Impacts of a gas cartel on the European gas market – selected results from the supply model EUGAS

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Abstract

This article introduces the simulation model EUGAS which allows a quantitative analysis of the long-term natural gas supply of Europe. Based on chosen parameter specifications, the simulation shows that no discernible physical gas scarcity at least for the next 20-30 years will occur in Europe. Significant investments in new production and transport facilities will be necessary during the next decades. Diversification of supplies and political considerations will have a significant impact on the development of new natural gas resources. Possibly, a new built gas cartel similar to the OPEC may modify the gas supply pattern of Europe.

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1. Introduction

Natural gas will achieve great importance as primary energy source for Europe in the 21st century. Today, natural gas covers approximately 23% of the Western European (OECD Europe) or 22% of the German primary energy demand.[1] According to the IEA, global natural gas consumption will increase more than 95% until the year 2030 and will exceed the consumption of coal by 2010. Simultaneously, the share of natural gas in the global primary energy supply will increase by 5% to 28% in 2030.[2] Reasons for the increase of the use of natural gas are the high resource availability, low specific carbon dioxide emissions compared to other primary energy sources and expected construction and

[1] IEA (2003), p. III.6.
[2] IEA (2002a), p. 110.

operation of gas-fired power plants, especially modern combined cycle gas turbine plants (CCGT) and combined heat and power plants (CHP).

The massive increase of natural gas supply in Europe leads directly to the question where the needed natural gas is to come from in the future. In a number of European countries, natural gas production stagnates or decreases. Therefore, the development of new sources to cover the rising demand seems to be indispensable. It has to be analysed quantitatively to what extent European countries can contribute to European natural gas supply in future, how much gas will have to be imported from outside Europe and from which time on, and upon which regions and sources the gas producers will depend on. Due to the high costs transportation is of special relevance for the analysis: By which routes will the gas flow to Europe and where or when might bottlenecks within the transeuropean transport system appear. A further question of interest is how the stability of the supply system could be guaranteed if political, technical or financial problems in one or more producing or transit countries arise.

2. Structure of the model EUGAS[3]

The model EUGAS (European Gas Supply Model) is a tool which allows a quantitative analysis of the future European natural gas supply. It is structured as a long-term, dynamic, interregional optimisation model. The objective and the restrictions of the model are linear (linear program).

The model optimises the European natural gas supply provided that demand is covered at minimum costs. The optimisation runs from 2005 to 2064. The time periods are extend to five-years in order to reduce the complexity of the model.[4] The model provides forecasts until the period 2030 (years 2030 to 2034). The extension of the optimisation period until 2060 is necessary in order to avoid the so-called end effect.[5]

[3] For further details see Perner (2002).
[4] The term 'period' always refers to the first year of a five-year period (model period 2005 covers the years 2005 to 2009, period 2010 the years 2010 to 2014 etc.).
[5] The technical and economic lifecycle of production and transport assets comprise 25 years and more. The optimisation period has to be extended in the same range in order to avoid the distortion of investment decisions at the end of the forecast period (2030).

Natural gas supply includes natural gas production (exploration, production, storage and processing close to the gas fields) and natural gas transportation by pipelines or LNG. Natural gas supplies to the European consumption regions are optimised using the following main decision variables:

- Extension and decommissioning of production capacities
- Annual production quantities
- Extension of pipeline capacities
- Extension and decommissioning of liquefaction and regasification plants
- Gas flows
- Supply volumes

The selection and distinction of the consumption and production regions within the model leans on facts of current and future production and consumption potentials of the countries. The centres of consumption are in most cases identical to the national states of Europe. In order to reduce the number of regions, Serbia-Montenegro, Bosnia-Herzegovina, Macedonia and Albania are combined to one region. The same applies to the Baltic states Estonia, Latvia and Lithuania. Moldavia is assigned to the Ukraine. Due to the geographical extension, Russia is divided into four regions of consumption (Western Russia, Volga-Urals, Komi and Western Siberia). Furthermore, for most supply countries outside Europe consumption areas are identical with the producing regions in order to reduce the number of variables.

Demand is split seasonally into three different load periods: summer, winter and a bipartite transitional period. In order to smooth the load fluctuations, existing storage capacities and publicly known storage extensions are included in the input data.

The European natural gas demand is covered by both, intra-European production and gas sources from outside Europe (figure 1). Denmark, the Netherlands, Norway, Great Britain and Russia are intra-European producing countries whose natural gas extraction is determined by model optimisation. Non-European producing countries are African states such as Algeria, Angola, Libya, Egypt and Nigeria; in the Middle East, there are Iran, Iraq, Qatar, Oman, United Arabic Emirates and Yemen. Also covered by EUGAS are the Caspian states Azerbaijan, Kazakhstan and Turkmenistan as well as the Caribbean states Trinidad & Tobago and Venezuela. In some cases, producing countries are further differentiated into sub-regions (e.g. Algeria and Russia are subdivided into 3 sub-regions).

For the reason of simplicity, Oman, Qatar, United Arabic Emirates and Yemen are combined to one production region (Middle East) as well as Trinidad & Tobago and Venezuela (Caribbean).

In the production regions mentioned above, capacity additions and decommissioning as well as the usage of available capacities are optimised. The available natural gas resources and costs of production are differentiated by the average size of the fields, the reservoir depth, the gas flows per well and (in case of offshore production) the water depth. Existing production capacities are integrated into the optimisation.

The natural gas production of those European countries not being listed as a production region (e.g. Germany, Italy or Romania) is exogenously implemented into the model. These are countries with gas resources which have only local impact on the gas supply. The output of natural gas of these countries is subtracted from domestic demand. The residual demand is to be covered by natural gas imports.

In the model, natural gas transportation comprises transports from production regions to Europe as well as long-distance transports within Europe. Between the regions, interconnections exist in form of pipelines and LNG. The model includes both existing and potential connections between the regions. Pipeline capacities between two countries may be interpreted as single pipelines or a bundle of pipelines. Liquefaction and regasification terminals are located along the coast. As with pipelines, LNG capacities in the model can represent both real single plants or a bundle of plants. Therefore e.g. the liquefaction plants of Venezuela and Trinidad & Tobago are assigned to one common transport node.

The long-distance transportation network in EUGAS is structured as a system of interlinked nodes or "hubs and spokes" (figure 2). Not included in the figure are LNG liquefaction terminals located far away (Angola, Middle East and the Caribbean states).

3. Mathematical formulation of the model

As a linear programme, EUGAS consists of an objective and several linear restrictions. Further on, a number of equations are used to define the revenues and costs of natural gas production and transportation (not to be described in the following chapters).

Objective

The model maximises the aggregated and discounted profits of the natural gas sector (objective). Profit (*TP*) is defined as the total of discounted sales revenues (*REV*, natural gas prices multiplied by the sold quantity of natural gas) minus the discounted costs of natural gas supply in all regions, for all gas producers and throughout the entire time period. The sales revenues are introduced into the objective in order to take the different calorific values of gases into account in an easy way (by modifying the natural gas prices). Apart from this, the chosen profit maximisation corresponds almost to a pure cost minimisation problem since both retail prices and sold quantities of natural gas are exogenously determined (and therefore fixed data) in the model.

The costs of gas supply comprise a) the capacity costs of natural gas production (*CCP*), b) the capacity costs of natural gas transport (*CCT*), c) the operating costs of natural gas production (*OCP*), and d) the operating costs of transport (*OCT*). Costs of LNG-tankers (*CTS*) and (if chosen) transit fees (*TRA*) are taken into account separately.

Revenues and costs are discounted using the interest rate *ir*. The model offers the option to set different discount rates for production and transport (*irpr*, *irtr*). This allows the integration of different risk exposures for production on the one hand and transport on the other. In this paper a discount rate of 10% is applied for both production and transport.

$$
\begin{aligned}
\underset{\max}{TP} \quad = \quad & \sum_{rtp} REV_{rtp} \frac{1}{(1 + ir)^{rtp}} \\
& - \sum_{rtp} (CCP_{rtp} + OCP_{rtp}) \frac{1}{(1 + irpr)^{rtp}} \\
& - \sum_{rtp} (CCT_{rtp} + OCT_{rtp}) \frac{1}{(1 + irtr)^{rtp}} \qquad (1) \\
& - \sum_{rtp} CTS_{rtp} \frac{1}{(1 + irtr)^{rtp}} \\
& - \sum_{rtp} TRA_{rtp} \frac{1}{(1 + irtr)^{rtp}}
\end{aligned}
$$

Restrictions

Balancing conditions

On the one hand, natural gas consumption must be covered by natural gas production. On the other hand, supply should not exceed demand over a longer period of time. Therefore the aggregated natural gas supplies *(SU)* of all gas producers *(sc)* must be identical to the natural gas demand *(D)*. This condition applies accordingly for all consumption regions *(cr)* and all model periods *(rtp)*. The yearly consumption is spread over three seasons *(sl)*.

Indigenous natural gas production (*inpr*) is – as described above – subtracted from domestic demand if it is not determined endogenously by the model. Only the residual demand is relevant for the optimisation. Domestic production of natural gas is spread among the three seasons in proportion to the demand.

$$D_{cr,sl,rtp} - inpr_{cr,rtp} \frac{D_{cr,sl,rtp}}{\sum_{m} D_{cr,sl,rtp}} = \sum_{sc} SU_{sc,cr,sl,rtp} \qquad \text{for all } cr,\ sl,\ rtp \qquad (2)$$

Supply restrictions

The natural gas suppliers *(sc)* can deliver as much natural gas to the markets as they produce. Therefore the aggregated natural gas supply (*SU*) of a producer is smaller or equal to his production (minus losses).

Natural gas production *(PM)* is in analogy to the reservoirs differentiated by "resource classes" (*rd* = reservoir depth, *gf* = gas flow rate, *sI* = field size, *wd* = water depth). The aggregated natural gas output is the sum of the total output from all resource classes. Production losses (calculated by the loss factor *lpr*) are subtracted from the produced gas volumes. Further on, local consumption *(D)* and net exports to countries outside of Europe (*dexo,* net exports defined as exports minus imports) are subtracted from the net production.

Transportation losses are calculated by multiplying the transport quantities *TR* with a loss factor *(ltr)*. The loss factor comprises the genuine transportation losses, gas consumption of compressors and LNG tankers (instead of gasoline) and losses of liquefaction and regasification plants. The scale of the loss factor depends on the transportation assets used (pipelines or LNG ships) and on the transport distance.

$$\sum_{cr,m} SU_{sc,cr,sl,rtp} + \sum_{i,j} [TR_{sc,i,j,rtp} \quad ltr_{i,j}]$$
$$\leq \sum_{pr \in pr(sc)} [\sum_{rd,wd,gf,si} PM_{pr,rd,wd,gf,si,rtp} \quad (1 - lpr_{pr,rd,wd,gf,si}) - D_{pr,sl,rtp} - dexo_{pr,sl,rtp}]$$

for all *sc, rtp* (3)

Capacity restrictions (production)

Gas production (*PM*, gross production) is in every time period restricted by the availability production capacities. Similar to the production quantities, the production capacities are differentiated by resource classes in order to reflect cost differences (*rd*, *gf*, *si*, *wd*). The installed capacities are defined as the capacities built up in previous periods *(CAP)* minus dismantled capacity (*CDP*).

After a period of constant output (plateau phase) the output is declining because of shrinking pressure in the gas deposits (declining phase). The decline of gas output is included in the model by the parameter *cp*.

$$PM_{pr,rd,wd,gf,si,rtp}$$
$$\leq \sum_{atp < rtp} [(CAP_{pr,rd,wd,gf,si,atp} - \sum_{rtp^* \leq rtp} CDP_{pr,rd,wd,gf,si,atp,rtp^*}) \; cp_{pr,rd,wd,gf,si,atp,rtp}]$$

for all *pr, rd, wd, si, atp, rtp* (4)

Production restrictions

In some countries natural gas extraction is limited because of political or technical reasons. E.g. under certain circumstances an increase of marketed gas production can be restricted due to technical reasons or the gas is needed for reinjection into oil or gas fields in order to stabilise the reservoir pressure. In order to catch up these special cases exogenous limits for natural gas production are integrated into the model (*prcap*). These limits do not refer to the natural gas output of single gas fields but to production regions as a whole.

$$\sum_{rd,wd,gf,si} PM_{pr,rd,wd,gf,si,rtp} \leq prcap_{pr,rtp} \qquad \text{for all } pr, rtp \qquad (5)$$

Resource restrictions

Natural gas production is limited by the availability of natural gas resources (*res*). Extracted natural gas volumes must be lower than the resources available at a certain point of time *(rtp)*. The decline of resources is reduced by the discovery of new deposits (exogenously given in the model). Available resources are therefore not fixed for all periods but evolve over time.

$$\sum_{rtp^* \leq rtp} PM_{pr,rd,wd,gf,si,rtp^*} \leq res_{pr,rd,wd,gf,si,rtp} \qquad \text{for all } pr, rd, wd, si, rtp \qquad (7)$$

Capacity restrictions (pipeline transport)

Gas transports *(TR)* are limited by available transportation capacities Gas flows run from nodes *(i)* to nodes *(j)* in the model (nodal network). Available pipeline capacities in period *rtp* are the total of capacities built in the past (*CAPIP*). Capacity can also be extended by additional compression in the direction of forward flows (*CADFW*) or (for Interconnectors only) reverse flows (*CADREV*). Additional compression is less costly than new built pipelines but limited to technical thresholds.

$$\sum_{sc} TR_{sc,i,j,rtp} \leq \sum_{atp < rtp} (CAPIP_{i,j,atp} + CACFW_{i,j,atp} + CACREV_{i,j,atp})$$

$$\text{for all } i, j, rtp \qquad (8)$$

Capacity restrictions (LNG-terminals)

Production of LNG is limited by available liquefaction capacities. Losses of LNG-production are taken into account by the loss factor *llq*. Installed liquefaction capacity is the total of plant capacity (*CALQ*) built in the past. Liquefaction plants can be decommissioned in the model. The reduction of plant capacity is taken into account by the variable *CDLQ*.

$$\sum_{sc,j} [TR_{sc,i,j,rtp} \quad (1 + llq_i)] \leq \sum_{atp\ <\ rtp} (CALQ_{i,atp} - \sum_{rtp^* \leq rtp} CDLQ_{i,atp,rtp^*})$$

for all *rtp, i* (LNG locations only) (9)

Capacity restrictions of regasification plants are similarly treated in the model as those of liquefaction plants. Installed capacity is the total of capacity additions (*CARP*) of the past. Capacity decommissioning (*CDRP*) is subtracted from installed capacities. Again, losses are taken into account (by parameter *lrp*) when calculating capacity needs.

$$\sum_{sc,j} [TR_{sc,i,j,rtp} \quad (1 + lrp_i)] \leq \sum_{atp\ <\ rtp} (CARP_{i,atp} - \sum_{rtp^* \leq rtp} CDRP_{i,atp,rtp^*})$$

for all *rtp, i* (LNG locations only) (10)

Input-Output conditions

At each node of the transport system the gas output must be smaller than the gas input, i.e. it is not possible to have a greater outflow than inflow at a node. This condition is valid for the aggregated natural gas flows of all producers, and also for the natural gas flows of each single producer (*sc*).

The gas outflow at a node *i* consists of the gas flows (*TR*) from this node to other nodes (*j*) and of the quantities of natural gas being transported from this node to end consumers (*SU*). Inflows to the node are the gas flows in direction of the node as well as natural gas quantities being produced at this node and available for sale. Transport losses are taken into account by a specific transport loss factor *(ltr)*.

Production *(PM)* is considered only if nodes in production regions are concerned. Production losses (factor *lpr*) and natural gas consumption *D* within the production regions as well as supplies to third countries outside Europe (parameter *dexo*) are to be subtracted in this case, again.

$$\sum_{j} TR_{sc,i,j,rtp} + \sum_{i,m} SU_{sc,i,sl,rtp} \leq \sum_{j^*} [TR_{sc,j^*,i,rtp} \quad (1 - ltr_{j^*,i})]$$
$$+ \sum_{\substack{pr \in pr(sc) \\ and\ pr = i}} [\sum_{pr,rd,wd,gf,si} PM_{pr,rd,wd,gf,si,rtp} \quad (1 - lpr_{pr,rd,wd,gf,si}) - D_{pr,sl,rtp} - dexo_{pr,rtp}]$$

for all *sc, i, rtp* (11)

Long-term supply contracts (optional)

Optionally long-term supply contracts can be integrated into the optimisation. The contracted gas quantities (fixed in the long-term import contracts) can be included into the model as minimum volumes of supply *(topmin)* of producers to the corresponding consumption regions. If a country's contracted gas volumes are higher than its consumption the import contracts are shortened according to their proportion in the supply portfolio of the demanding country (*pro rata*).

$$topmin_{sc,cr,rtp} \leq \sum_{m} SU_{sc,cr,m,rtp} \qquad \text{for all } sc,\ cr,\ rtp \qquad (12)$$

Risk diversification restrictions (optional)

Risk diversification e.g. based on efforts to diversify the supply portfolio of a gas importing country can also be integrated into the model by additional restrictions. In this case, natural gas supplies of an individual producer to a certain consumption region are limited. The limit (*maxsup*) can be interpreted as the maximum market share of a producer in a consumption region.

$$\frac{\sum_{m} SU_{sc,cr,m,rtp}}{\sum_{m} D_{cr,m,rtp}} 100 \leq maxsup_{sc,cr,rtp} \qquad \text{for all } sc,\ cr,\ rtp \qquad (13)$$

4. Main numeric assumptions of the model

Availability of resources

The model optimises the extraction of resources under economic considerations. The availability of resources and the costs of production and transportation are given. In order to include the dynamics of gas deposit discoveries, the model differentiates between known (proven) and unknown (not proven) resources. While known resources will be available starting from the year 2005, unknown resources can only be added in future time.

The unknown resources are to be discovered until the model period 2060. Table 1 shows the resources available for optimisation starting in period 2005.[6]

In some cases, gas producing countries reserve a part of their resources for future purposes. In order to avoid the depletion of all gas resources of a country or of a production region at the end of the optimisation period, end values are used for dynamic optimisation procedures. Natural gas consumption after 2064 will be covered by either previously reserved quantities of natural gas or by gas deposits that are not known by today.

Transport capacities

EUGAS optimises on the one hand additional construction of pipeline capacities and on the other hand the quantities of natural gas being transported via these pipelines (utilisation of pipelines). Existing pipeline capacities are included in the model as well as existing capacities of LNG export and import terminals.[7] Further on, facilities currently under construction are taken into account until model period 2005. Table 2 shows the assumed capacities for liquefaction plants, table 3 shows the same for regasification plants in Europe. Some of the export-terminals do not enter EUGAS with their full capacities because of supply commitments dedicated to regions out of the model coverage, e.g. gas from Trinidad or Norway for the United States. Therefore these capacities are not available for Europe, so they can not be part of optimisation.[8]

Production costs

Costs of natural gas production consist mainly of investments in the construction of wells, facilities at the surface of the wellhead, for pipeline infrastructure close to the wellhead, processing plants, metering, communication infrastructure and other systems. In addition, investments in production capacities include proportionately the costs of natural gas exploration. The investment leaves its mark as annual capital costs in EUGAS. The internal rate of return of natural gas production is assumed to be 10%. The production facilities are depreciated within 15 years. Annual operating costs are calculated at 2.5% of

[6] See BGR (2003), BP (2003), Cedigaz (2003), ENI (2003), ExxonMobil (2003), and IEA (2003).
[7] In analogy, existing production facilities are included in the model as exogenously given parameters.
[8] For more detailed information about LNG terminals see Drewry (2002), Clarkson (2002), GM (2001), Roe (2001), Drewry (1999), and Cedigaz (1999).

the investment. Further it is assumed that losses of natural gas production amount to 2% of the produced quantity of natural gas.

As mentioned above, gas reservoirs and production are assigned to one or several different "resource classes" in the model in order to record cost drivers of the gas resources. Resources are classified according to the following criteria:[9]

- Natural gas deposits in depth of less than 2500 m and of over 2500 m,
- Water depths of 0 m (onshore), of 0 m to 200 m and of over 200 m,
- Gas flow rates per well of less than 30 million ft^3/h, of 30-60 million ft^3/h and of over 60 million ft^3/h and
- Natural gas deposits with producible reserves of more than 1000 billion m^3, of 100 -1000 billion m^3 and of less than 100 billion m^3.

Additionally, production costs differ depending on the production region. Table 4 shows the range of costs in some mayor gas producing areas.[10]

Transport costs

Construction costs of pipelines are calculated using the diameter of the pipes. Costs are derived from data on pipeline costs in the US and Canada published annually in the *Oil and Gas Journal*.[11] Onshore, the specific investment costs are 1049 $/[km x mm]. For some regions such as permafrost or mountainous areas scaling factors are integrated in order to take different cost levels into account. Offshore, costs are 50% up compared to onshore pipelines due to their expensive laying technique. The economic lifetime of pipelines is estimated at 30 years and the internal rate of return of capital at 10%. Costs for compressors are included separately.

Within the model the annual operating costs of pipelines amount to 1% of the investment. Losses of pipeline transport are estimated at 0.4% per 1000 km of the volumes transported. Gas consumption of compression is added individually for each transport route according to the capacities of the compressors needed.

[9] For a more detailed description see Perner (2002), pp.110-127.
[10] Own calculation based on Perner (2002), NPD (2003), IEA (1995), OME (1995), Pauwels (1994), and Masseron (1990).
[11] See True (1999), Mohipour/Glover/Trefanenko (2001), and True (2003).

Investments for LNG terminals refer to moderate cost estimates. For liquefaction, investment costs about 230 $/(t/a) are used in this reference case, the investment costs for regasification plants amount 75 $/(1000 m^3/a) of gas vaporised. Investments for LNG tankers are calculated on a cost basis of 150-200 million $ per tanker with a capacity of 135000 m^3 of liquefied natural gas. The economical lifetime of the assets is set to 20 years and the internal rate of return on capital to 10%.

Annual operating costs of liquefaction and regasification plants amount to 3.5%, those of LNG tankers on 4% of the investment. Transport losses and natural gas consumption during the liquefaction and vaporization process are considered separately by subtracting these quantities from the treated quantities. Self-consumption of liquefaction plants amounts up to 8%, consumption of regasification plants up to 2% of the gas volumes. Transport losses and self consumption of LNG tankers are fixed as 0.15% per day (loaded) and as 0.05% per day (unloaded). The speed of LNG tankers is set to 18 knots (approximately 33 km/h), filling and unloading are estimated as 48 h per round trip.

For some routes transit fees can be taken into account in the model e.g. for pipeline transport via Ukraine or tankers passing the Suez channel. The integration of transit fees in the model is optional.

Technical progress

The oil and natural gas industry made great efforts in the last decades to develop new technologies for drilling, extraction, treatment etc. Research and development activities of oil and gas companies were driven – at least temporarily – by a massive downward pressure of oil and gas prices. Furthermore, oil and gas companies were forced to use new technologies in order to develop gas deposits in regions facing extreme climatic conditions (deserts, arctic waters, permafrost regions etc.) and reservoirs with very difficult technical conditions (e.g. high pressure, high temperature fields in the north sea). Additionally, oil and gas fields are these days often of smaller size than in the past and are located in greater reservoir or (offshore) water depth.

Future cost cuttings due to technological progress is difficult to estimate. In EUGAS, costs of natural gas production sink by 1 or 1.5% per year caused by technical progress. Further, it is assumed that the investment costs of pipelines and compressors will decrease by 0.5% per year onshore and by 1.5% per year offshore. Costs of LNG terminals are also reduced by 1.5% per year, except those of regasification plants: Due to a low cost cutting potential only cost reductions of 0.5% per year are taken into account.

The described cost reductions due to technical progress refer to the model period 2000. With increasing maturity of an industry, however, the increase of industry-specific knowledge in relation to the accumulated total knowledge of the industry decreases. Therefore, the rates of technical progress decrease 3% annually in the model. Cost savings induced by technical progress are “slowed down" in later model periods.

Natural gas demand

Natural gas consumption is exogenously given in EUGAS. Annual demand is spread over three seasons (summer, winter, intermediate) in the model (BCM per season). The demand regions are in most cases identical to the European states. All in all, a rather moderate increase in demand is assumed - at least in the reference scenario. Table 5 shows the development of consumption per year aggregated by geographic areas.[12]

5. Exemplary model results: Reference case

In the reference scenario, risk diversification, political constraints for gas production, long-term supply contracts and other "strategic" considerations are not taken into account. The simulation is based on a pure cost minimisation logic. Nevertheless, production and transport capacities installed before 2000 are set as exogenous parameters as well as transit fees which have significant impacts on the model results especially in the first periods.

[12] Own calculation based on EIA (2003), EU (1999), IEA (2002b), Cedigaz (2000), UN (1999), and Razavi/Tippee/Smock (1996).

Net-exports

One of the basic results of the reference scenario is that no shortage of gas supply occurs in Europe at least until year 2030, neither in the total system nor for individual model regions. Table 6 shows the development of net exports (to Europe) of the most important gas producing countries.[13]

Due to the reserve situation, the three EU member states UK, the Netherlands and Denmark alter from net exporting to net importing countries. The development is especially dramatic in the United Kingdom. Namely in the Southern North Sea the production will decline from about 60 BCM in 2005 to less than 20 BCM at the end of optimisation. In Britain's northern production regions no such break-in will occur because of rising volumes from West of Shetland area. Denmark and the Netherlands start (net-) importing from other countries in the periods 2025 respectively 2030.

Norway increases its gas production from 80 BCM in 2005 to more than 125 BCM in 2030 and exports substantially during the forecast period. But this is, at least in the long run, hardly enough to compensate the decreasing output of the UK and the Netherlands. Furthermore the country achieves its peak production not later than 2030, and the production moves more and more from fields in the southern North Sea to unfavourable fields in northern regions, e.g. the Norwegian Sea and the Barents Sea. Production costs in these regions are typically higher than in the North Sea. Additionally, gas produced in the Barents Sea is exported by using LNG tankers and not short distance pipelines like in the North Sea, increasing costs further.

Algeria, traditionally an important gas exporter for Europe, can raise its gas production, too. Similar to Norway, exports peak approximately in period 2025. Like Norway, Algeria has to develop new gas provinces, e.g. the In Salah Region in the Sahara, in order to increase production. Investments in new production and transport infrastructure are needed. E.g. in the case of the In Salah region, pipelines from In Salah to Hassi R'Mel and from there to South Europe have to be built until 2015. Nevertheless, the increase in

[13] As mentioned above, net exports are defined as gas production less domestic demand and exogenous preset exports to regions beyond the area covered in the model, e.g. gas from Algeria to Tunisia or from Egypt to Jordan or Syria.

costs for new gas until 2030 is lower in Algeria (about 0.90 $ per MBTU) than in Norway (up to 1.35 $ per MBTU).

Other African gas exporting countries also become more important for the European gas supply. Libya succeeds to export larger quantities of gas to Europe via the new constructed Libya-Italy pipeline (the so called "green stream" pipeline). While pipeline capacity to Europe will expand from 8 BCM (2005) to more than 30 BCM (2030) no extension of LNG-Terminals at Marsa el Brega will be realised. Natural gas from Egypt will be brought to Turkey through an extension of the Egypt-Jordan pipeline by 2015. Additional exports take place by LNG produced in liquefaction plants located in the Nile delta (up to 12 BCM/a). Nigeria exports its gas exclusively by LNG since the projected Trans-Sahara Pipeline generates excessive costs and transit fees should be paid to Algeria increasing costs further.

The most important gas supplier to Europe stays Russia. Russia looses market shares in the first model periods but can raise exports considerably later. The decrease of exports during the first years is caused by the decline of gas production of Western Siberian fields (Urengoi, Yamburg, Medvezhe) which have to be replaced by new fields in yet undeveloped gas provinces - especially Yamal and the Barents Sea. In the reference scenario, these provinces will supply larger quantities of gas not before 2015 (Yamal) respectively 2020 (Barents Sea). After commissioning production capacities will reach more than 150 BCM (Yamal) and about 60 BCM (Barents Sea) until 2030. Both regions need an entirely new production and pipeline infrastructure. Due to the difficult climatic conditions extremely high investments are needed to develop these provinces. As a consequence, Russian supply costs will increase notably when these regions are developed.

Iran, however, shows the highest increase in gas production. In 2000, Iran was not a gas exporting country at all, but according to the model results it evolves into one of the biggest suppliers for Europe until 2030. Gas from Iran is transported by both LNG and pipelines to European markets. In the reference scenario, pipelines run from Iran to Turkey and then to Europe using two different routes: a) to Greece and South Italy and b) through Bulgaria across the Balkan to Central and Western Europe. Last mentioned route starts operating by 2020 with an initial capacity of 8 BCM/a with later expansions up to 30 BCM/a until 2030. The Greece-Southern Italy-connection does not come on stream before

2030. Due to a large reserve base and convenient field sizes production costs are low in Iran (about 0.50 $/MBTU). Further more, some existing pipelines could be used for exports if additional compression was installed. As a consequence, costs of Iranian gas are in some cases lower than costs of Russian or Norwegian gas (especially from new developments in remote areas) - not only for Southeast but also for Western Europe. This holds especially if pipeline costs can be shared with other suppliers in this region, mainly Turkmenistan and Azerbaijan.

Increasing amounts of gas are delivered to Europe via LNG from the Middle East, mainly Qatar and with smaller quantities Oman and the United Arabic Emirates. Main destinations of Gas from the Persian Gulf are the Mediterranean import-Terminals especially in France, Greece and Italy. Trinidad becomes also a main supplier for Europe, namely for France, Portugal, Spain and the UK. Until 2030 no gas from Venezuela will be arriving Europe.

Gas transport

Pipeline transport occurs in the model in three main directions:

- East-West: From Yamal, Western Siberia, the Caspian region and Iran to Eastern Europe and then further on to Central and Western Europe.
- North-South: From the Norwegian, British and Dutch production regions to Western Europe.
- South-North: From North Africa to Southern Europe.

Figure 3 shows the most important existing and potential pipeline routes from production to consumption regions supplemented with LNG flows.

Especially the East-West direction gas flows need high investments in new pipelines. Examples for such investments are the Yamal-Europe route via Belarus, as well as the connection from the Barents Sea to Germany and Sweden crossing Finland. Table 7 shows exemplarily the development of some major projects.[14]

[14] For 2000 data see Perner (2002), EGM (2001), Cedigaz (2000), Zhao (2000), and EU (2000).

Additionally refurbishment of old infrastructure is necessary, e.g. the Soviet-built pipelines from Turkmenistan to Volga-Ural region and the transit pipelines passing the Ukraine.

The increase of LNG trade requires a large extension of both liquefaction and regasification capacities. Table 8 displays the development of LNG import infrastructure in Europe. Most notable is the comeback of the United Kingdom as an LNG import nation with the beginning of deliveries in the period 2005-2009, almost 30 years after the decommissioning of Britain's first LNG terminal at Canvey Island. Compared to the present situation, Belgium, France, Italy and Spain will raise their regasification capacities significantly. Additionally, Portugal joins the group of LNG importing countries in period 2005. In contrast, Germany will not use the option to build an import terminal at least until 2030, but could import LNG via the Terminal in Zeebrugge, Belgium.

The extension of transport infrastructure calculated by the model is, at least in the first model periods, lower than the total of all pipeline and LNG capacities currently planned in Europe. If all projects currently discussed were realised transport capacities would be higher than needed. As a consequence, Europe could face an ongoing situation of oversupply with natural gas in the first decade of this century, at least in some regions. Taking these results into consideration, it seems to be extremely questionable if all of the pipeline and LNG projects will be realised under the announced time schedules.

6. Exemplary model results: Impacts of a gas cartel

As shown above; large amounts of natural gas will be supplied to Europe by countries which are member of OPEC, especially Algeria and later on Iran. In future, it can not be excluded that the yet more informal meetings of some gas suppliers named Gas Exporting Country Forum (GECF) will become a comparable cartel like OPEC for the oil market.[15] In the following EUGAS scenario, a gas cartel is supposed for the periods 2015 to 2030. The settings orientate on the OPEC politics which are pretending production quotas for each country. All OPEC states shall be gas cartel members, namely Algeria, Iran, Iraq,

[15] See GECF (2003), GECF (2002), and Stern (2002).

Libya, Nigeria, Qatar, UAE and Venezuela. In addition, Egypt, Oman and Yemen are also affiliated to this group as they are member of OAPEC (Organization of Arab Petroleum Exporting Countries) or countries with similar politic surroundings like the OPEC states.

The production quotas applied in the model are shown in table 9. The volumes include gas exports to countries out of the model coverage and supplies to domestic customers. All other settings are equal to the reference case.

Changes of net-exports

As to be expected, the members of the fictitious gas cartel reduce their exports to Europe. Table 10 shows the net-exports of all producing countries for the relevant periods 2015 to 2030. Figure 4 gives an overview of the aggregated export modifications for the periods 2015 until 2030 compared to the reference case mentioned above.[16] Also shown are the countries which are able to increase their exports. Displayed are only those countries with significant changes.

The largest reductions of supplies are scheduled for Algeria, Libya and Nigeria followed by Egypt and Iran. For the Middle East, aggregated export volumes stay nearly the same. This result is based on the fact that in the reference case especially Oman and Yemen are not able to come into operation during the forecasted term. In this model run, production from Oman and Yemen replaces the reductions of exports of the other producers from Middle East, Qatar and UAE.

As shown above, no western European country will be capable to increase yearly production significantly. So the most important supply country, Russia, has to fill the gap supported by the other Former Soviet Union states Turkmenistan and Azerbaijan. Russia has to produce about 50 BCM per year in addition to the volumes of the base scenario. At a first glance this sounds moderate but referring to the transcend output peak of Western Siberian supergiant fields this is not a self-evident matter. So the development of Yamal and the Barents Sea has to start earlier and with higher production capacities than in the reference case. In order to achieve the ambitious production levels in time, investments had

[16] As mentioned above each period covers five years, so the aggregated difference must be multiplied with factor 5.

to be undertaken in early years and only negligible gas amounts would have to flow to other regions like China.

Gas Transport

The deviations in the production volumes compared to the reference case also have impacts on the construction of transportation infrastructure. Table 11 highlights some modifications concerning the above introduced pipeline projects for model period 2030.

As to be expected, pipelines from cartel members to demand regions are not expanded to such an extent as in the reference case. Especially routes from Algeria, Egypt, Iran and Libya need lower capacities. Contrarily, additional pipelines from the "new" Russian production regions, Yamal and Barents Sea, have to be installed.

Aggregated LNG import (regasification) capacities in Europe will be reduced from 137 to 128 BCM/a, with reductions being fragmented among most countries. Total liquefaction capacity relevant for the European market will be about 140 BCM/a in 2030, 10 BCM/a less compared to the base scenario (Table 12). The most significant increase in LNG export capacity, compared to the reference scenario, will occur in Angola. The African state isn’t a gas exporting country yet, and even in the reference case it won’t be a supplier for Europe during the forecast horizon. In the cartel scenario, it is LNG production from Angola that can fill the gap of lower LNG volumes from cartel members, mainly Nigeria, to a big extent.

Supply cost implications for Western Europe

As in the reference case, no physical shortage of gas will occur in Europe until the year 2030 even if a gas cartel will be established. Nevertheless, some effects on the supply costs can be observed. For most European countries an increase in marginal supply costs (cross border) is the consequence of a new gas supply mix. Table 13 displays the absolute and the relative changes of marginal supply costs for some Western European countries.

The most remarkable changes in supply costs can be observed in those countries which highly rely on Algerian and Iranian gas deliveries. Spanish import costs increase, in relative terms, the uppermost. The reason is that Algerian pipeline gas and LNG which is exported to Spain in the reference case have to be substituted by deliveries from Trinidad & Tobago in the cartel scenario.

The highest cost increase, in absolute terms, can be noticed for Turkey with more than 0.50 $/MBTU. This outcome is not surprising since the country highly depends on Iranian and Egyptian gas in the reference case. In the cartel scenario, gas supplies from these two (fictive) cartel members have to be replaced by volumes from the Yamal peninsula transported via the Blue-Stream-Pipeline, and by higher imports from the Caspian region, especially from Azerbaijan. Such an import portfolio mix is naturally combined with higher marginal supply costs.

Countries with a brighter diversification of supply sources like Germany, France or Italy are typically better secured from a sharp rise of supply costs. In these countries, the changes in marginal supply costs amount to less than 10% compared to the reference case. Hence, portfolio diversification is not only an insurance against potential supply interruptions but also against cost risks.

7. Conclusions

The model EUGAS is a powerful tool that allows the investigation of future European natural gas supplies. By using the model, future gas production in the most important production regions for Europe and gas transportation to European markets can be analysed quantitatively in a holistic context. In this article, two model runs have been analysed in detail: a reference case with no political or strategic restrictions for gas supplies and a cartel scenario in which a group of producers around Algeria and Iran form a "fictive" gas cartel with well specified production quotas.

In the reference case, it is shown that sufficient natural gas is physically available for the European market in the foreseeable future. No gas scarcity has to be feared because of a relatively convenient resource base achievable for Europe. Furthermore if all at present discussed infrastructure projects will be realised, a situation of over-supply might be possible, especially in countries like Turkey where current consumption stays broad behind the forecasted volumes. Nevertheless, the average transport distance from production to consumption regions increases, and fields have to be developed more and more under very unfavourable conditions (remote areas, harsh climatic conditions etc.). As a consequence, supply of additional quantities of natural gas is accompanied by significant investments in production and transport infrastructure. Good examples for such investments are the proposed export project from the Russian Barents Sea to Western Europe via the Baltic Sea or the extensive expansion of LNG facilities.

The reference case affirms that Russia remains the main producer of natural gas in Europe, as to be expected. Norway becomes the second largest European gas producer in the mid-term. Contrarily, the production volumes of Great Britain and the Netherlands have downward tendencies in the mid-term. Both countries will become net-importers during the forecast horizon. Algeria will extend its important position as a main gas supplier for the European market. Further on, the appearance of other non-European producers on the European gas market is a powerful trend. Especially Iran could take a very strong position for the European natural gas supply in the future. In addition, Nigeria, the Middle East and the Caspian states will supply increasing quantities of gas to Europe. As a consequence, the number of supply options will increase for European natural gas importers, which allows a higher diversification of deliveries. On the other hand, the stability of the political systems of some of the upcoming exporting countries could become a matter of concern.

As in the reference case, no real shortage of gas can be observed in the cartel scenario. Since supplies from "fictive" cartel members like Algeria, Libya or Iran are limited, Russia and Norway have to fill the gap. Additional to these traditional European trade partners, some newcomers like Angola or Azerbaijan are able to gain respectable market shares in Europe.

Nevertheless, a fictive gas cartel would have significant impacts on the gas supply costs for Europe. A sharp increase of delivery costs can be observed for some European countries in the cartel scenario since gas production is shifted from convenient gas fields like South Pars (Iran) or Hassi R'Mel (Algeria) to more expensive gas provinces in non-cartel member countries like the Norwegian and Russian Barents Sea which will not come on stream that early in the reference scenario.

Irrespective of the model scenario, large amounts of "new" gas will have to be brought to the European market in the coming years. No physical shortage in natural gas is observable until the end of 2030 (even under a cartel scenario) but heavy investments in new production and transport infrastructure is needed. It should not be up to the politics to choose the "right" gas purchase strategy for Europe for the future in detail, but politics should set an adequate general framework for private investments without distorting the market processes:

At first, in order to attract sufficient capital to finance the necessary investments, political institutions must set a stable long lasting political framework. International cooperation like the Energy Charter Treaty between demand, supply and transit countries seems to be essential in this context. Isolated and erratic political action is not suitable to acquire the strongly demanded private capital for infrastructure investments.

To guarantee the optimal allocation of international capital, an on going opening of all markets and market segments must take place. This holds not only for the European Single Market but especially also for upstream markets outside the EU like Algeria, Russia and other important gas producing countries. Only if the upstream business is opened up for foreign capital under adequate production and marketing conditions, expensive investment projects in yet undeveloped regions can be developed.

Diversification of gas deliveries should be part of the future gas import strategy of energy companies, nations and Europe as whole. Today, there are still some states which rely totally on supplies from one country. E.g. Finland, the Baltic States or some countries in East and Central Europe are totally sourced with Russian gas. Spain and Portugal depend heavily on supplies from Algeria but both make great efforts to reduce this dependency. LNG seems to be the most reasonable and effective option to increase supply diversification for these countries. For landlocked states, an extension of pipeline connections to neighbouring countries could be an adequate strategy.

Political support and subsidies for selected investment projects (Interconnectors, LNG facilities etc.) should be the exemption and well justified. Especially if subsidised investment projects compete with alternative non-subsidised projects the allocation of capital is distorted. Further on, new infrastructure projects can have a significant impact on existing infrastructure assets which had to be financed in the past. Politics should be aware that the exclusive support of one project can increase the financial risks for other projects and therefore can discourage private non-subsidised investments in gas assets in the mid and long term.

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Tables

Table 1: Resources in main supply countries

(in BCM)	Resources 2005
Russia	47.600
Iran	26.000
Middle East	18.810
Trinidad/Venezuela	4.760
Algeria	4.523
Iraq	3.100
Nigeria	2.940
Norway	2.861
Turkmenistan	2.860
Netherlands	1.650
Egypt	1.560
Libya	1.314
United Kingdom	1.140
Kazakhstan	1.050
Azerbaijan	1.000
Angola	370
Denmark	160

Table 2: Capacities of liquefaction plants (volumes available for Europe)

(in BCM/a)	2005
Algeria	30
Angola	0
Egypt	6
Iran	0
Libya	4
Middle East	12
Nigeria	14
Norway	3
Trinidad/Venezuela	10

Table 3: Capacities of vaporisation plants

(in BCM/a)	2005
Belgium	8
France	23
Germany	0
Greece	4
Italy	4
Portugal	3
Spain	21
Turkey	6
United Kingdom	4

Table 4: Cost range in main producing areas

(in US$ / MBTU)	lowest cost level	highest cost level
Algeria - Hassi R'Mel	0.3	1.0
Egypt - Niledelta	0.5	1.0
Libya - Wafa/NC 41	0.6	1.0
Netherlands - Groningen	0.2	0.5
Norway - Barents Sea	1.1	1.7
Russia - Western Siberia	0.4	1.3
Turkmenistan - Amu Darya	0.5	1.2
UK - Northern Northsea	1.0	1.7

Table 5: Natural gas demand

(in BCM/a)	2005	2010	2015	2020	2025	2030
Western Europe	479	533	580	612	626	628
Eastern Europe	85	100	110	120	123	123
C.I.S.	537	574	597	628	643	644
Others	149	181	201	215	220	221
Total	1249	1388	1488	1575	1613	1616

Table 6: Net-exports of main supply countries

(in BCM/a)	2005	2010	2015	2020	2025	2030
Algeria	81	97	103	103	103	92
Angola	0	0	0	0	0	0
Azerbaijan	-3	5	5	14	18	17
Denmark	5	5	3	1	-3	-4
Egypt	6	14	32	38	38	37
Iran	10	10	10	14	35	56
Iraq	0	0	0	1	7	9
Kazakhstan	-1	33	50	48	42	42
Libya	12	20	30	39	35	35
Middle East	4	10	19	22	28	30
Netherlands	35	29	16	15	7	-21
Nigeria	14	20	20	20	26	30
Norway	75	83	91	114	121	124
Russia	175	155	165	175	181	219
Trinidad/Venezuela	8	10	10	18	18	18
Turkmenistan	36	70	77	74	80	80
United Kingdom	5	-28	-31	-38	-53	-75

Table 7: Capacities of some major gas transport projects

(in BCM/a)	2000	2010	2020	2030
Algeria - Spain (Maghreb-Europe, Medgaz)	12	25	36	36
Belgium - United Kingdom	9	12	12	30
Egypt - Turkey (with branch to Cyprus, Syria)	0	2	26	26
Iran - Turkey		10	14	40
Iraq - Turkey	0	0	0	9
Kazahkstan - Russia	6	33	52	60
Libya - Italy	0	16	35	37
Norway - United Kingdom (Frigg, Marathon)	7	25	29	44
Russian Barents Sea - Finland (with extensions to Germany, Sweden, Baltic States)	0	0	22	63
Turkey - Bulgaria	0	0	8	33
Yamal Fields - Europe (incl. capacity for Western Russia)	0	0	120	160

Table 8: Development of regasification capacities

(in BCM/a)	2005	2010	2015	2020	2025	2030
Belgium	8	8	8	8	14	16
Germany	0	0	0	0	0	0
France	23	23	26	28	28	35
Greece	4	5	6	6	6	6
United Kingdom	4	11	19	25	32	32
Italy	8	8	8	8	14	16
Portugal	3	3	3	3	4	4
Spain	19	19	19	20	21	22
Turkey	6	6	6	6	6	6

Table 9: Maximum production in the cartel scenario

(in BCM/a)	2015	2020	2025	2030
Algeria	120	120	120	120
Egypt	60	60	65	65
Iran	120	120	140	150
Iraq	20	25	25	30
Libya	40	40	40	40
Middle East	20	20	25	25
Nigeria	30	30	40	40
Venezuela	5	5	5	5

Table 10: Net-exports in cartel scenario

(in BCM/a)	2015	2020	2025	2030
Algeria	76	74	73	73
Angola	0	9	9	18
Azerbaijan	14	18	18	17
Denmark	3	1	-3	-4
Egypt	25	21	25	24
Iran	12	7	35	35
Iraq	1	2	3	8
Kazakhstan	50	48	42	42
Libya	22	22	18	18
Middle East	19	20	25	25
Netherlands	16	14	7	-17
Nigeria	8	6	16	16
Norway	116	135	133	122
Russia	165	226	248	295
Trinidad/Venezuela	15	15	15	15
Turkmenistan	79	85	80	85
United Kingdom	-21	-41	-55	-76

Table 11: Capacities of pipeline projects in 2030

(in BCM/a)	Reference case	Cartel case	Diff.
Algeria - Spain	36	23	-13
Egypt - Turkey	26	13	-13
Iran - Turkey	40	30	-10
Libya - Italy	37	21	-16
Russian Barents Sea - Finland	63	73	+10
Turkey - Bulgaria	33	23	-10
Yamal fields - Europe	160	186	+26

Table 12: Capacities of LNG liquefaction plants in 2030

(in BCM/a)	Reference case	Cartel case	Diff.
Algeria	26	22	-4
Angola	0	18	+18
Egypt	12	12	0
Iran	16	11	-5
Libya	0	0	0
Middle East	30	25	-5
Nigeria	30	15	-15
Norway	18	23	+5
Trinidad/Venezuela	18	15	-3

Table 13: Marginal supply costs

(in US$/MBTU)	Reference case	Cartel case	Diff.	% change
Finland	2.07	2.26	0.19	9%
France	2.84	3.03	0.19	7%
Germany	3.00	3.18	0.18	6%
Greece	2.96	3.28	0.32	11%
Italy	3.30	3.31	0.01	0%
Spain	1.89	2.27	0.38	20%
Turkey	2.93	3.45	0.52	18%
United Kingdom	3.00	3.21	0.21	7%

Figures

Figure 1: Regional coverage of EUGAS

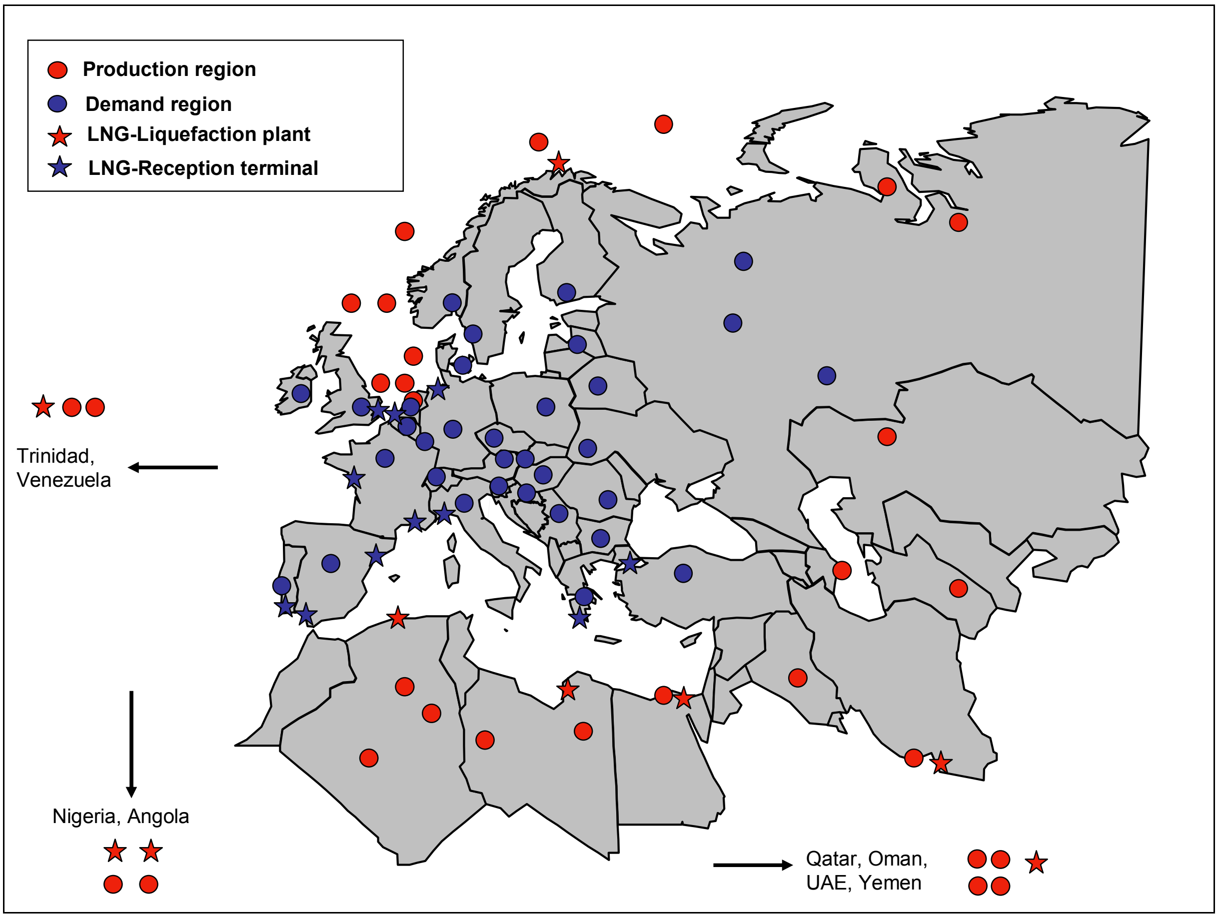

Figure 2: Transportation system of EUGAS

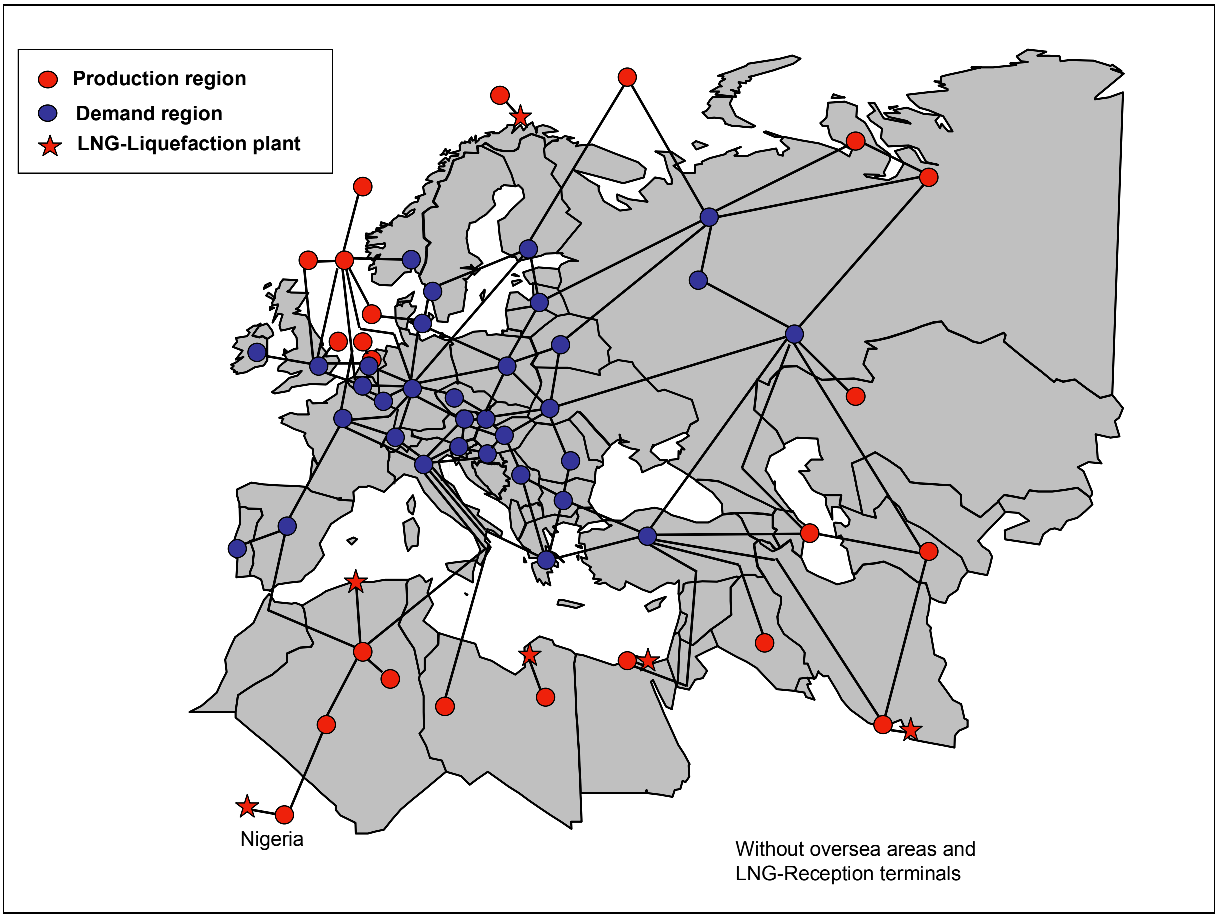

Figure 3: Export routes to Europe

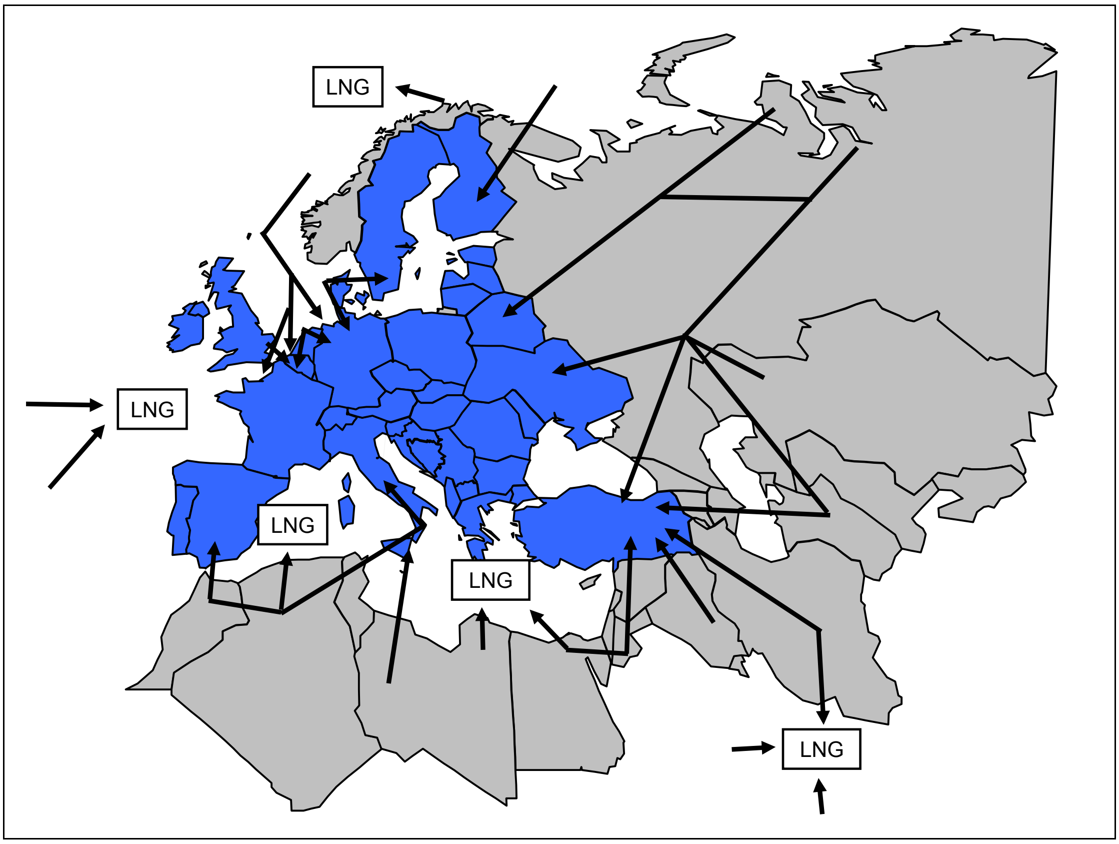

Figure 4: Changes of net-exports (BCM aggregated 2015-2030)