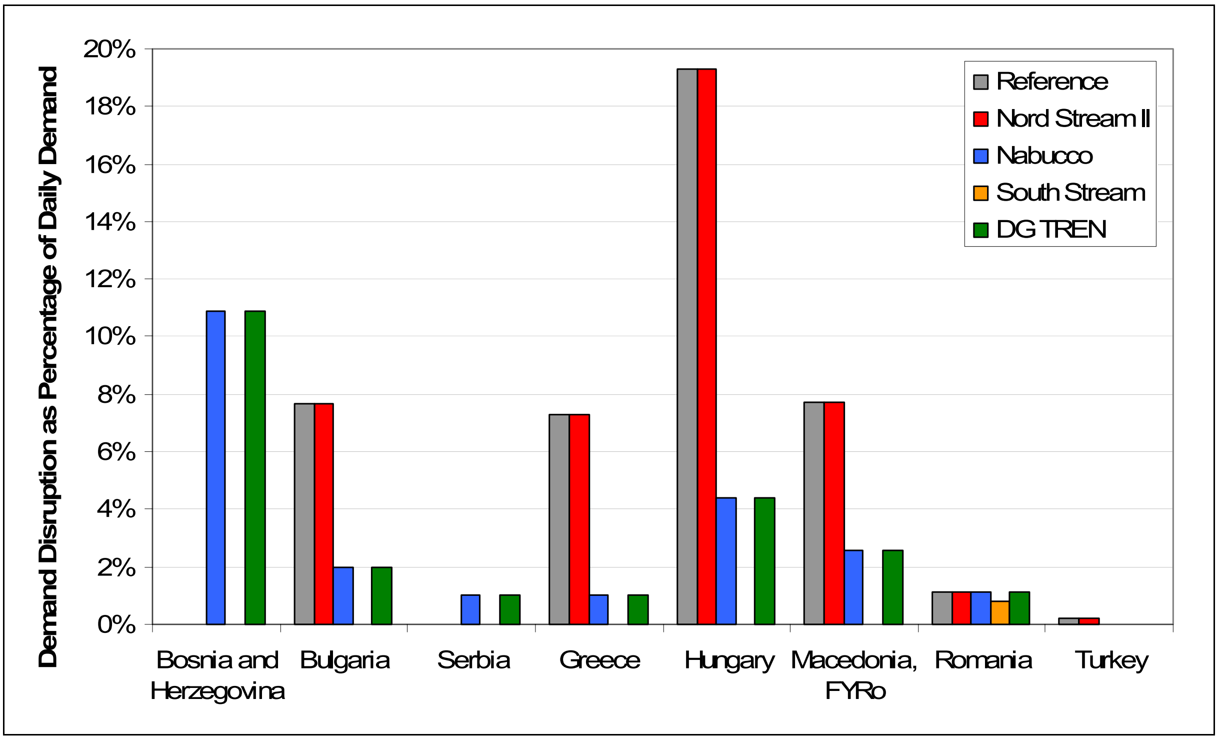
This stress scenario assumes that all transits of natural gas via Ukraine are halted for a duration of 28 days.[68] This period includes the peak demand day.[69] This security of supply simulation, hence, assumes a repetition of the January 2009 Russian-Ukrainian gas conflict with a prolongation to four weeks (instead of 13 days). In our model simulations, transits via Ukraine in January 2019 are between 186 to 345 million cubic metres per day (South Stream and Reference Scenario respectively) depending on which alternative infrastructure projects for Russian gas exports to Europe are available (Nord Stream II, South Stream). Hence, the

[68] I.e. for four weeks starting the first Friday in January.
[69] Assumed to be on the fourth Wednesday in January.

total disruption to the directly via Ukraine supplied countries also varies from 5.3 to almost ten billion cubic metres between the scenarios over the four weeks and is likely to have different impacts on consumers.

The most severe potential consequence of such a stress situation to consumers is the disruption of demand. Figure 49 presents the supply cut-offs consumers in all affected countries are projected to experience according to the model simulations. The scope of the disruption is displayed as a percentage of daily demand in excess of the supply disruptions some of the countries see in winters anyway due to other bottlenecks. Hence, Figure 49 shows the disruptions solely caused by the Ukraine transit halt, i.e. the total cut-offs minus those already displayed in Figure 48.

Figure 49: Demand Disruption during Ukraine SoS Simulation



Source: EWI.

Amongst EU member states, the one most severely affected country is Hungary in the Reference and Nord Stream II scenarios (without either South Stream or Nabucco) where almost another 20 percent of demand cannot be met during such a stress scenario. The simulations further yield shortages in Greece, Romania and Bulgaria in a range between one and eight percent of demand depending on the scenario. Generally, in the scenarios with one of the new major import pipeline projects in south-eastern Europe, either Nabucco or South

Stream, the consequences of the crisis to consumers are smaller (with South Stream even more so than with Nabucco). The only country experiencing (albeit very minor) disruptions to consumers in all scenarios is Romania. As this was not found to be the case in simulations of shorter (two-week-) disruptions of Ukraine transits (not reported in this document), it can be concluded that import, production and storage capacities of the country are sufficient for coping with short, temporary disruptions of imports from Ukraine, but not with ones stretching up to four weeks. For the Balkan countries with supply shortages without a crisis, the demand disruptions are generally larger during a Ukraine transit halt.

Hence, apart from these countries, severe effects for consumers in the rest of Europe are not projected by our simulations. Other consequences, however, could be price effects outside the severely affected countries. As an indicator for these, Table 5 presents the maximum change in marginal supply costs compared to a simulation without the disruption. It is important to note that these are not projections of wholesale price changes which cannot be computed. Market prices are impacted by other factors not taken into account by the model. Apart from simplifications of the model (see Chapter 3), such as inelastic demand, these mainly relate to uncertainty and expectations which are crucial for price formation in wholesale markets. Hence, even in a fully functioning market, wholesale prices may deviate from marginal supply costs. However, simulations of the January 2009 Russian-Ukrainian gas conflict with the applied TIGER model yield marginal supply cost changes which are on average (except the price spikes on the first day of the crisis) similar to those observed at the western and central European gas trading points (Bettzüge and Lochner, 2009). Therefore, interpreting the changes in short-run marginal supply costs of the simulations yields insights into the extra costs to the gas industry caused by a disruption of Ukraine transits. The values in Table 5 represent the maximum changes in marginal supply costs for each scenario relative to an otherwise identical time period without the crisis. (Due to the inelastic demand, marginal supply costs cannot be computed in countries with disruptions to consumers as this causes infinitely high marginal supply cost.)

Table 5: Increases in Marginal Supply Costs in Ukraine SoS Simulation in 2019

Country	Reference	Nord Stream II	Nabucco	South Stream	DG TREN
Austria	+ 3.8 %	+ 3.7 %	+ 4.4 %	+ 2.7 %	+ 4.1 %
Belgium	+ 1.1 %	+ 1.0 %	+ 0.4 %	+ 0.4 %	+ 0.8 %
Bosnia and Herzegovina	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Bulgaria	+ ∞	+ ∞	+ ∞	+ 1.5 %	+ ∞
Croatia	+ 0.2 %	+ 0.2 %	+ ∞	+ 1.4 %	+ ∞
Czech Republic	+ 2.1 %	+ 0.7 %	+ 2.3 %	+ 1.6 %	+ 0.8 %
Denmark	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Estonia	- 7.2 %	- 8.4 %	- 7.5 %	- 1.8 %	- 8.4 %
France (Northern Zone)	+ 0.4 %	+ 0.6 %	+ 0.1 %	- 0.0 %	+ 0.4 %
France (Southern Zone)	+ 0.0 %	+ 0.0 %	- 0.0 %	+ 0.0 %	+ 0.0 %
Germany (North)	- 0.1 %	- 0.2 %	+ 0.1 %	+ 0.4 %	- 0.2 %
Germany (South)	+ 1.1 %	+ 1.0 %	+ 1.5 %	+ 0.9 %	+ 1.2 %
Great Britain (Bacton)	- 0.1 %	- 0.2 %	- 0.1 %	+ 0.0 %	- 0.2 %
Great Britain (St. Fergus)	- 0.1 %	- 0.2 %	- 0.1 %	- 0.0 %	- 0.2 %
Greece	+ 0.4 %	+ 0.4 %	+ ∞	+ 0.0 %	+ ∞
Hungary	+ 0.0 %	+ 0.0 %	+ ∞	+ 3.1 %	+ ∞
Ireland	- 0.1 %	- 0.2 %	- 0.1 %	- 0.0 %	- 0.1 %
Italy (North)	+ 0.1 %	+ 0.1 %	+ 0.5 %	+ 0.1 %	+ 0.5 %
Italy (South)	+ 0.1 %	+ 0.1 %	+ 0.1 %	+ 0.0 %	+ 0.3 %
Latvia	- 6.1 %	- 6.4 %	- 6.1 %	- 1.4 %	- 6.3 %
Lithuania	- 8.3 %	- 7.8 %	- 8.5 %	- 1.7 %	- 7.8 %
Luxembourg	+ 1.1 %	+ 1.0 %	+ 0.4 %	+ 0.5 %	+ 0.8 %
Macedonia	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Netherlands	+ 1.1 %	+ 1.0 %	+ 0.4 %	+ 0.4 %	+ 0.8 %
Norway	- 0.0 %	- 0.2 %	- 0.2 %	+ 0.4 %	+ 0.0 %
Poland	- 0.0 %	- 0.2 %	+ 0.3 %	+ 1.4 %	- 0.3 %
Portugal	+ 0.0 %	+ 0.0 %	- 0.0 %	- 0.0 %	+ 0.0 %
Romania	+ ∞	+ ∞	+ ∞	+ ∞	+ ∞
Serbia	+ 0.2 %	+ 0.2 %	+ 0.3 %	+ 1.5 %	+ 0.3 %
Slovakia	+ 8.3 %	+ 6.4 %	+ 7.6 %	+ 5.3 %	+ 6.3 %
Slovenia	+ 2.9 %	+ 2.9 %	+ 3.4 %	+ 1.4 %	+ 3.2 %
Spain	+ 0.0 %	+ 0.0 %	- 0.0 %	- 0.0 %	+ 0.0 %
Sweden	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Switzerland	+ 0.3 %	+ 0.6 %	+ 0.5 %	+ 0.1 %	+ 0.5 %
Turkey	+ 0.1 %	+ 0.1 %	+ ∞	+ 0.0 %	+ ∞

Source: EWI.

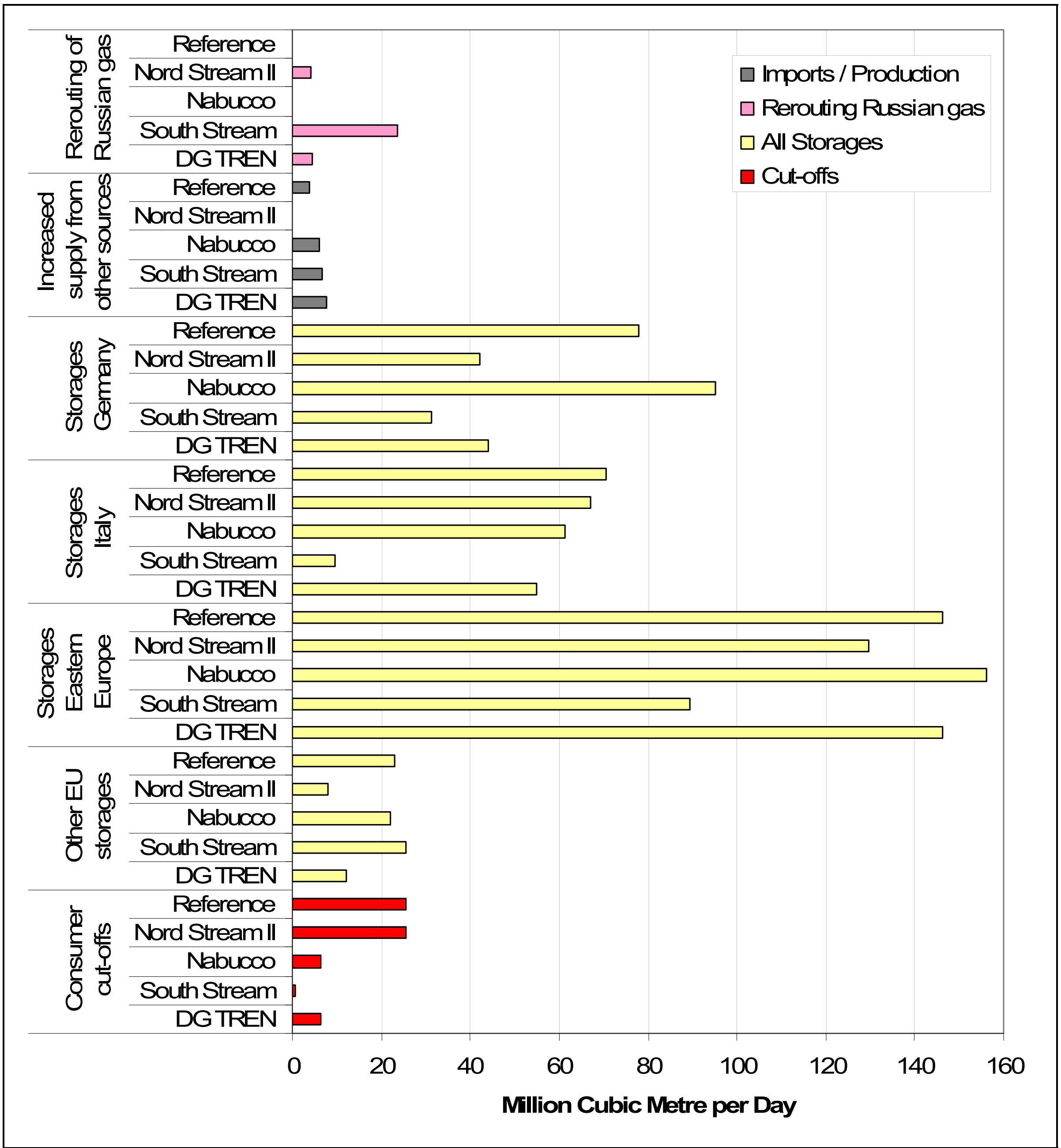
For the countries where demand can be met during a crisis, the changes in marginal supply costs are relatively small (also compared to simulations of the January 2009 crisis). The largest rise is observed in the Slovak Republic as the country is normally solely dependent on Russian imports via Ukraine and needs to be fully supplied from the west and its storages during a potential supply disruption from the east. Noteworthy, increases in supply costs are also observed for Austria, Slovenia and, to a smaller extent, the Czech Republic which also continue to receive a large share of their gas imports via Ukraine in 2019 (see also the gas flow analyses in Section 7.1). The countries which see supply disruptions in some scenarios generally also experience a significant increase in marginal supply costs in the scenarios where supply to consumers is maintained. Intuitively, the consequences for consumers in eastern Europe with respect to cut-offs (Figure 49) and supply costs (Table 5) are the smallest in the South Stream Scenario as this project essentially constitutes an alternative route for Russian gas to the countries otherwise depending on Ukraine transits.

In western Europe, the supply cost changes during such a crisis are found to be relatively minor and do not exceed two percent relative to a simulation without a disruption. (In some countries, which are supplied by Russian gas via other routes, marginal supply costs actually slightly decline. This is due to the fact that Russian gas volumes partially have to be rerouted when transit via Ukraine is not possible causing a higher availability of Russian gas volumes in other regions. In the simulated competitive market, more supply leads ceteris paribus to lower marginal costs (or prices).)

A map of the supply cost changes for the Reference case (together with new bottlenecks during the crisis) can be found in Section 9.3 (Figure 52). (For the other scenarios, the maps can be found in the Appendix starting on page 141.)

How the disruptions are compensated in the model simulations is illustrated in Figure 50, which displays the difference in average gas imports, gas production, storage withdrawals, and consumer cut-offs in the respective time period between the simulation with and without Ukraine crisis. It is thereby clear that natural gas storages compensate most of the transit disruption. Production flexibility in January is not high as most EU production facilities already operate near the maximum in a normal winter. Rerouting of Russian gas to the EU is also only possible in the scenarios with either Nord Stream II or South Stream as all Russian export pipelines would already be fully utilised in winter without either of those projects. Additional storage withdrawals are not only observed in the countries directly affected by the crisis but, almost to a similar extent volume-wise, also in Italy and Germany to enable west-to-east gas flows. Additional LNG imports (included in *Imports/Production* in Figure 50) are minor as the majority of LNG import capacities are located in countries from where transport to eastern Europe is not feasible (UK, France, Spain). Aggregated consumer cut-offs are, as discussed previously, highest in the scenarios with no new pipeline project in south-eastern Europe and lowest with South Stream. Generally, in the South Stream Scenario, transits via Ukraine are significantly lower (see Chapter 7.1). Hence, less compensation is necessary in case of a transit disruption leading to relatively lower additional withdrawals from storages in all countries.

Figure 50: Compensation of Ukraine Transits in Disruption Simulation (Daily Average)



Source: EWI.

Generally, the findings with respect to consumer disruptions and supply cost changes imply that especially western and central Europe is relatively well equipped for a repeated stop of gas imports via Ukraine. Nord Stream I as a direct route to Germany already enhances the availability of gas in central Europe greatly and benefits security of supply (compared to 2009). Nord Stream II increases these available volumes further. Nabucco and especially South Stream also enhance security of supply in south-eastern Europe. So do the reverse flow projects assumed to be realised which allow supplying gas from western and central to eastern

Europe during a disruption of Ukraine imports. Storages have the most important role in maintaining supply to consumers. Together, additional storage withdrawals in central (Italy, Germany) and eastern Europe contribute more than 90 percent to compensating the interrupted transits via Ukraine. Nevertheless, full security of supply (i.e. the avoidance of supply cut-offs to consumers) towards the simulated stress test is not achieved in any of the scenarios. Especially when there are no new major infrastructure projects in south-eastern Europe, supply disruptions cannot be avoided. We find that bottlenecks also still exist in the west-to-east direction, for instance from Germany to the Czech Republic or from the Czech to the Slovak Republic, which prevents further gas flows from central and western to eastern Europe. (For a full discussion of identified congestion in the crisis simulations, see Section 9.3.) Apart from the Balkans, the most severely affected EU member states are Hungary, Bulgaria and Greece with supply shortfalls between seven and 20 percent of demand.

Furthermore, for the mitigation scenarios described here to materialise, the establishment of an efficiently working and competitive gas market (which sends the required price signals for flow diversions and storage withdrawals) is required. If it is not in place in such a crisis, or if, for instance, government intervention prevents cross-border solidarity (which is efficient from a total system perspective), supply disruptions to consumers or price effects may be larger. (See also discussion on the assumptions of the model (Chapter 3) or at the end of the next section.)

9.2 Four Week Disruption of Algerian Exports in 2019

Like the Ukraine transit disruption, this stress scenario assumes that all exports of natural gas from Algeria via pipeline are halted for a duration of 28 days.[70] This period includes the peak demand day.[71] Regarding global LNG supplies – which are also likely to be affected from an Algerian gas export stop –, it is assumed that 25 percent of all LNG cargos to Europe in this time period do not arrive. This figure is based on the fact that Algerian LNG supplies to Europe made up 35 percent in 2008 (BP, 2009). Taking into account that many new LNG liquefaction projects are going online around the world in the period from 2009 to 2014, this relative share is likely to decline (not implying that absolute Algerian LNG exports to Europe fall). With respect to all other European LNG cargos, it is assumed that these can be rerouted between European countries, i.e. that supplies to Spain can be increased by decreasing

[70] I.e. for four weeks starting the first Friday in January.
[71] Assumed to be on the fourth Wednesday in January.

supplies to the UK. However, this rerouting only becomes effective after the first week of the crisis as it may take some time. Hence, 25 percent less LNG to Europe would be a reasonable estimate if Algeria fully ceased to export LNG[72] (and pipeline gas). The resulting total disruptions of pipeline and LNG supplies range between 320 and 343 million cubic meters per day depending on the scenario and is, hence, similar in scope to the Ukraine security of supply sensitivity (Section 9.1).

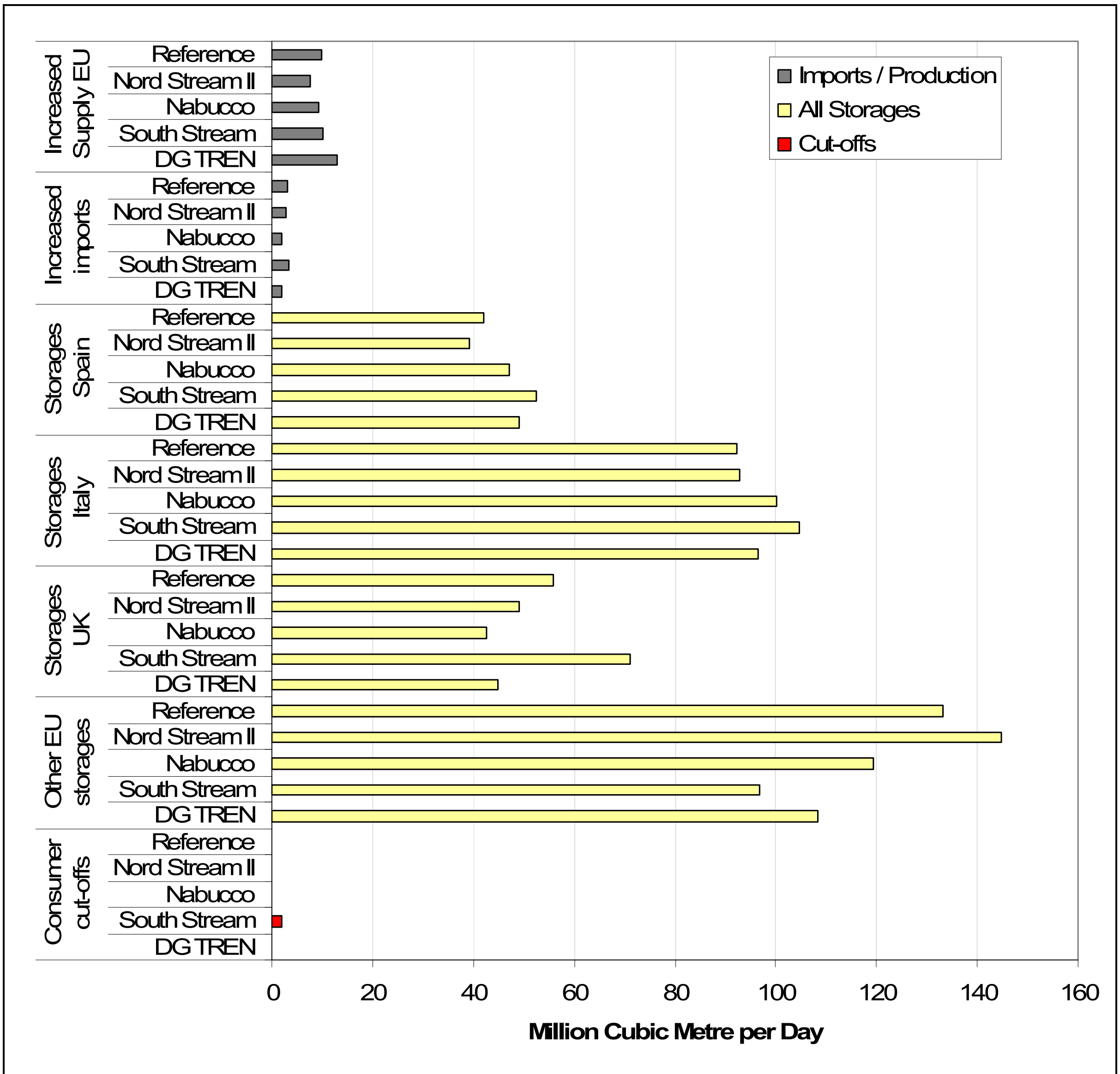
Within the modelling constraint that potential supply disruptions caused by technical system issues as a consequence of the drop-out of one (Italy) or two (Spain) system entry points are not detected, the model only finds limited supply disruptions as a consequence of the Algerian export stop. Gas flow diversions, the rerouting of LNG cargos, additional withdrawals from storages, and slight production increases by other suppliers are found to be able to mitigate the consequences of the hypothetical Algerian export stop from a capacity perspective.

The individual contributions of these compensation measures are quantified in Figure 51. Like in the Ukraine stress scenario, the most additional supply comes from gas storages. Additional withdrawals from storages in the two most directly affected countries, Spain and Italy, compensate about 40 percent of the total deficit together. The largest share, however, comes from underground gas storages in Italy which can provide about 100 million cubic metres of gas additionally. In Spain, however, there is much less storage capacity so additional withdrawals can only amount to about 40 million cubic metres a day. The decline in total LNG supplies to Europe also affects other countries including Great Britain (average daily decline in LNG imports of 60 million cubic metres per day), the Netherlands (up to -54), France (up to -27), and Portugal (-7). Spanish and Italian LNG imports decline by about 18 and 8 million cubic metres per day on average (see Table 14 in the Appendix for the decline of LNG cargos to all LNG importing countries and all scenarios). Consequently, other gas volumes in various European countries need to be procured from different sources to compensate for the LNG import shortfalls. About 18 percent of these volumes come from British gas storages, the majority of the remaining volumes from storages in other countries, most notable UGS in France and Germany. Again, as discussed in the context of the Ukraine security of supply simulation in Section 9.1, the flexibility of European production to increase output further in the winter months is limited. Hence, increases in production in the EU and imports from non-EU countries cannot significantly help to mitigate the effects of a

[72] Some of the Algerian LNG cargos may also be replaced by LNG from other sources as a consequence of the price effect in Europe.

hypothetical Algerian export stop. Disruptions occur in Spain and especially in the scenario which assumed that the MidCat pipeline as an additional interconnection from France is not built. With MidCat in place, additional gas transports from France to Spain are possible when pipeline imports from Algeria cease. This would enable a reduction of the consequences of this crisis to Spanish consumers.

Figure 51: Compensation of Algerian LNG and Pipeline Imports in Disruption Simulation (Daily Average)



Source: EWI.

The change in marginal supply costs for the day with the highest supply costs in the time period is displayed in Table 6 for each scenario (similar to Table 5 on page 96 for the Ukraine SoS simulation). Table 6 confirms that marginal supply costs do only increase to infinity as a consequence of the stress scenario on the Iberian Peninsula (in one scenario) indicating there are no disruptions to consumers in other countries. The largest increases in marginal supply costs are observed in the countries most directly affected, i.e. Spain, Portugal and (southern) Italy. Due to the effect on LNG volumes, marginal supply costs slightly rise in most European countries (which does not happen in the Ukraine SoS simulation where effects are largely confined to eastern Europe). This is also illustrated in a map of the supply cost changes for the Reference and South Stream (without MidCat) scenarios (together with new bottlenecks during the crisis) which can be found in the next section (Figure 54 and Figure 55). (For the other scenarios, the maps can be found in the Appendix staring page 144.)

Table 6: Increases in Marginal Supply Costs in Algeria SoS Simulation in 2019

Country	Reference	Nord Stream II	Nabucco	South Stream	DG TREN
Austria	+ 2.4 %	+ 2.5 %	+ 2.3 %	+ 2.8 %	+ 2.2 %
Belgium	+ 2.9 %	+ 2.9 %	+ 2.4 %	+ 2.7 %	+ 2.6 %
Bosnia and Herzegovina	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Bulgaria	+ 2.4 %	+ 2.2 %	+ 3.0 %	+ 2.7 %	+ 2.2 %
Croatia	+ 0.0 %	+ 0.0 %	+ 2.2 %	+ 2.5 %	+ 2.2 %
Czech Republic	+ 2.3 %	+ 2.1 %	+ 1.8 %	+ 2.8 %	+ 2.1 %
Denmark	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Estonia	+ 2.6 %	+ 2.4 %	+ 2.1 %	+ 2.8 %	+ 2.3 %
France (Northern Zone)	+ 1.6 %	+ 1.9 %	+ 1.1 %	+ 1.3 %	+ 1.2 %
France (Southern Zone)	+ 2.8 %	+ 3.0 %	+ 1.2 %	+ 1.4 %	+ 1.2 %
Germany (North)	+ 2.3 %	+ 2.2 %	+ 1.9 %	+ 2.8 %	+ 1.9 %
Germany (South)	+ 2.3 %	+ 2.3 %	+ 2.4 %	+ 2.7 %	+ 2.0 %
Great Britain (Bacton)	+ 2.2 %	+ 2.3 %	+ 2.2 %	+ 1.7 %	+ 2.5 %
Great Britain (St. Fergus)	+ 2.1 %	+ 2.1 %	+ 2.1 %	+ 1.3 %	+ 2.4 %
Greece	+ 0.0 %	+ 0.0 %	+ 3.3 %	+ 0.0 %	+ 3.5 %
Hungary	+ 0.0 %	+ 0.0 %	+ 2.3 %	+ 2.6 %	+ 2.2 %
Ireland	+ 2.0 %	+ 2.1 %	+ 2.0 %	+ 1.2 %	+ 2.3 %
Italy (North)	+ 2.5 %	+ 2.7 %	+ 2.8 %	+ 3.0 %	+ 2.7 %
Italy (South)	+ 7.4 %	+ 7.6 %	+ 6.7 %	+ 7.5 %	+ 7.2 %
Latvia	+ 2.6 %	+ 2.3 %	+ 2.2 %	+ 2.8 %	+ 2.1 %
Lithuania	+ 2.5 %	+ 2.3 %	+ 2.0 %	+ 2.8 %	+ 2.3 %
Luxembourg	+ 2.6 %	+ 2.6 %	+ 2.2 %	+ 2.7 %	+ 2.4 %
Macedonia	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Netherlands	+ 2.9 %	+ 2.9 %	+ 2.4 %	+ 2.7 %	+ 2.6 %
Norway	+ 3.5 %	+ 3.9 %	+ 3.7 %	+ 2.4 %	+ 3.9 %
Poland	+ 2.4 %	+ 2.2 %	+ 1.9 %	+ 2.9 %	+ 2.2 %
Portugal	+ 4.7 %	+ 4.8 %	+ 5.2 %	+ ∞	+ 5.1 %
Romania	+ 2.5 %	+ 2.3 %	+ 2.7 %	+ 2.9 %	+ 2.2 %
Serbia	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 2.7 %	+ 0.0 %
Slovakia	+ 2.3 %	+ 2.2 %	+ 1.9 %	+ 2.8 %	+ 2.1 %
Slovenia	+ 3.1 %	+ 3.2 %	+ 3.5 %	+ 2.8 %	+ 3.1 %
Spain	+ 7.3 %	+ 7.6 %	+ 5.8 %	+ ∞	+ 5.8 %
Sweden	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %	+ 0.0 %
Switzerland	+ 1.7 %	+ 2.0 %	+ 2.1 %	+ 3.0 %	+ 1.9 %
Turkey	+ 0.0 %	+ 0.0 %	+ 4.0 %	+ 0.0 %	+ 3.5 %

Source: EWI.

Generally, it can be concluded that the European gas market can well cope with a hypothetical stop of all Algerian exports to Europe. The diversion of LNG cargos, which was assumed to be effective within Europe after a couple of days, allows to "spread" the consequences in the form of increased marginal supply costs to a lot of consumers in many countries. However, this also implies that mitigation of the disruption can take place in many countries: For instance, storage volumes in the UK or Germany can help to compensate fewer LNG cargos coming to north western European countries. These LNG cargos, in turn, can be diverted to countries more exposed to Algerian (pipeline) gas such as Spain, Portugal and Italy.

Of course, apart from a competitive European gas market which provides the necessary price signals for such diversions to occur, a largely competitive LNG market and sufficient LNG import capacities in the different countries are required to realise the crisis mitigation scenario outlined in this section. Apart from potential technical issues not covered by the model, a tight LNG market, state intervention preventing supplies to other countries in a crisis, or other inefficiencies might lead to further supply disruptions and larger price increases as described here.

9.3 Implications on Market Integration

Chapter 8 outlined the findings of this study with respect to physical market integration in Europe during summer and winter months (with different demand levels) and on a hypothetical concurrent peak day in all European countries. As the previous two sections have shown, SoS stress scenarios may imply changing relative supply cost structures and diversions of gas flows. Both have an effect on the utilisation of infrastructure and, hence, the evaluation of transport capacity and congestion. Therefore, this section summarises where additional bottlenecks might occur if one of the two stress scenarios materialises.

Table 7 presents the bottlenecks computed by the model as a consequence of the supply disruptions. Similar to Table 4 (page 65, location of bottlenecks without crisis), Table 7 lists all investigated country pairs; bottlenecks between countries in a scenario are marked with colours for the peak and/or average winter day respectively – uncoloured (white) fields mark country pairs without additional congestion relative to the simulation without crisis. (The colour thereby only indicates the type of day (peak vs. average winter) for better illustration. Bottlenecks marked with *R* are in the reverse direction between the two countries relative to the bottleneck identified at that location in times without crisis.) In addition to the table, the directions of bottlenecks are displayed in Figure 52 and Figure 54 for the Ukraine and Algeria SoS sensitivities of the Reference Scenario respectively.

Generally, it can be noted that additional congestion largely occurs in the countries directly affected by the supply disruptions and in regions where (other) bottlenecks are also evident without a crisis (see Table 4). The latter is especially true for parts of eastern Europe where additional congestions occurs in both SoS sensitivity simulations; albeit in the Ukrainian one often in the reverse direction compared to the bottlenecks without crisis.

Table 7: Additional Bottlenecks as a Consequence of the Stress Simulations

	Ukraine stress scenario										Algeria stress scenario									
	Refer-ence		Nord Stream II		Nabucco		South Stream		DG TREN		Refer-ence		Nord Stream II		Nabucco		South Stream		DG TREN	
Countries	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day	Winter Day (ENTSOG)	Peak Demand Day
ES and PT																				
ES and FR																	[light green]	[dark green]		
GB and IE																				
GB and BE																	[light green]			
GB and NL																				
BE and NL																				
FR and BE																				
DE and NL																				
DE and BE																				
DE and FR																				
CH and DE																				
FR and CH																				
CH and IT																				
DE and DK																				
DE and PL																				
CZ and DE-S*											[light green]									
CZ and DE-E*	[orange]	[red]			[orange]	[red]														
AT and DE																				
AT and IT					R [orange]	[red]			R [orange]	[red]						[dark green]		[dark green]		
AT and SI												[dark green]		[dark green]						[dark green]
IT and SI					[orange]	[red]			[orange]	[red]								[dark green]		
HR and SI	[orange]		[orange]								[light green]		[light green]			[dark green]		[dark green]		[dark green]
HR and HU																				
AT and HU																				
HU and RO								[red]										[dark green]		
AT and SK							[orange]	[red]												
CZ and SK	R [orange]	R [red]	[orange]	R [red]	R [orange]	R [red]			[orange]	R [red]										
BG and RO							[orange]	[red]												
BG and GR							[orange]				[light green]		[light green]				[light green]			
BG and TR							[orange]				[light green]		[light green]				[light green]			
GR and TR																				
GR and IT	[orange]		[orange]		[orange]	[orange]			[orange]	[orange]										

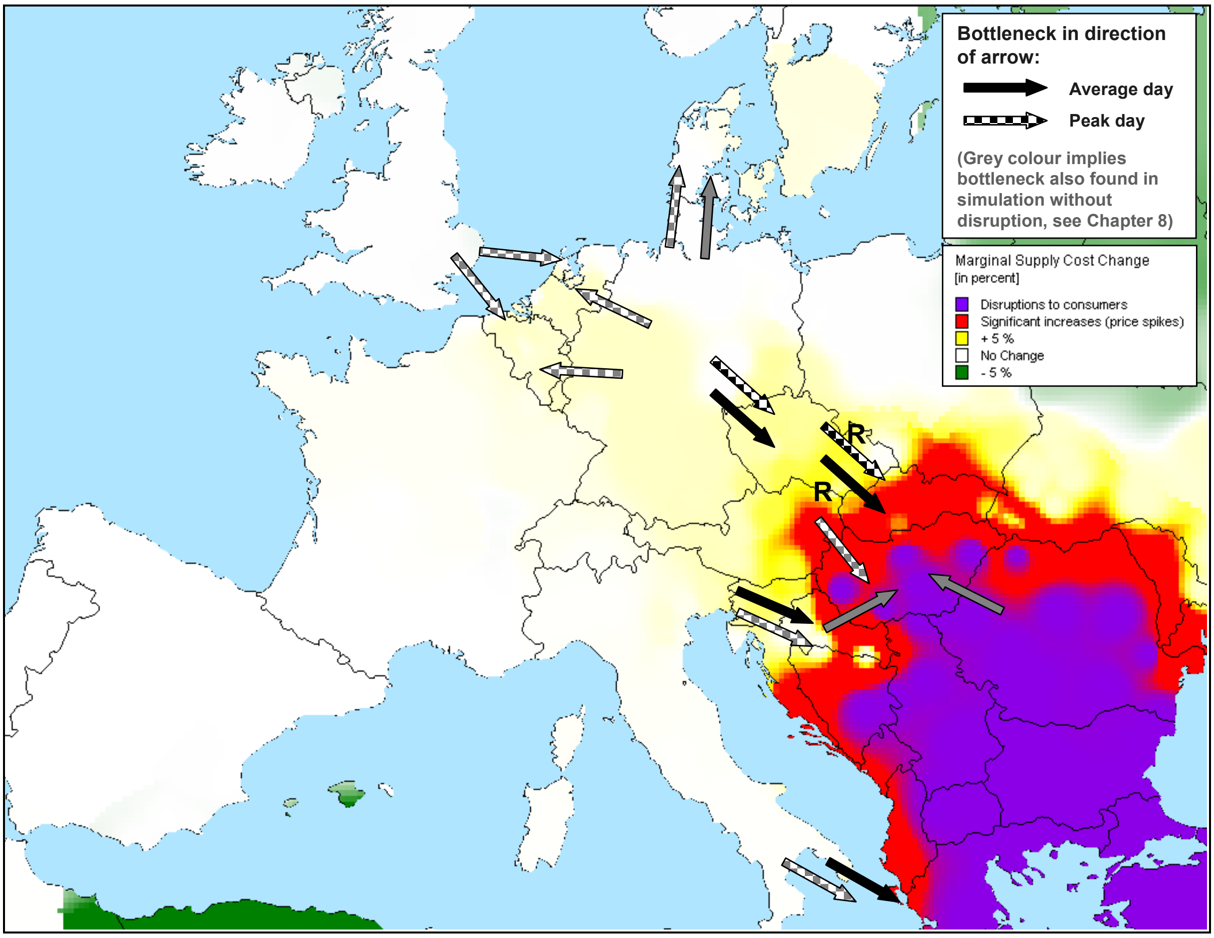
*Czech border with south (Waidhaus) and east Germany (Olbernhau) respectively

Additional bottleneck on average winter day in Ukraine SoS simulation: [orange] and in Algeria SoS simulation: [light green]
Additional bottleneck on peak demand day in Ukraine SoS simulation: [red] and in Algeria SoS simulation: [dark green]
No additional bottleneck: [ ]
Bottlenecks in reverse direction relative to simulations without SoS situation (previous chapter) are marked with **R**

Source: EWI.

Additional Congestion in Ukraine SoS Simulation

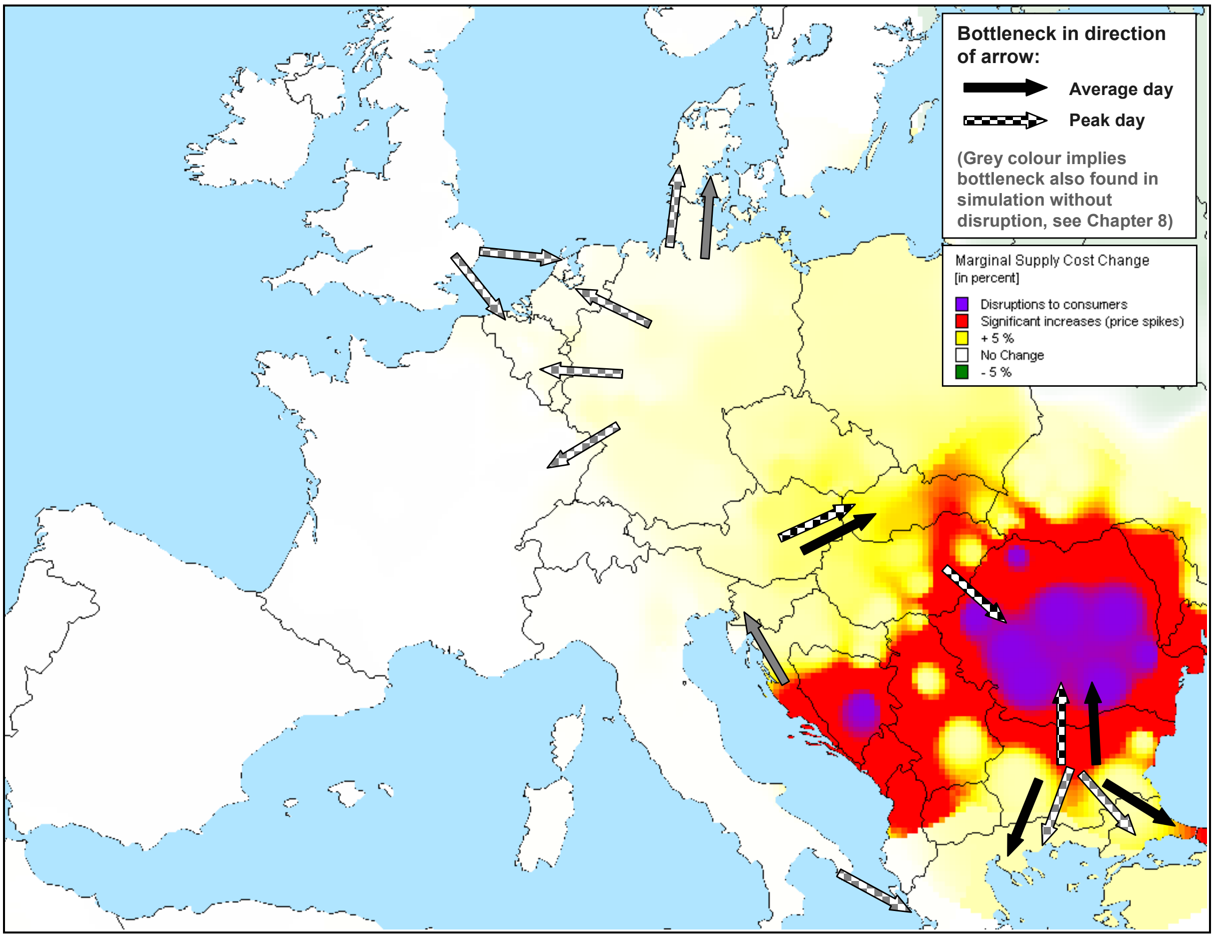
Figure 52: Ukraine SoS Simulation (Reference): Additional Bottlenecks and Marginal Supply Costs Changes



Source: EWI.

In the Ukraine SoS simulation (left hand side of Table 7), new bottlenecks are confined to central and eastern Europe. Despite the reverse flow projects realised after the 2009 Russia-Ukraine conflict, there are still some bottlenecks preventing additional west-to-east gas flows, namely between eastern Germany and the Czech Republic (where Nord Stream volumes can be routed south), the Czech and Slovak Republics and Austria and Hungary (although the latter bottleneck also existed without a crisis in most of the scenarios). With respect to Greece and Italy (which is investigated as a country pair because of the new offshore pipeline link between the countries (although there is no capacity from Italy to Greece)), the results show that a reverse flow on this pipeline would be beneficial in times of a disruption of Ukraine transits. Bottlenecks in the Nord Stream II, Nabucco and DG TREN scenarios are similar to the ones highlighted in Figure 52 (see Appendix C, page 141). In the South Stream Scenario, however, the alternative Russian export route implies that gas volumes are routed through different EU member states implying other additional congestion in case of a supply disruptions via Ukraine. The congestion is thereby largely confined to bottlenecks from Bulgaria to the neighbouring countries, see Figure 53.

Figure 53: Ukraine SoS Simulation (South Stream): Additional Bottlenecks and Marginal Supply Costs Changes



Source: EWI.

(However, as with all identified bottlenecks – see discussion in Section 8.1 – the observation of a bottleneck does not imply that it is necessarily efficient to invest in removing this constraint. This is especially true in the case of hypothetical security of supply scenarios with an unknown probability of becoming reality.)

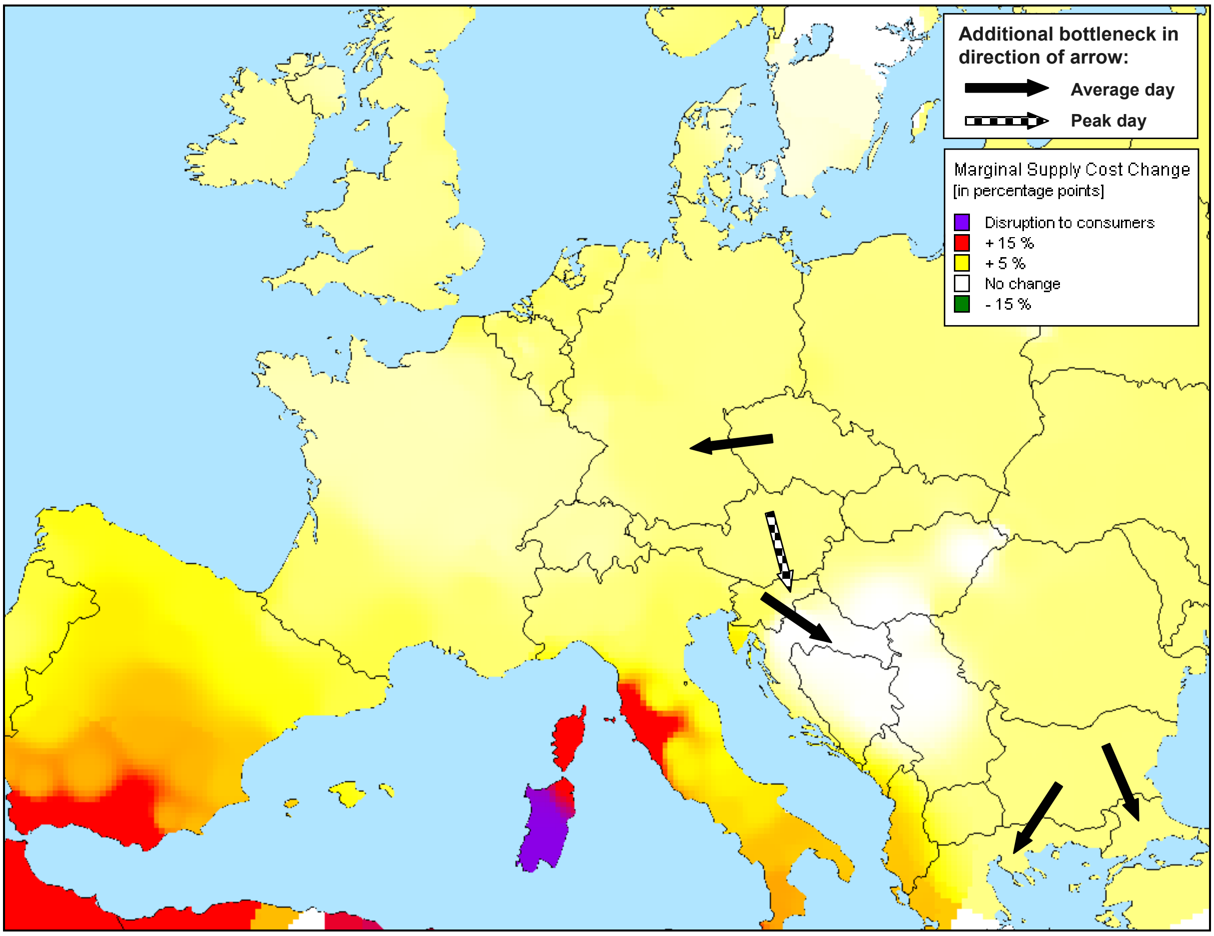
Figure 52 and Figure 53 also indicate the change in marginal supply cost to consumers or where disruptions to consumers take place.[73] The comparison of the two illustrations thereby

[73] The visualisation of supply disruptions outside the focus area of the security of supply sensitivity which also occurred on the average winter days (e.g. in Denmark and Sweden) is omitted in these illustrations. This also applies to Figure 54.

highlights that supply disruptions and marginal supply cost effects are much smaller with an alternative route supply gas to south-eastern Europe (see also Section 9.1).

Additional Congestion in Algeria SoS Simulation

Figure 54: Algeria SoS Simulation (Reference): Additional Bottlenecks and Marginal Supply Costs Changes



Source: EWI.

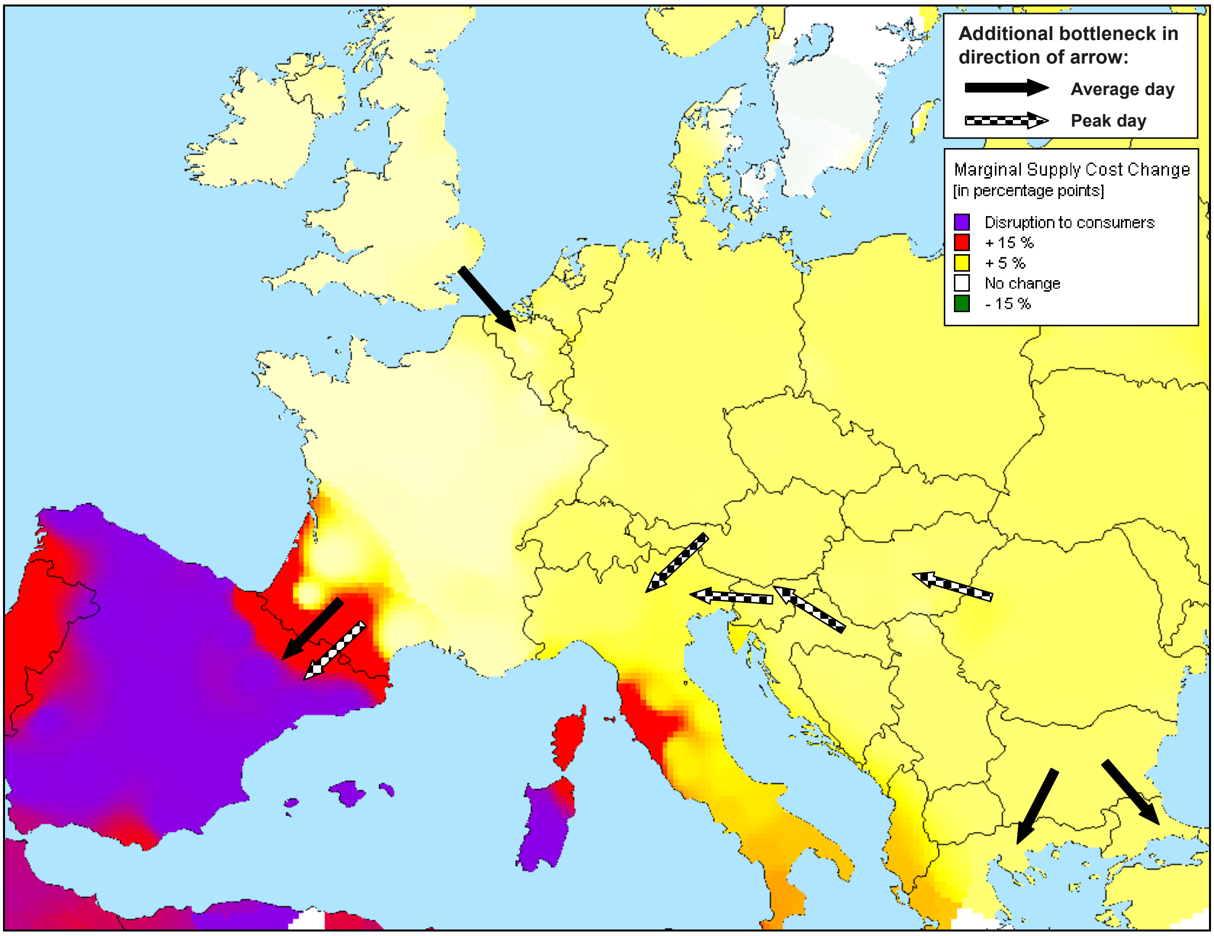
Regarding the Algeria security of supply simulation, additional bottlenecks are displayed in Figure 54 for a scenario with the MidCat pipeline and Figure 55 for the scenario without this project. (Note that in these maps, only additional bottlenecks are indicated as the ones existing anyway are less important for the interpretation of the results.)

In the Reference Scenario (Figure 54; and results for the other scenarios with MidCat are similar, see Appendix D starting page 144) additional congestion in such a crisis scenario is mainly identified into the countries where marginal supply costs rise due to the shortage of LNG volumes available to Europe, i.e.

- from Austria to Slovenia to Croatia (Krk terminal),
- from Bulgaria to Greece and Turkey,
- and also from Austria into Italy (DG TREN Scenario).

The situation is different in the scenario without MidCat (South Stream Scenario, Figure 55): As discussed previously, supply disruptions to consumers in Spain could then not be avoided, even if the market worked as efficiently as presumed by the model assumptions. Hence, a further bottleneck would become evident between France and Spain. Due to the supply disruptions in Spain in this scenario, the economic costs of congestion are relatively high then.

Figure 55: Algeria SoS Simulation (South Stream): Additional Bottlenecks and Marginal Supply Costs Changes



Source: EWI.

The results of this study with respect to security of supply also highlight the benefits of a competitive gas market in general, and a liquid LNG market in particular, to natural gas consumers in Europe. The simulated optimal responses to a crisis presume a functioning market which allows market players to actually implement these measures. Homogeneous and efficient practices with respect to capacity allocation for both pipelines and LNG terminals in Europe would reduce transaction costs and support the realisation of such efficient responses in the gas market in case of a crisis. With respect to LNG, the results specifically show that these volumes are of large importance for the whole European gas market – including countries which do not import LNG – and support the mitigation of gas supply disruptions. Hence, a flexible LNG supply market and the establishment of efficient (and harmonised) LNG import capacity allocation mechanisms benefit consumers beyond the borders of the LNG importing countries.

10 EWI Study in the Context of European Gas Infrastructure Analyses

In 2009, ENTSOG (2009) published its European Ten Year Network Development Plan as the first wide-ranging documentation on infrastructure (pipelines, LNG terminals, gas storages), infrastructure projects, production deliverability and import capacities. Considering those relative to an annual and a peak demand day scenario allows conclusions on the sufficiency of capacities for the demand-capacity balances for each European country.

With respect to security of supply, European and regional analysis is currently being carried out by the Pentalateral Energy Forum und the European Commission's Gas Coordination Group. However, work is still in progress with no results in the public domain yet.[74] Country-specific investigations of stress scenarios in the gas market on UK energy supply have been published by Ofgem (2009).[75]

This ERGEG-initiated study is one of the first to investigate issues of gas flows, market integration and security of supply with an encompassing model-based approach. The model validation showed that the applied TIGER model is an appropriate tool for such an analysis although some contract-induced gas flows cannot always be replicated. This approach allows for the possibility to explicitly consider natural gas flows and volumes as published technical capacities and interconnections of all relevant elements in the European gas transport infrastructure are considered (further pipeline-operational issues are not).

In terms of results, the model-based analysis allows investigations which exceed the scope of previous studies. However, the approach also confirms findings published by other institutions.

With respect to ENTSOG (2009)[76], EWI results are similar regarding the interconnection of countries and supply-demand gaps:

- ENTSOG reports sufficient capacities to cover demand (including the peak demand day) in Austria, Belgium, the Czech Republic, France, Germany, Ireland, Italy, Luxembourg, the Netherlands, Switzerland and the United Kingdom. (Although this is not explicitly

[74] The model the EU might apply to do so is presented by Monforti and Szikszaia (2010).
[75] "Project Discovery".
[76] An interpretation and summary of results with respect to bottlenecks and security of supply is provided in ENTSOG (2010).

stated by ENTSOG (2010), the same is true for all other considered countries except those stated below (DK, SE, SI, HU, BA, MK, RS).)

- This study confirms ENTSOG's findings. Additionally, the model-based approach also allows the conclusion that there is not only sufficient capacity, but that the gas volumes are also there to fill these capacities with natural gas (with one exception, see next paragraph) in all considered scenarios, with different demand projections, and on the peak demand day.
- Five of the six demand-capacity gaps identified by ENTSOG are also replicated by the EWI study as demand-supply gaps, which is not surprising as capacity is a prerequisite for the delivery of volumes. These concern the region of Denmark and Sweden, Hungary, Bosnia and Herzegovina, Macedonia and Serbia. What are not replicated are demand-supply gaps is in Slovenia which may be due to differing assumptions on LNG supplies to neighbouring Croatia.[77]

Apart from the stress scenarios, this study exceeds the work by ENTSOG (2009) in two other aspects: the variation of infrastructure assumptions between scenarios and the focus on gas volumes (in addition to capacities) enabled by the model simulation. This allows further conclusions:

- Potential demand-supply gaps are also a function of which new infrastructure projects are realised. The study at hand shows that the demand-supply gaps in south-eastern Europe are either reduced or fully eliminated if one of the major new import pipelines in the region is assumed to be in place. This is true for Greece, Hungary, Bosnia and Herzegovina and Serbia.
- In addition to the findings in line with ENTSOG outlined in the previous paragraph, taking into account gas volumes produces further insights on supply-demand balances as these volumes might not be available despite the capacity being there. This is found to be relevant for one country, Greece, under certain circumstances: Even though sufficient import capacity exists, high demand in Turkey might in some scenarios lead to a reduction in Turkey-to-Greece gas flows causing a supply-demand gap in Greece when demand in

[77] This study includes the Krk LNG terminal which then allows supplies from Croatia to Slovenia. Croatia is not explicitly considered in ENTSOG (2009).

Greece is also very high (peak demand day). While this may be only relevant in the extreme case of very high demand in both countries, it illustrates the importance of considering both capacities and volumes.

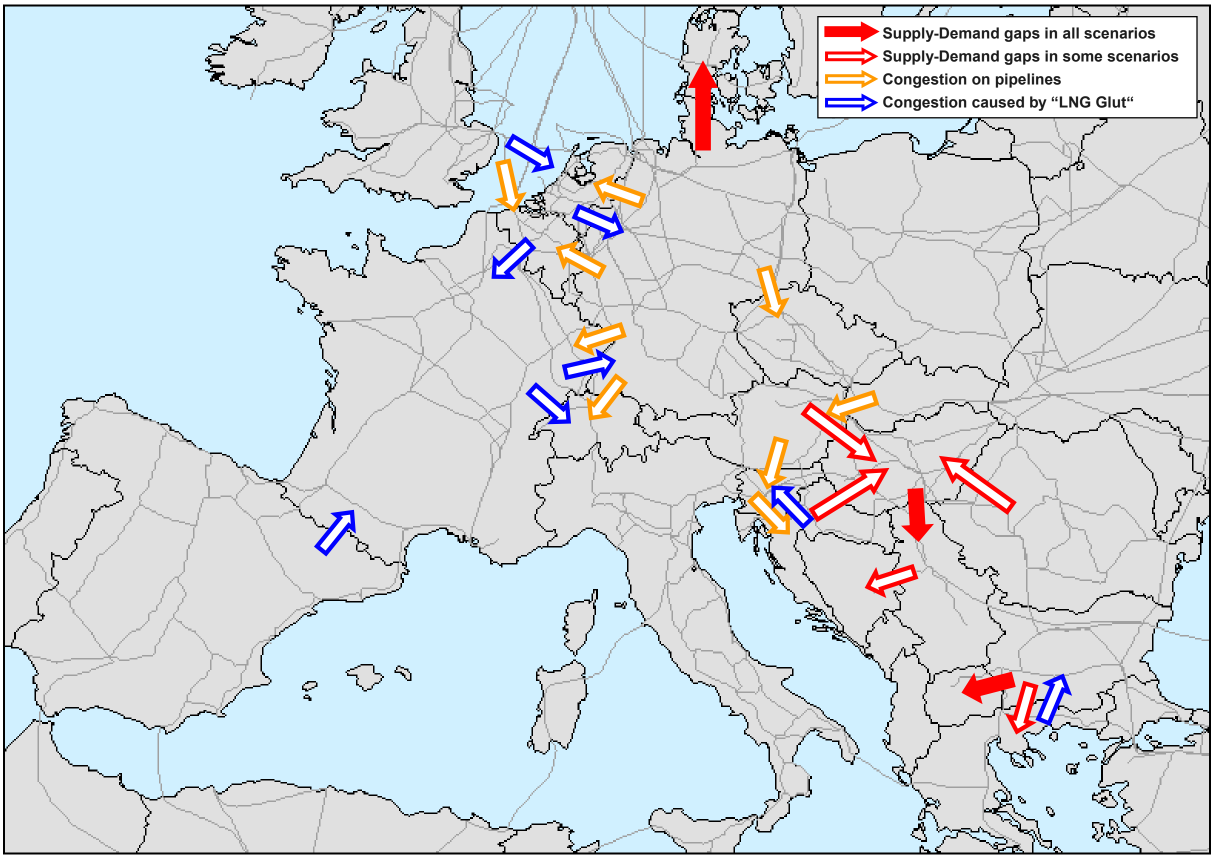
Furthermore, the volume-based approach also allows for the identification of congestion on pipeline routes. Hence, not only potential capacity issues leading to severe security of supply issues (supply-demand gaps) can be identified. This analysis also enables us to determine bottlenecks which limit market integration. Depending on the scenario and the considered time of the year, such congestion was identified between:

- the UK and the continent (peak demand day only),
- Germany and France, Belgium and the Netherlands (peak demand day only),
- Austria, Slovenia, Croatia (depending on LNG prices and time of the year)
- the Slovak Republic and Austria,
- and, in the case of temporally low LNG prices, also partially between Spain and France, France and Switzerland and Germany, Belgium and France, the Netherlands and Germany, Germany and the Czech Republic, and Greece and Bulgaria.

All major points of congestion identified in this study are also depicted in Figure 56.[78] The map, thereby, also highlights the value-added provided by this study compared to, for instance, capacity considerations as done by ENTSOG (2009): Such considerations are only able to detect bottlenecks leading to demand-supply (or demand-capacity) gaps. The model-based approach applied in this study, on the other hand, also enables the identification of congestion which is not so severe as to cause demand disruptions, but that hampers market integration. These kinds of bottlenecks are represented by the orange and blue arrows in Figure 56; the red arrows represent different demand-capacity gap causing bottlenecks which can be identified by a model-based as well as a capacity focused approach.

[78] This only represents a simplification and aggregation of the bottlenecks for illustrative purpose. The scenario specific results are presented in Table 4 (page 66) in Section 8.2.

Figure 56: Summary of bottlenecks in EWI Study



Source: EWI.

Regarding the security of supply stress scenarios, a classification of the EWI results in the context of the other Europe-wide studies is not yet possible due to this study being the first one to be published.

In the UK-focused analysis by Ofgem (2009), conclusions with respect to the UK are similar although not perfectly comparable:

- A simulated 40 percent reduction in LNG imports leads to severe price effects and demand reductions if it lasts for a whole 1-in-20 severe winter (Ofgem, 2009). This does not contradict our finding that a temporary four-week-decline in LNG imports could be compensated causing moderate effects on marginal supply costs and no demand reductions. The higher price effects found by Ofgem (compared to this study) are the consequence of the longer duration of the assumed LNG import reduction (whole winter vs. four weeks).

- With respect to a Russia-Ukraine dispute, Ofgem (2009) finds that the UK is well protected against such a crisis unless investment in infrastructure (storages) is low. As the study at hand presumes significant investments in storages in the UK, it can only be compared to the Ofgem (2009) scenarios with higher investments and, hence, mirrors their results that consequences in this case are rather small.

However, it has to be noted that focus and methodology of the studies differ.

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Appendix A: Assumptions

Table 8: ISO 3166 Country Codes

Country Code	Country Name
AT	Austria
AZ	Azerbaijan
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
BY	Belarus
CH	Switzerland
CZ	Czech Republic
DE	Germany
DK	Denmark
DZ	Algeria
EE	Estonia
ES	Spain
FI	Finland
FR	France
GB	United Kingdom (UK)
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IR	Iran, Islamic Republic of
IT	Italy
LT	Lithuania
LU	Luxembourg
LY	Libya
MK	Macedonia, Former Yugoslav Republic of
NL	Netherlands
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
RU	Russian Federation
SE	Sweden
SI	Slovenia
SK	Slovakia
TR	Turkey
UA	Ukraine

Source: http://www.iso.org/iso/country_codes/iso_3166_code_lists

Table 9: List of pipeline abbreviations

Pipeline (Project)	Full Name	Specification of Route
BBL	Balgzand-Bacton-Line	Balgzand (NL) - Bacton (GB)
GALSI	Gasdotto Algeria Sardegna Italia	offshore section: Koudiet Draouche (DZ) - Porto Botte, Sardinia (IT) - Piombino (IT)
IGI (also Poseidon)	Interconnector Greece-Italy	offshore section: Igoumenitsa (GR) - Otranto (IT)
Medgaz	Mediterranean Gaz pipeline	Hassi R'mel (DZ) - Almeida (ES)
MEGAL	Mittel-Europäische-Gasleitung	Waidhaus (CZ-DE border) - Medelsheim (DE-FR border) (2nd southern section from AT-DE border in Oberkappel)
MidCat	Midi – Cataluña Pipeline Project	Barcelona region (Martorell, ES) - southern France (Beziers) / (bi-directional)
NEL	Norddeutsche Erdgasleitung	Lubmin (DE) - Achim (DE)
OPAL	Ostsee-Pipeline-Anbindungs-Leitung	Lubmin (DE) - Olbernhau (DE-CZ border)
TAG	Trans Austria Gasleitung	SK-AT border - Baumgarten (AT) - AT-IT border
TAP	Trans-Adriatic Pipeline	Thessaloniki (GR) - Albania - Puglia region (IT)
TGL	Tauerngasleitung	Haiming (DE) - AT - Malborghetto/Tarvis (AT-IT border) / (bi-directional)
Transmed	Trans-Mediterranean Pipeline	Hassi R'mel (DZ) - Tunisia - Mazara del Vallo, Sicily (IT)

Source: EWI.

Table 10: Demand Scenario Assumptions for 2019

Country	EWI/ERGEG Demand [bcm / year]	ENTSOG Demand* [bcm / year]	ENTSOG Peak Day Demand* [mcm / day]
Austria	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	4.3	6.0	37
Czech Republic	9.1	13.0	71
Denmark	2.8	3.0	26
Estonia	0.7	1.0	3
Finland	4.9	5.0	24
France	43.0	53.0	421
Germany	93.4	81.0	500
Greece	5.1	7.0	35
Hungary	14.8	21.0	132
Ireland	4.9	6.0	28
Italy	80.8	102.0	433
Latvia	1.9	2.0	8
Lithuania	2.9	3.0	14
Luxemburg	1.4	1.0	7
Macedonia, FYRo	0.2	0.8	3
Netherlands	46.3	46.0	431
Norway	7.5	7.9	48
Poland	20.7	19.0	85
Portugal	3.9	8.0	32
Romania	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	98.9	90.0	483
Turkey	50.2	50.2	199
Total	597	654	3790

* EWI Assumptions for those countries where no ENTSOG data available:
Turkish Demand is based on WoodMackenzie (2008).
Data for the Balkan region is based on IEA (2009) with the trend being carried forward.

Source: EWI, ENTSOG (2009).

Table 11: Assumptions on Intra-European Pipeline and Interconnection Expansions

Countries	Interconnection Point / Pipeline	Capacity Addition until 2019 (in mcm/day)
AT	WAG reverse flow	43
AT	OMV-TAG System capacity increase	24
AT	TAG reverse flow	32 Arnoldstein / 18 Baumgarten
AT	TGL bidirectional	31
AT	Oberkappel	28
AT - DE	Burghausen/Überackern	15
AT - IT	Tarvisio	105
AT - SI	Murfeld/Ceršak	23
BE - DE	Eynatten/Raeren (EGT & RWE TNG & ENI)	23
BE - FR	Taisnières (H)	83
BE - NL	Zelzate GTS	22
BE - UK	Zeebrugge - Bacton	68
BG - MK	Zidilovo	2
CZ - PL	Cieszyn (1)	2
DE - AT	Burghausen/Überackern	7
DE - BE	Eynatten/Raeren (EGT & RWE TNG)	30
DE - CH	Wallbach (ENI GTD)	31
DE	NEL Pipeline *(only with Nord Stream II)*	60
DE	OPAL Pipeline Northern Part (to Groß Köris)	100
DE - DE/CZ	OPAL Pipeline Southern Part & Gazelle	88
DE - FR	Medelsheim/Obergailbach	56
DE - NL	Bunde - Oude Statenzijl H-gas	
- EGT		32
- Gasunie Deutschland		2
DE - PL	Lasów	5
DZ - ES	Almeria	22
ES - PT	Valença do Minho/Tuy	5
ES - FR	Biriatou	5.2
ES - FR	Larrau	14.2
ES - FR	Midcat *(except in South Stream Scenario)*	19.8
FR - ES	Larrau	14.2
FR - ES	Biriatou	5.2
FR - ES	Midcat *(except in South Stream Scenario)*	15.5
GR - IT	Greece-Italy link (TAP or IGI Poseidon)	22
HU - HR	Donji Miholjac / Drávaszerdahely	18
HU - RO	Csanádpalota / Arad	5
IT - SI	Šempeter/Gorizia	6
LT - RU	Šakiai	11
LY - IT	Gela	30
NL - BE	Zelzate (GTS)	29
NL - BE	's Gravenvoeren	33
NL - BE	Zelzate (GTS)	25
NL - DE	Bocholtz (ENI GTD)	32
NL - DE	Bunde – Oude Statenzijl L-gas (GasunieD)	15
NL - DE	Bunde - Oude Statenzijl H-gas	
- Gasunie Deutschland		2
- EGT		14
- WGT		5
NL - DE	Bocholtz	42
NL - UK	Julianadorp (H-gas)	71
NO - DE	Dornum (EGT)	42
NO - DE	Emden EPT (GasunieD)	18
NO - NL	NLCluster capacity Emden (NPT+EPT)	77
PT - ES	Badajoz / Campo Maior	9
RS - BA	Zvornik	2
SI - HR	Rogatec II	14
SI - IT	Šempeter/Gorizia	6
SK - AT	Baumgarten	200
TK - GR	Kipoi BMS	34
TN - IT	Mazara del Vallo	94
UA - HU	Beregdaróc	68
UK - BE	Bacton - Zeebrugge	55

Source: ENTSOG (2009), TSOs, and own assumptions.

Table 12: Assumptions on Storage Projects / Expansions

Coun-try	Name of facility	Type of facility	Comment	WGV* (mcm)	Start-up	Status
AT	Haidach	Reservoir	New facility	1200	2011	Under construction
AT	Schonkirchen Tief (Phase I)	Reservoir	New facility	850	2014	Planned
AT	Schonkirchen Tief (Phase II)	Reservoir	New facility	750	2018	Planned
AT	7fields	Reservoir	New facility	1155	Apr 2011	Planned
AT	7fields	Reservoir	New facility	570	Apr 2014	Planned
BE	Loenhout	Aquifer	Expansion	100	2010	Under construction
BG	Chiren	Reservoir	Expansion	450	2010	Planned
FR	Céré La Ronde/Soings	Aquifer	Expansion	400	2012	Under construction
FR	Etrez	Salt cavity	Expansion	400	2015	Under Construction
FR	Etrez/Manosque	Salt cavity	Expansion	100	April 2008	Live
FR	Hauterives	Salt cavity	New facility	150	2017 (full cap)	Committed
FR	Ile-de-France Nord/Gournay	Aquifer	Expansion	500	2013	Under construction
FR	Lussagnet / Izaute	Aquifer	Expansion	1100	2018	+100mcm/year
FR	Manosque	Salt cavity	Expansion	130	2015	Under Study
FR	Pécorade	Reservoir	New facility	750	2015	Planned
FR	Trois Fontaines	depleted field	New facility	80	2010	Under Construction
DE	Bierwang	depleted field	Expansion	359	2015	under construction
DE	Empelde	Salt cavity	New facility	110	2015	Planned
DE	Epe	Salt cavity	New facility	200	2011	Under development
DE	Epe EGS H-Gas	Salt cavity	Expansion	273	2011	under construction
DE	Epe Eneco	Salt cavity	New facility	100	2013	under construction
DE	Epe Nuon	Salt cavity	Expansion	80	2011	under construction
DE	Etzel EGL (share EGS)	Salt cavity	Expansion	250	2011	under construction
DE	Etzel EGS	Salt cavity	New facility	2500	2016	Planned/Committed
DE	Huntorf	Salt cavity	New facility	150	2015	Planned
DE	Jemgum	Salt cavity	New facility	1200	2012	Planned
DE	Kiel-Rönne	Salt cavity	New facility	70	2015	Planned
DE	Krummhörn	Salt cavity	Reparation	229	2011	under construction
DE	Peckensen Phase 2	Salt cavity	New facility	160	2010	Under construction
DE	Peckensen Phase 3	Salt cavity	New facility	180	2014	Committed
DE	Reckrod	Salt cavity	New facility	30	2015	Planned
DE	Reckrod-Walf	Salt cavity	New facility	120	2015	Planned
DE	Ruedersdorf	Salt cavity	New facility	300	2015	Under construction
DE	Wolfersberg	Reservoir	Expansion	45	2010	Planned
DE	Xanten	Salt cavity	Expansion	125	2015	Planned
HU	Szoereg-1	Reservoir	New facility	1900	2010	Under construction
HU	Zsana	Reservoir	Expansion	600	late 2009	Under construction
IT	Bordolano	Reservoir	New facility	1500	2013	Under construction
IT	Caleppio-Merlino	Reservoir	New facility	450	2013	Under construction
IT	Cellino & Collato	Reservoir	Expansion	552	2010	Under construction
IT	Cignone	Reservoir	New facility	200	2013	Committed
IT	Cornegliano	Reservoir	New facility	600	2015	Planned
IT	Cotignola & San Potito	Reservoir	New facility	915	2013	Committed

(continued)

Country	Name of facility	Type of facility	Comment	WGV* (mcm)	Start-up	Status
IT	Cugno Le Macine	Reservoir	New facility	740	2015	Planned
IT	Fiume Treste BCC1	Reservoir	New facility	350	2010	Under construction
IT	Fiume Treste C2	Reservoir	Expansion	200	2010	Under construction
IT	Fiume Treste DEE0	Reservoir	New facility	600	2010	Under construction
IT	Ripalta	Reservoir	Expansion	300	2010	Under construction
IT	Rivara	Aquifer	New facility	3000	2013	Planned
IT	Sergnano	Reservoir	Expansion	200	2010	Under construction
LV	Incukalns	Reservoir	Expansion	1000	2015	Planned
NL	Bergermeer	Reservoir	New facility	4100	2013	Planned
NL	Zuidwending	Salt cavity	New facility	180	2011	Under construction
PL	Bonikowo	Reservoir	New facility	200	2010	Committed
PL	Daszewo	Reservoir	New facility	30	2010	Under construction
PL	Kosakowo	Salt cavity	New facility	250	2018	Committed
PL	Mogilno	Salt cavity	Expansion	420	2018	Under construction
PL	Strachocina	Reservoir	Expansion	180	2012	Committed
RS	Banatski Dvor	Reservoir	New facility	800		
ES	El Ruedo	Reservoir	New facility	90	2011	Committed
ES	Gaviota	Reservoir	Expansion	570	2015	Committed
ES	Las Barreras	Reservoir	New facility	72	2011	Committed
ES	Marismas	Reservoir	New facility	300	2011	Committed
ES	Marismas	Reservoir	New facility	300	2013	Committed
ES	Poseidon	Reservoir	New facility	250	2010	Committed
ES	Yela	Aquifer	New facility	1050	2011	Under construction
TR	Tuz Gölü	Reservoir	New facility	1000	2015	Committed
GB	Albury Phase 1	Reservoir	New facility	160	2018	Planned
GB	Aldbrough phase 2	Salt cavity	Expansion	150	2013	Planned
GB	Bains	Offshore Reser	New facility	570	2013	Planned
GB	Baird	Offshore Reser	New facility	136	2016	Planned
GB	Bletchingley	Salt cavity	New facility	605	2010	Planned
GB	British Salt	Salt Cavity	New facility	1000	2016	Planned
GB	Caythorpe	Reservoir	New facility	200	2011	Planned
GB	Esmond / Gordon	Offshore reserv	New facility	4100	2015	Planned
GB	Fleetwood	Salt cavity	New facility	1700	2018	Planned
GB	Gateway	Salt cavity	New facility	1136	2019	Planned
GB	Hewett	Offshore Reser	New facility	5000	2015	Planned
GB	Hole House phase 2	Salt cavity	Expansion	27	2010	Under construction
GB	Holford (formerly Byley)	Salt cavity	New facility	170	2011	Under construction
GB	Isle of Portland	Salt Cavity	New facility	330	2015	Planned
GB	Saltfleetby	Reservoir	New facility	600	2011	Planned
GB	Stublach	Salt cavity	New facility	400	2013	Under construction
GB	Welton / Scampton North	Reservoir	New facility	435	2018	Planned
GB	Whitehill Farm	Salt cavity	New facility	420	2018	Planned

** Working Gas Volume for Expansion refers to additional WGV (not total WGV after expansion).*

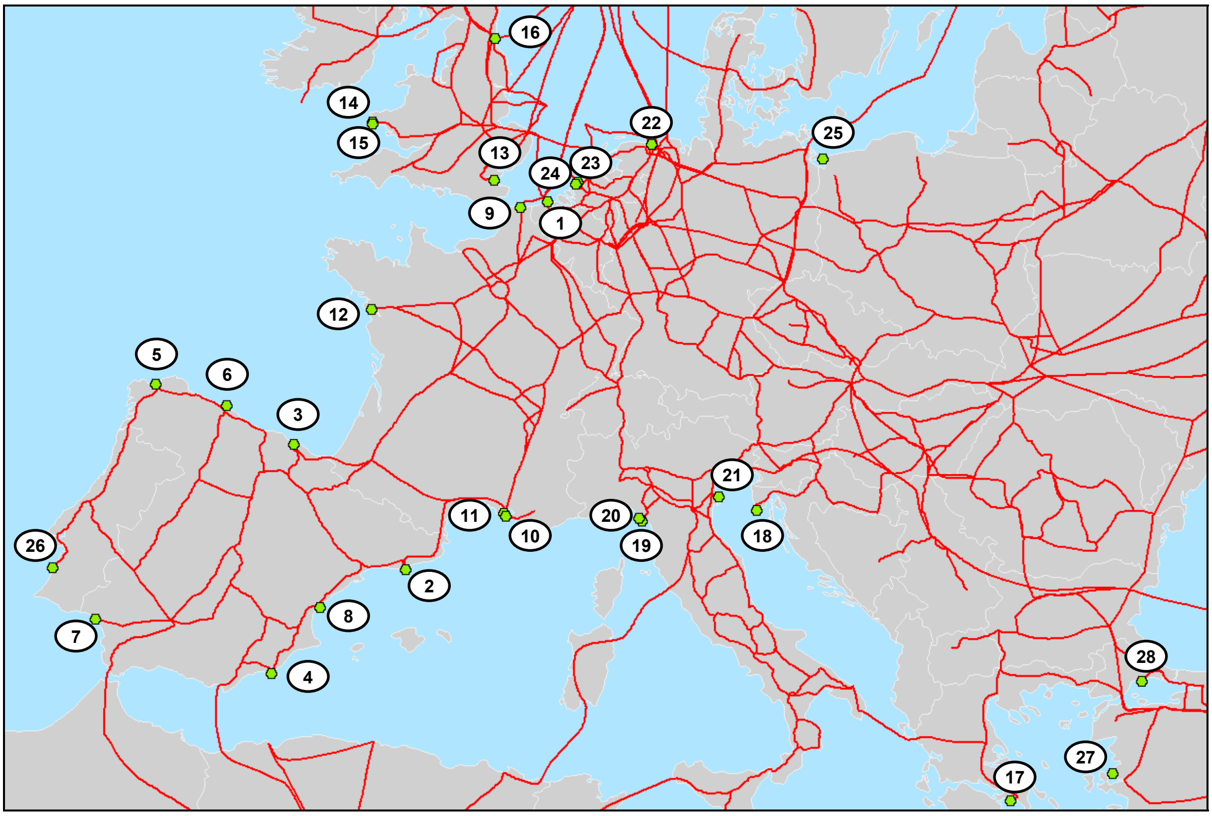
Source: Own assumptions, GSE, IGU (2006) and EGM (2007).

Table 13: Assumptions on LNG Import Terminals

Coun-try	Name	Comment	Hourly Capacity [1000m^3/h]*	Nominal An-nual Capacity [bcm/year]*	Storage Capacity [1000m^3 LNG]*	Start-Up	ID in ac-company-ing map
BE	Zeebrugge		1700	4.5	261	01.01.1987	1
BE	Zeebrugge	Expansion	1700	9	380	01.10.2008	
ES	Barcelona		1950	17.1	540	01.01.1969	2
ES	Barcelona	Expansion**	1950	17.1	680	01.01.2011	
ES	Bilbao		800	7.0	300	01.01.2003	3
ES	Bilbao	Expansion	1200	10.5	450	01.01.2015	
ES	Bilbao	Expansion**	1200	10.5	600	01.01.2015	
ES	Cartagena		1350	11.8	437	01.01.1989	4
ES	Cartagena	Expansion**	1350	11.8	587	01.01.2010	
ES	El Ferrol		412.8	3.6	300	01.05.2007	5
ES	El Ferrol	Expansion	825.6	7.2	300	01.01.2013	
ES	El Musel (Gijon)	New Terminal	800	7	300	01.01.2011	6
ES	El Musel (Gijon)	Expansion	1000	8.8	450	01.01.2013	
ES	Huelva		1350	11.8	610	01.01.1988	7
ES	Huelva	Expansion	1650	14.5	760	01.01.2015	
ES	Sagunto		1200	10.5	450	01.01.2006	8
ES	Sagunto	Expansion	1400	12.3	750	01.01.2012	
FR	Dunkerque	New Terminal	1400	10.0	380	01.01.2014	9
FR	Fos Cavaou		1160	8.25	330	01.02.2010	10
FR	Fos Tonkin		1150	7.0	150	01.01.1972	11
FR	Montoir de Bretagne		1600	10	360	01.01.1982	12
FR	Montoir de Bretagne	Expansion	1600	12.5	360	01.10.2011	
GB	Isle of Grain		708	4.4	200	01.07.2005	13
GB	Isle of Grain	Expansion	1750	13.4	800	01.10.2008	
GB	Isle of Grain	Expansion	2380	20.8	1000	01.10.2010	
GB	Milford Haven (Dragon)		700	6	336	01.09.2009	14
GB	Milford Haven (South Hook)		2000	11	465	01.10.2009	15
GB	Milford Haven (South Hook)	Expansion	2000	21	775	01.12.2009	
GB	Teesside Gas Port		470	4.12	0	01.03.2007	16
GR	Revithoussa		750	5.3	130	01.01.2000	17
HR	Krk LNG	New Terminal	1700	15.0	n/a	01.01.2014	18
IT	Livorno (offshore)	New Terminal	420	3.75	137.5	01.10.2011	19
IT	Panigaglia (La Spezia)		436	3.5	100	01.01.1971	20
IT	Panigaglia (La Spezia)	Expansion	915	8	240	01.01.2014	
IT	Rovigo (offshore)		1000	7.6	250	01.10.2009	21
NL	Eemshaven	New Terminal	1000	12	n/a	01.10.2013	22
NL	Rotterdam (GATE)	New Terminal	1230	12	540	01.10.2011	23
NL	Rotterdam (LionGas)	New Terminal	900	9	495	01.10.2010	24
PL	Swinoujscie	New Terminal	500	2.5	n/a	01.01.2014	25
PT	Sines		900	5.2	240	01.01.2003	26
PT	Sines	Expansion	1350	8.5	390	01.05.2012	
TR	Aliaga		680	6	280	01.01.2006	27
TR	Marmara Ereglisi		685	5	255	01.01.1992	28

Source: Assumptions by EWI based on publicly available sources.

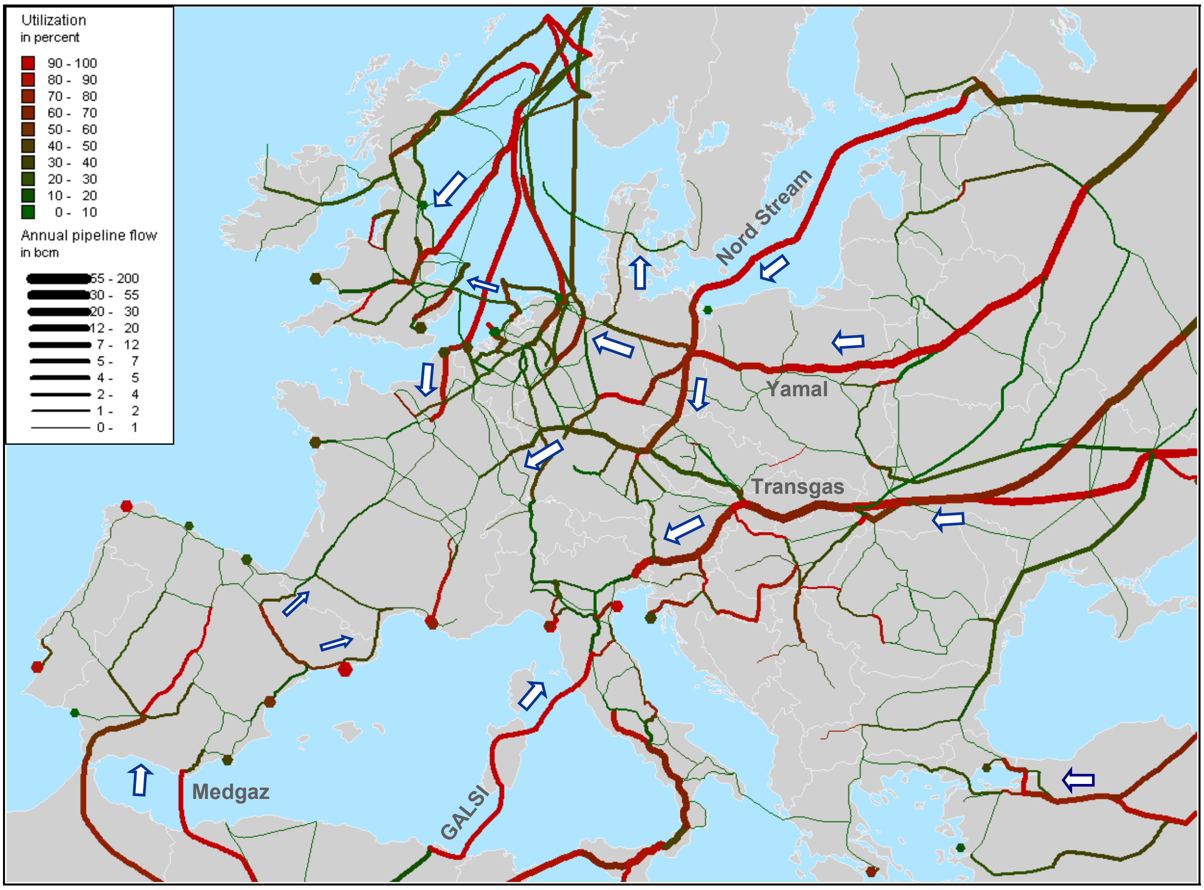
Figure 57: Overview of LNG Terminal Locations



Source: EWI.

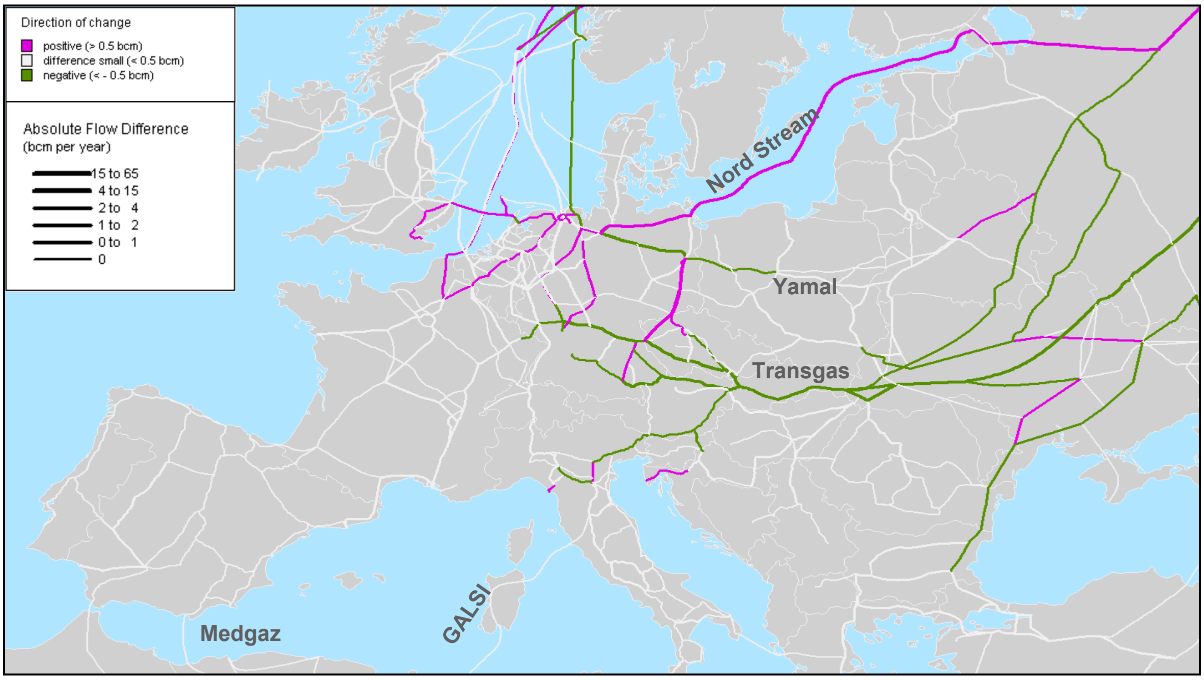
Appendix B: Additional Gas Flow Charts

Figure 58: Annual Gas Flows 2019 – Reference Scenario (ENTSOG Demand)



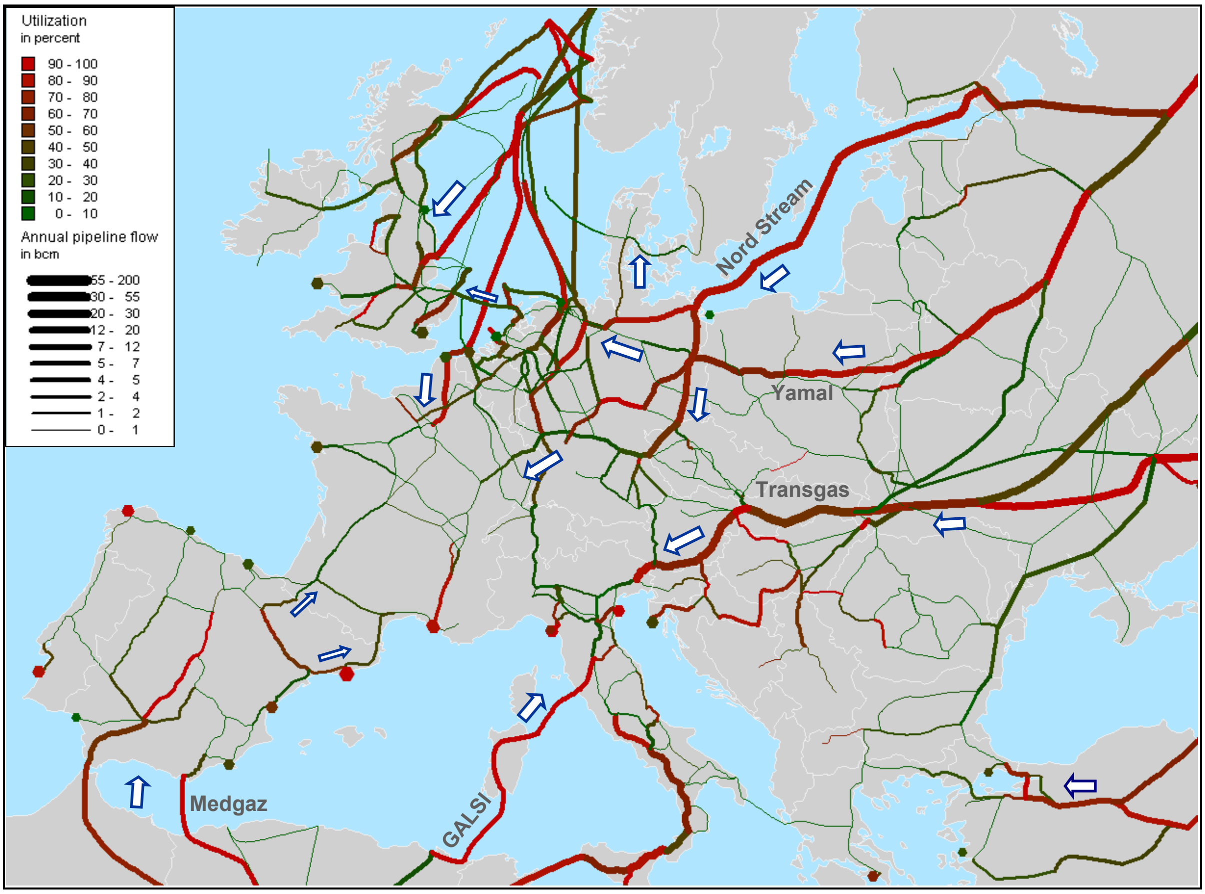
Source: EWI.

Figure 59: Absolute Change of Annual Gas Flows 2019 – Nord Stream II vs. Reference Scenario



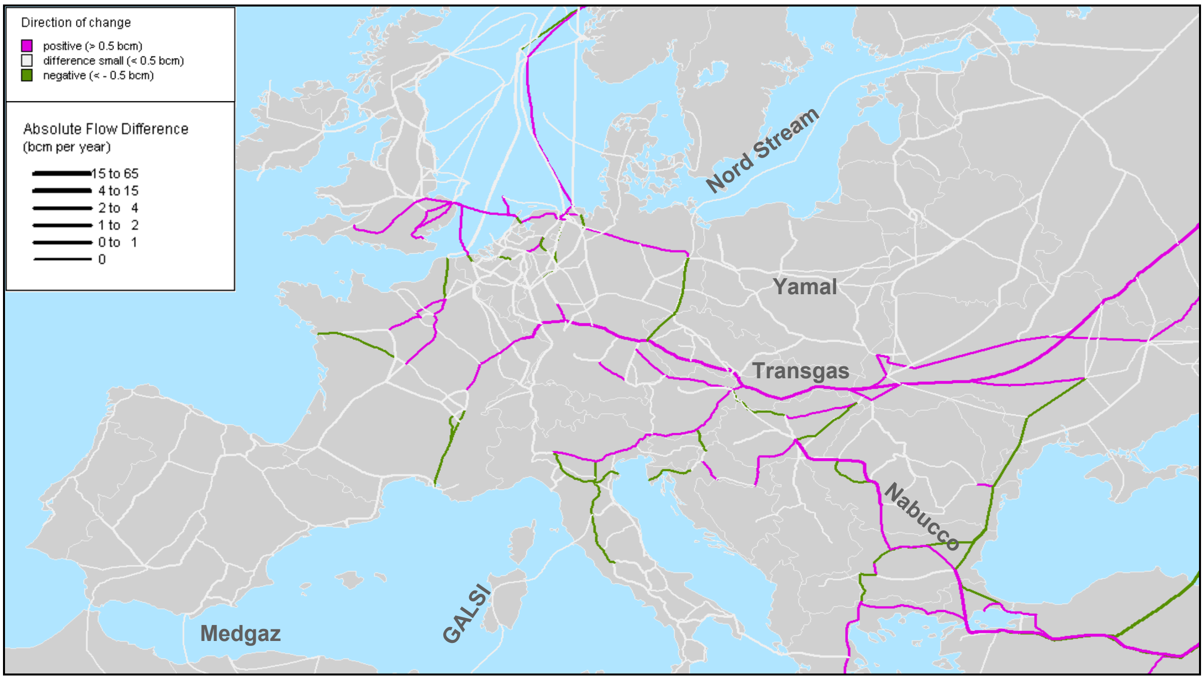
Source: EWI.

Figure 60: Annual Gas Flows 2019 – Nord Stream II Scenario (ENTSOG Demand)



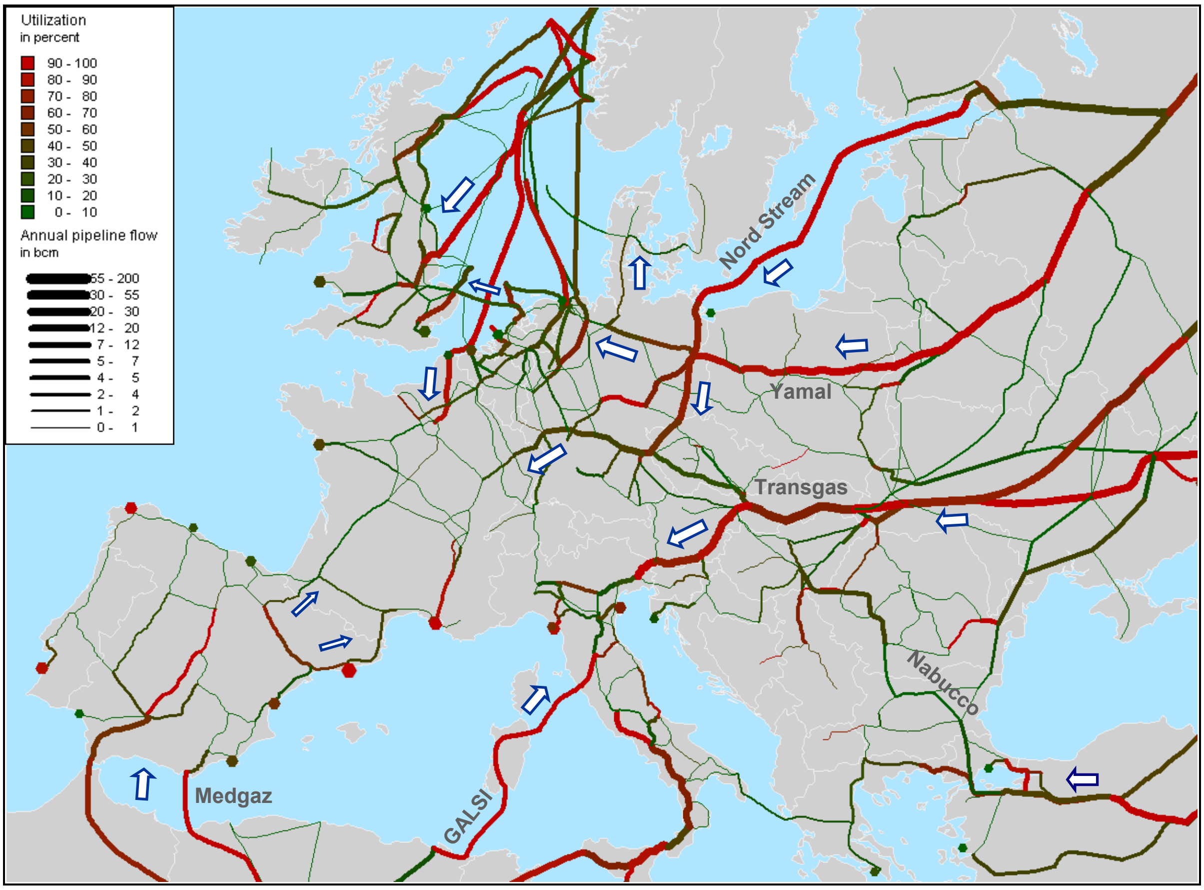
Source: EWI.

Figure 61: Absolute Change of Annual Gas Flows 2019 – Nabucco vs. Reference Scenario



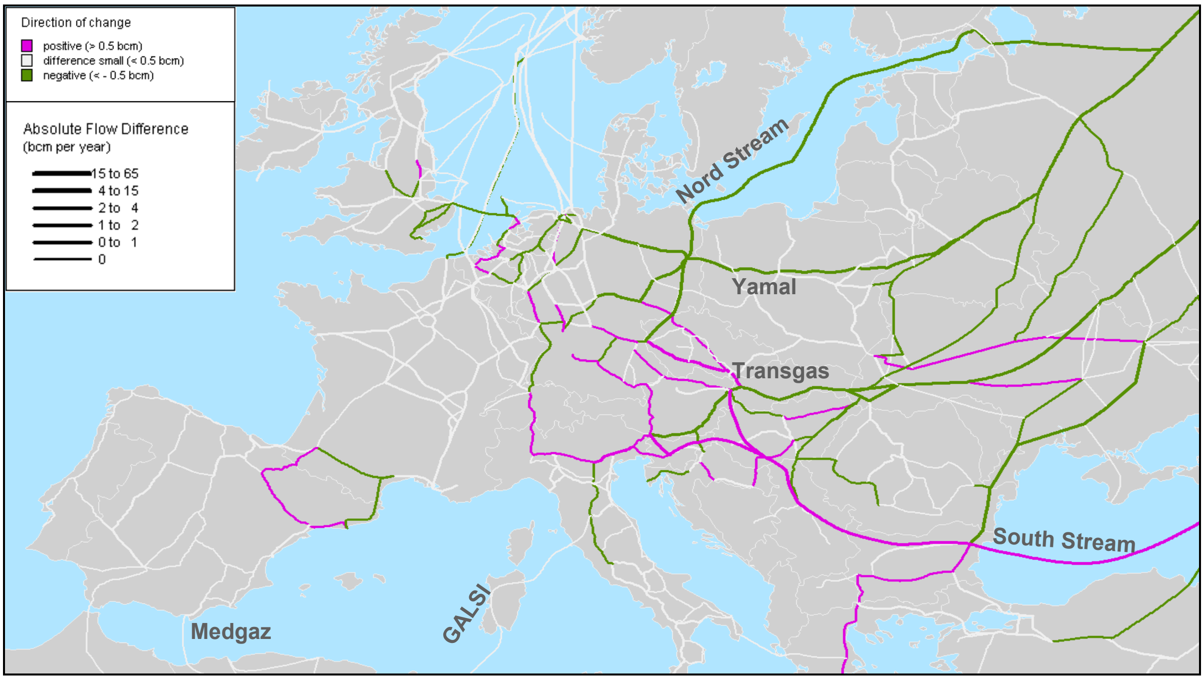
Source: EWI.

Figure 62: Annual Gas Flows 2019 – Nabucco Scenario (ENTSOG Demand)



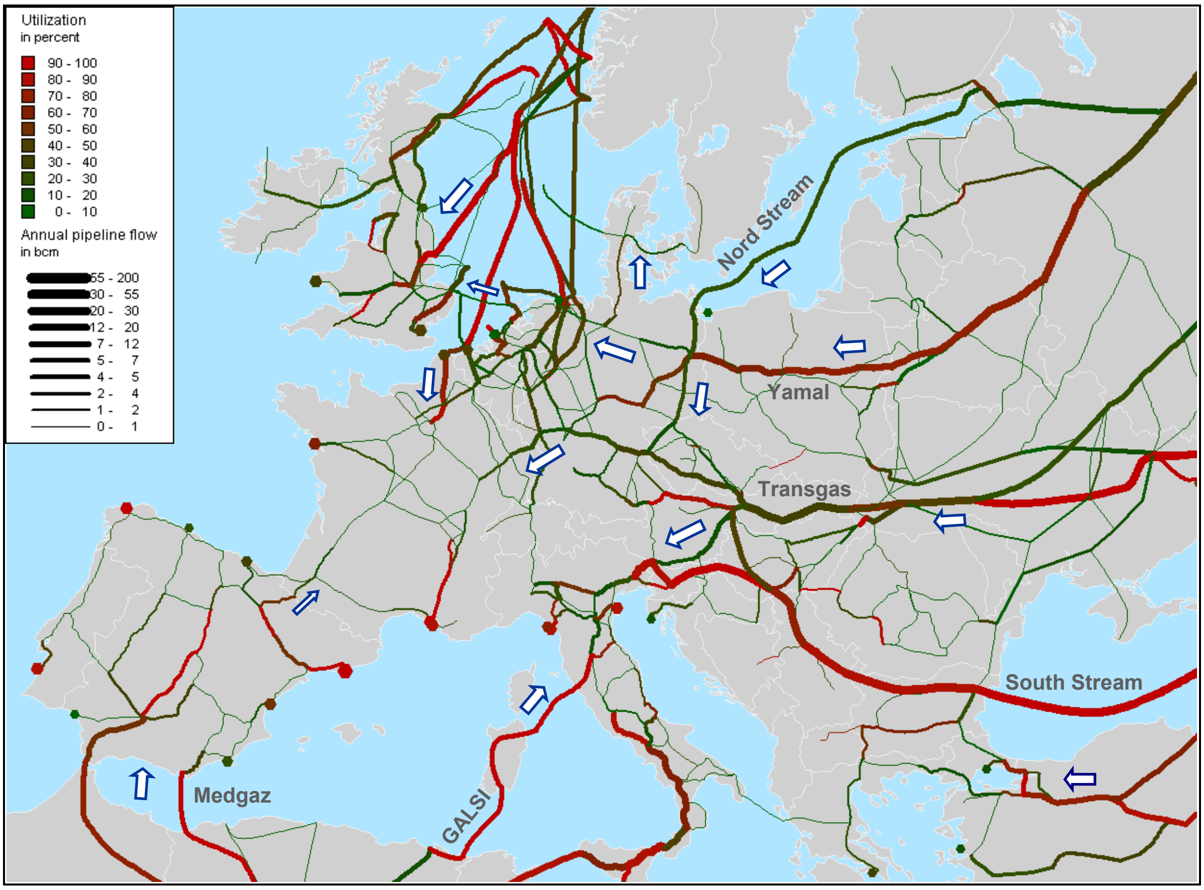
Source: EWI.

Figure 63: Absolute Change of Annual Gas Flows 2019 – South Stream vs. Reference Scenario



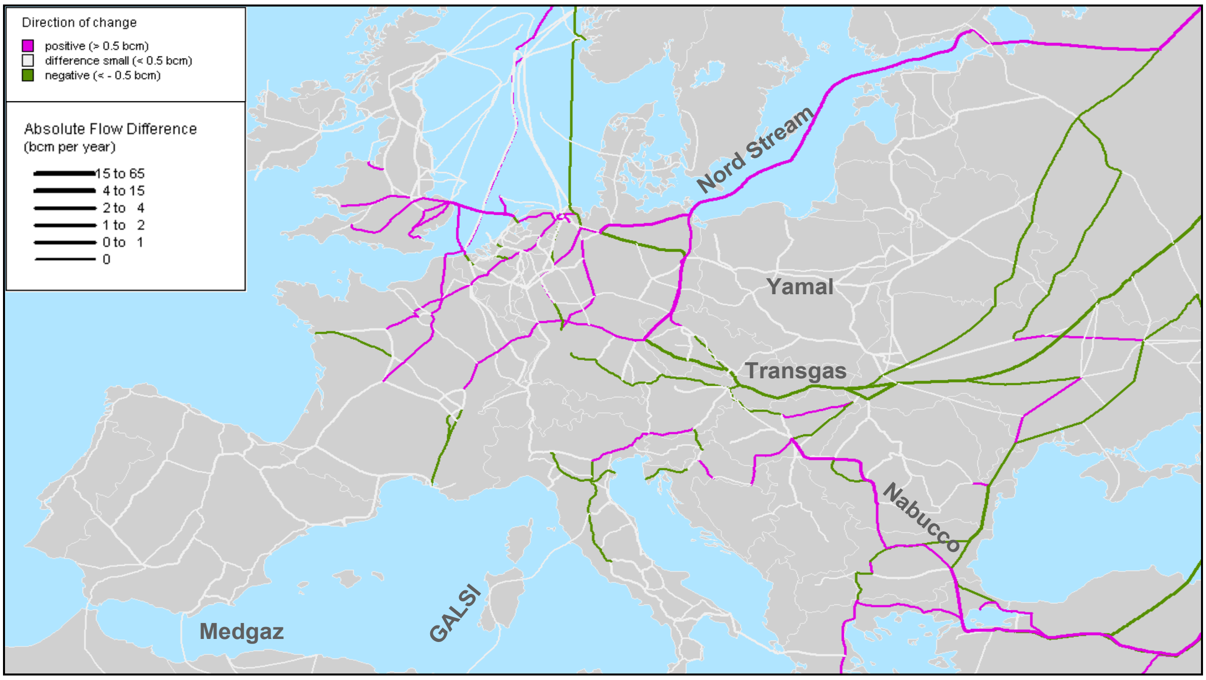
Source: EWI.

Figure 64: Annual Gas Flows 2019 – South Stream Scenario (ENTSOG Demand)



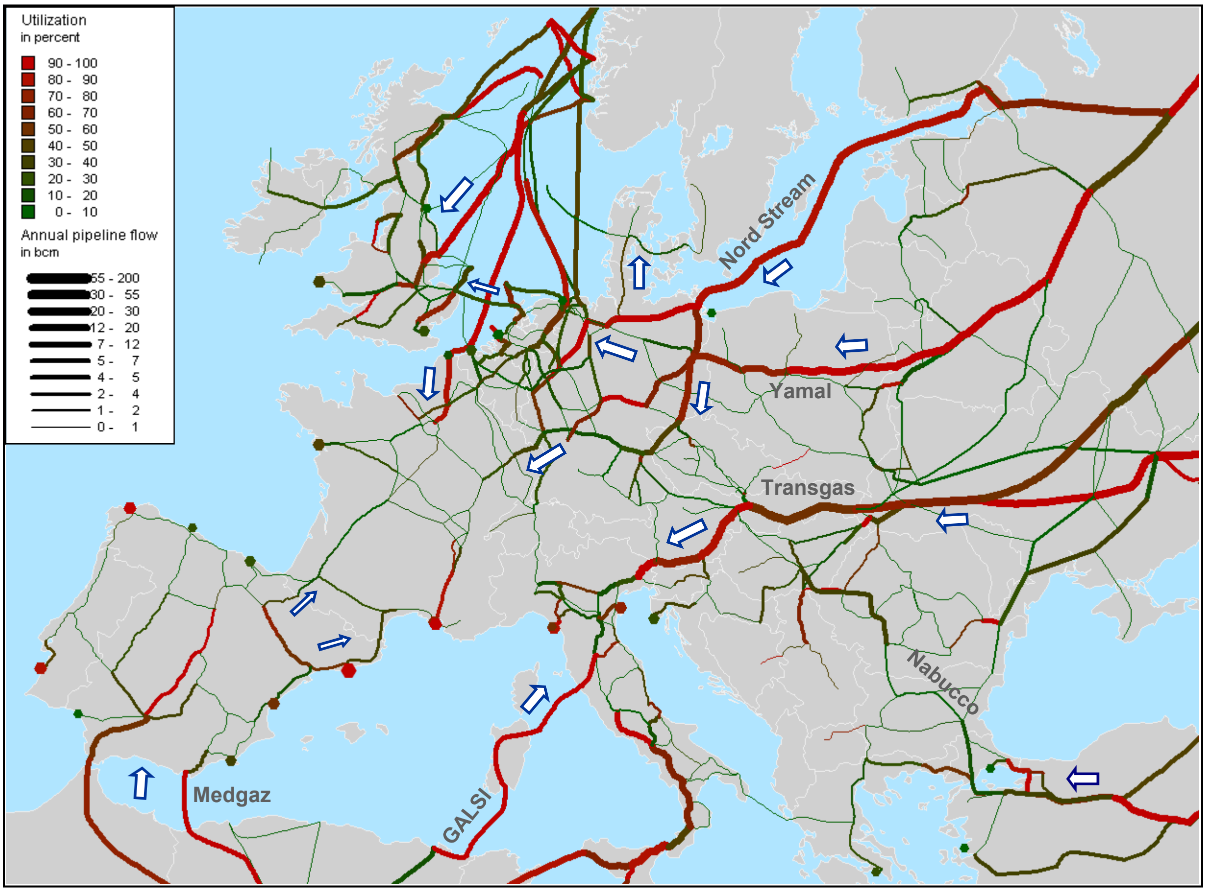
Source: EWI.

Figure 65: Absolute Change of Annual Gas Flows 2019 – DG TREN vs. Reference Scenario



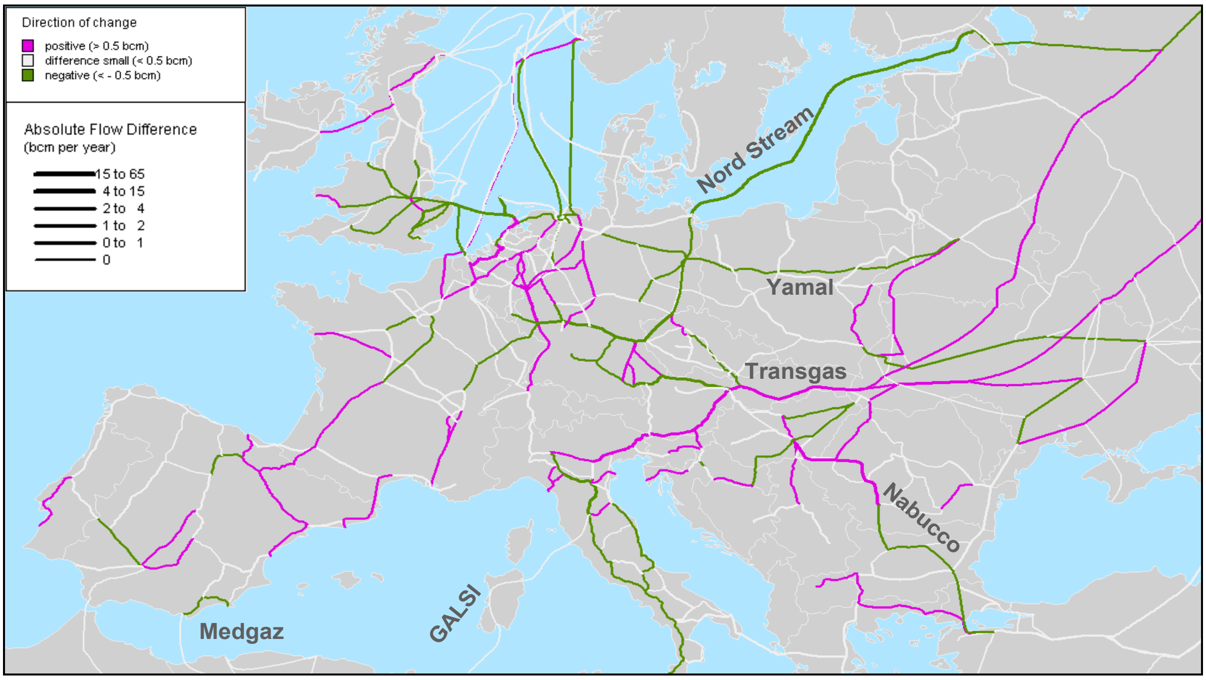
Source: EWI.

Figure 66: Annual Gas Flows 2019 – DG TREN Scenario (ENTSOG Demand)



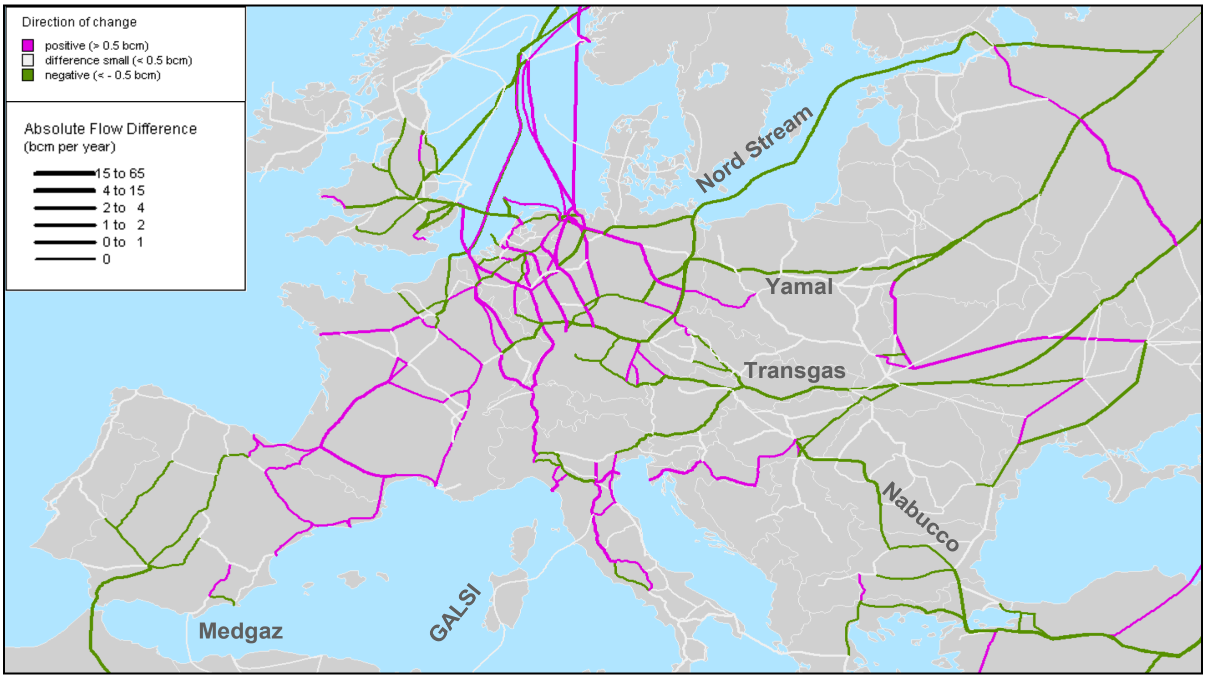
Source: EWI.

Figure 67: Absolute Change of Annual Gas Flows 2019 – DG TREN Scenario (ENTSOG vs. EWI/ERGEG Demand)



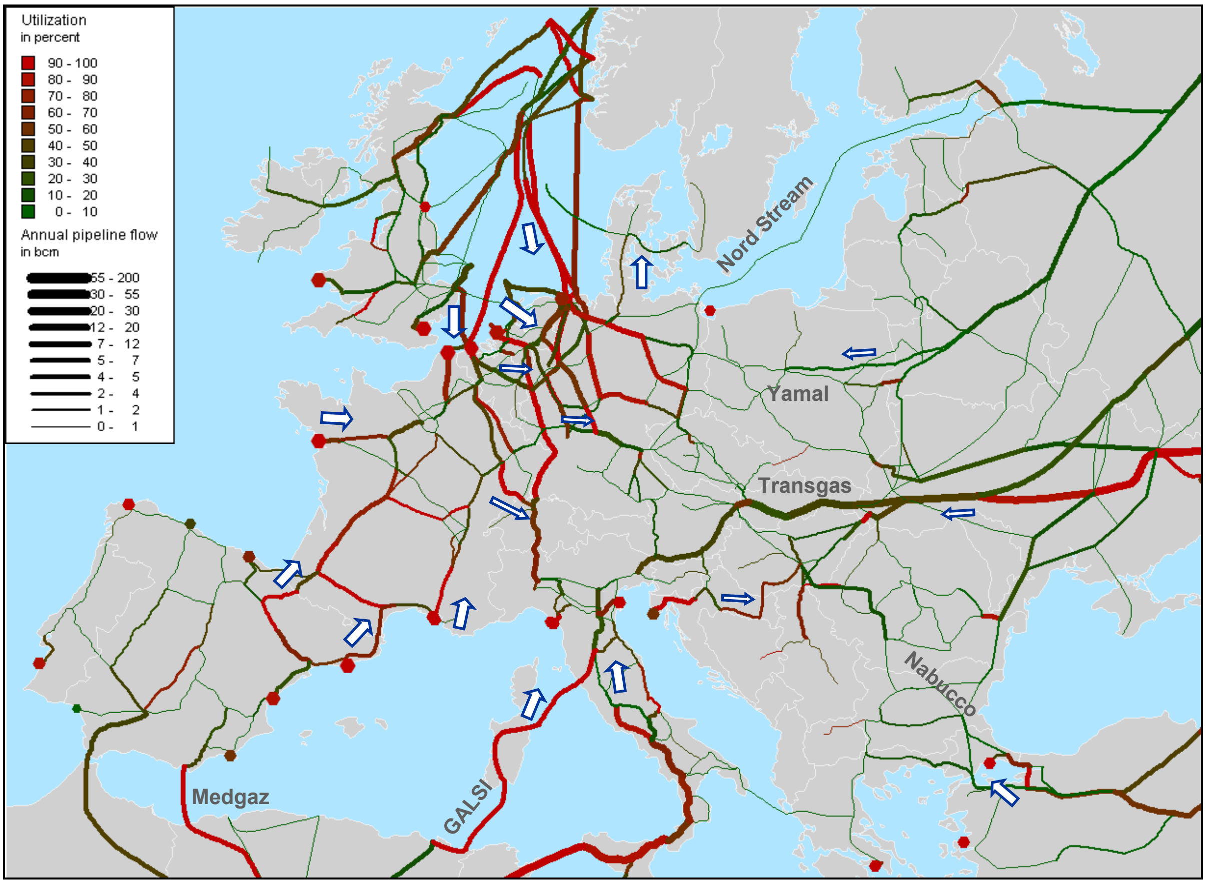
Source: EWI.

Figure 68: Absolute Change of Annual Gas Flows 2019 – LNG Glut vs. DG TREN Scenario (EWI/ERGEG Demand)



Source: EWI.

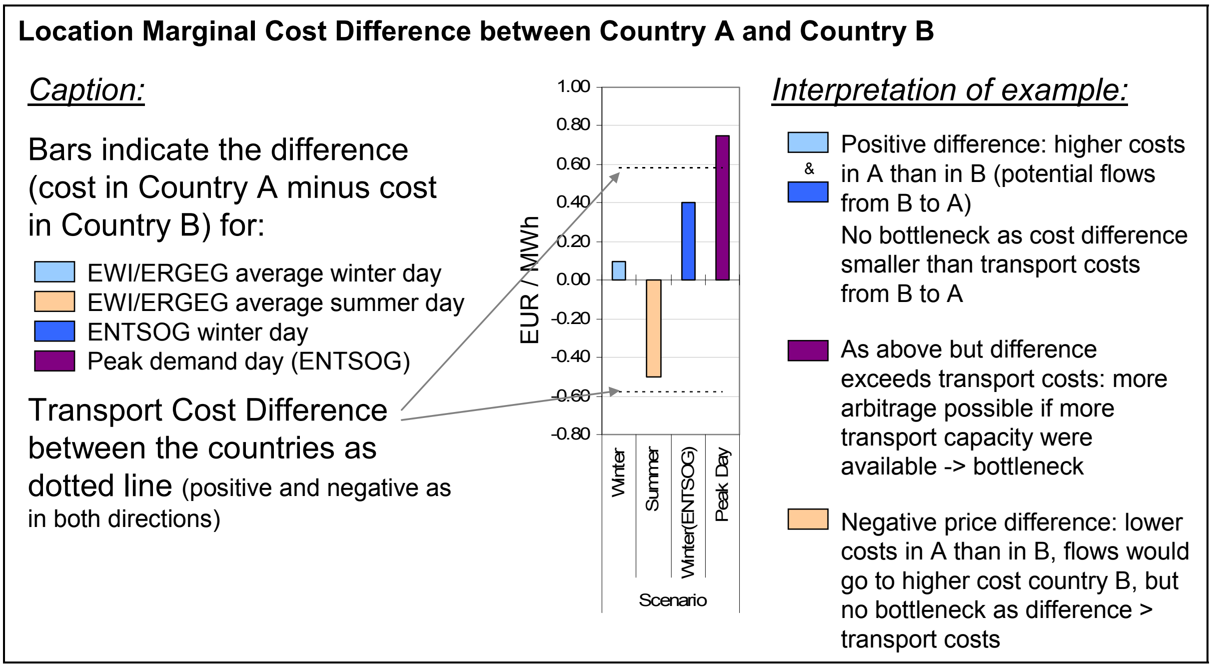
Figure 69: Annual Gas Flows 2019 - LNG Glut Scenario (ENTSOG Demand)



Source: EWI.

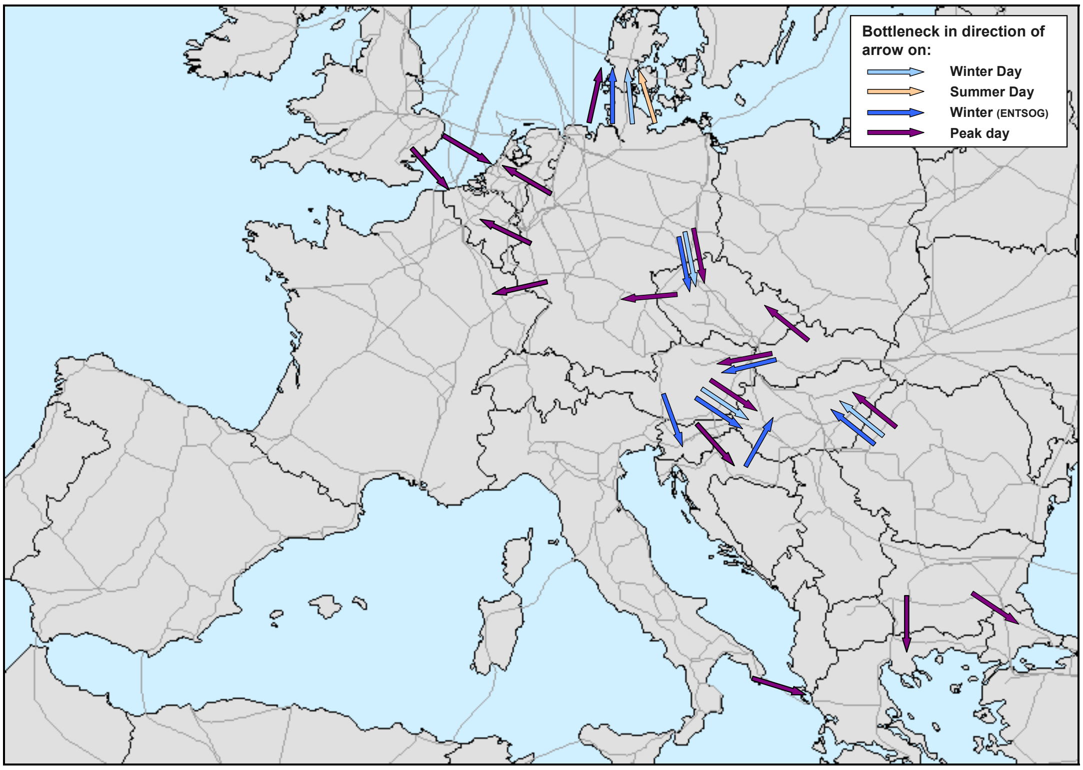
Appendix C: Additional Market Integration Charts

Figure 70: Guide on Market Integration Charts



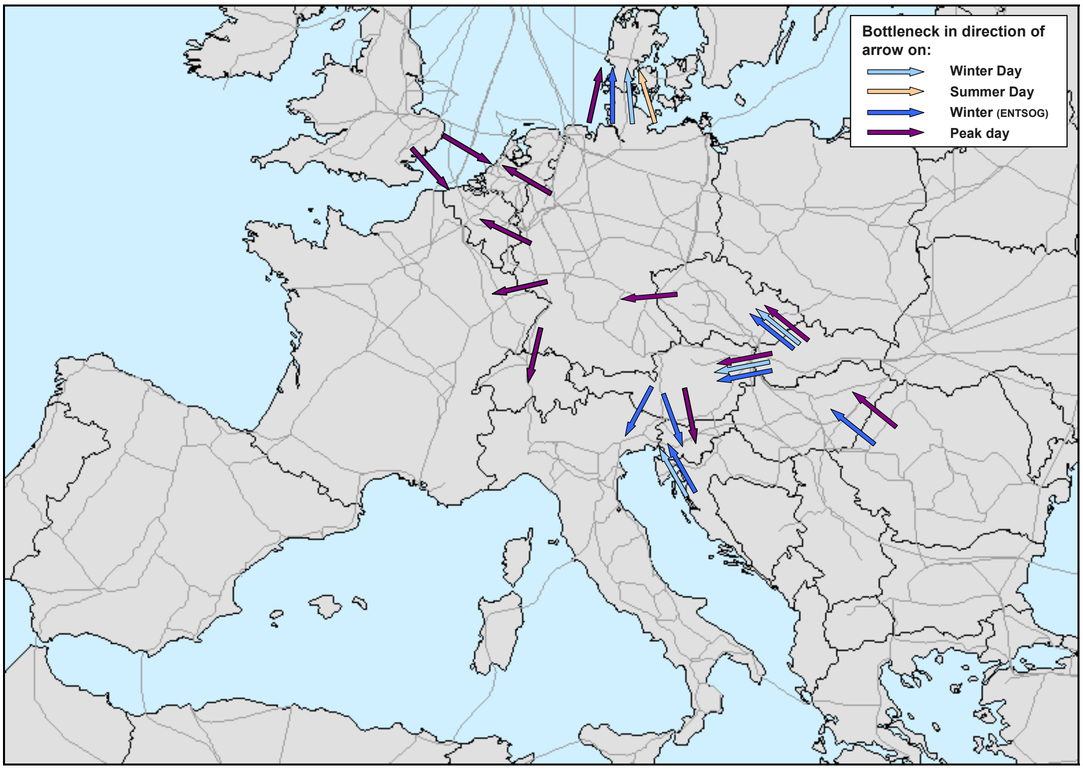
Source: EWI.

Figure 71: Location of Bottlenecks 2019 - Nord Stream II Scenario



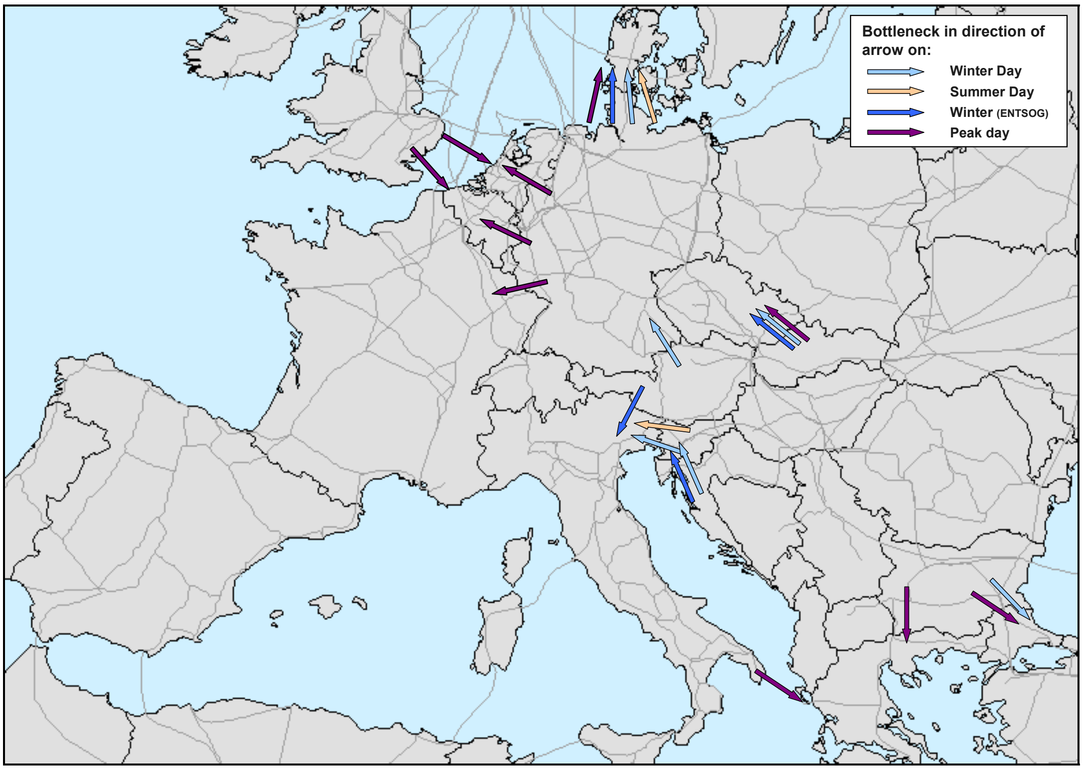
Source: EWI.

Figure 72: Location of Bottlenecks 2019 - Nabucco Scenario



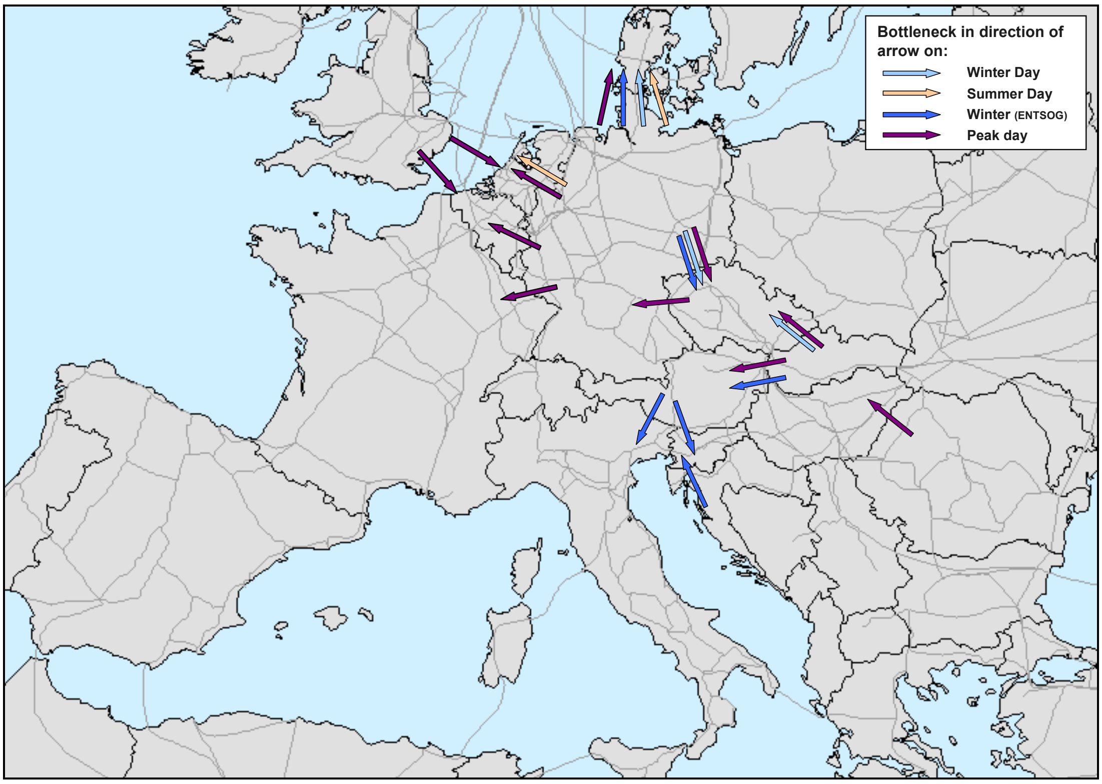
Source: EWI.

Figure 73: Location of Bottlenecks 2019 - South Stream Scenario



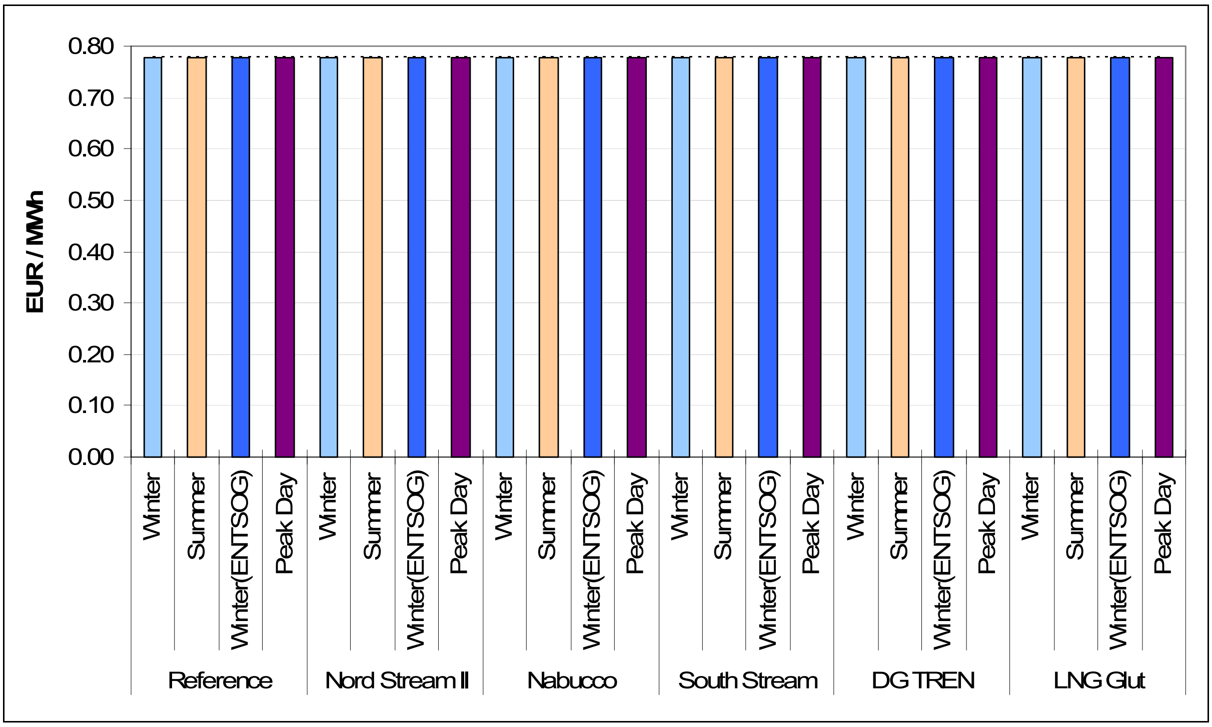
Source: EWI.

Figure 74: Location of Bottlenecks 2019 - DG TREN Scenario



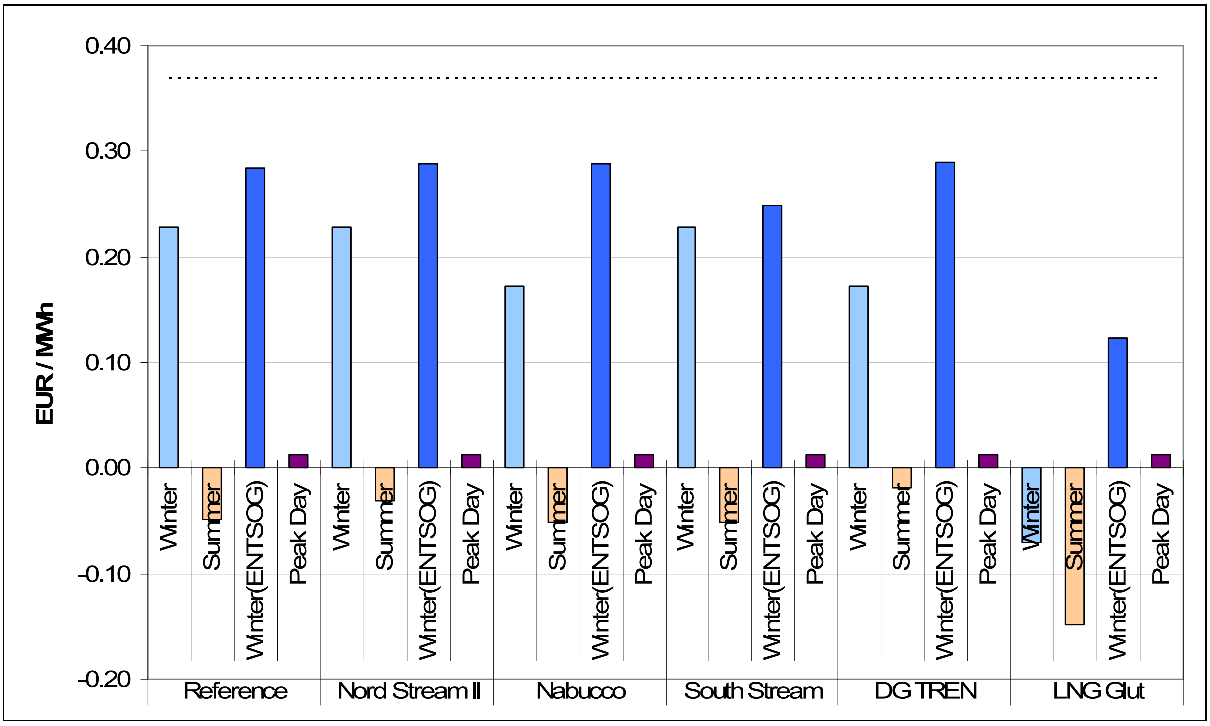
Source: EWI.

Figure 75: Marginal Supply Cost Difference between Ireland and Great Britain



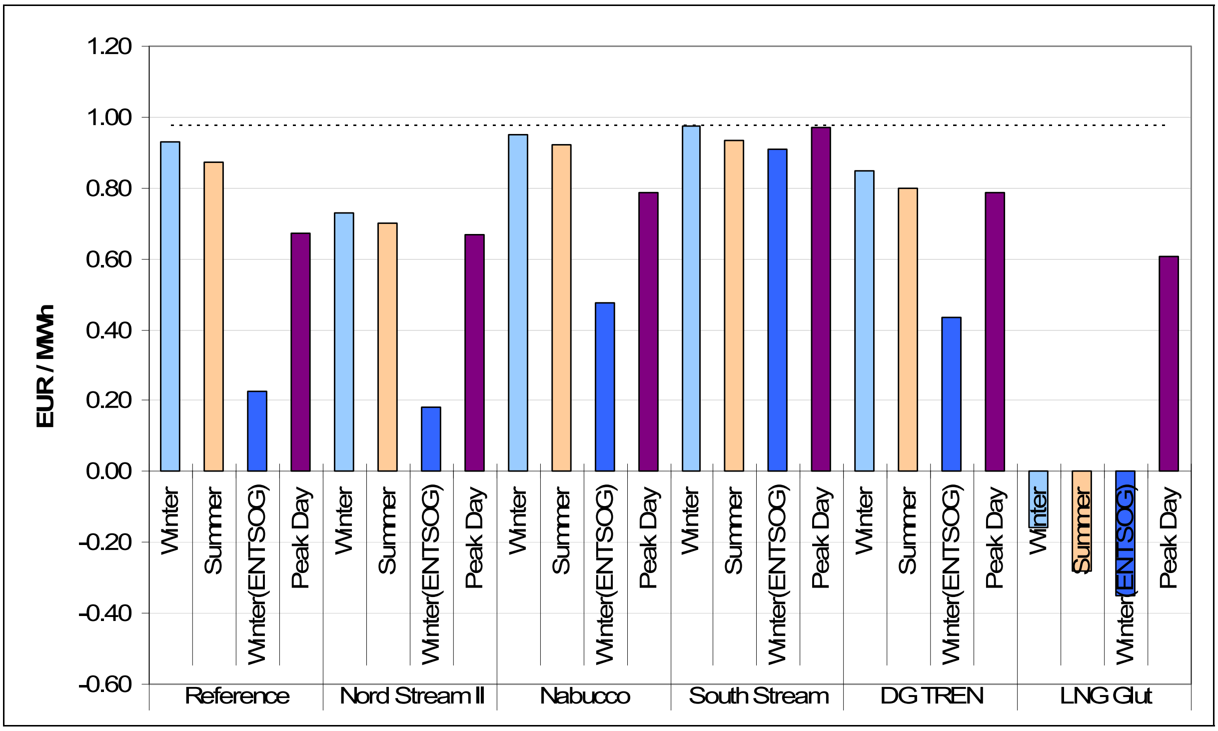
Source: EWI.

Figure 76: Marginal Supply Cost Difference between Belgium and Netherlands



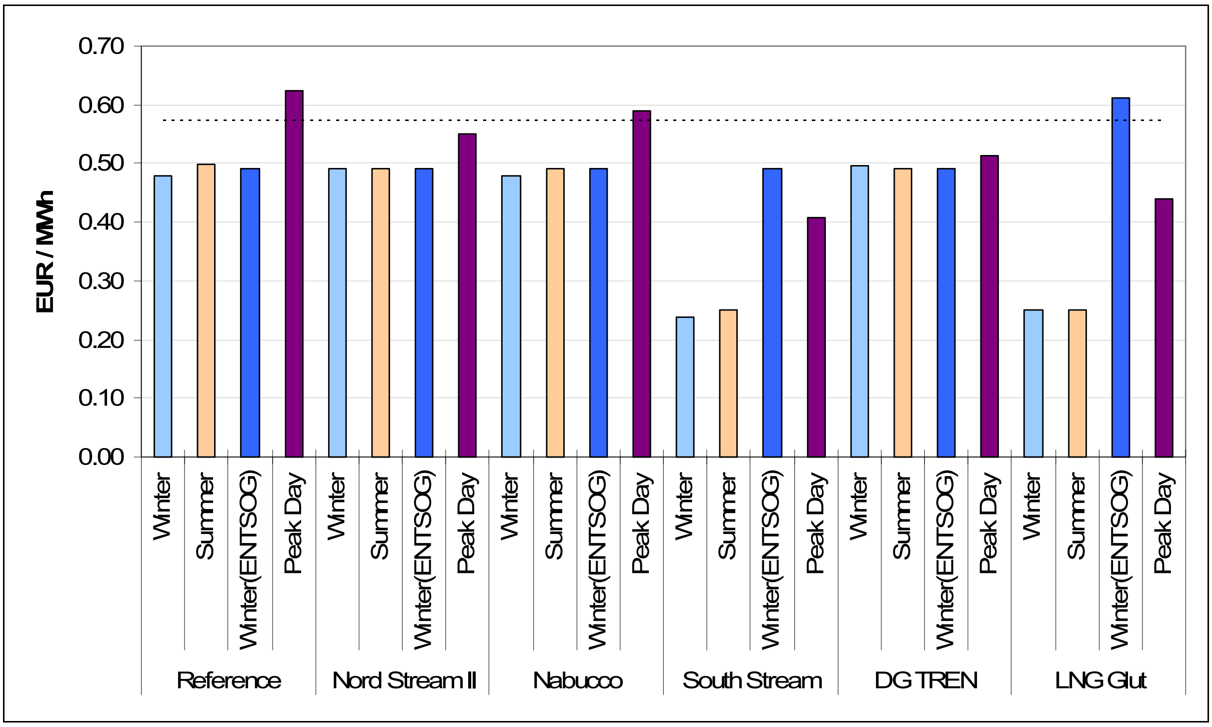
Source: EWI.

Figure 77: Marginal Supply Cost Difference between Germany and Austria



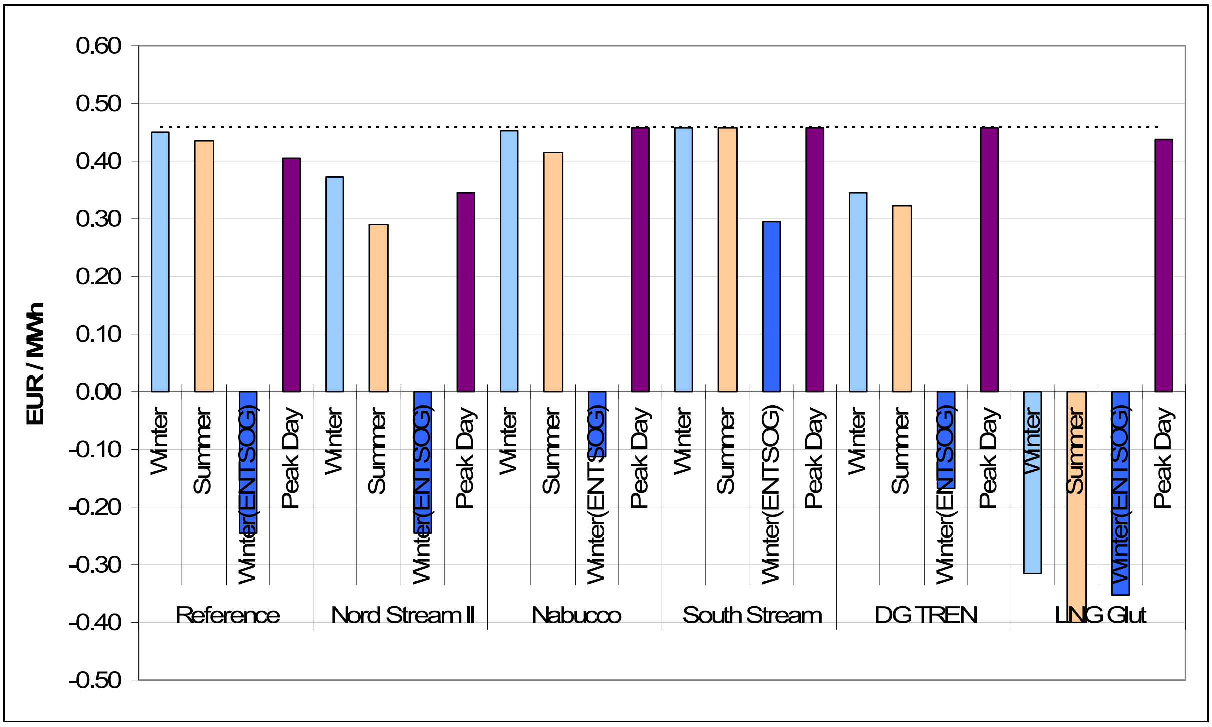
Source: EWI.

Figure 78: Marginal Supply Cost Difference between Switzerland and Germany



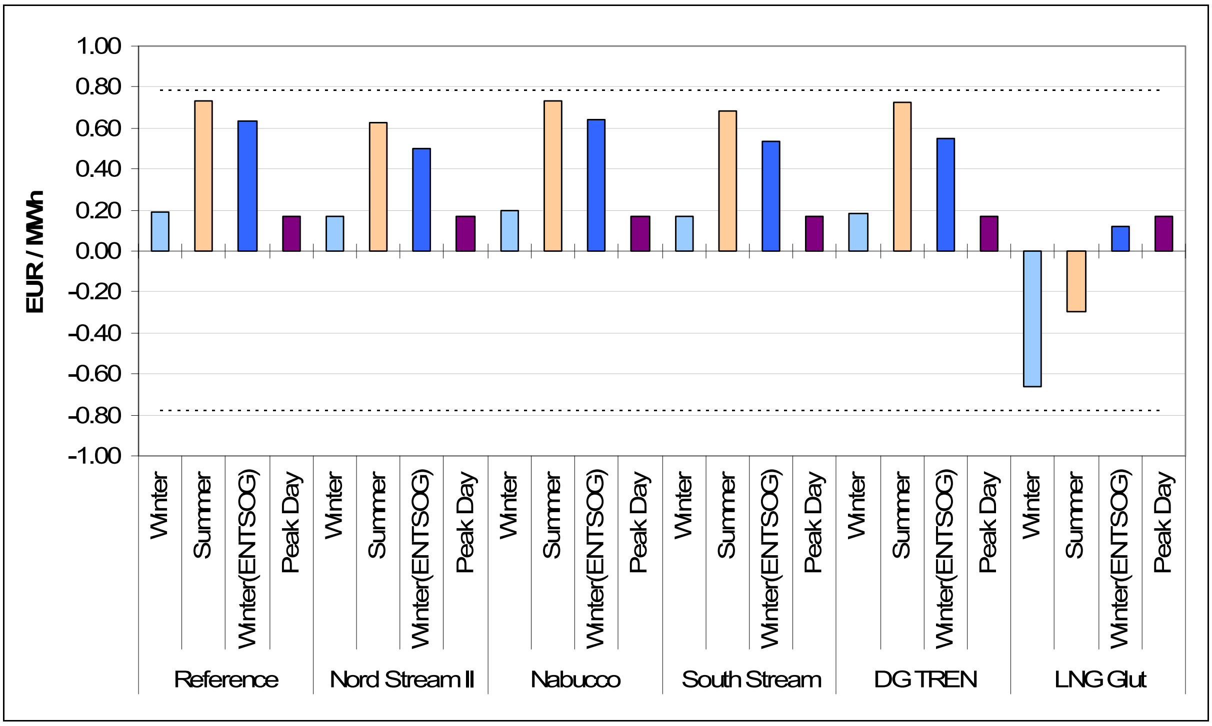
Source: EWI.

Figure 79: Marginal Supply Cost Difference between Italy and Switzerland



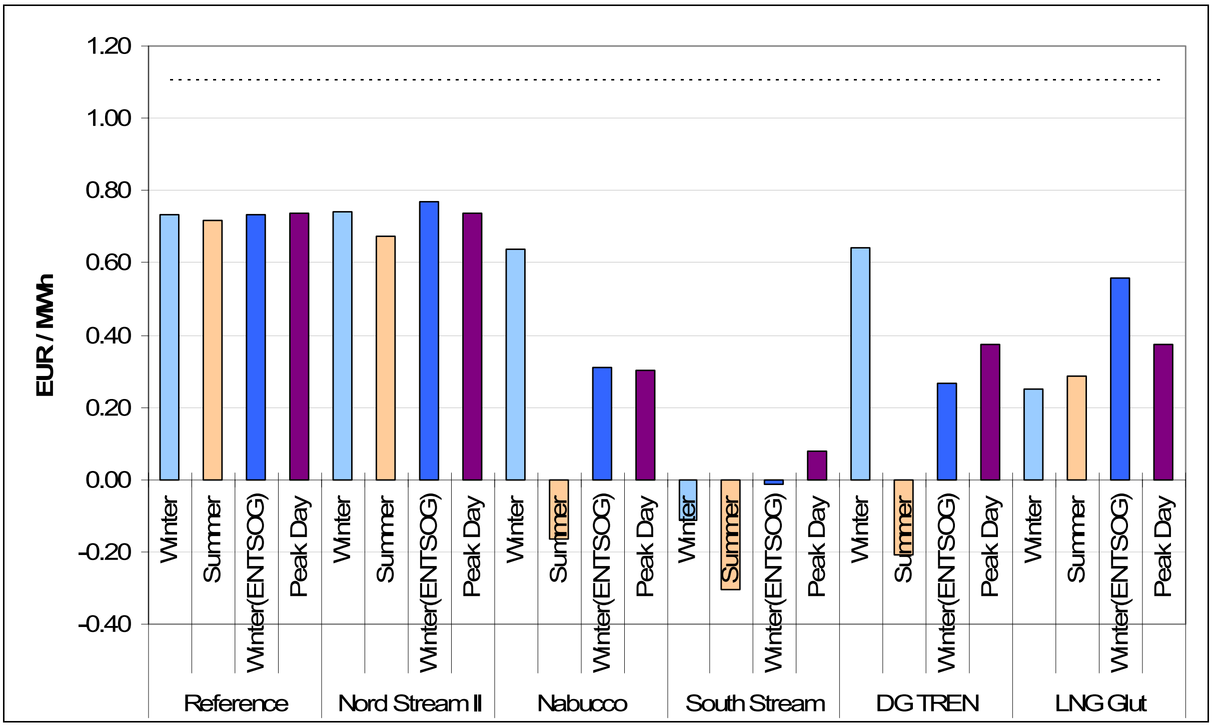
Source: EWI.

Figure 80: Marginal Supply Cost Difference between Poland and Germany



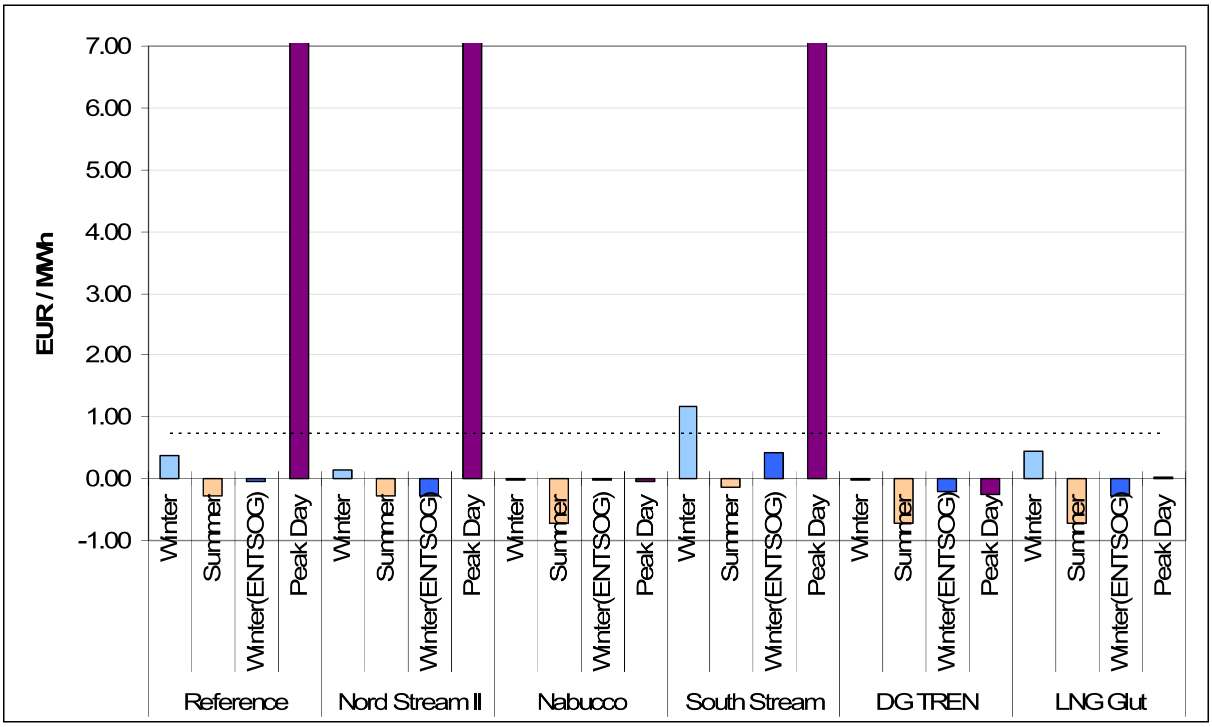
Source: EWI.

Figure 81: Marginal Supply Cost Difference between Bulgaria and Romania



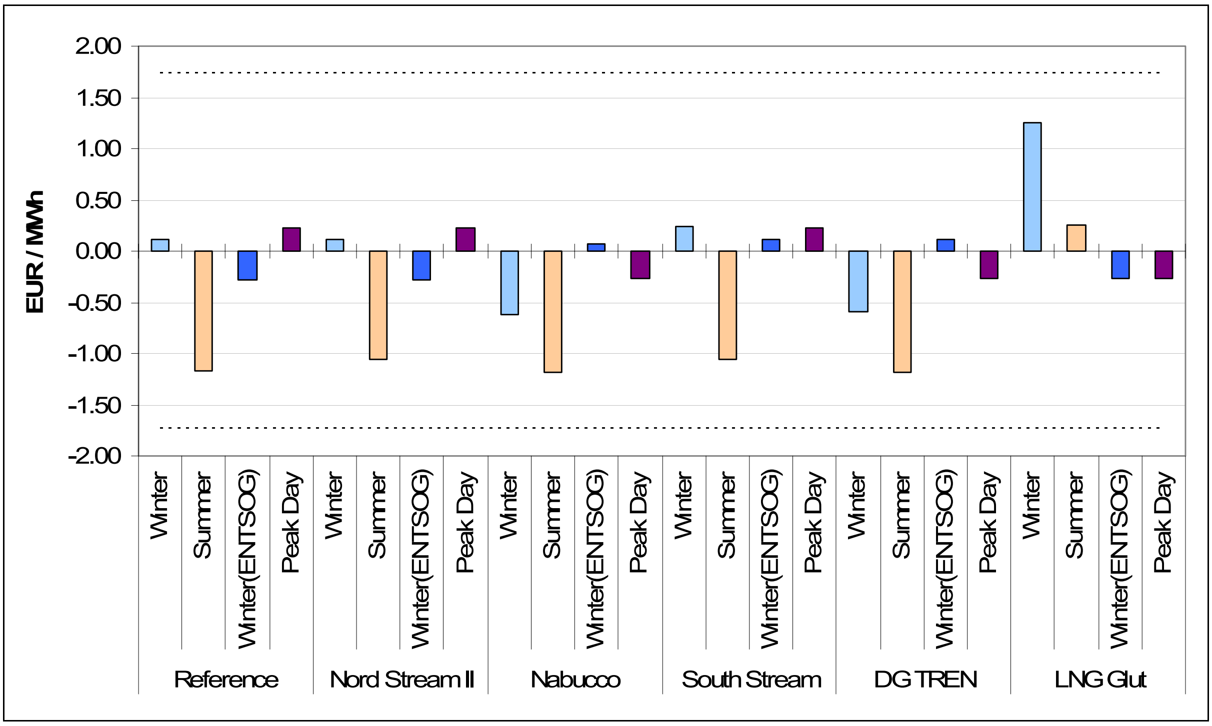
Source: EWI.

Figure 82: Marginal Supply Cost Difference between Turkey and Bulgaria



Source: EWI.

Figure 83: Marginal Supply Cost Difference between Turkey and Greece



Source: EWI.

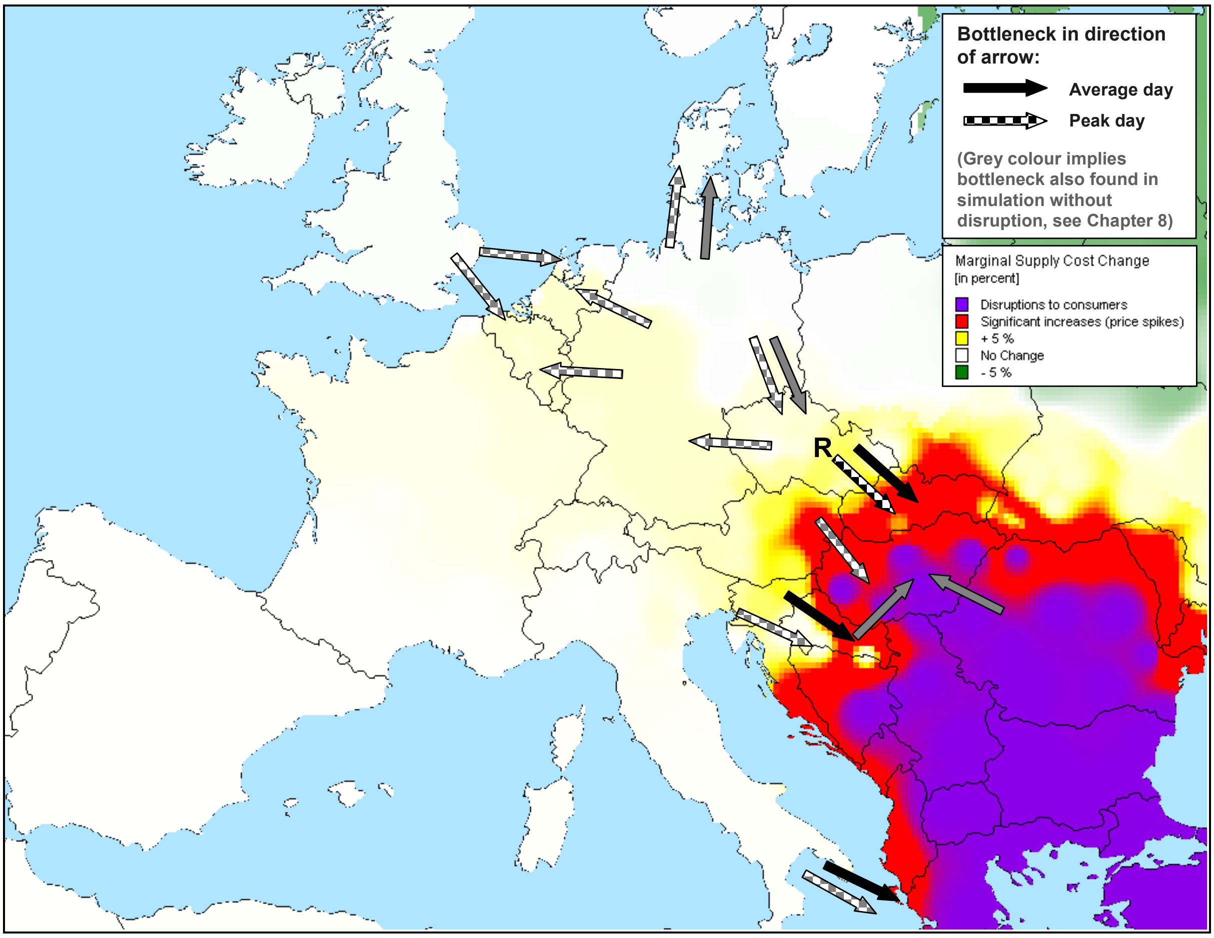
Appendix D: Security of Supply Sensitivities – Further data

Table 14: Decline in LNG Imports in Algeria SoS Stress Simulation in mcm/day

Country	Reference	Nord Stream II	Nabucco	South Stream	DG TREN
GB	-62.2	-65.8	-67.7	-49.0	-69.2
BE	-23.4	-23.1	-24.1	-4.9	-24.1
NL	-21.0	-18.2	-2.3	-54.0	-1.7
FR	-26.8	-27.3	-19.8	-20.5	-9.5
ES	-16.5	-13.9	-18.3	-18.1	-20.3
PT	-3.5	-3.4	-3.7	-3.5	-3.7
IT	-7.6	-7.6	-7.6	-7.6	-7.6
GR	0.0	0.0	0.3	-1.4	-0.2
TR	-6.4	-8.5	-5.7	-2.4	-5.9
HR	0.0	0.0	-1.7	-12.6	-4.9

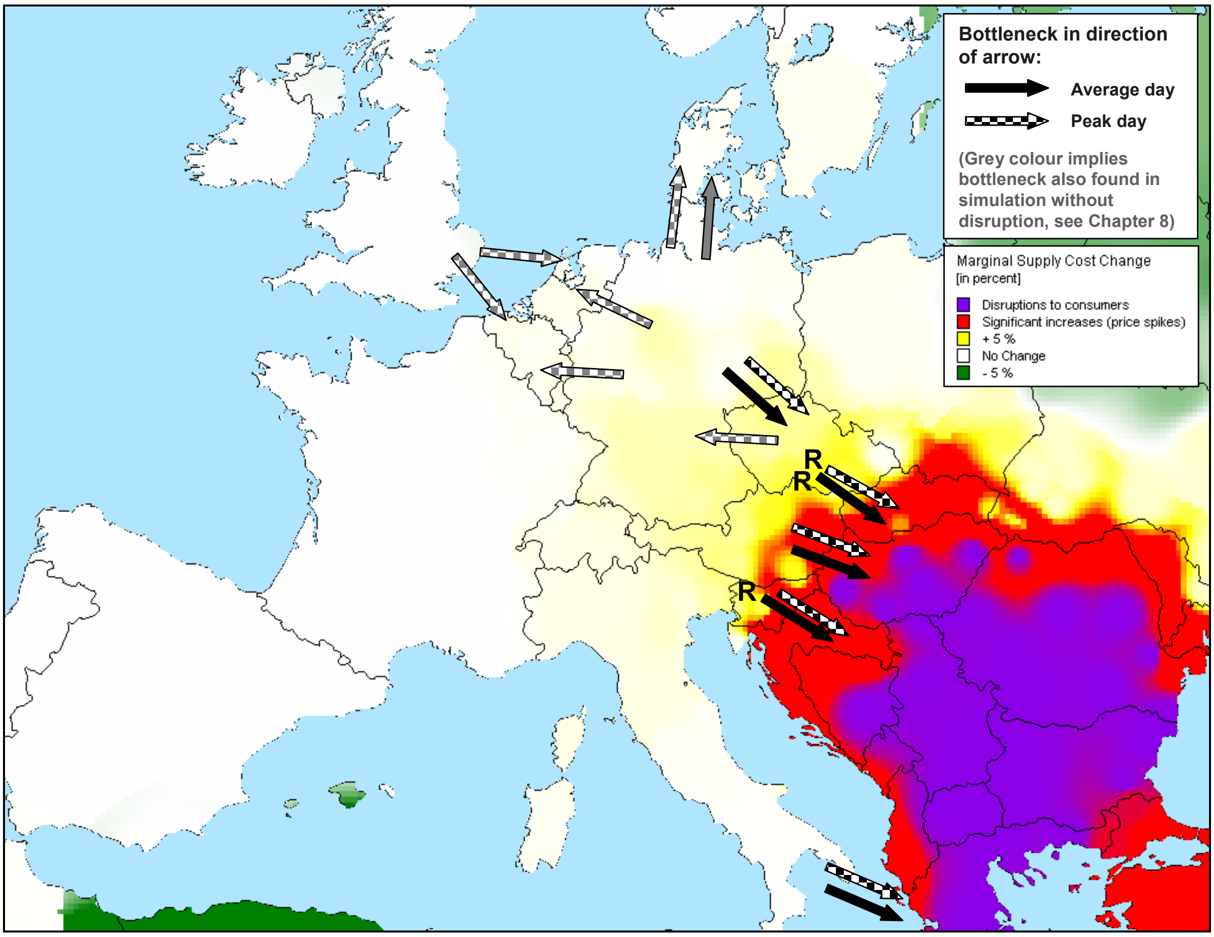
Source: EWI.

Figure 84: Bottlenecks and Marginal Cost Changes in Nord Stream II - Ukraine SoS Simulation



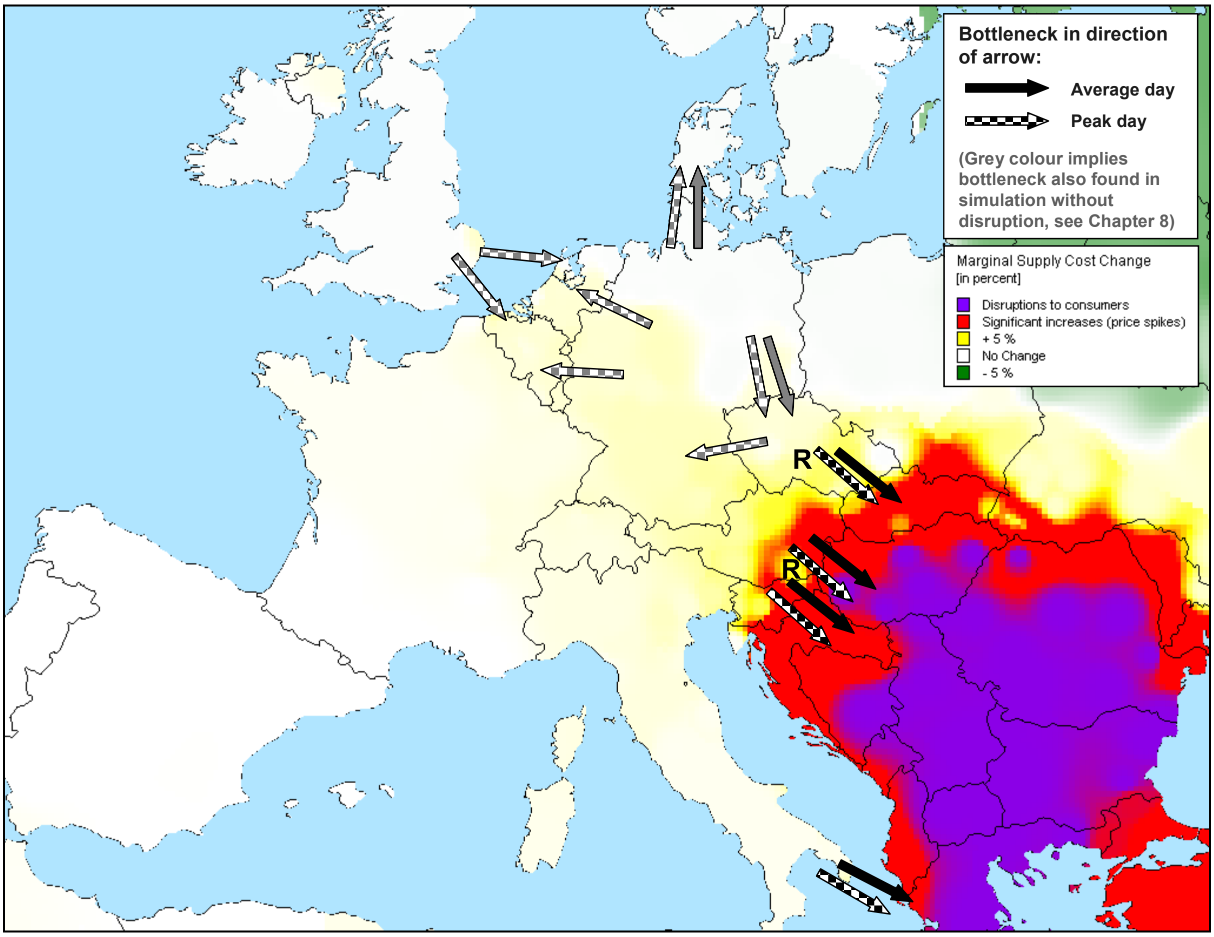
Source: EWI.

Figure 85: Bottlenecks and Marginal Cost Changes in Nabucco - Ukraine SoS Simulation



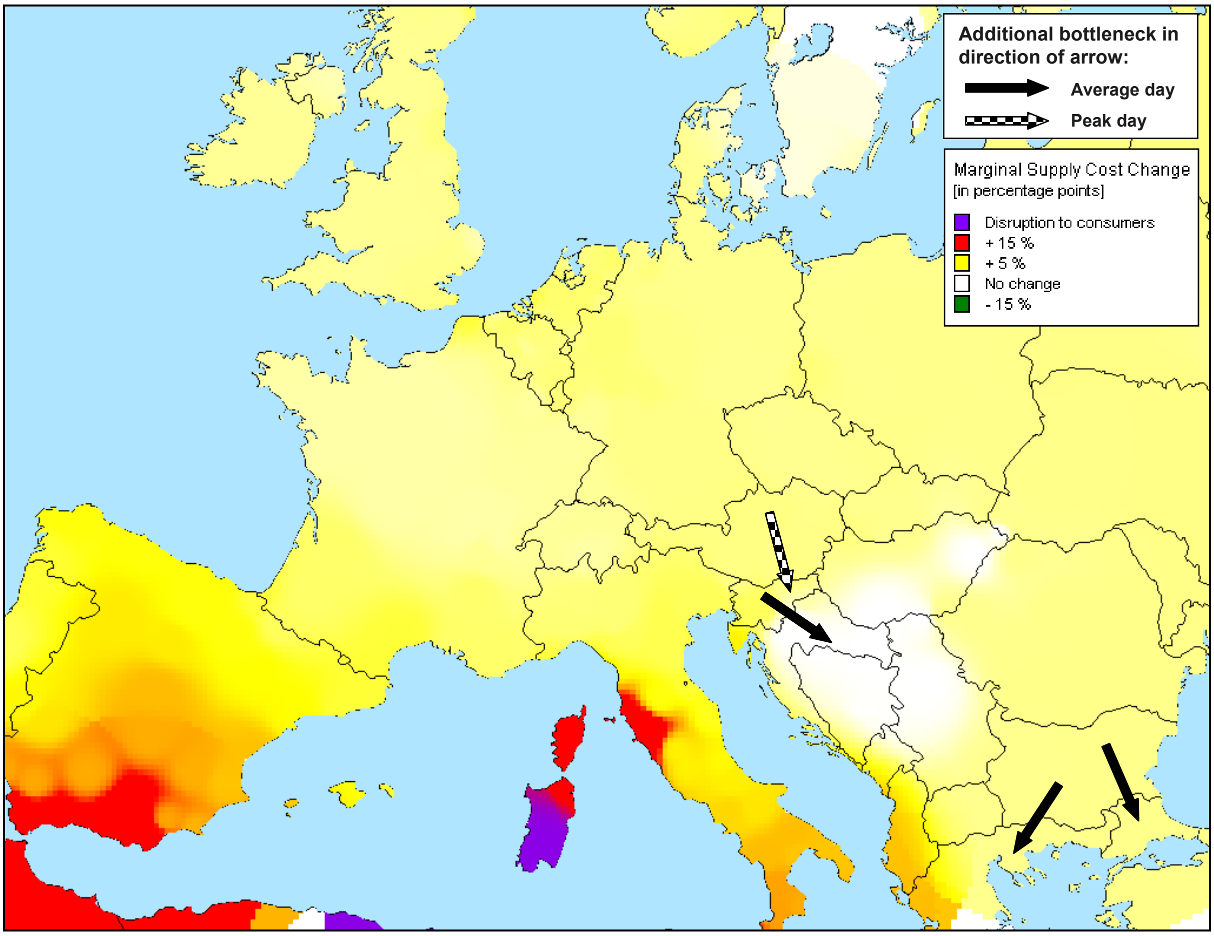
Source: EWI.

Figure 86: Bottlenecks and Marginal Cost Changes in DG TREN - Ukraine SoS Simulation



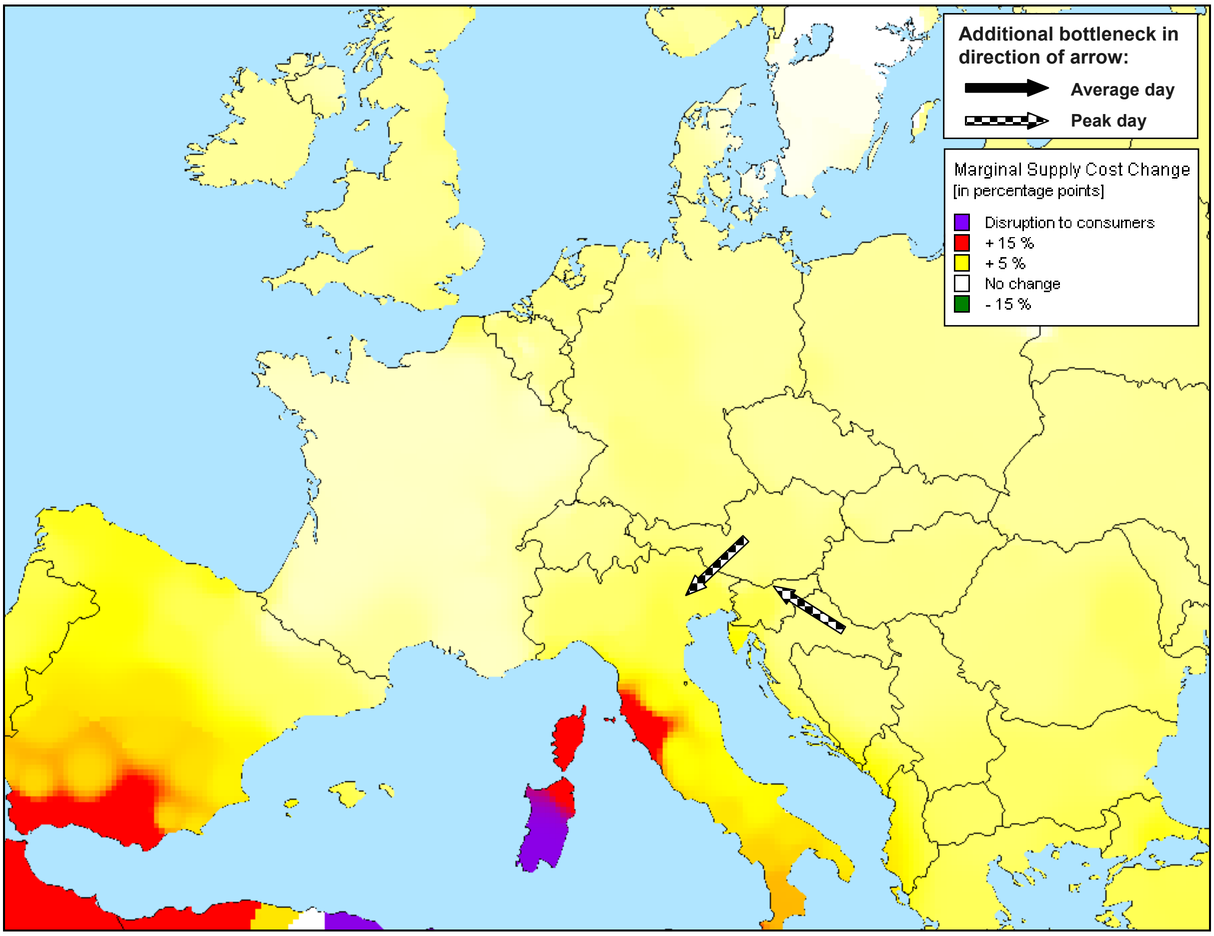
Source: EWI.

Figure 87: Bottlenecks and Marginal Cost Changes in Nord Stream II - Algeria SoS Simulation



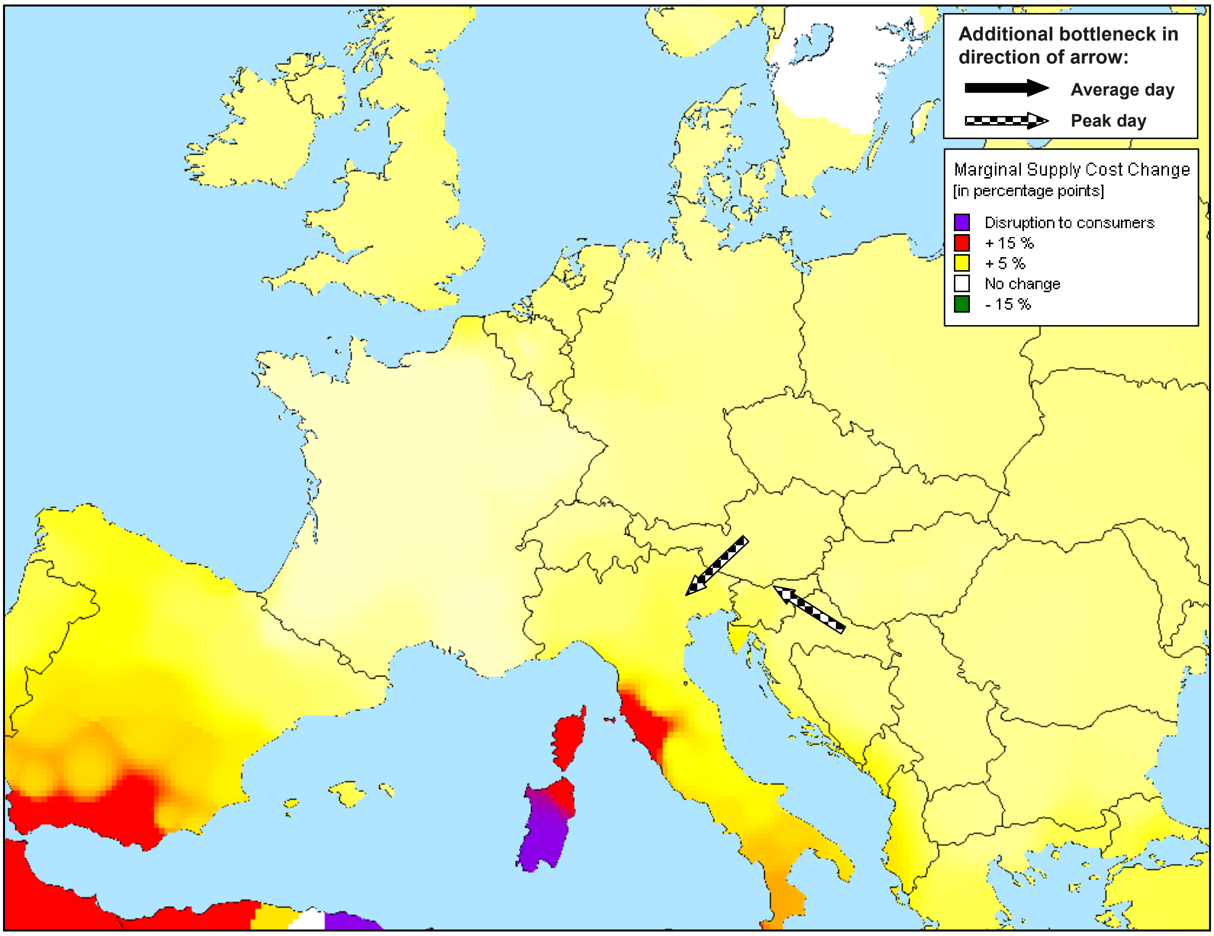
Source: EWI.

Figure 88: Bottlenecks and Marginal Cost Changes in Nabucco - Algeria SoS Simulation



Source: EWI.

Figure 89: Bottlenecks and Marginal Cost Changes in DG TREN - Algeria SoS Simulation



Source: EWI.

Appendix E: Short description of MAGELAN Gas Supply Model

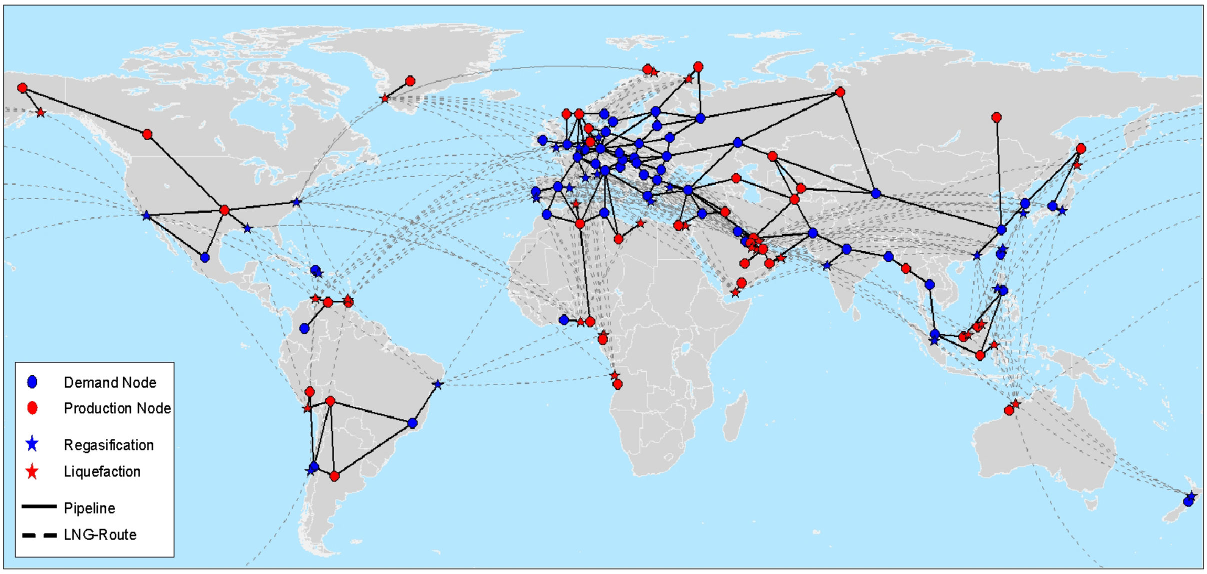
MAGELAN is a long-term optimisation model of investments in natural gas production and transport. It was developed at EWI (Seeliger, 2006) to optimise natural gas supply including investments in production and infrastructure capacity up to 2035. It is an intertemporal and interregional cost-minimisation model. The model's objective function includes both capital and operating costs of global gas production and transport. Inefficiency, which could arise due to strategic behaviour by market players, is therefore not reproduced by the model. (However, incorporating such strategic actions would require strong assumptions regarding the type of competition which in turn would significantly impact the results of the model.) Using linear optimisation as an approach yields the advantage that results are solely based on objective data. These results can therefore be interpreted as a first-best benchmark in the sense that they represent the social welfare maximising outcome.

The optimisation in MAGELAN is subject to all relevant technical restrictions in production and transportation of natural gas. That includes limited reserves and resources, the need to balance demand and supply as well as in- and outflows for each country (and the system as whole) and all capacity restrictions for infrastructure.[79] The gas world in MAGELAN is modelled as an interconnected grid consisting of 139 nodes for production, transport and consumption. One node usually represents one country. In countries where production or liquefaction or regasification of LNG takes or might in the future take place, additional nodes have been implemented to provide for these facilities. A map of the coverage of the model which includes all potential pipeline and LNG connections is depicted in Figure 90.

Major inputs of the model are assumptions on demand developments, existing reserves and production costs per production region as well as existing infrastructure and all relevant cost parameters. Based on existing capacities of the transport and production stages, the model can in later periods endogenously expand capacities or build new facilities where possible (as illustrated in Figure 90). Further, optimal production and transported volumes between nodes are determined endogenously. Model outputs are therefore all capacity additions and expansions as well as production per production region and volume flows between nodes on an annual level.

[79] A mathematical formulation of the model can be found in Seeliger (2006).

Figure 90: Overview Gas Supply Model MAGELAN



Source: EWI.

Therefore the model determines which producers supply gas to which importing country and, hence, derives annual supply mixes for each demand region. The additional information on production and transport capacity costs further permit to estimate the long-run average costs of gas supplied by the different suppliers.

For information of the specific reference parameterisation applied for the calculation of the supply costs which entered this study, see Lochner and Bothe (2009), which is also the source of this brief model description.