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Natural gas corridors between the EU and its main suppliers: Simulation results with the dynamic GASTALE model

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Abstract

Growth in gas demand poses a challenge for European energy consumers and other gas-importing countries in terms of an increasing dependency on gas imports and consequently also supply security. This paper focuses on interactions among demand, supply, and investments in natural gas corridors, namely pipeline transport, LNG, and storage facilities, affecting the European natural gas market over the period 2005–2030. A number of policy scenarios, including a business-as-usual (BAU) scenario, are formulated to study the impact of demand uncertainty and delays in investment on the gas transport infrastructure required in the long run in Europe. The analyses indicate that substantial investments in gas transport corridors are needed to accommodate imports and seasonal demand variations. Analysis of scenarios of supply interruption, in the form of suddenly reduced import capacity for particular pipeline routes, indicates that portions of Europe could experience price increases of up to 100% in the case of a year-long interruption. To accommodate import needs and to mitigate possible disruptions, pipeline connections running from East to West need to be given special priority.

Keywords: Natural gas markets; Dynamic market models; Investment analysis

1. Introduction

There is increasing concern about potential threats to the long-term (2010–2030) security of gas supply for EU consumers. This is particularly so for the accession countries in Central and Eastern Europe, who depend upon imports from a single large supplier and expect gas demand to grow strongly. These supply security concerns are driven by the following structural changes in gas markets in Europe:

- *Liberalisation of national gas markets in the EU and progressive creation of an integrated European internal gas market.* This transition increases uncertainty for investors in gas production as well as in the infrastructure necessary to connect these remote production locations outside the EU with main consumer markets in the EU.
- *Expansion of the EU to include new member states.*
- *Growing gas demand in the EU due to the fuel's convenience and environmental benefits and, consequently, a strongly increasing dependency on imports*, expanding from the current 40% up to probably around 70% in 2030.

Security of gas supply for consumers is basically an issue of risk. All energy supply systems inherently pose a certain level of risk for consumers, but the question is what level and type of risks are acceptable. The answer depends on the context in which the question is posed. The scope of this study is the medium- and long-term gas markets in Europe wherein the EU consumer is largely and increasingly depending on natural gas imports. Moreover, the EU mainly depends on a relative small number of key

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gas exporters with remote production locations. Furthermore, supply security in the energy and gas sector is generally more important, e.g., for political and economic reasons, than supply security in other industries, because of the lack of substitution possibilities in the short term. Today, alternatives to consumption of gas are few and limited in availability. Furthermore, another distinguishing characteristic of gas supply is its complete dependency on monopoly-controlled pipeline networks. Consequently, there are generally high costs involved in gas supply interruptions. What constitutes "adequate" security depends very much on the consumers' willingness to pay for higher security levels, which tends to fall at higher levels of security while at the same time the marginal costs of providing extra security tend to be increasing. Supply security can be improved by constructing sufficient alternatives to potential supply disruptions in the form of storage capacity, alternative suppliers and contractual guarantees from the suppliers. These options can cushion sudden disruptions in supply and reduce impacts on prices. In this paper, we operationalise this concept by calling a system "secure" if the analysed disruption scenarios result in temporary wholesale gas price increases of not more than 20%, or "moderately secure" if those scenarios instead cause a temporary price increase between 20% and 50%.

Unfortunately, optimal levels of security are difficult to assess, because perceptions of risk are subjective and differ among stakeholders. What policy makers can do, however, is try to assess if security levels are within a certain and acceptable margin for a majority of consumers.[1] The role of infrastructure capabilities and capacity is becoming more critical, and adequate investments are needed to avoid major bottlenecks in the future so that gas supplies can be provided to consumers at reasonable prices. The purpose of this paper is to analyse the long-term markets for, and economic impacts of new investments in natural gas corridors, namely pipeline, LNG, and storage facilities in Europe, with a focus on supply security.

As a tool for studying the "supply security of gas" in the EU, this paper uses GASTALE,[2] a computational game-theoretic model with investment decisions by transmission storage system operators (TSOs) and storage system operators (SSOs). The model is a multiyear extension of two earlier, static versions of GASTALE. The first version represented both trader and producer market power, and is described by Boots et al. (2004). Egging and Gabriel (2006) extended that model by including inter-seasonal tradeoffs for storage. Neither version considered investments or more than 1 year. Details on the mathematical formulation of the multiyear GASTALE are provided in Lise and Hobbs (2008); the application here differs from that paper by including a more detailed geographical disaggregation of the production and consumption zones. The multiyear version solves for a short-run equilibrium in each 5-year period, and makes investments at the beginning of each period based on anticipated market conditions including congestion costs at the end of each period.

The market structure assumed by this version of GASTALE is as follows. Market participants include producers, consumers, arbitrageurs, TSOs, and SSOs. Producers contract with pipelines and LNG shippers to transport gas to customers in consuming countries. Producers can exercise market power, playing a Cournot game against other producers as well as arbitrageurs and storage, and optimise net revenues against price elastic demand. However, owners of transmission and storage are assumed to be regulated or otherwise operated in such a way that transmission is priced efficiently. That is, the price of transmission (or storage) equals long-run variable cost, unless transmission (storage) capacity constraints are binding, in which case the price of transmission (storage) reflects a congestion premium in order to clear the market for transmission (storage) capacity. Because of this assumption, transmission (storage) can be equivalently modelled as being owned by a single TSO (SSO) who is price-taking.[3] Although producers anticipate demand changes in response to price, they do not exercise market power with respect to transmission, that is, they are price-taking with respect to the cost of pipeline and LNG shipping. These transmission assumptions are consistent with some other models (Boots et al., 2004; Gabriel et al., 2005) and differ from others that have more sophisticated representations of the costs and technical characteristics of transmission (O'Neill et al., 1979) and storage (Guldmann, 1983).

Additional structural assumptions include the following. The SSO can profit from buying gas in the low demand (and thus low price) seasons, storing it, and finally selling it to end user sectors in the high demand seasons. Storage operators are assumed to take ownership of the gas they store, so as an alternative modelling assumption, they could exercise market power against demand during seasons when stored gas is sold. In this paper, SSO are assumed to be price-takers. Arbitrageurs/traders within the regions of the EU sell the gas to the consumers in three sectors: power generation, industry, and core firm customers (including residential and commercial users). Arbitrageurs, who are price-takers, purchase the gas from the producers and are only arbitraging among market sectors within a country, and not between countries. Basically, arbitrage makes sure that the wholesale price for different sectors is the same. Prices can differ among countries where countries that are closer to cheaper gas sources will have a

[1]For a further discussion of these issues consult the final report of the ENGAGED project (Van Oostvoorn, 2003). For a discussion of the gas supply security in the Netherlands see Algemene Energieraad (2005).

[2]Version 4.4.

[3]This formulation is inspired by imperfectly competitive electricity market models (Neuhoff et al., 2005; Lise et al., 2006) in which scarce transport capacity is allocated by a system operator in order to clear the market for transportation capability.

lower price than countries that are further distant from gas sources, because of the considerable (long-run marginal) cost involved to transport gas upstream and possible congestion on transmission connections. In 2005, the price difference due to congestion can be very large, as no new investments can be undertaken. However, from 2010 onward, congestion can be reduced by expanding the natural gas transmission network and, as a result, lower price differences would be expected.

The investment game is a unique feature of this model. Its structure is as follows. Investments are undertaken recursively and only for pipeline, LNG and storage facilities, whereas gas production capacity is based on an exogenous scenario. Investment decisions are made by the corridor managers, namely the TSO for pipeline and LNG transmission facilities, and the SSO for the storage facilities. They base their investments on expected congestion prices and to bring the level of congestion down to acceptable levels, defined as being no more than 20% above long-run marginal costs for pipelines and LNG facilities and no more than 10% above long-run marginal costs for storage facility. A lower threshold is applied to storage because it is mainly used for within-year arbitrage from low to high demand periods, and involves considerably lower investment costs than pipeline and LNG facilities, which concern transport of gas from producer to consumer. However, if congestion prices would otherwise be above those levels, the model adds capacity until congestion prices equal those thresholds. While most of the 59 investment options we consider are endogenous (model-made) decisions in GASTALE, in the manner just described, two particular pipeline options discussed later in this paper are fixed, reflecting political commitments to investments that the model would find uneconomic. In addition, as explained later, political considerations mean that four particular pipeline connections and one liquefaction facility cannot expand beyond a predetermined level even if economic; it turns out that the latter restrictions generally are not binding before 2020.

The model does not consider investments in production capacity by producers; instead exogenous scenarios define the amount of production capacity. This is because the focus of this paper is on transport infrastructure investment, and also because modelling of the effect of investment production costs and intertemporal production constraints is complicated and controversial. However, it is in theory, possible to endogenise production capacity: Gabriel et al. (2003) provide a model that includes capacity–production relationships as well as tradeoffs between gas production in different periods, considering the size of the resource and effect of withdrawal rates on the resource. The result was a model with over a million decision variables, as the data requirements to characterise the dynamic characteristics of different production fields are onerous. Bothe and Seeliger (2005) and Zwart and Mulder (2006) both formulated models where the depletion of gas fields is taken into consideration as well as investments in production capacity. The former model represents only perfect competition while the latter in addition models Cournot competition. Zwart and Mulder (2006) consider investments in production capacity as a dynamic game in which producers try to maximise the resource rent over a long time horizon.

The outline of the paper is as follows. Section 2 summarises the assumptions and the scope of the model. The model consists of 10 EU consumers and 12 producers, of which nine are located outside the EU. Section 3 derives the business-as-usual (BAU) scenario. Section 4 presents the analysis with the model for four policy scenarios, namely the high and low demand scenario, the (investment) deferral scenario and a number of disruption cases to test the resilience of the gas network after investments are realised. Section 5 provides conclusions.

2. Model summary

GASTALE models the main consumers and producers of natural gas in Europe. The gas market is typically characterised by a mismatch in space between production and consumption, which are connected with each other via (on- and off-shore) transport pipelines and an LNG shipping network. The model distinguishes among the following market participants:

- Producers (possibly) with market power (who decide on production and transport to the border of the country of consumption, earning the wholesale price);
- Price-taking TSOs (who regulate transport through on- and off-shore pipelines and LNG shipping);
- Price-taking arbitrageurs (who trade gas among power generation, industries, residential, and storage until the wholesale price is equal for each sector within each country);
- Price-taking SSOs (who regulate injection and extraction for storage facilities for storage during the low demand warm season and for consumption during the medium and high demand seasons); and
- Consumers in the different sectors.

Arbitrageurs are implicit in the effective demand curves facing producers in each country, and are assumed to be competitive in this paper.[4] Investments decisions are considered for expanding the capacity of the pipeline network, and the capacity of liquefaction, regasification, and storage facilities. A schematic overview of the relation among the actors is provided in Fig. 1.

This paper uses GASTALE to study gas corridors and supply security of gas in the period 2005–2030. A model

[4]As explained in Boots et al. (2004), these traders can be represented as behaving either competitively or a la Cournot; this results in different forms for the effective demand curves at the border for producer gas. Cournot trader assumptions can be incorporated into the version of GASTALE of this paper using the approach of Boots et al. (2004).

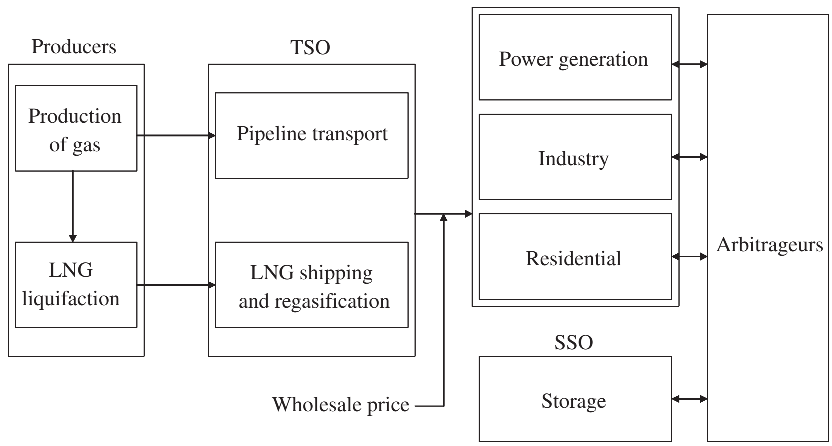

Fig. 1. Linkages between actors in the gas chain in GASTALE.

Table 1
Producers and consumers in GASTALE

Country/ region	Node	Included countries
Algeria	AL	Algeria
Azerbaijan	AZ	Azerbaijan
BALKAN	BK	Romania, Bulgaria, Greece, Croatia, Bosnia-Herzegovina, Serbia, Macedonia, Albania
BALTIC	BT	Poland, Estonia, Latvia, Lithuania, Finland, Sweden
BENELUX	BX	The Netherlands, Belgium, Luxemburg
CENTRAL	CE	Hungary, Czech Republic, Slovakia
DEDK	D	Germany, Denmark
Egypt	E	Egypt
FR	FR	France
IBERIA	IB	Spain, Portugal
Iran, Iraq	IR	Iran, Iraq
ITALP	IT	Italy, Austria, Switzerland, Slovenia
Libya	L	Libya
Nigeria	NG	Nigeria, Angola, Trinidad-Tobago
Norway	NW	Norway
Qatar	Q	Qatar, Oman, Yemen
Russia	R	Russia, Turkmenistan, Kazakhstan, Uzbekistan
TR	T	Turkey
UKIE	U	UK, Ireland

Note: Country/region in CAPITALS are consumers, while country/region in **bold font** are producers.

year represents 5 years around the model year, for example: 2005 represents 2003–2007 and so on. A substantial part of production of natural gas takes place in the EU, which is sufficient to meet about 60% of the demand in 2005. Of this 60%, about 50% is produced by UKIE (see Table 1 for the meaning of regional abbreviations), BENELUX, and DEDK, while the other 10% is considered as indigenous production within the EU and is subtracted from demand in the model. The remaining 40% of demand is met by production outside the EU, namely Algeria, the Caspian countries, Egypt, Iran–Iraq, Libya, Nigeria, Norway, Qatar, Russia, and others. The model distinguishes among consumers in 10 European regions; besides UKIE, BENELUX, and DEDK, these also include BALKAN, BALTIC, CENTRAL, FR, IBERIA, ITALP, and TR. The data of the model are mainly based on OME (2007), Van Oostvoorn (2003) and Van Oostvoorn and Lise (2007). The data for storage capacity and liquefaction and regasification capacities are taken from recent IEA gas information (IEA, 2005). Fig. 2 provides a map of Europe indicating the location of and linkages among the producers and consumers included in GASTALE.

3. Calibration and derivation of the BAU scenario

3.1. Demand assumptions

Our demand curve calibration process can be summarised as follows. In order to calibrate the linear demand curve for each location, season, and year in the model, it is assumed that the curves pass through a specified price–quantity point with an assumed elasticity. The specified point is obtained by an iterative process that obtains an initial demand curve by temporarily assuming that firms behave competitively and taking the realised levels of demand in 2005 as fixed. A competitive equilibrium, in which the cost of meeting demand is minimised, is then computed, yielding a set of corresponding prices. After passing the demand curves through those points, the BAU solution, based on the below assumptions, is obtained, which generally yields higher prices and lower quantities demanded. The demand curves are then shifted outwards until the BAU solution yields the realised 2005 quantities demanded. Details on this calibration process in the next several paragraphs.

Given the resulting demand curves, scenarios of market structure can be considered that recognise that the actual gas market is characterised by large producers who likely possess market power. Assuming firms behave à la Cournot might be somewhat more realistic, but this generally exaggerates the actual level of exercised market power. Moreover, under the price elasticities assumed, GASTALE shows that the level of demand under Cournot competition would be about 20% lower than under perfect competition, and prices several-fold higher. Long-term

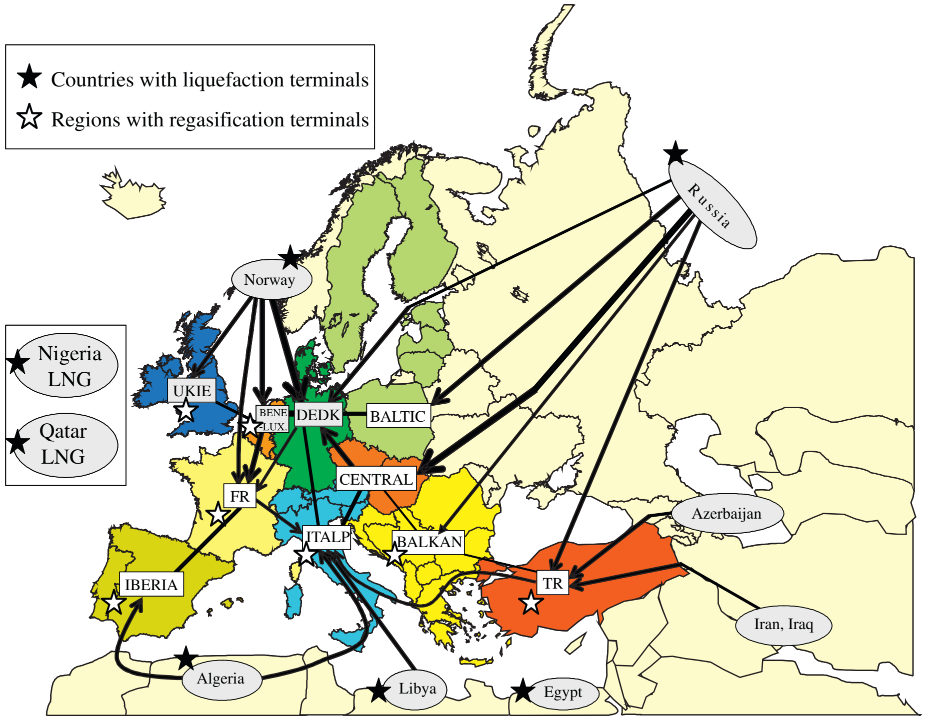

Fig. 2. Location of and linkages among consumers and producers.

contracts and political considerations likely mitigate such extreme exercise of market power.

Therefore, a BAU scenario is derived in which the firm's ability to exercise market power is reduced; namely Russia is assumed to exercises market power on 25% of their export potential to the EU, while all other firms exercise market power on 75% of their export potential to the EU. This is equivalent to assuming that Russia supplies 75% of its capacity under fixed long-term contracts, and others supply 25%, with the remainder being sold in the short-term market where market power can be exercised. This is a more realistic representation of the present situation in which there is partial market power in a market with a substantial share of long-term contracts. The BAU scenario can also be interpreted as reflecting the situation where Russia is willing to supply gas at a relatively lower cost in order to sustain a market share of 25% in the EU market, which is more consistent with recent history.

In order to obtain a match between each year's total demand in the BAU case with the demand forecasts of the Directorate General of Transport and Energy (DG TREN) PRIMES (EU, 2004), the demand curves initially calibrated to the perfect competition solution were shifted outwards. The amount of shift was equivalent to demand under perfect competition being increased by 12%, 6%, 10%, 13%, 15%, and 16%, for the years 2005, 2010, 2015, 2020, 2025, and 2030, respectively. Note that the DG TREN PRIMES scenario is based on an oil price scenario rising from 20$/barrel in 2000 to 28$/barrel in 2030 in constant 2000 prices, an assumption we have maintained in this paper. In summary (Fig. 3), the calibration procedure chooses a fixed demand Q^0 for perfect competition, obtains P^0 from the competitive run, assumes a price elasticity and then derives initial demand curves, solves for the BAU (partial market power) solution based on forward-contracting assumptions, and finally adjusts the demand curves outward so that the BAU solution's quantities equal Q^0.

While elasticities are uncertain, their relative levels among different consuming sectors are relatively well established. We assume average retail price elasticities of −0.25 for households, −0.40 for industry, and −0.75 for power generation (Egging and Gabriel, 2006), which are equal among all consuming countries. As a result, elasticities will be higher in the wholesale market. The relative values can be justified as follows. Households generally have little scope for switching and are given the lowest elasticity. Industries have more flexibility in planning their operation, and are assigned a somewhat higher elasticity. Power generators, however, can even switch to other technologies when the gas price varies, e.g., coal, and they are assigned the highest elasticity.

The total regional consumption is divided over the three seasons in the year, namely low, shoulder, and high demand, representing April–September; February, March, October, November; and December–January of each calendar year, respectively. The allocation of seasonal demand is based on the number of degree-days (Van Oostvoorn, 2003). As a result, gas demand in the residential, power and industrial sector, respectively shows large, medium, and no seasonal variation. The demand for residential heating is for instance much higher in winter and nearly negligible in summer.

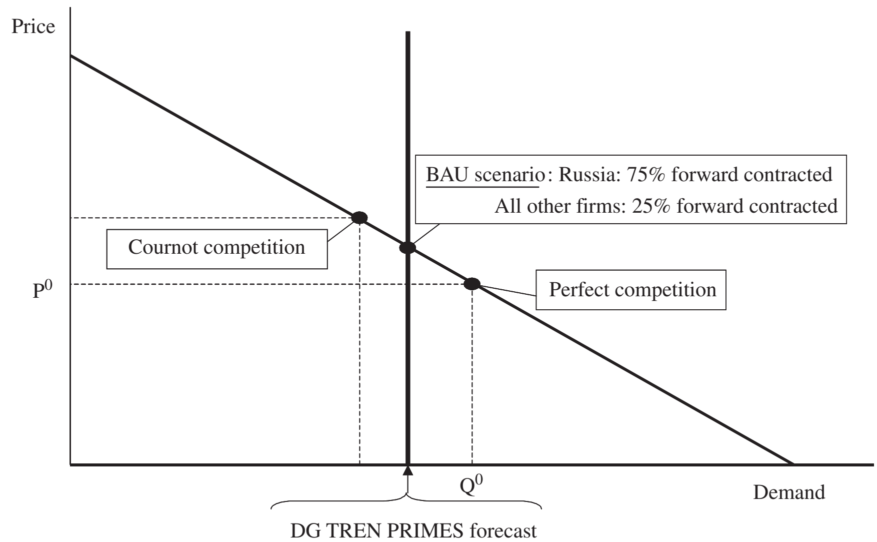

Fig. 3. Calibration of the GASTALE model.

3.2. Production costs assumptions

We assume that gas is simultaneously extracted from several fields that may have different long-run marginal extraction costs. Production capacity gives the yearly capacity of the fields that are exploited, which have different marginal costs. A profit-maximising producer who extracts from two or more fields extracts gas from a particular field until its marginal cost equals the marginal cost of the other fields, including opportunity costs of leaving gas in the ground. Thus, the marginal cost of producer f equals the marginal cost of its active fields. GASTALE aggregate over all active fields and derives a single production cost function per producer. The marginal cost functions are divided into two segments: one segment (designated by variable q_f), which is nonlinearly increasing for the first 90% of the export production capacity Q_f, following Golombek et al. (1995, 1998) and a second segment (designated by variable q_f^{peak}) for production in excess of 90% of capacity. In case of production below 90% capacity long-run marginal costs are assumed to increase, while they are assumed to be constant in the last 10%. The latter assumption is a simplification that enhances the numerical stability of the solution procedure, without loss of generality.

$$
\begin{aligned}
&CQ'_f(q_f) = A_f + B_f q_f + C_f \ln(1 - q_f/Q_f)\\
&\quad A_f, B_f > 0, C_f < 0, 0 \leqslant q_f \leqslant 0.9 \times Q_f\\
&CQ'_f(q_f^{\text{peak}}) = D_f\\
&\quad D_f > 0, 0 \leqslant q_f^{\text{peak}} \leqslant 0.1 \times Q_f
\end{aligned} \tag{1}
$$

Long-run marginal production costs are used here a proxy for opportunity costs of production. Using short-run costs of gas extraction alone would underestimate the full short-run costs, which should also include the present worth of foregone marginal revenues if the gas was instead extracted in a later year. These are more likely to be related to long run than short-run extraction costs, assuming that prices in the future are generally reflective of long-run marginal costs.

Table 2
Parameter values of the marginal production cost function

Producing country/region	A_f (€/kcm)	B_f (€/kcm^2)	C_f (€/kcm)	D_f (€/kcm)
Algeria	13	0	−5	29.51
Azerbaijan	10	0	−8	36.42
BENELUX	5	0	−12	44.63
DEDK	6	0	−12	45.63
Egypt	15	0	−5	31.51
Iran, Iraq	7	0	−5	23.51
Libya	12	0	−5	28.51
Nigeria	15	0	−5	31.51
Norway	12	0.10	−8	62.37
Qatar	10	0	−5	26.51
Russia	5	0.02	−4	28.05
UKIE	20	0	−10	53.03

Source: Based on data from OME (2007) and Van Oostvoorn (2003).

The anticipated marginal costs (CQ') over the period 2005–2030 are taken as input for deriving the parameters A_f, and C_f (OME, 2007), where the *average* marginal costs for the first 90% of capacity correspond with these marginal costs. The marginal costs increase over time for Norway and Russia, which leads to nonnegative values of B_f. Table 2 shows the assumed parameter values of the marginal cost functions.

3.3. Transmission assumptions

The model allows for transshipment, e.g., from Russia to CENTRAL and then from CENTRAL to DEDK. Russia can also transport directly to the DEDK, although the capacity is low. The long-run marginal costs are estimated using a simple formula: $0.012 \times$ distance on-shore $+ 0.021 \times$ distance off-shore (North and Baltic seas) $+ 0.027 \times$ distance off-shore (Black and Mediterranean seas) where cost is in €/kcm[5] and distance is in km, reflecting that on-shore transport is cheapest, whereas off-shore transport in the Black and Mediterranean seas is more expensive due to the greater depth of these seas than in the North and Baltic seas.

In order to bring the model more in line with the expected political reality, no new capacity beyond currently planned additions is permitted to be added to four particular pipeline corridors in the BAU scenario, otherwise the capacity expansion would lead to unrealistic high investments in those locations. These include the corridor between Norway and the UKIE (NW_U) and three South–North corridors, namely the corridors between Algeria and IBERIA (A_IB), Algeria and ITALP (A_IT), and Libya and ITALP (L_IT). For instance, allowing unlimited pipeline expansion capability between Norway and the UK leads to a model outcome in which all Norwegian gas would be shipped to the UK and transported to mainland Europe from the UK onwards. This is unlikely to happen; our imposition of a limit on the total possible pipeline capacity in that corridor diverts investments in pipelines from Norway to DEDK and BENELUX. Meanwhile, an unlimited pipeline expansion capability between North Africa and South Europe would yield an expansion of pipeline capacity far beyond existing plans. Restricting the total possible pipeline capacity there results in more LNG liquefaction capacity (which is relatively more expensive) in order to still ship gas to Europe. Such a politically desirable (and more realistic) diversification of investments would not be the result of a model that focuses solely on market economics. An approach with bargaining among producers and transit countries is a theoretically attractive way to represent such political dynamics (see, e.g., Hubert and Ikonnikova, 2004; Von Hirschhausen et al., 2005). Such bargaining/cooperative game models can be used to explore the economic rationale for large-scale pipeline investment decisions. An equilibrium model such as GASTALE can be used to estimate the market outcomes and income distribution consequences of alternative agreements and investments, which are required inputs for such analyses.

Some pipeline plans are motivated by political considerations rather than the market economic principles embodied in GASTALE. Thereupon, two pipelines are fixed in the model because the political decision to build and maintain them has already been taken, namely the link between Russia to Turkey (R_T, Blue stream) and the link between Russia and DEDK (R_D, Baltic line). All other pipelines connections in the model are expanded endogenously based on their economics, e.g., bringing their level of congestion back to acceptable levels (see also Fig. 2 and Section 1).

[5]kcm = thousand cubic meter.

Finally, due to geographic, political and strategic reasons it is unlikely that Russia is going to transport LNG to Europe on a large scale. However, in order to show the economic potential of such shipments, the model allows Russia to liquefy gas for export to the EU, but subject to a very modest upper limit.

3.4. Investment cost assumptions

In GASTALE, we also make assumptions concerning the cost of incremental capacity. Depreciation and interest rates are important factors in determining investment costs and establishing whether an investment is worthwhile. Depreciation of capital is assumed to be 3.3% per year for pipelines, liquefaction, and regasification (lifetime of 30 years), and 1.7% for storage (lifetime of 60 years). The real interest rate is set at 10% per year. This interest rate is commonly used for private sector investments (NCEDR, 2005). A higher interest rate would make investments more expensive, and as a result a lower rate of investment could be expected.

3.5. BAU results

To illustrate the outcome in the BAU scenario, average wholesale prices are presented in Fig. 4. The most remarkable outcome is that prices in 2010 are lower than in 2005 and then increase from 2015 onwards, stabilising by 2030. A reason for this price drop is new investments in 2010, most notably by a pipeline expansion of 168 bcm[6] within the EU (see Table 3), which can improve competition considerably, as some previously isolated markets will be opened to multiple producers. Such an efficiency improvement is no longer possible from 2015 onwards, leading to rising prices. It is remarkable to find the lowest prices in Turkey in all scenarios and all years, demonstrating Turkey's proximity to gas sources, which in turn indicates that Turkey may become an important gas transit hub on the "East–West route". The 2020 BAU scenario shows, for instance, an export of 31 bcm via Turkey to BALKAN and 10 bcm to ITALP, and additionally 52% is imported from Iran and Iraq, 30% from Caspian, and 18% from Russia to serve a Turkish demand of 42 bcm.

Studying the price developments in the 10 consuming regions also leads to a number of insights. Two factors influence the prices, namely the distance from major producers and the number of producers that can access the market. These factors are most favourable in Turkey so its prices are the lowest, followed by BALKAN. The Eastern European countries (BALTIC and CENTRAL), having few alternatives other than Russian production, face the highest prices. The next highest prices occur in France, which is a result of its lack of substantial production capacity or neighbouring producers. The prices in UKIE are the highest in 2005 due to very high peak

[6]bcm = billion cubic meter.

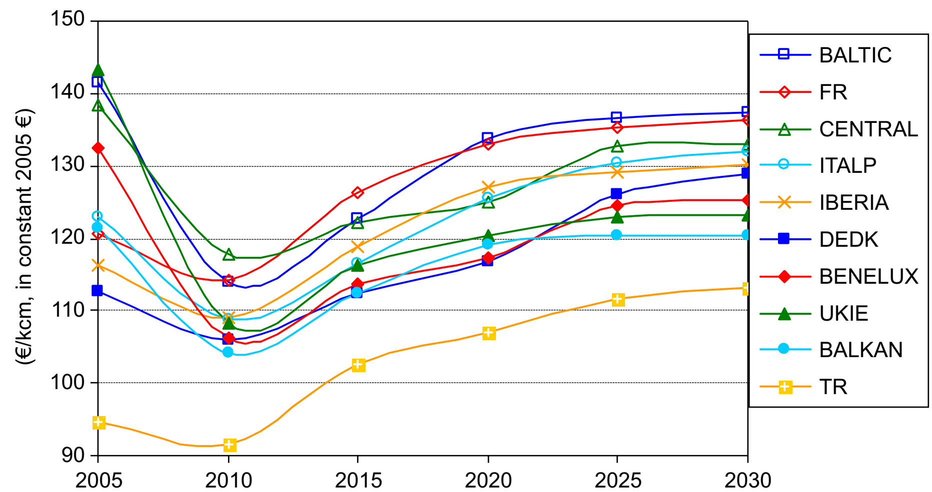

Fig. 4. Average wholesale prices in the BAU scenario, weighted-averages across seasons.

demand. However, in the long run, UKIE prices are relatively low and only slightly higher than the BALKAN prices. The reason for this price relief in UKIE is that it is economically attractive to remove critical bottlenecks to that region as soon as possible. The BAU solution suggests adding 5.6 bcm of storage and 43.2 bcm of regasification facilities by 2010 (Table 3).

4. Results of policy runs

4.1. Scenarios

Section 3 specified a realistic BAU scenario that is consistent with a well-known official energy scenario (EU, 2004). Below we define a number of other scenarios that analyse the impacts of changes in key assumptions in the model. These are assumptions that, if changed, have a large impact on the structure and capacity needs regarding gas transport infrastructure in Europe, i.e., locations and capacities of structural elements such as LNG handling facilities, storage, and pipelines.

We can address at the same time questions that arise from the BAU scenario results. Note that each alternative scenario must not only have a coherent justification with consistent drivers but it must also be consistently translated into changes in the model specifications and parameters.

Next we propose short "storylines" that underpin four alternative scenarios, taking the BAU scenario as the starting point. The main driving factors of these scenarios are possible external developments that are likely to highly influence the structure and capacities of gas infrastructure in the long term and therefore the optimal gas corridors.

4.1.1. Low demand scenario

There are several recent (compared with 2002–2003 expectations) trends that can change long-run expectations concerning the development of gas demand in Europe. These are:

- Continuation of the current high oil prices and therefore high gas prices at the EU borders. High energy expenditures would lead to relatively low GDP growth rates, and low rates of investment by industries that can use both fuels would result.
- A possible nuclear renaissance, increased use of electricity from renewable sources, and coal gasification power plants. The low demand projections in OME (2007) will be used to specify this scenario. It is clear that gas demand by the power sector will be less in the longer term in this scenario compared with BAU.
- Since the level of demand has already decreased considerably, gas will be more easily available, thereby making substitutions more likely. Therefore, the demand elasticity is increased by an arbitrary but minor 20%, to reflect somewhat easier substitution possibilities.
- There is also uncertainty about LNG delivery because deliveries can be augmented or cancelled at the last minute thanks to the flexibility of this means of gas transport. In this scenario, we assume a reduction of 20% (relative to BAU levels) of the exogenous capacity of exports to the EU from Egypt, Nigeria, and Qatar over the period 2005–2030, while the production capacity of other producers are the same as the BAU levels. Ideally, LNG flows would be modelled in a world LNG trade model to study the effects, e.g., EMF (2007). However, in the long-run time span of the model (25 years), an average decrease of 20% below BAU levels could be considered a considerable reduction in LNG supply. This reduction is a reasonable consequence of a less attractive EU market for LNG suppliers (stronger downstream competition for relatively smaller markets in EU, causing smaller revenues and profits) caused by these lower gas demands.

4.1.2. High demand scenario

Yet for a variety of other reasons, in the long run, it is plausible that other drivers will cause the demand for gas to increase beyond the levels assumed in the BAU scenario. From a supply security point of view, i.e., resilience against gas supply disruptions, the EU must be prepared for such a possibility. The drivers could be:

- Restoration of a period of lower oil and gas prices at the EU borders. So gas prices after a few years of turmoil and high prices in the world might decline to levels that were common a few years ago. Due to lower energy expenditure, relatively high GDP growth rates and confidence in investment in gas-using technologies result.
- Increased demand because of (a) environmental goals such as meeting the Kyoto agreement and other targets for greenhouse gas emission reductions, combined with (b) reduced supply from alternative power sources, such as renewables and nuclear, compared with the BAU case, and (c) an increased demand for electricity and gas for space conditioning. Resistance to the nuclear option continues, leading to decommissioning of existing nuclear power plants. The high demand projections by OME (2007) are used to formulate this scenario.
- Since the level of demand has already increased considerably, the availability of spare production capacity is reduced, leading to somewhat lower substitution possibilities. Therefore, the demand elasticity is decreased by an arbitrary but minor 20%, to reflect somewhat more difficult substitution possibilities.
- Other changes are an increase of 20% as compared with BAU levels of the exogenous capacity of export to the EU in Egypt, Nigeria, and Qatar over the period 2005–2030, while the production capacity of other producers are the same as the BAU levels. This increase is a consequence of a more attractive EU market for LNG suppliers, due to higher profits for suppliers to EU, caused by the higher gas demand by consumers. This increase is required because GASTALE does not model an international market for LNG and would otherwise ignore this effect.

4.1.3. Deferral of investment in infrastructure scenario (deferral scenario)

The past decades have been characterised by vertically integrated companies and long-term contracting of gas; this stability facilitated the development of (and investments in) required gas transport and related infrastructure facilities. However, the EU Gas Directive (2003/55/EC) has promoted vertical disintegration (“unbundling”) and has discouraged long-term contracts because they are perceived to block out competition. In the present uncertain market environment, such investments are often postponed, especially among EU countries, because of doubts about the existence of long-term markets for the gas they would provide. To understand the influence of postponed investments in long distance pipelines, storage capacity, and gas corridors, a scenario is developed in which investments are delayed. This implies the following assumptions:

- Perceived market risks inflate the cost of capital, because banks prefer to loan to facilities with long term, fixed contracts. As a result, investment delays occur in all pipeline, LNG, and storage projects. We simulate this effect by assuming that investment costs are considerably higher, namely a price increase of 50% above long-run marginal costs per pipeline and LNG facility and a price increase of 25% above long-run marginal costs per storage facility, as compared with, respectively 20% and 10% in the BAU case.
- It is very difficult to build LNG regasification terminals, leading to low LNG investments as well. The “not-in-my-back-yard” syndrome can be illustrated by the Italian case, where 15 LNG terminals are proposed, while only one is currently being built, namely off-shore near Venice. Off-shore LNG terminals, though perhaps less objectionable to the public, are typically more expensive. Therefore, we also assume higher LNG investment costs, namely a price increase of 50% above long-run marginal costs as for other investments.

4.1.4. Short-term supply security scenario (disruption cases)

To test the resilience/robustness of the solutions in the short term (2010 situation) and in the longer term (2020), it is useful to simulate how a sudden unexpected supply disruption is coped with in the BAU scenario via operational strategies, namely rerouting of imports and use of spare storage capacity. The ability to use these strategies to prevent very high prices is a measure of the resilience and adaptability of the system. The results are analysed to identify and assess whether additional infrastructure investments are necessary to meet a reasonable level of supply security against high gas prices for EU consumers. This situation is especially relevant since January 2006 when Gazprom interrupted its gas supply to the Ukraine for a few days due to a stalemate in pricing negotiations.[7] In model terms, a “disruption” is defined by a complete pipeline closure for particular pipelines between EU and non-EU countries for an entire year. In particular, pipeline availability in 2010 or/and 2020 is reduced for three sets of routes in three separate sets of simulations: Algeria–IBERIA and Algeria–ITALP; Azerbaijan–Turkey and Iran/Iraq–Turkey; and Russia–CENTRAL, respectively.

4.2. Comparison of prices and demands

We first compare the BAU with the low and demand scenarios, as well as the deferral scenario, while the

[7] For a policy discussion on the issue of supply disruption see for instance Correljé and van der Linde (2006).

disruption scenario is considered separately later. In order to illustrate the scenarios, Fig. 5 presents total quantity demanded in the four scenarios. The figure illustrates how the low and high gas demand scenarios compare to the demand in the BAU scenario.

Fig. 6 presents the total (quantity-weighted) average prices in the EU. Prices in the low demand scenario are lower than the BAU prices, while prices in the high demand scenario are higher. Prices are the highest in the deferral scenario. The prices exhibit a high sensitivity to the demand and deferral assumptions.

4.3. Realised transport and storage

The investment and gas flow patterns are summarised in Tables 3 and 4, respectively, where the seasonal flows are aggregated into yearly totals. As a consequence, the actual usage of pipelines shown is often below capacity, even where new capacity is added, due to partial use during the low demand season. Investments are lower and/or later in the deferral scenario as compared with the BAU scenario. This result holds for all four types of investments, namely expansion of storage, pipelines, liquefaction, and regasification capacity. This logically follows from the increase in investment costs we assumed in the deferral case.

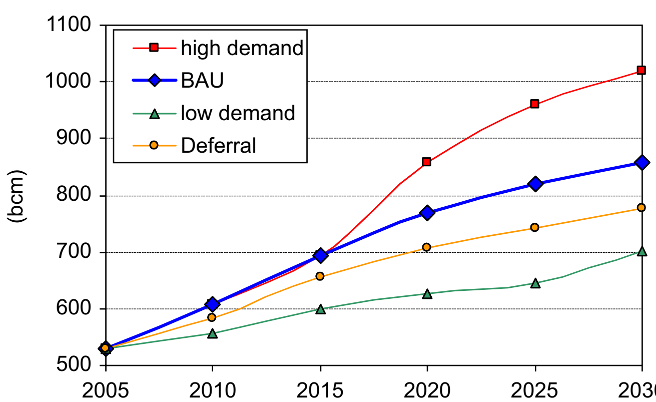

Fig. 5. Total annual demand for gas in the EU.

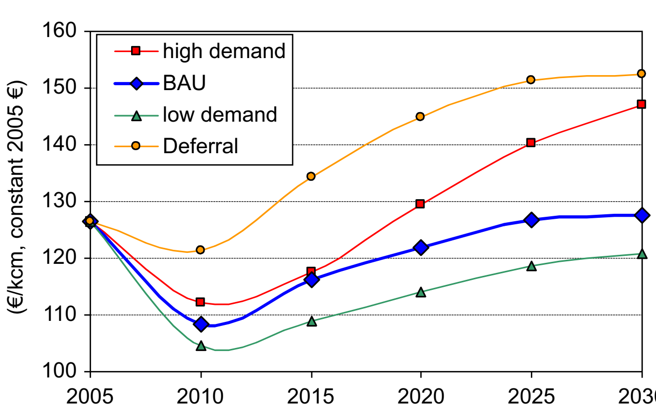

Fig. 6. Total average gas prices in the EU, weighted-averages across seasons and countries.

The following insights can be derived from Table 4. Storage capacity is gradually increasing over time, although the amount of storage usage in the four policy scenarios varies. In 2010, due to delays in corridor investment, the amount of storage is the highest in the deferral scenario. This shows that the *usage* of storage facilities goes up in a situation with tighter gas corridors, since storage of summer gas and its resale in the winter can substitute for scarce winter transportation capacity. In 2015, the amount of storage is the highest in the BAU scenario, but not much different from the high demand and deferral scenario. From 2020 onwards the amount of storage is the highest in the high demand scenario due to the rapidly increasing demand. Storage capacity is fully used in the market from 2015 onwards in the high demand and deferral scenario and from 2020 onwards in the low demand scenario. Meanwhile in early years there is spare capacity, indicating that there is spare storage capacity in 2005; when storage constraints are not binding, gas prices in different seasons differ only by the assumed storage operating costs.

The term "flexibility" or "swing supply" can be defined as the difference between the volumes supplied to consumers in the medium/high demand seasons (October–March) and low demand season (April–September) (last set of rows in Table 4). Swing supply in Europe can come either from increased production and imports, or from storage. Table 3 shows that over time, storage increases its dominance as the main source of swing supply. Storage is an important instrument for managing swing production and arbitraging between low summer prices and high winter prices. Alternatively, excess transport capacity can be constructed that is only used for transport during medium and high demand seasons. However, the last rows of Table 4 show that pipeline capacity is not constructed to provide swing supplies, because the swing supplies from production and imports become less important over time.

As an extreme case, in the high demand scenario, swing supply in 2030 is nearly fully provided by storage with only a very small portion made up by LNG. In the early years, Russia is an important swing supplier, being the producer that increases output the most in the colder months. But in later years, it entirely gives up the role of swing producer in the high demand and the deferral scenario. In the deferral scenario, a small amount of swing supply (4.6 bcm) is provided by Norwegian production in 2030. In the BAU scenario in 2030, flexibility is provided by pipelines from Russia (8.7 bcm), Norway (6.3 bcm) other countries (5.9 bcm), and LNG (15.9 bcm) with storage accounting for the remaining 77% of flexibility. The contribution of storage to swing supply in 2030 is lowest in the low demand scenario with a share of 64%. In addition to storage, Russian (14.1 bcm), Norwegian (9.7 bcm), other pipelines (9.3 bcm), and LNG (23.2 bcm) provide flexibility in 2030 in that scenario.

Pipelines remain the dominant mode of transport in the future, providing the following percentages of total

Table 3
Detailed overview of investments (bcm/year)

	High demand scenario					BAU scenario					Low demand scenario					Deferral scenario				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Storage																				
BALKAN-TR	0.0	0.7	3.2	5.2	4.3	0.0	0.3	2.1	2.6	2.9	0.0	0.0	1.3	2.4	2.6	0.0	0.0	3.0	2.5	2.9
BALTIC-CENTRAL-ITALP	0.1	2.6	7.7	8.6	5.4	0.0	2.6	4.0	3.9	3.7	0.0	0.8	2.6	1.2	5.0	0.0	3.9	2.5	5.5	4.2
BENELUX-DEDK-FR	0.0	5.9	16.8	10.3	10.5	0.0	7.1	13.9	8.3	6.3	0.0	0.4	9.8	7.2	9.0	0.0	4.0	17.9	4.4	5.2
UKIE	7.0	8.7	11.3	5.4	5.5	5.6	11.3	7.4	3.5	3.2	3.8	5.7	6.3	1.2	3.4	6.5	9.3	5.9	4.4	3.0
Total new investments	7.1	17.9	39.0	29.5	25.7	5.6	21.4	27.4	18.2	16.1	3.8	6.9	20.0	12.0	20.0	6.5	17.3	29.3	16.8	15.3
Pipelines																				
South–North[a]	32.7	39.0	28.7	18.3	17.9	39.2	37.6	25.1	18.6	17.9	35.1	36.7	28.4	18.8	17.9	29.0	47.0	25.2	17.9	17.9
North–South[a]	13.5	7.3	24.2	18.3	19.2	15.9	14.7	16.3	18.3	18.8	14.4	9.9	11.8	15.8	17.5	11.8	18.2	16.3	18.3	18.8
East–West	11.4	21.1	108.7	102.9	85.1	10.0	24.7	60.5	58.1	60.4	6.7	6.2	18.1	21.7	52.0	6.1	3.0	12.1	29.7	42.8
Within EU	178.2	98.5	134.6	99.6	81.1	167.9	78.6	82.6	68.6	63.3	147.4	65.2	52.9	64.4	68.2	102.7	48.6	37.1	31.7	38.6
Total new investments	235.8	166.0	296.2	239.1	203.3	233.1	155.6	184.4	163.6	160.3	203.7	118.0	111.3	120.7	155.6	149.7	116.8	90.6	97.6	118.1
Liquefaction																				
Algeria-Libya	0.5	1.7	15.7	19.1	21.9	0.1	1.9	16.2	18.7	21.9	0.3	1.3	5.3	15.9	19.1	0.8	0.0	5.0	16.8	19.1
Egypt	23.1	10.1	8.1	8.6	9.1	19.2	8.3	6.7	7.2	7.6	14.7	4.9	7.1	5.8	6.1	7.7	11.3	9.4	7.8	6.7
Nigeria-Qatar	41.4	32.1	39.5	33.1	35.2	34.2	30.9	25.7	27.6	29.4	19.4	22.3	19.3	21.1	24.2	6.7	33.5	33.6	29.0	27.7
Russia[a]	8.5	1.7	1.7	1.7	1.7	8.5	1.7	1.7	1.7	1.7	8.5	1.7	1.7	1.7	1.7	0.0	1.7	7.5	1.7	1.7
Total new investments	73.5	45.7	64.9	62.4	67.9	62.0	42.8	50.3	55.1	60.5	42.9	30.2	33.3	44.4	51.0	15.2	46.5	55.4	55.3	55.2
Regasification																				
BALKAN-ITALP	13.8	16.4	23.7	14.8	17.9	11.2	12.8	18.4	13.2	14.6	7.5	7.5	15.5	14.0	12.1	1.4	14.6	18.0	15.2	17.6
BENELUX-FR	13.3	12.7	14.1	17.5	16.6	10.0	12.1	14.1	13.2	12.9	5.0	6.2	13.4	10.9	13.8	0.4	7.8	23.5	18.2	13.9
IBERIA-TR	0.0	0.0	14.6	21.6	18.5	0.0	0.0	5.2	8.1	11.0	0.0	0.0	0.2	7.9	10.7	0.0	0.0	2.7	6.2	3.8
UKIE	46.3	7.8	11.2	12.1	16.3	43.2	9.4	10.7	19.5	22.0	36.3	5.7	3.9	8.8	14.5	23.5	9.9	11.3	14.2	18.5
Total new investments	73.4	36.9	63.6	66.0	69.3	64.4	34.3	48.4	54.0	60.5	48.8	19.4	33.0	41.6	51.0	25.2	32.3	55.4	53.8	53.9

[a]Pipeline connections from Algeria to IBERIA cannot expand beyond 36 bcm, Algeria to ITALP cannot expand beyond 47 bcm, Libya to ITALP cannot expand beyond 24 bcm, Norway to UKIE cannot expand beyond 45 bcm, while Russian liquefaction capacity cannot expand beyond 10 bcm.

Table 4
Total use and operational capacity for storage, pipelines, liquefaction and regasification, and flexibility (bcm/year)

	High demand scenario					BAU scenario					Low demand scenario					Deferral scenario				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Storage																				
Total stored	58.2	84.2	116.2	136.0	150.4	55.6	86.2	106.5	115.9	122.4	48.5	65.9	84.3	89.3	101.9	66.8	82.9	105.3	113.4	119.3
Storage capacity	72.3	84.2	116.2	136.0	150.4	70.7	86.2	106.5	115.9	122.4	68.9	70.1	84.3	89.3	101.9	71.6	82.9	105.3	113.4	119.3
Pipelines																				
Total transported	677.4	780.8	987.6	1087.0	1117.1	668.7	760.8	845.1	884.2	903.9	616.0	668.4	687.3	705.7	756.7	629.4	678.9	684.3	681.4	692.8
Pipeline capacity	851.6	889.7	1053.3	1124.2	1147.4	848.9	877.1	931.1	946.9	956.8	819.5	815.0	806.2	800.0	829.7	765.5	768.7	747.0	727.5	731.8
LNG																				
Total LNG transported	110.6	140.3	189.7	226.0	256.0	96.7	129.6	157.0	183.5	209.8	77.1	90.8	111.8	129.7	155.7	67.3	104.2	144.7	177.9	203.1
Liquefaction capacity	135.5	158.5	196.9	226.5	256.5	123.9	146.0	171.9	198.4	225.7	104.9	117.6	131.3	153.7	179.1	77.2	110.8	147.7	178.4	203.8
Regasification capacity	147.9	160.1	196.9	230.0	261.0	138.9	150.0	173.3	198.4	225.7	123.3	122.1	134.6	153.7	179.1	99.7	115.3	151.5	179.9	203.8
Flexibility[a]																				
RU-pipeline	38.3	20.6	11.2	0.0	0.0	41.3	20.8	15.8	8.7	8.7	48.8	37.6	28.6	18.5	14.1	28.0	12.6	1.2	0.0	0.0
NO-pipeline	9.9	8.2	5.1	4.4	0.0	11.0	10.5	7.5	6.3	6.3	12.3	11.6	10.7	11.3	9.7	9.5	8.8	4.9	4.4	4.6
Pipeline-other	10.6	8.5	2.9	0.8	0.0	11.7	8.9	4.4	5.5	5.9	13.4	11.0	12.8	12.5	9.3	9.4	7.1	1.2	1.5	1.7
LNG	24.8	18.2	7.2	0.4	0.2	27.1	16.3	14.9	14.8	15.9	27.7	26.6	19.4	24.0	23.2	9.9	6.6	3.0	0.4	0.6
Storage	58.2	84.2	116.2	136.0	150.4	55.6	86.2	106.5	115.9	122.4	48.5	65.9	84.3	89.3	101.9	66.8	82.9	105.3	113.4	119.3

[a]Flexibility is defined as the difference between the amount transported in the cold season (October–March) and the warm season (April–September).

transport in 2030: 83% (low demand scenario), 81% (high demand and BAU scenario) and 77% (deferral scenario). These percentages are lower than in the early years of the simulations, indicating that although LNG plays a minor role now, its relative importance is increasing. The variation among the four scenarios is accounted for by their capacity assumptions, where the exogenous capacity of export to the EU from Egypt, Qatar, and Nigeria is 20% higher in the high demand scenario, 20% lower in the low demand scenario, and unchanged in the BAU and deferral scenarios. This also explains why LNG investments are the lowest in the low demand scenario, while the other investments are the lowest in the deferral scenario; namely the LNG export capacity is somewhat reduced, implying a lower need for investment in LNG regasification facilities in Europe.

4.4. Investment patterns

Table 3 allows us to contrast investments in capacity within the EU (regasification, storage, and within-EU pipelines) to investments outside (liquefaction and pipelines connecting to non-EU countries). It shows that the within-EU investments in capacity (in bcm/year terms) constitute 56% (592 bcm), 52% (461 bcm), 51% (398 bcm), and 45% (259 bcm) of total capacity investment in the high demand, BAU, low demand and deferral scenarios, respectively. This clearly illustrates that delays in investments in the deferral scenario largely occur on the connections within the EU.

Comparing the investment expenditures between within-EU and outside-EU investments results in the conclusion that all policy scenarios follow the trend of the BAU scenario fairly closely. In the deferral case 30% of the investment costs are incurred within the EU and 70% of the investment costs outside the EU over the period 2005–2030. In other cases, the low demand investment costs within the EU increase to 38%, while they decrease to 26% in the high demand scenario.

Fig. 7 presents total investment costs by investment category for all years and scenarios. It reveals that the investment costs in the BAU and high demand scenario are nearly the same in 2010 and 2015. In 2010, there is somewhat more investment in LNG in the high demand scenarios, which is due to the assumed increase of exogenous capacity of export to the EU by 20%. The investments in the high demand scenario are considerably higher from the year 2020 onwards. This increase is especially pronounced for pipelines. Investment costs for the deferral and low demand scenarios are substantially lower, where the investment cost is lowest for the deferral demand scenario in 2010 and 2030. This is due to the delay in investments in the deferral case, where the demand is as high as in the BAU case, but this demand is not met due to the demand response caused by higher prices. Note, however, that the similar investment cost in the deferral scenario compared with the low demand scenario translates into much less capacity (Table 3), since investments are assumed to cost 2.5 times as much in the deferral scenario.

4.5. Disruption cases

Finally, the GASTALE model can also be used to address short-term policy questions. In order to gain insights into the effects of a gas supply disruption lasting a year, three additional cases have been simulated, namely a case where the gas pipeline transport from Algeria is disrupted (*Algerian case*); gas transport from Azerbaijan

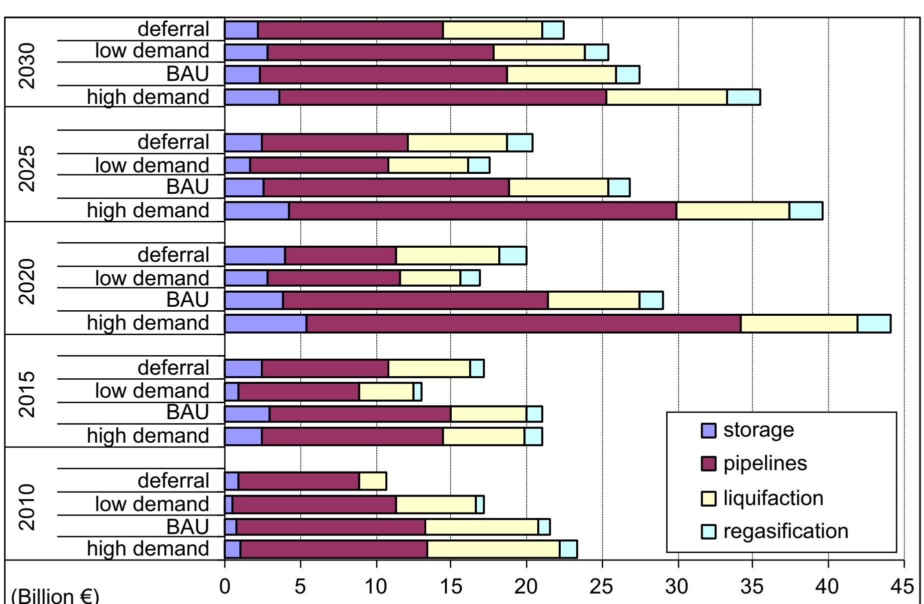

Fig. 7. Total yearly investment cost (in 2005 constant €).

and Iran and from Iraq to Turkey is disrupted (*Caspian case*); and gas transport through the Ukraine is disrupted (*Russian case*). These three cases are simulated for the years 2010 and 2020 and since this disruption cannot be anticipated by investments in such a short time period, investments are excluded as a possible response (thus, the BAU investment levels are imposed). However, operating responses are possible, in particular arbitrage between summer storage and winter extraction as well as rerouting of gas shipments.

Fig. 8 shows that in the Algerian case, prices increase the most in neighbouring regions, namely France, ITALP and IBERIA. This effect is more pronounced in 2020 than in 2010. The price effect in the Caspian case is greatest in Turkey, BALKAN and somewhat in CENTRAL, with the highest price increase in Turkey of nearly 20% in 2010 and an increase of 80% in 2020. The larger price increase in the later year reflects the fact that larger flows are supplied to Turkey and a disruption then leads to a need for larger volumes from alternative sources at the same time that gas resources become scarcer. In contrast, the increase is worse earlier on in the Russian case, in which CENTRAL prices increase by 108% in 2010 but only 53% in 2020. Here the argument works in the opposite direction, where the EU dependence on Russia is reduced to some extent over time as the result of the availability of more alternative gas corridors. The importance of Russian gas supplies is demonstrated by the result that in 2020, a disruption of the Ukrainian pipeline causes price increases to be observed all over EU except in Turkey and BALKAN, which largely depend on other suppliers. Hence, by the definition of supply security provided in Section 1, above, security is high in the Algerian and Caspian case in 2010 and moderate in the Russian case in 2010 and the Caspian case in 2020. Meanwhile supply security is critically low in the Russian case in 2010 and the Caspian case in 2010. Hence, the East–West corridor needs particular attention in order to guarantee supply security in the EU.

Fig. 9 shows the supply changes due to disruptions. First of all, it follows that 100% of the supplies of the Caspian are disrupted in the Caspian case, while 70% supplies from Algeria in the Algerian case and only 40–50% from Russia in the Russian case are interrupted. The lower percentages are due to the availability of alternatives, namely LNG for Algeria and other pipelines for Russia. In the Algerian case, additional production is provided by Norway and Russia, and in the Caspian case mainly by Russia, but also by Norway and long distance LNG. The most interesting case is the Russian case, in which long distance LNG mainly increases production, but surprisingly production in Azerbaijan and Iran goes down as well as in Russia. This is because of the increased transit of Russian gas through the Blue stream to reach the EU market, displacing some transit capacity from Central Asia.

A broadly similar analysis was also performed with an earlier version of GASTALE in the ENGAGED study (van Oostvoorn, 2003). In contrast to that study, we find a lower price response and more regional specific effects. Two reasons for the lower price response here is that the current version of GASTALE has storage facilities (and thus more flexibility) and allows producers to partially exercise market power, whereas the previous disruption study with GASTALE did not consider storage and assumed that producers fully exercised market power à la Cournot. The latter assumptions resulted in much greater price impacts of disruption.

5. Conclusions

This paper has presented the results of a dynamic game-theoretic model of the liberalised European gas market. A BAU scenario is specified in such a way as to mimic expected developments in the EU. This involves allowing the model in the BAU scenario to choose some investments based on economic fundamentals, while other decisions are constrained by political considerations. After establishing

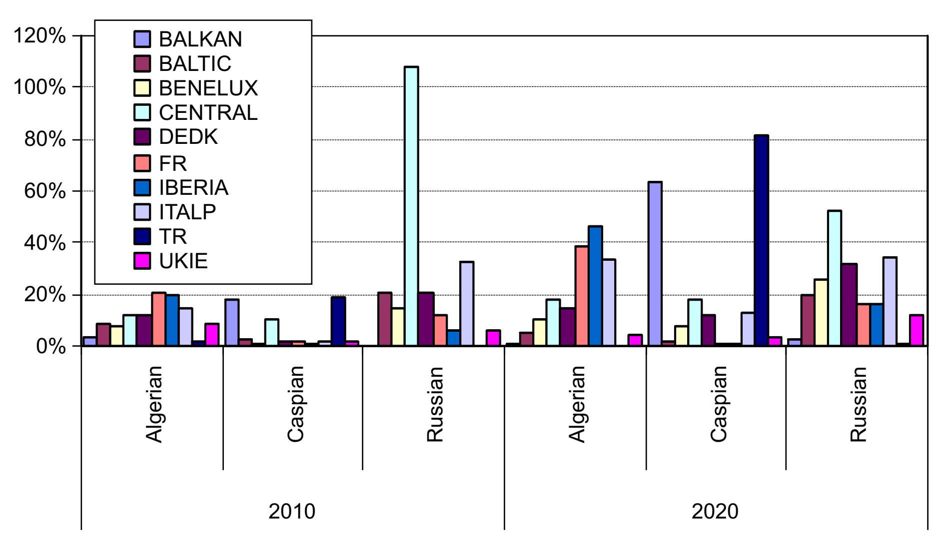

Fig. 8. Price increases relative to the BAU case due to a supply disruption via three routes in 2010 and 2020.

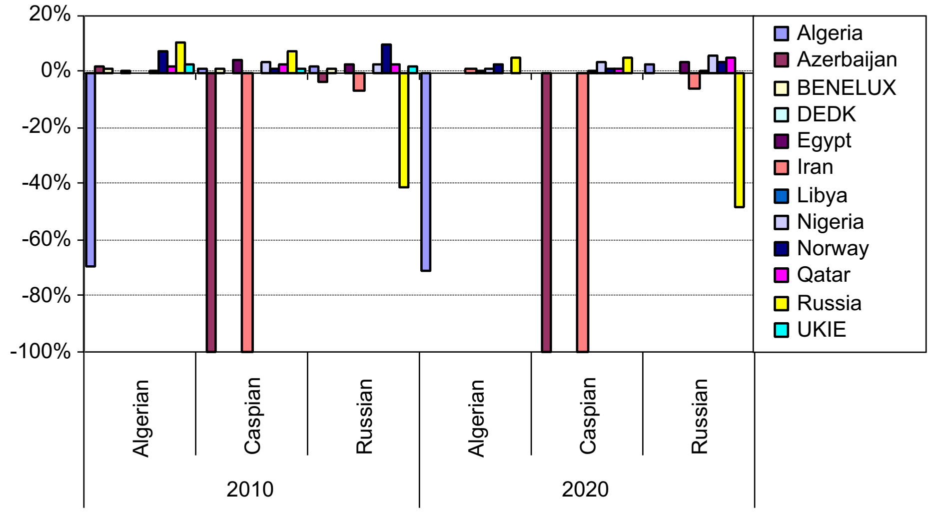

Fig. 9. Changes in supply relative to the BAU case due a supply disruption via three routes in 2010 and 2020.

the BAU scenario, four policy scenarios based on varying demand and investment deferrals are defined for the period 2005–2030. In addition, the BAU scenario is subjected to sudden transport interruptions in 2010 and 2020 to assess the vulnerability of the EU market to disruption.

On the basis of the model-based analysis, the main conclusions can be summarised as follows:

- Already considerable investments are needed by 2010. In the longer term, substantial investments are needed to build sufficient gas transport infrastructure capacity in Europe to connect the EU with its key suppliers.
- In the very short run through implementation of a number of what we call "smart" investments in EU intra-pipeline connections between the different EU countries, market access and competition in EU country markets will increase substantially.
- During the peak demand period (winter season), Iran and Russia are always (2005–2030) marginal (price setting) gas suppliers. Meanwhile, Nigeria, Qatar, Egypt, and Azerbaijan are sometimes marginal suppliers (2005, 2010) and sometimes reap rents (from 2015 onwards), while other suppliers mainly reap rents (i.e., produce at full export capacity to EU). Over the whole year, out of 12 producers, only DEDK always produces at maximum capacity in all scenarios; other countries that are occasionally at maximum capacity all year include Libya (from 2010 onwards in the BAU, high demand and deferral scenarios), BENELUX (from 2015 onwards in all scenarios), and UKIE (from 2020 onwards in the BAU, high demand and deferral scenarios). In the BAU and deferral scenarios, all other eight producers are always marginal producers, at least during low demand (summer season). In contrast, in the low demand scenario, all producers except DEDK and BENELUX are always marginal producers, whereas by 2030 in the high demand scenario by 2030, only Norway remains a marginal producer.
- LNG capacity will expand at a high pace. Yet despite the impressive growth of LNG terminal capacity, pipelines are expected to stay the dominant means of gas supply/transport in Europe in the future. In 2030 about 20% of total supplies to EU are transported in the form of LNG, and 80% via pipelines.
- Lower and higher demand scenarios ($\pm 20\%$) lead to lower and higher investments ($\pm 30\%$), respectively, and lower and higher border supply prices ($\pm 10\%$), respectively.
- Impacts of "deferral of investments" in gas infrastructure drives up gas prices ($+25\%$) in the next decade and moreover leads to a "lower resilience" to interruptions in gas supply and less supply security for consumer countries.
- Storage comes forward as the best option for arbitrage between summer and winter demand volumes, whereas LNG is the second best option.
- With hindsight, in the past some investment decisions for gas transport projects have not always been based on economics. In particular, certain pipeline projects that are imposed exogenously upon the model solution would not have been selected by model if treated instead as endogenous variables.

We elaborate upon several of these below.

Price differences among countries depend on two major factors, namely (1) the distance from main suppliers and (2) the impact of strategic behaviour of Russia, the largest producer. For instance, prices in France are high due to factor (1), while the prices in the Baltic countries are high due to factor (2) from 2015 onwards as their dependency on Russia continues. Prices are the lowest in Turkey, due to good access to several nearby producers, namely Russia, Azerbaijan and Iran, making Turkey an important transit hub to the EU. For this reason, flows never occur from the EU towards Turkey. Prices in the low demand scenario are lower than the BAU prices, while prices in the high demand and deferral scenario are higher than the BAU prices. By assumption, investments of all four types are either lower or later in the deferral scenario as compared with the BAU scenario; tighter capacities yield appreciably higher gas prices as a consequence.

The disruption cases, in which pipeline capacity through particular countries bordering Europe is greatly restricted for a full year, causes large increases in prices in countries near to the point of import. The price impact is higher for disruption of imports from Algeria and Azerbaijan/Iran in 2020 due to higher gas flows from those countries in that year, while the price effect is lower for CENTRAL in 2020, due to availability of alternative gas supplies. Disrupted supplies are mainly made up by Russia in the Algerian and Caspian case, with long distance LNG mainly providing the extra production in the Russian case, while supplies from Central Asia are reduced due to more Russian transit through Turkey.

Storage is an important instrument for managing swing production and arbitraging between low summer demand and high winter demand. Alternatively, excess transport capacity can be constructed for use only during medium and high demand periods. However, the latter option is rarely used in the model, indicating that storage is the more economic source of swing production in the long term.

Upper bounds have been placed upon the expansion of some pipeline connections in the BAU scenarios, while some pipeline connections that would not have been economically justified have been fixed in the model. We conclude that proposed pipeline connections of Russia to Germany (through the Baltic Sea), and Norway to France (not restricted in the analysis) are mainly constructed for political reasons, because they are substantially more expensive than existing alternative routes. The connection of Russia to Turkey (thought the Black Sea) is not an economic investment at present, but could become economic about one decade later. In contrast, pipeline connections of Norway to the UK and of Northern Africa to Spain and Italy are economically attractive and in the absence of political upper bounds on their capacities, the model would add capacity to those connections rather than switching to LNG if decisions concerning these pipelines were to be based on economic reasons alone.

Similarly, the ability of Russia to transport gas as LNG to EU is limited from above in the model. This is due to geographic, political, and strategic reasons reflecting the Russian government's policy that favours pipelines, despite the possible cost advantages of LNG. The fact that this constraint is also binding with a high shadow price indicates that Russian LNG exports are an attractive option from a purely economic point of view and could substitute for a portion of the existing pipeline network. The pipeline connection between Egypt and Turkey is also an economically attractive project. But because it is politically uncertain whether this connection will ever be realised, the model does not allow for its construction.

The analyses in this paper indicate that substantial investments in gas transport corridors are needed to provide for increased imports to the EU. These amount to about 20 billion € of yearly investment, of which about 50% is needed for pipelines, 40% for the LNG train and 10% for storage facilities. The pipeline connections between North Africa into EU, Norway into UK and Turkey into the Balkan countries need to be assigned as having the highest priority, as the investments will be undertaken in the BAU scenario by 2010. Around 2015, the Russia into Central Europe and Turkey into Italy pipeline projects should be given the next highest priority. By 2020, the corridors from Norway into Benelux and Russia into the Balkan countries should be given a third-order priority. Later in 2025, the Norway into Germany and the Russia into Baltic projects should be assigned a fourth-order priority. There are no other additional investments on pipelines identified by 2030 in the model solutions. The Balkan into Turkey and Norway into France connections have a low priority.

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