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NATGAS
A Model of the European Natural Gas Market[1]

The NATural GAS model is an integrated model of the European wholesale gas market providing long-run projections of supply, transport, storage and consumption patterns in the model region, aggregated in 5-year periods, distinguishing two seasons (winter and summer). Model results include levels of investment in the various branches, output and consumption, depletion of reserves and price levels. The NATGAS model computes long-term effects of policy measures on future gas production and gas prices in Europe. NATGAS is an equilibrium model describing behaviour of gas producers, investors in infrastructure (pipeline, LNG capacity, as well as storage), traders and consumers. NATGAS covers the main European demand regions, including the United Kingdom, Germany, the Netherlands and Italy. Moreover, it covers the main origins of supply on the European market, such as Russia, Norway, Algeria, the Netherlands, the United Kingdom and LNG. In this memorandum, we first discuss the theoretical background as well as the model specifications. Afterwards, we describe the data we used, present some results and assess validity by computing sensitivities and comparing with current developments.

[1] This memorandum is written as part of the project on Dutch gas-depletion policies (see Mulder and Zwart (2006a)). The authors of this memorandum benefited from discussions with representatives of the gas industry, TNO-NITG and government as well as a number of external and internal colleagues, in particular Rob Aalbers (SEO) and Cees Withagen (UvT) and seminar participants at the 2005 IAEE Conference in Bergen. We also benefited from earlier work on gas modelling at CPB by Jeroen de Joode and Mark Lijesen. Of course, the usual disclaimer applies.

1 Introduction

The European natural gas market is undergoing profound changes as a result of a number of factors. Since the late 1990s, the market has been moving towards an organisational structure relying on the principle of competition between market participants. This change of the market system coincides with technological developments, not only driving down costs of production and exploration, but also opening the way to economic long distance transport of gas in liquefied form, so that more remote production centres gain importance. Another major development affecting the European gas market is the gradual depletion of gas resources in Europe itself, which will necessarily force European countries to adjust focus to new sources of gas outside the EU.

These developments create a shift of paradigm in the European gas markets that will take place during the coming decades. In the light of these changes, it is of importance to reconsider policies that were adopted in the pre-liberalisation gas era, in order to test them for robustness under the new market circumstances. One of the approaches to aid such policy analysis is to develop a computable equilibrium model, based on theoretical concepts and gas market data, giving a framework of analysis that allows to consistently keep track of the available data and its interrelations. Such a model may be used to gain insight into the implications of policy decisions on behaviour of economically rational market agents.

Our objective is to develop a model of the long-term European gas market, NATGAS, describing investments and production decisions as well as consumption and transport patterns of gas. As a basis for describing the competitive interactions among market players we will start from a game theoretic approach, describing gas actors as profit maximising entities. The interaction of these market players leads to an equilibrium, the characteristics of which can be studied under various policy scenarios.

In this note we will first present some background information on essential features of the European gas market. Then we discuss the modelling approach to this market, which is in part based on received theory on electricity markets, and in addition incorporates ideas from resource economics. Next, we describe the NATGAS model in terms of objective functions (and constraints) for the individual market participants. We then discuss the input data of the model, and make an assessment of the models result by comparing with projections from other sources. Finally we explore some policy questions that may be addressed using the model.

2 European gas markets

A model of the gas market is a description of the real market, capturing its fundamental features. To construct an empirically well founded model, it is necessary to consider the essential characteristics of the European gas market. In this section we discuss these characteristics. We first focus on gas production, finiteness of resources and the expected developments in the demand-supply balance in Europe. We then discuss the seasonal characteristics of the market and the associated role of flexibility, and we conclude by outlining the developments in competitive restructuring of the market initiated by the EU.

2.1 Gas supplies and demand

One of the core characteristics of the gas market is the finiteness of resources. As countries endowed with natural gas resources explore these assets and bring them to production, the stock of gas declines. As a result after some period indigenous supplies are bound to dry up and external gas supplies are needed to meet domestic demand. As a consequence of this feature, gas supply-demand balances are subject to significant changes over longer time periods. For the Western European market, such changes now appear to be imminent. We here first briefly describe the historic evolution of gas supplies to Europe, then comment on the current prospects for indigenous European gas supplies and future reliance on more remote and new sources of gas.

The European natural gas market started its development in the 1960s, after the discovery of the giant Groningen gas field in the Netherlands. Importance of natural gas increased after the 1973 oil crisis, as Europe strived to decrease its dependence on the Middle East oil producing countries. This process was encouraged by the new gas finds in the North Sea, in the British, Norwegian, Dutch and Danish sectors of the continental shelf. Expansion of transport pipeline capacity towards, mainly, Russia and Algeria made these countries with their huge gas reserves into prominent suppliers of the European markets.[1]

Currently Russia has turned into leading gas supplier to Europe, with a market share of some 25% of a total European demand of around 500 billion cubic metres (bcm) of gas[2] in 2001, closely followed by the UK. The Netherlands provide about 15% of European gas, while Norway is fourth. Algeria’s exports to Europe are still restricted by cross-Mediterranean pipeline capacity of some 32 bcm per year.

[1] see e.g. Seeliger (2004) for an overview of historic developments

[2] or over 5000 TWh of energy

Remaining gas stocks of in particular the UK, and to a slightly lesser extent the Netherlands, are declining, however. Table 2.1 gives some key figures on remaining resources in the various regions. Reserves are the part of total resources that have been discovered and are recoverable and commercial. Reserves decline as gas is produced, but new reserves can be added by exploration and discovery of new fields, or by changes in technological or economic circumstances. Total remaining resources also include potential additional reserves (discovered but not technically or commercially producible) or undiscovered resources[3]. Clearly numbers for non-discovered resources are to some extent speculative, based on general geological data on the region, and we here use midpoint estimates of ranges typically reported. Reserve to production ratios are obtained by dividing current reserves by current annual production.

Table 2.1 Reserves and reserve-to-production ratios for selected countries[a]

	Proven reserves in bcm[b]	remaining resources	Reserve-to-production ratio (years)
Norway and Denmark	2467	5319	38
United Kingdom	905	1550	8
The Netherlands	1449	1815	20
Algeria	4500	5636	53
Russia	32960	77696	46
Iran	26000		>100
Qatar	14400		>100

[a] based on national government data, IEA and Seeliger (2004)

[b] billion cubic metres

Observing table 2.1 one finds that on a medium- to long-term time scale, the supply situation in Europe is to change drastically, as the resources in the UK and the Netherlands will be reaching exhaustion within the coming decades. On the demand side, on the other hand, European gas consumption is expected to keep on growing. The major driving factor of this growth is the expected increase in the share of gas-fired electricity plants in power production (see e.g. IEA (2005b)), of course depending on realised prices for gas. This divergence between supply and demand projections calls for additional sourcing of gas from outside the EU.

Currently, the gas market is still a regional market, as transport is dominated by gas flows through pipelines. Increasingly however, shipping of gas in liquid form (LNG) gains importance, as costs of gas liquefaction and LNG transport are falling. Although at present only a small fraction of global gas trade is in LNG, its importance will grow as supplies will become dependent on the huge gas reserves in areas more remote from the main consumption regions. As shipping of gas offers much greater flexibility than pipeline transport, one may expect an

[3] see e.g. DTI (2005) for terminology

increasingly global market for gas.

Future supplies to Europe will therefore rely not only on expansion of exports from existing (pipeline) suppliers (Norway, Russia, Algeria), but also on new imports from other countries, possibly in the form of LNG. Clearly this will involve significant investments in production and pipeline capacity as well as LNG import terminals over the coming decades.

2.2 Flexibility

Demand for gas varies significantly over time. For example, use of gas for heating by residential consumers creates a seasonal pattern, while also on a daily time scale differences in usage during day and night time can be observed. Part of these demand variations are predictable (e.g. more gas use in winter), while on top of this average foreseeable pattern, variations occur by exogenous factors (such as short-term temperature fluctuations). The size of demand fluctuations differs strongly over sectors (energy-intensive industry typically has a more constant demand for gas). As distributions of gas consumption over sectors vary considerably between different countries, swing in gas demand will also differ between countries. IEA (2002) discusses this in more detail.

To accommodate these patterns in consumption, supply of gas has to be flexible. In principle various mechanisms of creating flexibility exist.

- Changing output of production (production swing). Gas fields have different capabilities of changing output levels. In theory any gas field can temporarily be shut down (for example in low demand summer). It is, however, not always economic to produce far below maximum capacity. Some gas fields produce gas only as a by-product of oil (associated or wet gas), implying that actual output is driven by oil economics. For gas production in more remote areas, where capital costs of transport are high, capacity will be kept sufficiently low to ensure continuous utilisation in order to recover investment costs. In Europe, a large part of output variation is created by the onshore Dutch Groningen field. Also many fields on the UK Continental Shelf used to produce gas with relatively high swing.
- Variable imports. At the country level, a potential source of gas flexibility is imports. This requires that in low demand periods, import capacity is not fully used. Again, for long distances, such seasonal overcapacity may be uneconomic.
- Storage. A third option is to store gas produced in low demand periods and release it in high demand seasons. Storage of gas occurs in depleted gas fields and underground water reservoirs (aquifers), in salt caverns, or in liquefied form in LNG storage units. Furthermore the ability to operate the transport grid at different pressures allows for short term storage in the grid itself, known as line pack.

- Load management. Large gas users may be able to react to high gas prices by reducing their gas demand. This is in particular the case for electricity producers, who at any moment evaluate the choice whether to produce power by burning gas or to buy power from the electricity market.
- LNG. Import of liquefied natural gas does not rely on fixed pipelines. Therefore, shiploads of LNG can easily be redirected to differing markets depending on price movements. Although the majority of LNG contracts are still long term, the trade in spot LNG (LNG not traded in long term contracts) is growing rapidly.

2.3 Markets

The EU initiated the liberalisation of the European gas markets by issuing European Directives on the internal gas markets in 1998[4] and 2003[5]. The objective of these measures was to open the gas markets formerly dominated by state-owned monopolies to competition. Main mechanisms to achieve successful entry of new market players were the unbundling of these monopolies into separate transmission system operators and production and trading coapnies, creation of third-party access to the grids, as well as the gradual opening of end user markets to competition.

The liberalisation process is still in its infancy. Its current success differs over the various EU member states. The United Kingdom have been among the first in the world to liberalise their gas market, and now enjoy a competitive wholesale market with a liquid short term market place for wholesale gas contracts. Scarce network access capacity as well as storage capacity are allocated partly through auction mechanisms.

Elsewhere in Continental Europe, liquid short term markets have only recently started to develop, mainly in Belgium and the Netherlands, and to some extent in Italy. The Zeebrugge hub in Belgium derives its liquidity mainly from the presence of the interconnector that is used for daily arbitrage with the UK market. Liquidity on the recently initiated virtual market place in the Netherlands, called TTF (Title Transfer Facility) is growing fast DTe (2005).

The larger part of continental trade, however, is currently still dominated by long-term contracts. Most transport capacity, which is allocated on a first-come-first-serve basis, is mainly used by the former (unbundled) monopolists. The need for markets generating short term price signals will, however, increase as competition for the newly liberalised end users grows, and presumably one may expect a development similar to the development in electricity markets. There, within a few years, spot markets have been created, and a slow change towards market-based allocation of transmission capacity can be observed. It is precisely the larger

[4] EU Directive 98/30/EC

[5] EU Directive 2003/55/EC

players in the electricity market that are among the greatest initiators of market reform in the gas markets[6], as they are in a position to take advantage of the growing value of short-term flexibility in the gas markets.

In our modelling approach, we assume that the transition to efficient markets will continue. This means that markets will be accessible for domestic and foreign producers as well as independent traders alike. Infrastructure capacity, such as pipelines, storage and LNG import terminals, will either be allocated to independent players by an efficient auctioning procedure, or will be used competitively by independent owners. In either case (implied) prices for such capacity will reflect marginal usage costs in case of slack capacity, or a scarcity price rationing demand for these services when capacity is fully used. Investments will be such that a sufficient degree of shortage remains to make up for investment costs. In the next section we will elaborate further on modelling the gas market.

3 Modelling gas markets: theoretical considerations

The model we wish to develop supposes a market for gas with imperfect competition between production companies. In addition, gas transmission companies sell available transport capacity between regions to producers and traders at a price required for efficient rationing, while investing to expand capacity in the long term. Finally, independent operators invest in, and use, storage and LNG import capacity.

A key component of the model should be the intertemporality, that arises from three sources. The first source of intertemporal relationships between decisions is the scarcity value of gas: due to the finiteness of gas reserves, there is an opportunity cost to extracting gas that is related to future gas prices. Secondly, on a medium-term time scale, intertemporality arises due to investment decisions: current investment determines future capacities of production and transport equipment, and hence influences future production decisions. Finally, on a short time scale, intertemporal constraints are generated by the ability of market participants to store gas in (low-demand) summer, and use it in (high-demand) winter periods. In this section we discuss the implications of these issues for modelling the gas market, referring to the related literature.

[6] The first transactions on the newly launched spot gas exchanges in Belgium and the Netherlands were between major European electricity companies

3.1 Imperfect competition

Competition on the natural gas market is imperfect due to the existence of physical and legal restrictions on the supply side. To account for this we will describe behaviour of gas producers in terms of competition in quantities using a conjectural variations approach. According to this approach, producers optimise their individual profits using production and investment quantities as decision variables. In doing this they realise the impact their individual production and investment decisions will have on future prices. In the most stringent limit of zero conjectural variations, producers assume that in equilibrium, their own strategies do not impact their competitors' quantity choices. Increasing conjectured responses towards one gives results closer to perfectly competitive behaviour. In that case, producers would assume that any withholding of supplies on their part would be met by comensating supplies by their competitors. They would therefore operate as price takers.

Quantity competition may be considered a sensible approach to market behaviour in the gas market, especially in the long run, due to the capital intensiveness of the sector, the importance of capacity constraints in the market and the relatively high costs of storing gas. Furthermore, the large entry barriers due to the required licenses for gas exploration, and to some extent, the indivisibility of gas fields, reduces the scope for margin erosion due to new entry, and, hence, leaves the number of players per country relatively small.

The quantity competition assumption has been widely used more in strategic modelling of energy markets. Golombek et al. (1995, 1998) used a Cournot model of the European gas market to assess the impact of liberalisation on prices in Europe, while Mathiesen et al. (1987) compared Cournot, competitive and collusive equilibria in the European market. In Boots et al. (2004), the impact of traders in a conjectural variations production market is investigated. Strategic modelling in the electricity sector is much more widespread, and also here the Cournot model and variations thereof have received much attention. Early examples are Borenstein and Bushnell (1999) who study the Californian market , and Bergman and Andersson (1995) for the Swedish market, who both attempted to predict effects of the coming deregulation of electricity generation in those respective jurisdictions. Much attention has been devoted to modelling the effects of constraints in transport capacity in electricity markets. Smeers and Wei (1997) and Hobbs (2001) provide models where scarce transmission capacity, and its efficient rationing, are incorporated in the Cournot framework.

The basic conjectural variations model assumes that all producers make their quantity decisions simultaneously. This assumption need not be valid in the gas market for various reasons. Investment lead times differ widely for various countries. It is often argued that e.g. investment lead times for Russian production are much longer than those for other countries supplying Europe. As a result of this, one may argue that Russia has a first-mover advantage, as it can credibly commit to increase future output, influencing other producers' investment decisions. Competition on the gas market may therefore have Stackelberg characteristics.

A different reason for non-simultaneous producer decisions lies in the widespread government intervention in national gas markets (see Mulder and Zwart (2006b)). Government policies can restrict profit optimising behaviour, both on the upside and the downside. As an example, the Dutch government has implemented a production cap on production from the Groningen field.

We incorporate such characterisitics in the model by allowing for exogenous constraints on production. Stackelberg behaviour by Russia would then be modelled as a minimum production constraint. We do not solve for the optimum level (this would lead to large computational problems), but rather base these levels on projections of actual production.

Equilibrium conditions for such models consist of a set of first order conditions, corresponding with the individual profit maximization of all agents represented by the model (e.g. producers, consumers, transmission system operators, traders, operators of storage facilities, etc), subject to a set of constraints (e.g. production does not exceed capacity). As a simple example to illustrate the mathematical structure of the model equations, consider a single monopolist (not facing any resource constraints) optimising its profit - revenues minus costs - under the constraint that its production x is positive, but cannot exceed production capacity C. Given a price, which depends on supply as $P(x)$, and production costs $c(x)$, the monopolist solves

$$\max\left(xP(x) - c(x)\right) \text{ subject to } x \geq 0,\, x \leq C.$$

Introducing a dual variable μ for the capacity constraint, the first order conditions take the form

$$\begin{aligned} &x \geq 0, \quad && xP'(x) + P - c'(x) - \mu \leq 0, \quad && x \cdot \left(xP'(x) + P - c'(x) - \mu\right) = 0, \\ &\mu \geq 0, && x - C \leq 0, && \mu \cdot (x - C) = 0. \end{aligned} \tag{3.1}$$

Such sets of equations are known as complementarity conditions, and this type of mathematical problem is known under the name of (mixed) complementarity problem (MCP). The use and solution of MCPs has been extensively studied, for instance in the context of electricity models (see, for an overview, Hobbs and Helman (2004)). Large MCPs (containing thousands of variables) can be solved efficiently using the PATH algorithm which we will apply within the modelling environment GAMS.

3.2 Investment and finite resources: a dynamic game

A long-run strategic model of the gas market necessarily is a dynamic game, as market players repeatedly interact in the market. Furthermore, decisions taken in one period affect behaviour in the next. Current investments in production or transmission assets enable market players to expand production or trade in future periods. Moreover, in a market such as the gas market, where resources are finite, gas currently extracted reduces total resources and therefore limits future production. Therefore, one needs to devise a model that covers multiple periods, and allows for temporal interdependencies of decisions.

In general, dynamic games may involve strategies that are functions of the whole history of the game. Players would, in that case, condition their actions on past observed behaviour of their competitors. Such information structures are relevant for explaining cartel behaviour, which involves so-called punishment strategies that cartels employ to prevent their members from deviating from the coordinated strategy.

Such ‘closed-loop’ strategies typically are hard to compute in realistic examples (and moreover, do not in general lead to unique equilibria). Furthermore, one might argue that in actual complex markets, in the long run, players are unlikely to incorporate all historic information on their competitors’ behaviour in their current decision making. A more common approach in the literature is to restrict attention to two classes of strategies. The first is that of open-loop games, where strategies are functions only of time: firms formulate their strategies once and commit to these. A Nash equilibrium in such a game consists of a set of (time-dependent) strategies such that no player would wish to choose a different strategy given the choices of its competitors. One might phrase this as saying that, while the strategies of the game are dynamic, the game itself is not, as all strategies are chosen and fixed initially.

The second equilibrium type is the feedback equilibrium (or Markov perfect equilibrium), which extends the strategy space to functions depending both on time and on a set of current state variables, involving e.g. the current production capacities and resource stocks of itself and its competitors. This means that, in contrast to the open-loop game, the feedback game is truly dynamic, and equilibrium in the game is required to be subgame perfect[7]. Feedback equilibria allow for consideration of the effects of pre-emptive investment by players, who anticipate that their current investments will affect the future investment behaviour of their competitors. A disadvantage of the feedback approach, however, is its numerical intractability for larger models. Feedback equilibria have been computed analytically in stylised models (such as symmetric

[7] This means that equilibrium strategies are defined and optimal even if at some previous point a player might have deviated from the equilibrium.

linear quadratic models, see Reynolds (1987)), and numerically in discrete models, see e.g. Pakes and McGuire (1994). In this discrete setting, computation time grows exponentially in the number of variables, which prevents solution for more realistic models.

While feedback models may more realistically capture a wider set of strategic behaviour, their computation is therefore prohibitive in most realistic models. The limited research that has been done on the differences between the two game forms in investment models indicates that the outcomes of the two approaches are, in those cases, not drastically different (Reynolds (1987), Murphy and Smeers (2003)). A general result seems to be that the equilibrium in the feedback equilibrium would involve slightly larger capacities and lower prices than the open-loop model (but higher than the perfectly competitive result). This effect can be ascribed to the desire (or threat) of pre-empting one's competitor, which leads one to slightly overinvest.

These sources studied feed-back models for general capital intensive markets. The case for finite resource markets, such as the natural gas market, may be slightly different as a result of the intertemporal resource constraints. Withagen et al. (2003) show that in a situation where a Stackelberg monopolist operates in a market with competitive fringe suppliers, the open-loop equilibrium is equivalent to the feed-back equilibrium in those situations where the former exhibits dynamical consistency. This means that along the open-loop equilibrium extraction paths, players would not wish to change their producion plans if given the opportunity to do so at a later stage. In our model, the open-loop equilibrium can indeed be shown to be dynamically consistent.

As mentioned, the two main sources for intertemporality over longer time scales in the natural gas market derive from the investment in capacity, which relaxes production and transmission constraints in subsequent time periods, and from the resource constraint, which limits aggregate production over all time periods. The investment problem in power markets has been addressed by Denis et al. (2002), Pineau and Murto (2003) and Murphy and Smeers (2003). These authors all focus on investment in production capacity. We are not aware of extensions to the transmission market.

We combine the approach to investment with the finiteness of resources. A constraint on the sum of production quantities, when binding, results in a non-zero shadow price, the so-called resource rent, in the optimisation of production in each period. This shadow price may be interpreted as a mark up to the marginal costs of producing, which increases with time at a rate equal to the discount rate of the problem. There exists an extensive literature on these resource rents, in particular in the competitive and the monopoly (cartel) case, see e.g. Withagen (1999) for an overview. An application of intertemporal optimisation under Cournot competition in energy markets is given in Bushnell (2003), in a complementarity model of electricity markets including hydropower generation. Hydropower production is constrained by the capacity of the water reservoir, which is filled only gradually (or in some seasons).

4 The NATGAS model

In NATGAS, we model behaviour of gas producers potentialy supplying Europe, gas consumption in Europe, the actions of transmission operators building and operating third-party-access pipelines connecting the various regions, investments in storage facilities and LNG import capacity, and actions of traders arbitraging the various regional and seasonal markets. We are interested in the long-run behaviour of market participants, on time scales where the finiteness of the various resources is of importance, as well as in shorter time-scales in which capacity is effectively fixed. We model time as a sequence of discrete periods, each consisting of multiple seasons (e.g. summer and winter) to account for periodic variation in demand. In solving the model we use period steps of multiple years.

4.1 Producers' behaviour

Producers are characterised by the country (index i) they are located in. We allow for multiple producers n_i within a country, but will treat these as symmetric in the model. (One might set n_i equal to the inverse of the production HHI in each market). An exception is the Dutch system, where we differentiate between production from the large, low marginal cost Groningen field (producing low-cal gas) and the other fields (small fields), mainly located on the Dutch Continental Shelf. Producers are assumed to optimise the net present value of their operations, using two strategic variables: production quantities and investments. Production quantities $x_{i,j,s,t}$ are chosen for each consumption market j, season s and time period t. Investments in capacity, leading to available capacity $I_{i,t}$, are chosen for each period t. These capacities will determine the bounds on total production in each period, in each country. Each producer maximises his value V (we suppress part of the indices and arguments for readability)

$$V_i^{producer} = \sum_{t,s,j} \delta^t \left[(P_j - w_{ij}) x_{ij} - c - K \cdot (I_{it} - D_{it}) \right] \tag{4.1}$$

over its decision parameters $x_{i,j,s,t}$, production,and $I_{i,t}$, investments. The maximisation is subject to constraints:

$$\begin{array}{lcll}
x, I & \geq & 0 & \\
\sum_j x_{ijt} & \leq & I_{i,t-1} & (\mu) \\
I_{it} - D_{it} & \geq & 0 & (\lambda) \\
\sum_{jt} x_{ijt} & \leq & R_i & (\sigma)
\end{array}$$

Producers are assumed to have access to, generally, a large number of fields in the region i. In each period a producer may invest capital to develop a number of fields, leading to an increase in its total production capacity I. Marginal investment costs are K, and will increase over time. We treat the possible range of investments as quasi-continuous. Once these investments have been sunk, the producer has production capacity at its disposal to use for production x, at variable costs c, generally well below capital expenses for developing the fields. It may sell its per period production to various consumption regions, with prices P, using pipeline capacity available at costs w. By depleting the developed fields, however, total production capacity I declines, by the term D which depends on depletion x. After some periods' production, fields get depleted and investments in new fields may be made to bring capacity I up again to its previous levels.

The value, V, consists of revenues minus costs in each period, discounted at discount factor δ. We set the discount rate equal to 5% in our base case calculations. Revenues equal price P_j times quantity, for each market, season and period. Costs incorporate transport costs to bring production from the production country i to market j (given by the auction price w_{ij} clearing the transport market), and production costs. Integral long-run production costs vary from around 1 cent per cubic metre for the large Groningen field in the Netherlands, to 4-9 cents for off-shore fields in the Dutch, English and Norwegian North Sea, and over 10 cents for Russian production.

Production costs consist of variable operating costs, $c(x)$, and investment costs. The latter increase with depletion of the region's resources, as increasingly more difficult fields will need to be developed. We model this increase of investment costs as an exponential function of the region's depletion rate, where costs rise by a factor $e^2 \simeq 7.4$ as total remaining resources decline from their initial value R (the smallest fields remaining will usually be highly costly to produce). Furthermore, investment costs will rise over time since costs of new exploration activities need to be included as proven resources R_0 are depleted, and currently undiscovered resources have to be converted into proven reserves. We account for exploration by including an additional exploration cost when production exceeds proven reserves. Total per unit investment costs K per unit of capacity I are therefore a function of cumulative past production $\sum x$ in the region:

$$K_i(\sum x) = K_i^0 \exp\left(\frac{\sum x}{2R}\right) + E_i \frac{e^{\alpha(\sum x - R_0)}}{e^{\alpha(\sum x - R_0)} + 1} \tag{4.2}$$

The latter term captures the jump to inclusion of exploration costs E_i, but smoothes this out, with smoothing parameter α[8]. We will finally allow for technological progress by annually reducing investment costs K_i^0 and E_i by a small percentage.

In the marginal costs c' for the Groningen field, we allow for a mark-up representing the loss of option value due to production. The Groningen field is currently highly flexible, and can

[8] for large α the function converges to a step function

therefore exploit variations in short term prices. A higher volatility of spot prices would therefore entail higher option value for the Groningen field. This option value is not represented in the value function (of course, the ability to benefit from seasonal price variations is). The true value function therefore includes a term representing this option value. Furthermore, this term depends on remaining reserves in the field, and as such would give a contribution to the first-order conditions determining production: additional output now would destroy part of the flexibility value at the end of Groningen's life. In de Joode and Mulder (2004) the benefit of saving base load Groningen production in order to capture future option value from short-term flexibility was studied. The authors concluded that, depending on e.g. price volatility, the effect was of the order of 1-3 cents per cubic metre.

Production capacity I_t declines with use, modelled by the depreciation factor $D(I,x)$; the depreciation of capacity arises by depletion of developed fields, which leads first to declining pressure, and hence capacity, and secondly to fields being depleted altogether. The speed of depletion will depend on the typical sizes of reservoirs in the region. In our model, we assume that without investment, production capacity depreciates at a percentage per year equal to its utilisation rate (total production as a percentage of capacity) divided by a 'characteristic time' t_i^*, that is region dependent. For (typically) large fields, t_i^* will be long, while small fields may be depleted in 5 to 10 years.

Production is subject to a set of constraints. The Greek letters in brackets are the shadow variables associated to each constraint. Firstly, in each period total production (x) is limited by available production capacity (I). We take into account the lead times of investments in production capacity and other infrastructure by using a suitably lagged capacity in this constraint. Secondly, we require that investments are zero or positive, so that installed capacity cannot be divested (investments are sunk costs). Finally, aggregate production is limited by total available resources (i.e. including undiscovered resources); the associated shadow price σ gives rise to the resource rent, which viewed from a 'current value' perspective, grows with δ^{-1} each period.

In addition to these constraints, we add for selected producers constraints on the minimum or maximum value of annual production. These might reflect political limits on production, or can be interpreted as a reduced form of a Stackelberg equilibrium.

The conjectural variations assumption on production is embodied in the functional dependence of the price P_j in market j on player i's supplies $x_{i,j}$ into this market. Clearly P_j depends on the total quantity delivered to this market, $X_j = \sum_i x_{ij}$. In the Cournot framework, players assume that $\frac{\partial X_j}{\partial x_{ij}} = 1$, i.e. in optimising they take their competitors' deliveries as fixed. For more competitive assumptions, $\frac{\partial X_j}{\partial x_{ij}} < 1$, with as a limiting case perfect competition, where producers anticipate their own deviations from equilibrium quantities to be completely compensated, in equilibrium, by their competitors'.

Let us finally note that taxation is not included in the above formulation of producer optimisation. Taxation has no influence on optimal behaviour if it has no effect at the margin. For EU producers, currently taxation mainly consists of a profit tax. Royalties, for instance, have generally been abandoned for offshore production. Such profit taxes would appear in the value function as a multiplier of the entire value, and as such would not influence the equilibrium conditions (not even if tax rates differ over producers). This is a simplification, as tax distortions do occur also with existing profit taxes, mainly as a result of cost cash flows not being tax deductible when they are made, but only with a delay according to their depreciation schedules. Some countries have for this region introduced accelerated depreciation schemes, or account for distortions by so-called fiscal uplift allowances.

4.2 The transmission operators

We assume that transmission companies are unbundled from production companies. Therefore, we consider a non-strategic (price-taking) transmission operator that builds and expands transmission links between, firstly, production regions i and markets j, and secondly, between different markets j and j'. The latter set of links is also used by traders to arbitrage away price differences between markets. The available capacity is auctioned to market players, resulting in prices that are required to ration demand for transmission capacity to available capacity. We will assume that there are linear variable costs of transporting gas between two regions, with constant marginal costs tc_{ij}. We will furthermore assume no netting, i.e. transport flows that run counter to the main direction of flow (so-called backhaul) are not assumed to free up more capacity for the main flow direction.

The transmission company's problem is to maximise, for each link, total discounted cash flows,

$$V_{ij}^{transmission} = \sum_{t,s} \delta^t \left((w_{ij} - tc_{ij}) y_{ij} - K_T (T_{ijt} - \text{depr} \cdot T_{ij,t-1}) \right), \tag{4.3}$$

over total flow y_{ijts} across each link in each period, and total transport capacity T_{ijt} for each link. Again, this is subject to some constraints:

$$\begin{array}{lcll} y, T & \geq & 0 & \\ y & \leq & T_{t-1} & (\theta) \\ T_t - \text{depr} \cdot T_{t-1} & \geq & 0 & (\tau) \end{array}$$

Similar conditions hold for the intermarket (jj') capacities and flows. As already noted above, w_{ij} denotes the scarcity price of transmission capacity, which is considered exogenous by the transmission operator, and which is determined by the market clearing conditions for transmission capacity, as described below. K_T are the per unit investment costs for capacity, which we consider constant for a given link. The costs do depend on the distance between the two connected nodes (and are larger for subsea links). The factor depr represents a potential depreciation factor. Although pipeline capacity only deteriorates slowly, this factor may represent the decline in other infrastructure in mature offshore areas, where for example gas treatment platforms may be removed as production declines. The rest of the problem is similar to the producer problem.

In the transmission network we allow for a distinction between low and high calorific gas. The Dutch Groningen field as well as German production is assumed to consist of low calorific gas, while the remainder of production is high calorific. Markets for low-cal gas are localised in (parts of) the Netherlands, Belgium and Germany. Systems of low- and high-cal gas are separate, but some communication between them is allowed for. High-cal gas can be pumped into the low-cal system when mixed with nitrogen (quality conversion), whereas some low-cal gas can be mixed with high-cal gas while remaining within the quality specification range of the high-cal system. Since these flows between the systems can fluctuate over the seasons, this allows some flexibility to be shared among both systems. Capacity for both directions is considered to be limited.

4.3 Storage

We assume storage, located in each consumer market j, is solely used for arbitraging gas prices between seasons; in a two-season setting, this implies injecting gas in summer and withdrawing in winter. In the model, storage operators are considered to be price takers[9]. Storage quantities $stor_s$ (positive for extraction, negative for injection) are chosen to optimise profits in each period,

$$V_j^{storage} = \sum_s (P_j - c_{stor}) stor_s - K_S(storcap_t - storcap_{t-1}) \tag{4.4}$$

subject to

$$\begin{array}{lcll}
stor_s & \geq & -storcap & (\psi^-) \\
stor_s & \leq & storcap & (\psi^+) \\
\sum_s stor_s & = & 0 & (\psi) \\
storcap_t - storcap_{t-1} & \geq & 0 & \phi
\end{array}$$

[9] It may well be argued that, as a result of limited access to in particular depleted fields, the market for seasonal storage is characterised by entry barriers making it less than perfectly competitive. We will incorporate this by assuming a mark-up on storage costs.

One might assume both variable costs c_{stor} of injection and withdrawal, which would require negative c_{stor} for injection. In the model we will allocate these costs to extraction only, i.e. $c_{stor} = 0$ for negative $stor_s$. In practice the difference does not matter because storage is typically sold, under Third Party Access (TPA), in bundles consisting of a combination of injection, storage and extraction.

4.4 Arbitrage

While producers i decide which markets j to deliver to, price differences between different markets cannot diverge as long as transmission capacity is available to traders trying to arbitrage the markets. Arbitrageurs are modelled as price takers optimising, for each period and season,

$$V^{arbitrage} = \sum_{jj'} \left(P_{j'} - P_j - w_{jj'}\right) a_{jj'}, \tag{4.5}$$

where $a_{jj'}$ is the volume of gas bought in market j and sold in market j'. Only markets j and j' that are directly connected are considered in the sum.

4.5 LNG imports

We incorporate the imports of LNG from a global, exogenous, LNG market by price taking traders. Imports of LNG require the construction of LNG import terminals in each market. The capacities of such terminals limit total imports in each season. LNG-operators thus optimise V^{LNG},

$$V_j^{LNG} = \sum (P_j - P_{LNG} - c_{LNG}) LNGimp - K_{LNG}(LNGcap_t - LNGcap_{t-1}) \tag{4.6}$$

subject to

$$\begin{array}{lcll} LNGimp, LNGcap & \geq & 0 & \\ LNGimp & \leq & LNGcap & (\nu) \\ LNGcap_t - LNGcap_{t-1} & \geq & 0 & (\omega) \end{array}$$

Buyers of LNG in the various markets compete with each other on a global LNG market. Supply on this global market is limited; we model the aggregate residual supply curve for LNG to Europe as a straight line, with a season dependent intercept and a constant slope,

$$p_{LNG} = p_0 + p_1 \sum LNGimp.$$

Furthermore, we assume a maximum available amount of LNG for Europe (that might arise from exogenous limited LNG production capacity in exporting countries), which is in accordance with projections from IEA.

4.6 Demand

The demand side of the market is considered to be price taking. We define for each country an aggregate wholesale demand (increasing with time), consisting of large industrial users and power stations that may themselves be active in this market, and supply companies acting on behalf of smaller consumers. Consumers strive to maximise their surplus, CS_j, by adjusting their demand d_j,

$$CS_j = S_j(d_j) - P_j d_j. \tag{4.7}$$

In the model we will consider quadratic gross surplus S_j, leading to linear demand functions,

$$P_j = S'_j = a_j - b_j d_j. \tag{4.8}$$

The b-parameter is representative of the inverse size of the market. a and b will be fixed by calibrating on observed price-quantity pairs, and on an assumed gas-price elasticity, $-\frac{d\log d}{d\log P}$. We incorporate in the model an exogenous growth of gas demand, which will affect only the b-parameter, making it time dependent.

4.7 Market clearing

We close the model with the market clearing conditions for the markets for gas and transmission services. Firstly, in each market demand equals supply, or

$$\frac{a_j - P_j}{b_j} = \sum_i (n_i x_{ij}) + stor + \sum_{j'} (a_{j'j} - a_{jj'}). \tag{4.9}$$

Secondly demand for transmission services equals supply of transmission services,

$$\sum_{(i,j'')} n_i x_{ij''} + a_{jj'} - a_{j'j} = y_{jj'} \tag{4.10}$$

where the sum is over producer deliveries that use transmission link (jj')[10]. The clearing conditions determine prices P_j and $w_{ij}, w_{jj'}$.

4.8 Solving the model

The mathematical model consists of the first order conditions for all the above players' value functions. Because of the constraints, these conditions take the form of a (mixed)

[10] We allocate the various flows from producers to markets to the transmission links along the shortest route, i.e. we ignore the possibility of producers selling gas via a detour.

complementarity problem. In their individual optimalisations, players take into account all data of other players. Each agent takes as fixed the decisions of other players at the solutions to their individual optimisation (except for the producers who employ conjectured variations on their rivals). The same holds for the market clearing prices, except again for producers who take into account their own decisions'impact on gas prices. Prices and quantities for all periods are solved simultaneously.

5 Model data

5.1 Production

5.1.1 Reserves

Since only a few countries or regions account for most of gas production and consumption in Europe, we aggregate total supply and demand into these main markets. The supply regions that we explicitly model are given in table 5.1, together with current estimates of their remaining resources. As mentioned, the total reserves in each production area can be distinguished in known reserves, and an estimate of reserves that have either not yet been found, or are located in as yet uneconomic areas[11]. We take data on these categories of reserves from reports published by national governments for the UK, Norway and the Netherlands, and from OGP (2003).

Table 5.1 Reserves[a]

	Proven reserves in bcm[b]	Discovered and undiscovered potential	Total
Norway and Denmark	2467	2852	5319
United Kingdom	905	645	1550
The Netherlands, Groningen	1068	0	1068
The Netherlands, small fields	381	366	747
Germany and Austria	367	420	787
Italy	182	215	397
Eastern Europe	358	614	972
Algeria	4500	1136	5636
Russia	32960	44736	77696

[a] Source: National governments and OGP (2003)

[b] billion cubic metres

[11] This might include for example gas that requires new production technology to be efficiently developed.

5.1.2 Production capacity and costs

For each country, current available production capacity is derived from monthly maximum production quantities, estimated from IEA (2005a). The magnitude of production capacity will change as time progresses and resources are extracted (lowering capacity), or new fields are developed (raising capacity).

Per region we assume all producers to face the same average costs, except for the Netherlands where we distinguish between the low cost Groningen field and the higher cost small fields. Production costs consist of initial investment costs, proportional to the capacity that is installed, and operational costs that we assume to be proportional to the amount of gas produced. As a starting point for operational costs (including loss of gas), we estimate that these amount, on average, to 10% of the total investment costs[12][13]

These two cost components can be converted into an average cost figure, using the expected life of individual fields. The latter is governed by a 'characteristic time', t^*: in t years, a region's production existing capacity will decline by a factor t/t^*, leading to exponential depreciation of production capacity.

The discount factor applied in the model is the same for all investments. It is set at a rate of 5% in real terms, consistent with Mulder and Zwart (2006a).

We calibrate initial investment and operational costs such that the average costs computed from them correspond with average cost estimates for the various regions from TNO and IEA, see table 5.2. We furthermore assume that as resources in a region are depleted, investment costs increase, as progressively more challenging or smaller fields are taken into production. This is partly offset by technological progress, which we set at a 1% decline in investment costs per year in our base case.

When reserves are exhausted, capacity expansion involves additional exploration activity, leading to extra costs. Based on information from producers, we estimate exploration costs E at 0.02 euro/m^3 (annualised).

5.1.3 Degree of competition

Finally we have to make assumptions on the level of competition in the various production markets. This is firstly represented by the number of firms active in the market. Most production countries are currently dominated by one large (state) monopolist. In the base case, we assume,

[12] From cost data on UK off-shore production, there appears to be large variation in this cost share. The model results turn out to be mainly sensitive to aggregate average costs, and not so much to the precise split between short- and long-term costs.

[13] For Russian supplies, we assume a lower share of variable costs, as the average costs in the table mainly consist of costs for transport to the Russian border.

Table 5.2 Production capacities in modelled producing regions[c], as well as estimated average cost range of production [d]

	Production capacity in bcm/y	average costs in euro/m^3	characteristic time t^*
Norway and Denmark	83	0.05-0.08	15
United Kingdom	110	0.05-0.09	10
The Netherlands Groningen	76	0.005-0.01	15
The Netherlands small fields	44	0.04-0.06	10
Germany and Austria	29	0.05-0.08	10
Italy	14	0.03-0.05	10
Eastern Europe	28	0.05-0.08	10
Algeria	85	0.02-0.03	15
Russia	140[e]	0.10-0.15[f]	15

[a] Source: IEA (2005a), based on maximum monthly production for OECD countries, NationalGrid website for UK, EZ (2005) for the Netherlands

[b] based on data provided by TNO-NITG

[c] Source: IEA (2005a), based on maximum monthly production for OECD countries, NationalGrid website for UK, EZ (2005) for the Netherlands

[d] based on data provided by TNO-NITG

[e] production for Europe

[f] costs including transport to Russian border

therefore, that the number of producers per region (or better, the inverse of the Hirschman-Herfindahl index[14]) equals one, except for the UK where many players compete (6 in the model), the Dutch small fields, and Norway, where monopolist GFU was recently split up, leading to a market dominated by two companies, Norsk Hydro and Statoil.

The second determinant of competition is the conjectural variations parameter (which may differ between firms). In our baseline scenario, we put this value at 0.25, but as it has large implications on model results, we will explore its variation in various scenarios.

Finally, we allow for constraints on annual production for political or technical reasons. In the base case we constrain production in the smaller European regions to current figures. Furthermore, we assume a minimum bound on Russian production to Europe of 140 bcm in the baseline scenario, to incorporate its potential Stackelberg leadership. For Algeria, which has very low costs of supply, we implement a cap on production of 100 bcm, since part of its production may be expected not to be directed to Europe, as the country strives for diversification of its supplies.

[14] The Hirschman-Herfindahl index, or HHI, is a measure of competition in the market. It is obtained by summing squares of the production shares, and, in symmetric markets, equals the inverse of the number of market players.

5.2 Demand

We aggregate total demand into a limited number of consumption regions, as listed in table 5.3. We take initial demand in each market from IEA (2005a). We assume demand to be price responsive, and governed by a linear price-demand relationship.

Estimates of elasticity of gas demand vary widely. Short-run elasticities are typically quite small, ranging approximately between 0 and -0.5. Estimates for longer-term elasticities (of relevance for our long-term model) where found in Stam (2003) to range from 0.18 to 0.65. In our baseline scenario we use an elasticity of 0.25.

Table 5.3 Demand centres with 2003 demand figures, in bcm. [a]

region	gas demand
Belgium	15
Eastern Europe	80
France	44
Germany, Austria, Switzerland	106
Iberian peninsula	26
Italy	77
Netherlands	50
UK and Ireland	105

[a] Source: IEA (2005a)

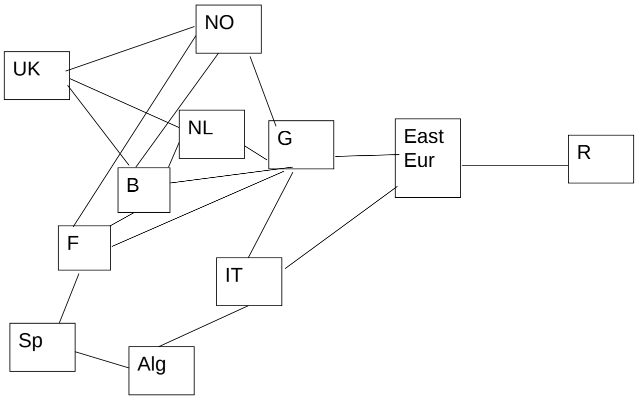
Annual demand is distributed over winter and summer in a 65 to 35 ratio. This corresponds to current Dutch ratios, and is higher than currently in other regions. Swing ratios may increase elsewhere as gas penetration in the household segment increase. If gas use for base-load electricity production increases, it is likely that this ratio will decrease. We furthermore make a distinction between high and low-cal gas, where we estimate the latter market at 90 bcm/y, distributed over the Netherlands, Begium and Germany.

5.3 Transport capacity

The representation of the transmission grid connecting the production regions and regional markets is depicted in figure 5.1.

Current transport capacities on the main routes connecting the model's regions are summarised in table 5.4. For capacity additions to long-range transmission pipelines, we calculate investment costs of 0.2 euro/m^3/1000 km, based on data provided by TNO-NITG. Further, we assume variable costs of transport, tc, for e.g. compression and losses, to equal 0.005 euro/m^3/1000 km.

Figure 5.1 Representation of the European gas network



We assume that in particular the offshore transmission systems for the Netherlands and the UK, two mature areas, will experience relatively fast depreciation. According to industry, Dutch offshore infrastructure will not be in use anymore after around 20 years as a result of too high investment and operational costs. In the model we assume exponential depreciation of off-shore infrastructure equal to 3% per year. This was calibrated to provide production rates consistent with current forecasts of small fields production over the next 20 years.

Table 5.4 Initial transport capacities (in bcm per year) [a]

	Alg	Bel	E.Eur	Fra	Ger	Ita	NL	Nor	Rus	Spa	UK
Algeria	-	-	-	-	-	25	-	-	-	10	-
Belgium	-	-	-	28	10	-	11	12	-	-	20
Eastern Europe	-	-	-	-	115	2	-	-	168	-	-
France	-	28	-	-	13	-	-	14	-	2	-
Germany	-	10	115	13	-	32	51	52	-	-	-
Italy	25	-	2	-	32	-	-	-	-	-	-
Netherlands	-	11	-	-	51	-	-	-	-	-	-
Norway	-	12	-	14	52	-	-	-	-	-	11
Russia	-	-	168	-	-	-	-	-	-	-	-
Spain	10	-	-	2	-	-	-	-	-	-	-
UK	-	20	-	-	-	-	-	11	-	-	-

[a] based on Perner (2002)

5.4 Storage

Storage for seasonal flexibility occurs mainly in depleted gas fields or aquifers; higher cost storage in salt caverns or LNG installations is used for short-term flexibility. As our model focuses on medium- and long-term developments, we concentrate here on the former type. Capacity costs for storage decline with volume; countries with large depleted gas reservoirs have a cost advantage in building such capacity. Moreover, onshore capacity has lower costs than offshore. In table 5.5 we describe current available seasonal storage capacity, and give a rough estimate on investment costs based on existing facilities (based cost estimates in Clingendael International Energy Programme (2005) and ILEX (2005), and natural availability of various storage options in various countries). We assume variable operating costs of storage being in the order of 2% of capital expenditures (based on TNO-NITG data), but wil incorporate higher values of 3 cents per m3 as a representation of potential mark ups due to monopoly power in the storage market.

Table 5.5 Storage capacities (working volumes, in bcm) of storage in European markets[a]

	Working volumes in bcm	investment costs in euro/m^3 working volume
Netherlands	4.5	0.8
Belgium	0.5	1.5
UK and Ireland	2.8	0.9
Germany, Switzerland and Austria	13.8	1
France	9.6	1.5
Italy	12.7	0.8
Spain	1.3	1.5
Eastern Europe	11.6	0.8

[a] Source: IEA (2005a)

5.5 LNG capacity

Terminal costs are generally site-specific. We start from a base line capacity cost assumption of 30 million Eur/bcm/yr (based on cost data from EIA (2003)). Depending on proximity to consumption regions, we add a markup for transportation costs, consistent with pipeline capacity costs of 20 million Eur/bcm per 100 km. This basically results in costs for LNG terminal capacity being slightly lower in the Netherlands, Belgium, the UK and Italy, and higher in Eastern Europe.

LNG prices are determined on a global market, and prices above which LNG will be attracted to the European market will therefore reflect market movements in prices of oil and gas in other global regions. It is mainly through these prices that long-term gas prices will remain linked to global oil prices. Apart from this, total LNG supplies available will be limited in the short term, as global liquefaction and shipping capacity has to be expanded. In line with IEA forecasts, we assume an annual growth of available supplies (for the European market) of around

10 bcm/yr, starting from an initial 50 bcm/yr. For LNG prices we assume a spread between seasons, and an elasticity of supply reflecting larger costs for more remote production. Based on forecasts of future gas prices, and currently observable seasonal spreads in prices (e.g. in the US futures market), we assume costs of 0.13 and 0.17 euro/m^3 in summer and winter respectively in the baseline scenario, and a cost difference of 0.02 (based on OME (2004) supply curve data) between the closest and most distant sources used (i.e. the cost slope declines as supply capacity grows). We will explore sensitivity to these assumptions.

Table 5.6 LNG import capacities (in bcm per year) in European markets[a]

	capacity in bcm/y
Belgium	5.3
France	15.3
Spain	16.3
Italy	3.7
Eastern Europe	2.2

[a] Source: IEA (2005a)

6 Model results

Now we turn to the model's output. The input data for the model that we have discussed above constitute the base case parameters. We now run the model for the base case parameter assumptions, and discuss the base case model projections.

We run the model using time periods of 5 years, extending over 10 periods. We will consider results up to 30 years in the future (i.e. the first 6 model periods, each comprising a winter and a summer period). The remaining, final periods' model results will be increasingly affected by the end of the modelling horizon after 50 years. In the model, players will not invest in these last periods, as the majority of the revenues from those investments will occur after the artificial modelling horizon, and will therefore not be taken into account in the optimisation. In contrast, the first 30 years' results can be verified to be insensitive to the precise choice of horizon.

We evaluate the model's predictions for the first five-year period, as well as the developments into the future. Where applicable we compare to actual observable data. It is important to keep in mind that the data in the model were calibrated on actual current figures. The various capacities (such as production, transport, storage) correspond to actual values, and demand was calibrated to match observed 2003 demand levels. A large part of the first period's output is heavily influenced by these data (for instance because some producers produce at maximum capacity). On the other hand, some of the model's first-period results differ substantialy from actually observed values. This is not particularly worrying as it should be recognised that current institutional arrangements differ significantly on some points from the liberalised structure assumed in the model. Nevertheless, it is useful to do this comparison to analyse which factors might explain potential discrepancies.

6.1 Production

We first focus on aggregate annual production for Europe. Table 6.1 lists the model results for the first period, and compares this to actual production (2003 values, non-EU imports based on Energy Markets Consultants (2005a)).

Table 6.1 Supply to Europe (2003)

production region	model	actual
Norway and Denmark	81	79
United Kingdom	103	109
The Netherlands Groningen	41	34
The Netherlands small fields	40	39
Germany and Austria	20	24
Italy	14	15
Eastern Europe	26	23
Algeria (by pipe)	35	34
Russia	140	141
LNG imports	22	32
Total	521	530

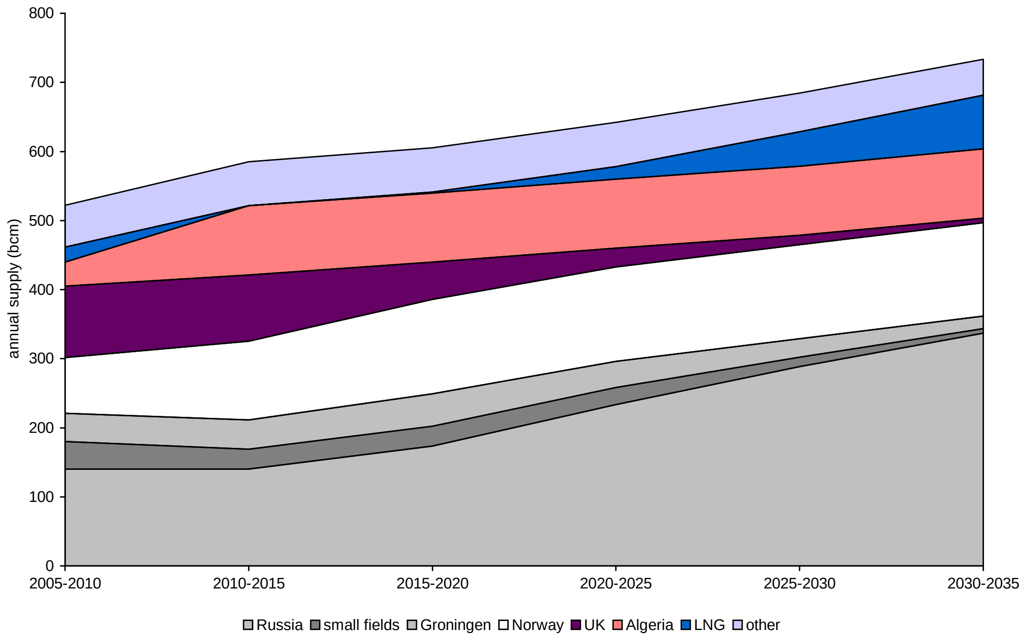
Output is fairly well in line with actual results. In fact supplies of many countries are at or near the maximum allowed by initial production capacity or transport capacity.

Turning to the development of supply quantities in future periods, figure 6.1, we find that the largest changes at first occur in supplies from Algeria, where a lot of transport capacity is added to relieve constraints that were binding in the first period. (We assume investment lead times of 5 years here). Other more modest increases come from Norway and Russia. Further in time, we see that while production in the Dutch small fields and the UK declines rapidly, additional increases in supply come from Russia, Algeria, Norway, and, in particular after 15 years, from a fast growth in LNG imports.

6.2 Prices

In the base case, prices gradually increase over time. We show in table 6.2 initial period and final period prices for the base case. While initially prices between regions diverge as a consequence

Figure 6.1 Development of supplies to Europe from major sources



of limited transport capacity, in the final model period prices more or less equilibrate over Europe. Winter-summer price differences are around 4 cents, driven partly by the assumed LNG price structure. Price levels reflect long-run averages, as short-run fluctuations in supply and demand are not incorporated in the model.

6.3 Transport

Next we focus on transport flows between countries. Tables 6.3 and 6.4 give resulting annual cross-border flows for the first period (years 0-5) and the final period (years 25-30), respectively. Table 6.5 furthermore presents the development of flows for some key cross-border connections.

Transport capacity increases gradually to accommodate the growing production over time. The largest expansion occurs between Algeria and Italy: rapid growth to 71 bcm/y over the first 5-year period, and continued growth from there. Also the link between Algeria and Spain expands, though to a slightly smaller extent. Here growth takes place to 28 bcm/y in the 5-10 year window. Other significant expansion occurs between Norway and Germany, and Norway and the UK. Also a connection between the Netherlands and the UK is predicted in this base scenario, with flows gradually growing to 28 bcm/y.

Table 6.2 Prices

	years 0-5		years 25-30	
	winter	summer	winter	summer
Ger	14	11	17	13
IT	17	14	17	13
Fran	17	13	17	13
NL	14	11	17	13
B	17	11	17	13
Sp	19	13	17	13
EastEurCons	14	11	16	13
UKCons	18	10	17	13
NLLow	13	10	19	14
BLow	22	10	19	14
GerLow	14	10	18	14

Table 6.3 Transport flows in initial period

	Rus	Nor	Alg	Ger	Ita	Fra	NL	Bel	Spa	E.Eur	UK
Russia	0	0	0	0	0	0	0	0	0	-140	0
Norway	0	0	0	-52	0	-14	0	-4	0	0	-11
Algeria	0	0	0	0	-25	0	0	0	-10	0	0
Germany	0	52	0	0	-32	-13	19	-7	0	80	0
Italy	0	0	25	32	0	0	0	0	0	1	0
France	0	14	0	13	0	0	0	0	-1	0	0
Netherlands	0	0	0	-19	0	0	0	-9	0	0	0
Belgium	0	4	0	7	0	0	9	0	0	0	8
Spain	0	0	10	0	0	1	0	0	0	0	0
Eastern Europe	140	0	0	-80	-1	0	0	0	0	0	0
UK	0	11	0	0	0	0	0	-8	0	0	0

6.4 LNG capacity

As can be seen from figure 6.1, LNG imports will play a more important role in future supplies to Europe. While current LNG terminal capacity is located mainly in Spain and France, growth is forecasted to occur mainly in Italy, and later in the UK, as demonstrated in table 6.6.

6.5 Flexibility

The model also includes seasonality in demand, so we can investigate the future sources of flexibility. The main ones are presented in table 6.7. The quantities represent the difference of winter and summer supplies for each source.

In the initial period, total European seasonal swing is 135 bcm/y, growing to 191 bcm/y in

Table 6.4 Transport flows in final period

	Rus	Nor	Alg	Ger	Ita	Fra	NL	Bel	Spa	E.Eur	UK
Russia	0	0	0	0	0	0	0	0	0	-337	0
Norway	0	0	0	-80	0	-14	0	-3	0	0	-39
Algeria	0	0	0	0	-72	0	0	0	-28	0	0
Germany	0	80	0	0	7	-44	-115	-4	0	213	0
Italy	0	0	72	-7	0	0	0	0	0	34	0
France	0	14	0	44	0	0	0	-10	2	0	0
Netherlands	0	0	0	115	0	0	0	-14	0	0	-59
Belgium	0	3	0	4	0	10	14	0	0	0	-9
Spain	0	0	28	0	0	-2	0	0	0	0	0
Eastern Europe	337	0	0	-213	-34	0	0	0	0	0	0
UK	0	39	0	0	0	0	59	9	0	0	0

Table 6.5 Annual transport flows (bcm) for selected pipelines

	years 0-5	years 5-10	years 10-15	years 15-20	years 20-25	years 25-30
Algeria-Italy	25	72	72	72	72	72
Algeria-Spain	10	28	28	28	28	28
Norway-UK	11	28	39	39	39	39
Norway-Germany	52	70	80	80	80	80
Nehterlands-UK	0	9	28	46	53	59

the final period. We find that in the first period, supply of swing relies mainly on storage. Also Groningen is an important supplies of swing in Europe. After the expansion of import capacity from Algeria, a relatively competitive source of ags for (Southern) Europe, this country supplies swing. Total storage contributes 95 bcm (47.5 bcm injection in summer, 47.5 bcm withdrawal in winter). Other important sources are Groningen and later Algeria. LNG starts contributing only in later periods, when it takes a more prominent role in supplies to Europe. Although swing in Russian supplies is relatively very small, due to the large total supplies from it does take an important role.

7 Assessment of the model

7.1 Introduction

Ideally, a model's results should be validated by assessing how well it performs on historic data. For our model this is problematic as major assumptions underpinning the model, i.e. a competitive European gas market, were not valid in the past. We developed the model to assess the effects of liberalisation of the European gas market. The presence of sufficiently liquid wholesale markets for gas, on which competitors can enter, and the independence of

Table 6.6 LNG terminal capacities (bcm/y), installed capacity at end of period

	years 0-5	years 5-10	years 10-15	years 15-20	years 20-25	years 25-30
Germany	0	0	0	0	4	4
Italy	4	4	4	11	16	23
France	15	15	15	15	15	19
Netherlands	0	0	0	0	7	22
Belgium	5	5	5	5	5	5
Spain	16	16	16	16	16	16
Eastern Europe	2	2	2	2	2	9
UK	0	0	24	46	68	92

Table 6.7 Major sources of seasonal swing (winter minus summer supplies)

	years 0-5	years 5-10	years 10-15	years 15-20	years 20-25	years 25-30
Algeria	0	28	29	29	29	29
Russia	0	18	0	3	13	24
Groningen	18	23	23	19	18	18
UK	7	6	0	0	0	0
LNG	2	0	0	10	8	8
storage	95	30	77	91	100	107

infrastructure owners from production incumbents, are key components of the model. This contrasts with the pre-liberalisation era, where gas supply, transport and storage was an essentially monopolistic integrated business on national markets, and a competitive European gas market did not exist. Even today the ideal underlying the model is still far from reached. Rather, we try to get a sense of what the future effects will be of the competitive gas markets that are envisaged today.

Therefore, we have to rely on other methods of assessment. Firstly, we evaluate the plausibility of the output of the model. This also includes an evaluation of the robustness of the model's results to changes in input parameters. In particular, we study the impact of changing those parameters that th model is most sensitive to. We focus on the competitivity of production (the conjectural variations parameter) and on the exogenous LNG prices and see how changing these affects the model's output. Secondly, we define four possible scenarios involving different combinations of these parameters, and assess the plausibility of the future gas scenarios simulated with the model, by comparing these results with current developments and forecasts presented by other institutions.

7.2 Model sensitivities

One test of the validity of the model is to assess its robustness against changes in the parameters of the model. We conducted a sensitivity analysis by running the model with adjustments subsequently made to each parameter of the model, and comparing how key model results change as a consequence of those changes. Changes in assumed demand growth obviously change future production levels. Variations in cost parameters mainly affect Russian production and LNG imports: these two supplies are both on the margin, and reductions in production costs or pipeline costs shift volume from LNG to Russian pipeline gas, while decreases in LNG prices or costs shifts the balance towards LNG. Also market prices are affect most by changes in LNG prices and Russian gas. Changes in competitivity (either changes in demand elasticity or in producer competition) also give non-negiligible effects.

Since in particular future competitivity and future LNG prices, as input data, are hard to predict, we now focus on the impact of varying assumptions on the competitivity parameter, and on the exogenous price level above which import of LNG becomes viable. The competitivity parameter may in principle range from the perfect competition level 0, to the Cournot level 1. A priori, we cannot determine which level will be representative of the level of competition in the future European gas market, but we may get intuition for realistic values by studying the changes in gas prices and sources induced by varying the parameter.

We compare the benchmark case of full competition, where prices will reflect (long-run) marginal costs of production and transport (including opportunity costs), with non-fully competitive scenarios, characterised by conjectural variation parameters equal to 0.2, 0.3 and 0.4, and the most extreme case of pure Cournot competition (parameter equal to 1). In figures 7.1 and 7.2, we illustrate the effect on Dutch prices, LNG imports, and imports from Norway and Russia.

Figure 7.1 Dutch prices and LNG imports varying with competition

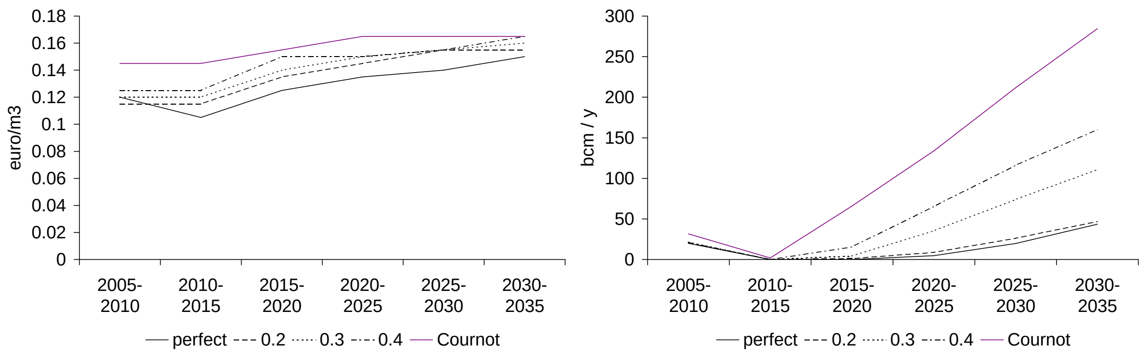
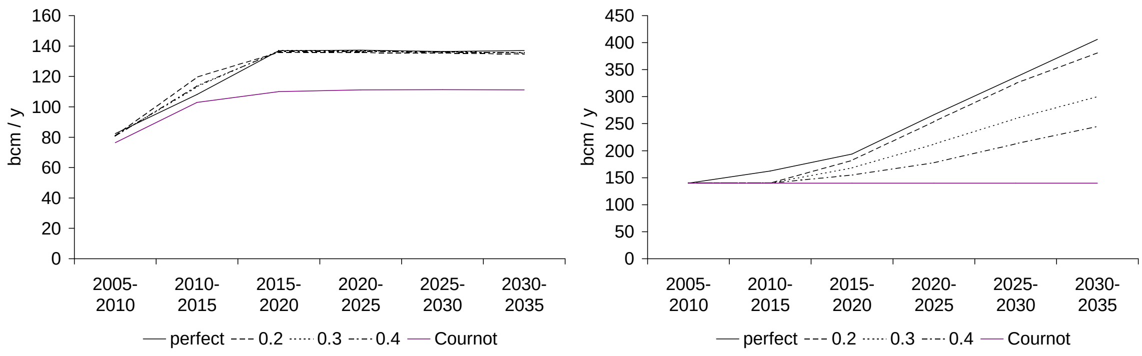


Figure 7.2 Norwegian and Russian imports varying with competition



We see that perfect competition gives rise to significantly lower prices than the other parameter values. The threshold price for importing LNG is only reached towards the end of the model period (and initially in some countries as a consequence of transmission constraints), and total imports of LNG remain low. Imports come mainly from Russia in later periods, and in fact Russian exports may well exceed what many observers consider Russian production capable of in practice. Norwegian production appears less sensitive to the level of competition.

Since in these computations, prices for LNG have been left unchanged, under no variant do prices range high above the 0.17 euro/m^3 winter threshold price, but we see that as competion decreases, this requires increasingly high supplies of LNG. In fact one of the main consequences of changing competition levels in the last periods is a shift between Russian imports and LNG (as other sources are then nearing depletion or are constrained (Algeria). Under Cournot assumptions, Russian imports never exceed their lower bound of 140 bcm per year.

Prices above which LNG inputs become competitive are therefore also a crucial input in the model, and we consider variants of the baseline scenario (with competition factor 0.25) with varying LNG price levels. The values we choose are ‘low’ (0.13 euro/m^3), ‘base’ (0.15 euro/m^3), ‘high’ (0.18 euro/m^3). Winter and summer threshold prices are two cents above and below these average price levels. In figures 7.3 and 7.4 we again compare the same outputs as above for these variants.

We see that for the high variant, LNG hardly plays a role, with the other assumptions unaltered. For LNG available at lower price levels, both Russian and Norwegian imports are partly displaced by LNG.

7.3 Scenarios

We found that the model is relatively robust to small changes of most individual parameters. On the other hand, some of the parameters that the model is more sensitive to are inherently difficult

Figure 7.3 Dutch prices and LNG imports varying with LNG prices

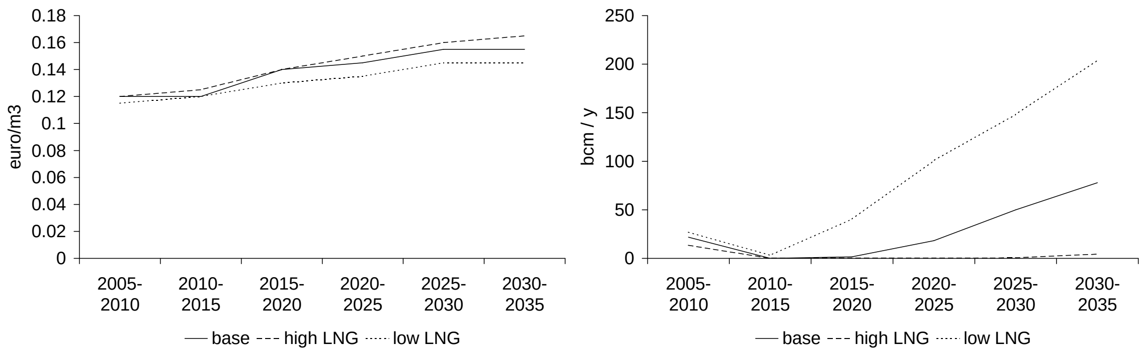
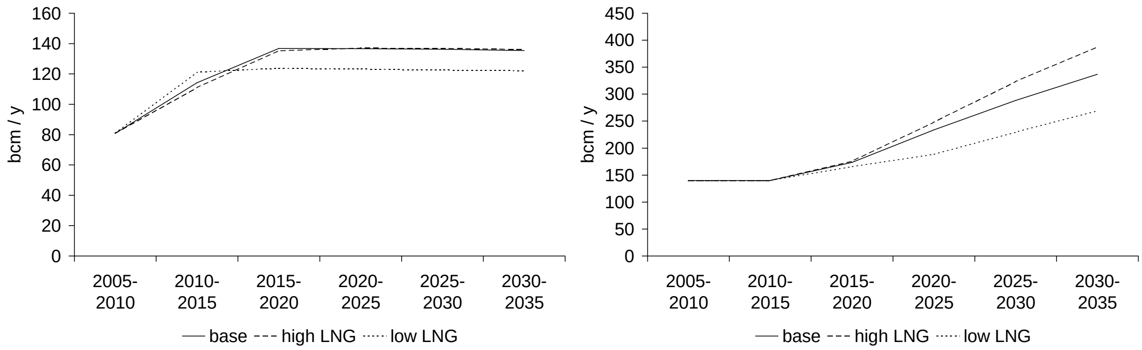


Figure 7.4 Norwegian and Russian imports varying with LNG prices



to calibrate, in particular future levels of competition, both between traditional suppliers and involving LNG supplies. We studied effects of variations of these parameters on model outcomes. We now proceed to study the effects of changing multiple parameters at the same time by constructing four alternative plausible scenarios.

The scenarios were introduced in Mulder and Zwart (2006a). We list the characteristics of these scenarios in table 7.1.

Table 7.1 Characteristics of scenarios

Parameter	Baseline	Competition	Seller's market	High prices
competition parameter	0.25	0.15	0.45	0.25 and 1 [a]
demand growth	1.5%	1%	1.5%	2 %
LNG prices	0.13	0.15	0.18	0.28

[a] Competition factor is 1 for non-EU suppliers. In addition, in this scenario the Russian minimum exports to Europe are reduced to 120 bcm/y

We again look at the same output factors as considered in the above variants in figures 7.5

and 7.6.

Figure 7.5 Dutch prices and LNG imports in different scenarios

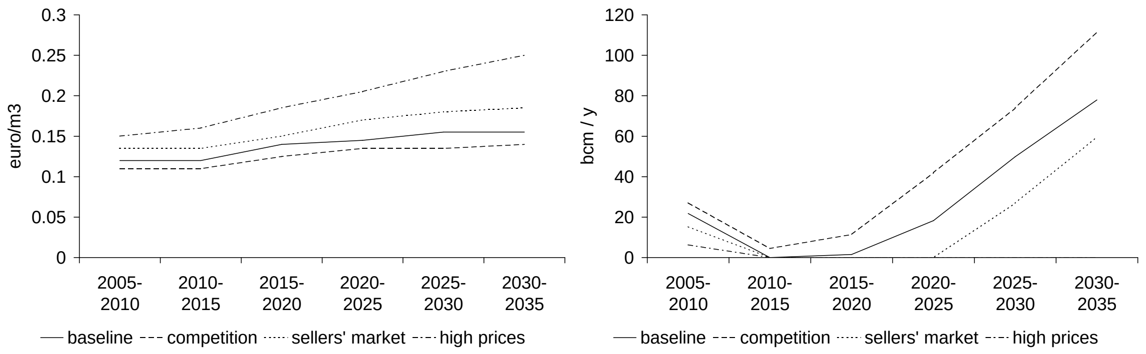
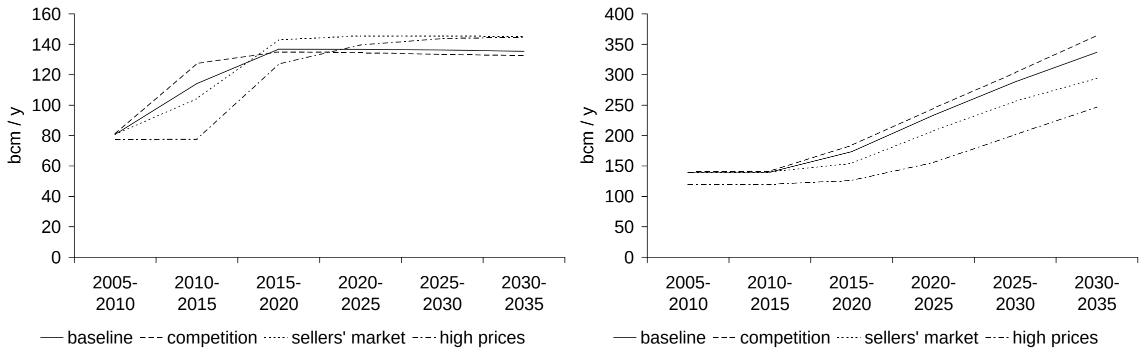


Figure 7.6 Norwegian and Russian imports in different scenarios



We see a large range of prices related to the scenarios. LNG imports play an important role in particular in the more competitive scenarios. Prices in Europe are too low to attract LNG at the higher LNG price levels, even at reduced levels of (pipeline) competition. The shortfall of LNG in these latter scenarios is made up by additional supplies by Norway and Russia.

7.4 Comparison to current developments and other models

We can also check the plausibility of the model results by comparing with actual developments in the industry, as well as longer-term forecasts by various other institutions.

7.4.1 Current developments

Given the fairly long lead times in construction of large scale gas infrastructure, currently planned projects give information on major developments in the gas market for at least the first 5 years. We list here some of the current major developments in pipeline and LNG construction (drawing from Clingendael International Energy Programme (2004), Seeliger (2004), Stern (2004), Energy Markets Consultants (2005b), Gas Matters (2005)).

As far as transport capacity is concerned, various planned projects are discussed in the literature:

- Norway: Norway's pipeline capacity to Europe is to be significantly expanded by the construction of the 24 bcm/year Langeled pipeline bringing gas from the newly discovered Ormen Lange field to the UK. This adds to the existing capacity to the UK (the Vesterled pipeline). Apart from this new line, a second line of similar size (Symphony line) is under discussion. Connections with continental Europe are not expected to be expanded over the coming decade.
- North Africa: Algeria currently pipes gas to Spain (pipeline through Morocco) and to Italy (via Tunisia). Capacity of both lines will be expanded by around 5 bcm/year. In addition, a new line to Spain, the 8 to 16 bcm/year Medgaz line, is under construction, and a new line to Italy, the 8-10 bcm/year Galsi line is planned. Besides these lines, the Green Stream pipeline connecting Libya to Italy is under construction. The capacity will be 11 bcm/year.
- Russia: Russia exports gas mainly through the Ukraine. Although aggregate capacity is around 135 bcm/year, a large part of this capacity remains unused. Disputes over gas payments with the Ukraine in the 1990s led the Russians to construct an alternative route to Europe via Belarus, to reduce dependence on the transits through the Ukraine. In spite of the large transport capacity already present, plans are made to construct a new pipeline across the Baltic sea to Germany. A partnership with Wintershall over this 20-30 bcm/year project was recently concluded. In addition to Russia, also the Caspian region may deliver pipeline gas to Europe in the near future.
- Netherlands/UK: Another large project currently under construction is the BBL pipeline between the Netherlands and the UK, with planned capacity of 16 bcm/year.

The field of LNG import capacity attracts a lot of interest currently. The largest LNG importers, France and Spain, are expanding existing terminals as well as considering new build. Also in Belgium, the grid operator is considering expanding the Zeebrugge import terminal. A large new player in the field is the UK, where the first phase of the Isle of Grain facility was recently completed. Expansion of this facility and plans for two facilities in Milford Haven may lead to capacity of over 40 bcm/year in the coming decade. In Italy, plans were announced to construct an offshore LNG terminal in Italy for reception of Qatar gas. A second terminal is planned near Brindisi. In the Netherlands, various plans for construction of terminals have been announced recently.

In the model, initially large pipeline investments take place from Norway, both to the UK and to Germany, in all four scenarios. Capacity to the UK grows by 20 to 30 bcm/y in the first model decade, and is therefore in line with actual investments. Also, the connection to Germany is further expanded to around 70 or 80 bcm/y to accommodate the large growth of Norwegian production. In the south, the model forecasts even larger growth of capacity from North Africa to Spain and Italy than can be seen from actual current investments, as demonstrated for the base case in table 6.5. Again, this is shared among all scenarios, with in Sellers' market scenario, a slight shift from Italy to Spain. The predicted growth of transport from the Netherlands to the UK, between 5-10 bcm/y in after 5 years, growing to 20 bcm/y in the next period (with highest flows in the Competition scenario, and lower flows in the Sellers' market and High prices scenarios) is in line with the BBL project. In the east, on the other hand, the model results show no capacity expansion from Russia in the first decade, although these do come online in the following periods. This may well be because the actual plans for expansion do not derive from capacity shortage per se, but from a lack of diversification in current transport routes, as mentioned above. This is not factored into the model.

We see that the model results do show capacity expansion in the same regions as actually observed (except for the Russian connection), although generally modelled capacities exceed actually planned capacities, especially in the Mediterranean region.

Looking further at LNG capacity, we see that the modelled growth of LNG is reflected in large activity in LNG terminal capacity in particular in the Competition scenario, where LNG growth is most significant. Here we observe a large growth in the UK (5 bcm/y initially, but then increasing to a capacity of around 40 bcm/y after a decade) coincides with actual investments. Also investments in Italy, and to a smaller extent in France are modelled, but these occur later in time, after some 15 years. In the other scenarios, LNG growth takes off later.

7.4.2 Comparison to IEA projections

The International Energy Agency publishes forecasts on the gas sector in its World Energy Outlook. We compare IEA's forecasts for Europe for the year 2030 from the WEO IEA (2005b) to the model results in table 7.2.

While we see close agreement in projections for imports from Norway, projections for

Table 7.2 IEA forecasts

	IEA 2030	model period 5
EU production	147	100 - 115
Norwegian imports	135	133 - 145
Russian imports	155	200 - 300
African imports	184[a]	100
LNG imports	250	0 - 75
price level	0.13	0.13-0.23

[a] including LNG from Nigeria and North Africa

Russia and LNG differ widely over all scenarios. As we saw, these quantities were quite sensitive to assumptions in LNG prices and competitivity, with an exchange taking place between the two as assumptions changed. Apparently, to reproduce the IEA projections we would have to change the balance between the two, by lowering LNG prices relative to Russian prices, as discussed in the variants above. Although both projections foresee gradual decline of European production, in our model the decline is projected to be steeper than in the IEA's forecasts. IEA's general expectation of price levels in Europe coincides with our model's in the Baseline and Competition scenarios.

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