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Future evolution of the liberalised European gas market: Simulation results with a dynamic model

Wietze Lise[a,b,*], Benjamin F. Hobbs[c]

[a]*IBS Research & Consultancy, Aga Han, Agahamami Cadessi 1/6, Cihangir, 34433 Beyoglu, Istanbul, Turkey*
[b]*Energy Markets and International Environmental Policy group, ECN Policy Studies, Energy Research Centre of the Netherlands, Amsterdam, The Netherlands*
[c]*Department of Geography and Environmental Engineering, The Johns Hopkins University, Ames Hall 313, 3400 North Charles Street, Baltimore, MD 21218, USA*

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Abstract

Strategic behaviour by gas producers is likely to affect future gas prices and investments in the European Union (EU). To analyse this issue, a computational game theoretic model is presented that is based on a recursive-dynamic formulation. This model addresses interactions among demand, supply, pipeline and liquefied natural gas (LNG) transport, storage and investments in the natural gas market over the period 2005–2030. Three market scenarios are formulated to study the impact of producer market power. In addition, tradeoffs among investments in pipelines, LNG liquefaction and regasification facilities, and storage are explored. The model runs indicate that LNG can effectively compete with pipelines in the near future. Further, significant decreases in Cournot prices between 2005 and 2010 indicate that near-term investments in EU gas transport capacity are likely to diminish market power by making markets more accessible.

JEL classification: C61; C72; L13; L95; Q41

Keywords: Complementarity modelling; Energy economics; Gaming; Natural gas; Investment; Optimisation; European Union

1. Introduction

Structural changes in the European gas market have led to political concern about potential declines in the long-term (2010–2030) security of gas supply. This is particularly so for the accession countries in Central and Eastern Europe, who anticipate a strongly growing gas demand and import dependency. These structural changes include:

- progress towards an integrated European internal gas market; this increases uncertainty for investors in production as well as transmission infrastructure to accommodate imports; on the other hand, a more integrated market may result in a greater range of supply alternatives, which can blunt possible threats by individual countries of cut-offs by a major supplier;
- expansion of the European Union (EU);
- growing gas demand in the EU and thereby a strongly increasing gas import dependency, expanding from the current 40% to approximately 70% in 2030.

The purpose of the paper is to present a recursive-dynamic model of the European gas market for analysing how these structural changes might affect European gas supplies and prices. To demonstrate the scope of the model, the model is calibrated at a high aggregation level and three illustrative scenarios are presented and discussed.

The scope of this study is the medium- and long-term gas market in Europe, wherein EU consumers increasingly depend on natural gas imports. Moreover, they rely mainly on a relative small number of key gas exporters with

*Corresponding author. Tel.: +90 212 252 2460; fax: +90 212 252 2430.
E-mail address: wietze.lise@ibsresearch.com (W. Lise).

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remote production locations. We propose a computational game theoretic model with recursive dynamics to represent investment by transmission system operators (TSOs) and storage system operators (SSOs). The model solves for a short-run equilibrium among producers in each 5-year period, and simulates investments by transmission and storage owners at the beginning of each period based on the anticipated value of those investments.

The assumed market structure is as follows: market participants include producers, consumers, TSOs and SSOs. Producers contract with pipelines and liquefied natural gas (LNG) shippers to transport gas to customers in consuming regions. Producers can exercise market power, which we model by assuming that they play a Nash–Cournot game against other producers as well as storage, and anticipating how consumer willingness to pay (price) depends on quantity supplied. In a Nash non-cooperative game, each player chooses its strategy believing that other players will not deviate from their optimal strategy; in the Cournot version, the strategic variable is quantity sold, and each player acts as if he/she believes that it can change its sales without other players reacting. However, owners of transmission and storage are assumed to be regulated, or otherwise operated, so that transmission is priced efficiently. That is, we assume that the price of transmission (or storage) equals long-run variable cost (including capital costs), 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. These cost assumptions are consistent with other models of the gas [1,2] and electricity markets [3,4] in which scarce transport capacity is allocated by a system operator in order to clear the market for transportation services. More sophisticated models of costs and technical constraints for transmission [5] and storage [6] are possible. Because of the congestion pricing assumption, transmission (storage) can be equivalently modelled as being owned by a single TSO (SSO) who is price taking, as we show below. The SSO can profit from buying gas in the low-demand (and thus low price) seasons, storing it, and selling it to end-user sectors in the high-demand seasons.

Our model builds further on static versions of the Gas mArket System for Trade Analysis in a Liberalising Europe (GASTALE) model to include dynamics of investment. The original version considers trader market power [1], and the model was extended by including inter-seasonal storage but just for a single year [7]. The full model is presented in this paper, because this model is a significant extension of [7] in several ways and yet more compact in its formulation. First, production has been split in 90% base production with non-linear costs and 10% peak production with constant costs to improve convergence to the model solution. Second, the production–transport mass balance and the transport–supply mass balance is separated à la COmprehensive Market Power in Electricity Transmission and Energy Simulator (COMPETES) [8], reducing the number of equations considerably. Third, transport of LNG is fully separated from transport by pipelines, by distinguishing among liquefaction, transport and regasification. Fourth, and most importantly, storage and transmission can be expanded and multiple years are considered. In addition, this model also suppresses some of the details of [1] about gas marketing within countries. The version of GASTALE presented here structures the investment game as follows: investments are undertaken recursively and only for transmission and storage facilities whose capacities are most limiting and thus have the most congestion. In particular, TSOs make investment decisions based on a feedback information structure. The congestion information is updated for each 5-year period. In this version of GASTALE we consider four types of investments, namely expansion of liquefaction, regasification, storage and pipeline capacity.

The extension of GASTALE was mainly developed to address the policy question of energy corridors. For that reason the model does not consider investments in gas production capacity; we instead define exogenous scenarios of the amount of production capacity, as several other models do, e.g. [9–11]. Moreover, investment and production in natural gas is a complex multiyear optimisation in which a field's productivity reflects both investment and available resource; that is, its production function: production in a given year = *f*(capital, short-run operations costs and the remaining resource). Because of the complexity of this production function, we consider only short-run production capability. In addition, the question of exploration is essentially a different one from the question of transportation of known reserves. Finding new gas reserves is surrounded with more uncertainty than investing in gas transmission corridors. However, more complex formulations are possible; [12] represents capacity–production relationships as well as tradeoffs between gas production in different periods, considering the resource size and effect of withdrawal rates on the resource. The result was a model with over a million decision variables, the data requirements to characterise the dynamic characteristics of different production fields are onerous; this data was not available for the model application in this paper. [9] formulates a dynamic model where depletion of gas fields is taken into consideration as well as investments in production capacity.

The paper is organised as follows Section 2 discusses the assumptions and scope of the model. The model is parameterised with two EU consuming regions and five producers; all data is obtained from [13,14]. The model itself is described in Section 3. Section 4 presents results for three scenarios concerning strategic behaviour of firms. The results of these scenarios illustrate the type of results that the model can generate. Section 5 concludes the paper. The appendix contains conditions defining market equilibrium, consisting of optimality conditions for each market participant plus market-clearing conditions.

2. Discussion of model and input assumptions

2.1. The GASTALE model

GASTALE version 4.4.2 models the main consumers and producers of natural gas in Europe. The gas market is characterised by a "mismatch" in space and time between production and consumption, which are connected with each other via (on- and offshore) transport pipelines, an LNG shipping network and storage. The model distinguishes among the following market participants:

- producers (who decide on production and transport to the region of consumption, earning a wholesale price),
- TSOs (who provide transport through on- and offshore pipelines and LNG shipping),
- SSOs (who regulate injection into storage during the low-demand warm season and withdrawals for consumption during the medium- and high-demand cold season) and
- consumers in various sectors.

Only producers are assumed to have market power. Investments decisions are considered for expanding the capacity of pipeline network and liquefaction, regasification and storage facilities.

Since the purpose of this paper is to demonstrate capabilities of a recursive-dynamic game theoretic model of the gas industry to analyse questions of interest to policy makers, the application involves a model that is reduced in size. Production of natural gas takes place in the EU15 (the old Member States), which together comprise one player in the model, and this production capacity is sufficient to meet about 55% of the demand in 2005. The remaining 45% of demand is met by production outside the EU, namely Norway, Russia, Algeria and LNG from other countries. The model distinguishes between consumers within the EU15 and CEEC10 (the new member states, excluding Cyprus and Malta which have no gas demand, and adding Bulgaria and Romania).

2.2. Demand and supply side

Consumption and elasticities are used to calibrate a linear demand curve for consumer sectors in each consuming region (Tables 1 and 3). Each curve passes through the (quantity, price) pair corresponding to Table 1 consumption and competitive gas supply prices, with slope determined by assumed elasticity at that point. The consumption in CEEC10 is the actual quantity demanded in that market, net of local production, which is assumed to be consumed locally (circa 32% of consumption).

While exact elasticities are uncertain, the relative levels in Table 1 can be justified. Households have relatively little scope for switching, and so have the lowest elasticity. Industries have more flexibility in their operations, and so have a somewhat higher elasticity. Power generators can switch to other technologies (e.g. coal) when gas prices rise, hence they have the highest elasticity. A more sophisticated representation of demand response would represent investment decision making by consumers in which capital stock turns over, and efficiency of that investment would be based on present and forecast prices; as a result, long-run responses to sustained changes in prices would be more elastic than in the short run. Such intertemporal demand relationships are a future research topic.

Table 1
Natural gas demand (bcm/year) over 2005–2030

Region	Market segment	2005	2010	2015	2020	2025	2030
EU15	Industries	136	144	154	161	168	177
EU15	Power generation	137	171	217	242	256	247
EU15	Residential	168	183	192	208	214	222
CEEC10	Industries	26	29	35	41	49	55
CEEC10	Power generation	27	37	48	63	78	95
CEEC10	Residential	34	40	46	52	57	62

Source: Derived from [13,14].

Table 2
Storage capacity and marginal cost of storage in 2005

Region	Capacity (bcm/year)	Marginal operational cost (€/kcm)	Cost of investment (€/m^3)
EU15	54.6	30	5
CEEC10	15.5	35	4

Source: Derived from [13,14].

Table 2 shows the assumed initial values for capacity, marginal operational cost of storage and cost of investment in storage capacity. Storage operating costs also include transport of stored gas between storage facility and gas transport network.

In order to derive demand seasonal variations, Table 3 presents relative load factors for industry, power generation and residential sectors (the latter including the commercial sector). Industrial demand is assumed to be the same in every season, but power demands vary somewhat because of higher winter power demands. Variation in residential demand is the largest, because of winter heating loads.

Table 4 shows the major gas-producing (and exporting) countries relevant to Europe's gas supply. For Algeria and Russia, assumed production capacity is smaller than actual production, because we are interested only in the capacity available for supply (export) to Europe.

We assume that gas is simultaneously extracted from several fields that may have different unit costs, which increase at higher levels of production. To facilitate solution of the model, we assume a smooth increasing marginal cost function for the first 90% of capacity. The last 10% is produced at a constant marginal cost DD_f,

Table 3
Relative load factor for each regional market segment and number of days per season

Region	Market segment	Low demand (summer)	Medium demand (early spring, late autumn)	High demand (winter)	Elasticity
CEEC10	Industries	1	1	1	−0.40
CEEC10	Power generation	0.93	1.04	1.14	−0.75
CEEC10	Residential	0.07	1.48	2.82	−0.25
EU15	Industries	1	1	1	−0.40
EU15	Power generation	0.93	1.04	1.14	−0.75
EU15	Residential	0.25	1.51	2.22	−0.25
	Number of days per season	183	120	62	

Table 4
Assumed production capacity for export to EU and marginal costs over 2005–2030

Firm	Region	Production capacity (bcm/year)									
		2005	2010	2015	2020	2025	2030	AA_f	BB_f	CC_f	DD_f
Algeria	Algeria	88	97	116	135	144	153	10	0	−5	26.51
EU15	EU15	266	248	226	203	188	173	12	0	−10	45.03
Norway	Norway	92	94	95	95	98	100	12	0.1	−10	64.60
Russia	Russia	189	200	250	300	350	400	12	0	−5	28.51
World LNG	World LNG	63	95	106	117	126	134	11	0	−5	27.51

Source: Derived from [13,15].

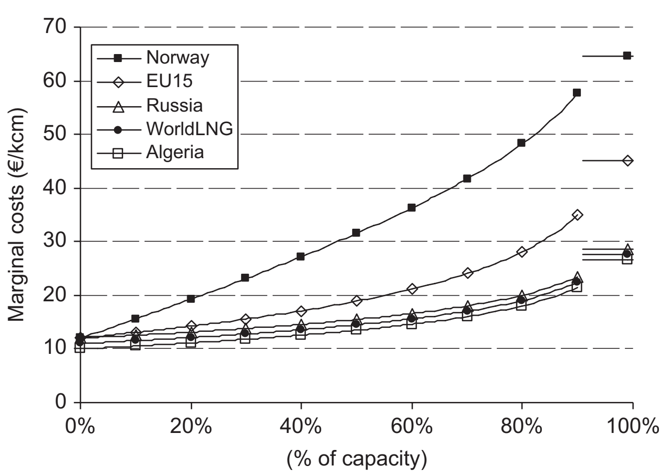

Fig. 1. Marginal production costs.

which can be interpreted as peak load production (see Fig. 1). Production capacity represents the daily capacity of exploited fields, and the marginal cost of producer f is the marginal cost of its active fields. For the first 90% of production, marginal cost is a smooth and increasing function of production [10–11]:

$$CQ_f'(q_{fop}) = AA_f + BB_f q_{fop} + CC_f \ \ln(1 - q_{fop}/Q_{fop}),$$
$$AA_f, BB_f > 0, \quad CC_f < 0, \quad q_{fop} < Q_{fop} \tag{1}$$

For the last 10%, the marginal production cost is assumed to be constant at a high level as shown in Fig. 1; this results in significantly improved convergence compared to GASTALE's previous formulation. The parameters are based on [15–17]. The model can be viewed as implicitly representing a portion of long-run costs via shadow price on production capacity, when capacity is binding. Note that the LNG cost function reflects assumptions about world price of LNG and thus opportunity cost of not selling the gas elsewhere.

2.3. Gas corridors: transmission operating costs

Transmission of gas can take place in two manners. Table 5 presents the marginal transportation expense, investment costs, and capacity for the pipeline network. These costs are derived from transport distances, with a distinction drawn between onshore and offshore pipelines. Note that the model allows for transhipment, e.g., from Russia to CEEC10 and then from CEEC10 to EU15 (Fig. 2). Russia can also transport directly to the EU15, although the capacity is low. Table 6 shows the assumed marginal LNG transport costs. Those costs include all operational expenses involved with liquefaction, shipping, and regasification. Liquefaction and regasification capacities and investment costs associated with LNG transport are shown in Table 7.

Table 5
Pipeline marginal transportation costs, investment cost and capacity in 2005

Exporting region	Importing region	Interface	Marginal transportation cost (€/kcm)	Investment cost (€/m^3)	Capacity (bcm/year)
Algeria	EU15	A_EU	13.8	2.8	36.5
CEEC10	EU15	CE_EU	18.0	3.6	127.8
EU15	CEEC10	EU_CE	18.0	3.6	127.8
Norway	EU15	N_EU	36.0	7.2	146.0
Russia	CEEC10	R_CE	42.0	8.4	175.2
Russia	EU15	R_EU	70.8	14.2	9.1

Source: Derived from [13].
Note: The model allows for transhipment, e.g. from Russia to CEEC10 and then from CEEC10 to EU15. Russia can also transport directly to the EU15, although the capacity is low.

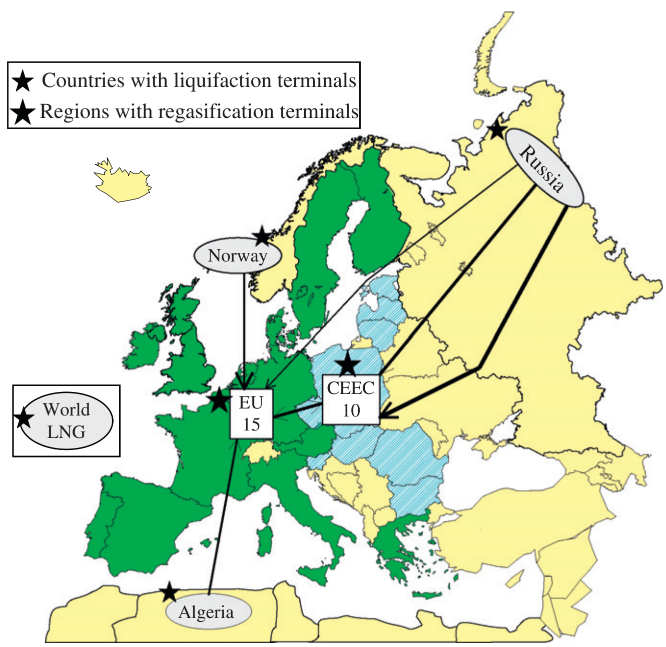

Fig. 2. Geographical coverage of the version of GASTALE.

Table 6
LNG transport costs in 2005

Exporting region	Importing region	Marginal transportation cost (€/kcm)
Algeria	EU15	45.4
Algeria	CEEC10	46.5
Norway	EU15	51.0
Norway	CEEC10	62.0
Russia	EU15	52.0
Russia	CEEC10	63.0
WorldLNG	EU15	58.7
WorldLNG	CEEC10	55.8

Source: Derived from [13].

2.4. Investment considerations and dynamics

To parameterise the GASTALE model, we also need to make assumptions concerning the cost of augmenting existing transportation, liquefaction, regasification and storage capacity. Typically, the additional costs for new investments, as well as depreciation and interest rates are important factors. The additional cost for new liquefaction, regasification and storage capacity are shown in Tables 2 and 7. The additional cost for new pipeline capacity depends on length (Table 5 provides the investment costs for all interfaces). Depreciation of capital is assumed to be 1.7% per year for storage and 3.3% for pipeline, liquefaction and regasification capacity. The real interest rate is set at 5% per year, a common interest rate for public sector investments [18].

The demand forecast in the model is mainly based on the Directorate General of Transport and Energy (DG-TREN) reference projections [14]. This translates into a growth, between 2005 and 2030, of consumption by 47% for EU15 and 146% for CEEC10. Actual consumption depends on price levels through the demand curve, so these growth rates apply to quantity demanded in the competitive scenario. On the other hand, production capacity in EU15 is reduced by 35% between 2005 and 2030. But over the same period, production capacity increases exogenously in Algeria (+75%), Norway (+9%), Russia (+112%) and World LNG (+114%).

2.5. Error and validation analyses

Error and validation analyses of the computational model GASTALE have been performed as follows. First, the model code and solutions were verified to confirm that all constraints, such as energy balances (supply = demand) and capacity limits are indeed satisfied by solutions. Although PATH is the most widely used computational method for complementarity problems, and is widely recognised to be robust, it can sometimes terminate prior to finding a solution due, for example, to model misformulations. We have confirmed that the numerical solutions indeed represent equilibria that satisfy all constraints. Second, price projections have been compared to EU market prices experienced over 2000–2004, and overall price levels as well as price differences among countries for the early years of simulations are consistent

Table 7
LNG liquefaction and regasification capacities and investment costs in 2005

Region	Liquefaction capacity (bcm/year)	Liquefaction new investment cost (€/m^3)	Regasification capacity (bcm/year)	Regasification new investment cost (€/m^3)
Algeria	28	6	0	0
EU15	0	0	9	2
CEEC10	0	0	62	2
Norway	2	6	0	0
Russia	2	6	0	0
WorldLNG	40	6	0	0

Source: Derived from [13]. Costs for using these facilities are included in LNG transport costs.

with experience and in line with official EU scenarios [14]. Third, we have undertaken constructive validity tests, which consist of sensitivity analyses to determine whether the model is appropriately sensitive to changes in assumptions, especially those that are particularly uncertain, namely price elasticity and behaviour of Russian suppliers. We have confirmed that changes in those assumptions (especially in market power cases) affect the solution in expected ways (for instance, more market power or less price elasticity results in higher prices, especially in areas most affected by Russian supplies). Thus, the model satisfies a construct validity test with respect to those assumptions, in that the model reacts to changes in assumptions in a manner broadly consistent with theory.

3. Model description

The GASTALE model includes the following indices, variables and coefficients. Variables are designated as lower case Latin letters (primal variables) or lower case Greek letters (LaGrange or dual variables), while coefficients are given in upper case. Dual variables are not defined in this subsection, but are instead introduced within parentheses to the right of their constraints in the models. Indices and their sets are represented by lower and upper case Latin letters, respectively.

3.1. Model notation

3.1.1. Indices and sets

$n, n' \in N$ set of nodes in the gas transmission network. Nodes are equal to regions

$c, c' \in C \subset N$ set of gas-consuming nodes, a subset of all nodes

$o \in O \subset N$ set of origin nodes where gas is produced, a subset of all nodes

$k \in K$ set of arcs of connected nodes in pipeline distribution network

$f, f' \in F$ set of gas production firms. Firms can be assigned to multiple nodes

$p \in P$ set of seasons {low, medium, high}, corresponding to the months {(Apr–Sep), (Feb, Mar, Oct, Nov), (Jan, Dec)}, respectively

$y \in Y$ set of 5-year periods. Here $Y = \{1,2,3,4,5,6\}$, so the time horizon is 25 years (since $Y = 1$ is year 2005)

For simplicity, the index y is suppressed in the below variables, coefficients, and functions.

3.1.2. Primal variables

An asterisk on a variable x (x^*) indicates that the variable is exogenous to the market player in whose optimisation problem the variable appears, even though that variable is endogenous to the market. An example can be price p; a price-taking (competitive) firm naïvely views it as fixed, although the full market model equilibrates price in order to equate supply and demand.

Producer's physical variables

q_{fop} million cubic meter (mcm)/day production by firm f located at o during season p (first 90% of capacity)

q_{fop}^{peak} mcm/day production by firm f located at o during season p (last 10% of capacity)

t_{focp} mcm/day pipeline transport by firm f at o to c during season p

tl_{focp} mcm/day LNG shipping transport by firm f at o to c during season p

s_{fcp} mcm/day sales by firm f to c during season p

Hence, a firm either transports through a pipeline or LNG shipping; the possibility of sequential pipeline–LNG shipping is excluded from the model, but could in general be accommodated.

TSO's variables

z_{kp} mcm/day inter-region pipeline flow through arc k during season p

x_{ocp} mcm/day inter-region LNG transport from o to c during season p

SSO's variables

e_{cp} mcm/day extracted from storage by SSO for c during season $p = \{2,3\}$
i_{cp} mcm/day injection into storage by SSO at c during season $p = \{1\}$

Price variables

p_{cp} wholesale price of gas, in €/thousand cubic meters (kcm), for c during season p
wt_{kp} €/kcm for transport through arc k during season p
wtl_{ocp} €/kcm for shipment of LNG from o to c during season p

3.1.3. Coefficients and functions

Producer's coefficients/functions

D_p number of days per season p
$CQ_f(q_{fop})$ total cost, in €/kcm, of production by firm f (see Eq. (1))
DD_f marginal cost, in €/kcm, of peak production by firm f
MU_{fcp} market power mark-up, defining whether firm f behaves competitively ($MU_{fcp} = 0$) or strategically (Cournot, $MU_{fcp} = 1$), at c during season p
Q_{fop} mcm daily production capacity of firm f at o during season p
TL^{out}_{fo} LNG regasification capacity of producer f at o

TSO's coefficients/functions

$CZ_k(z_{kp})$ total cost, in €/kcm, of transmitting flow z_{kp} on arc k (linear)
Z_k upper mcm limit for flow on arc k (pipeline capacity)
$CX_{oc}(x_{ocp})$ total cost, in €/kcm, of operating the transmission system from o to c (linear)
GTC_{nck} gas transmission capability: a 0–1 parameter, denoting if transmission can take place between n and c through arc k
LTC_{oc} LNG transport capability: a 0–1 parameter, denoting if LNG can be shipped from o to c
TL^{in}_c LNG regasification capacity at c

SSO's coefficients/functions

$CS_c(i_{cp})$ total operational storage costs, including within-region transport to storage, in €/kcm, as a function of injection i_{cp} (linear)
SC_c upper mcm/day limit for storage capacity at c

Market coefficients/functions

$P_{cp}(.)$ €/kcm inverse demand function for c during season p
$P_{cp}(\Sigma_{f\in F}\, s_{fcp} + e_{cp}) = A_{cp} + B_{cp}\ (\Sigma_{f\in F}\, s_{fcp} + e_{cp})$, where A_{cp} is the price intercept and B_{cp} the slope. If this function passes through point $\{P^0{}_{cp},\ S^0{}_{cp}\}$ and has an elasticity of $\varepsilon_{cp} < 0$ at that point, then
$A_{cp} = (1 - 1/\varepsilon_{mcp})P^0_{mcp}$
$B_{cp} = P^0_{cp}/(S^0_{cp}\varepsilon_{cp})$
This point $\{P^0_{cp}, S^0_{cp}\}$ is derived from a competitive calibration model run by assuming a fixed demand S^0_{cp} and then deriving the implied price (dual variable for S^0_{cp}), which depends on the price of gas, transport cost, production cost and network constraints in that season. The parameters A_{cp} and B_{cp} are then obtained by passing the function through the competitive quantity–price pair, assuming elasticity at that point.

3.2. Profit maximisation problems and market-clearing conditions

3.2.1. Producer model

Each producer f maximises profit by choosing sales s_{fcp}, earning the wholesale price. It also chooses production (q_{fop}, q^{peak}_{fop}) and transmission via pipelines (t_{focp}) or shipped as LNG (tl_{focp}), paying production costs and the long-run price of transmission (including congestion):

$$\max_{\substack{q_{fop},q^{peak}_{fop},s_{fcp}\\ t_{focp},tl_{focp}}} \sum_{p\in P} D_p \Bigg\{ \sum_{c\in C}\Bigg[(1-MU_{fcp})p^*_{cp} + MU_{fcp}P_{cp} \times\Bigg(\sum_{f\in F} s_{fcp} + e^*_{cp}|_{p=2,3}\Bigg)\Bigg] s_{fcp} - \sum_{o\in O}\Bigg[\sum_{c\in C}\Bigg(\sum_{k\in K} GTC_{ock}wt^*_{kp}t_{focp} + LTC_{oc}wtl^*_{ocp}tl_{focp}\Bigg) + CQ_f(q_{fop}) + DD_f q^{peak}_{fop}\Bigg]\Bigg\} \tag{2}$$

subject to

$$s_{fcp} - \sum_{o\in O}(t_{focp} + tl_{focp}) = 0(\theta^S_{fcp}) \quad \forall f \in F,\ c\in C,\ p\in P \tag{3}$$

$$-q_{fop} - q^{peak}_{fop} + \sum_{c\in C}(t_{focp} + tl_{focp}) = 0(\theta^P_{fop}) \quad \forall f \in F,\ o\in O,\ p\in P \tag{4}$$

$$\sum_{c\in C} tl_{focp} \leqslant TL^{out}_{fo} \quad (\gamma^{out}_{fop}) \quad \forall f \in F,\ o\in O,\ p\in P \tag{5}$$

$$q_{fop} \leqslant 0.9 \times Q_{fop} \quad (\mu_{fop}); q_{fop}^{peak} \leqslant 0.1 \times Q_{fop} \quad (\mu_{fop}^{peak}) \quad \forall f \in F,\ o \in O,\ p \in P \tag{6}$$

$$q_{fop}, q_{fop}^{peak}, t_{focp}, tl_{focp}, s_{fcp} \geqslant 0 \quad \forall f \in F,\ o \in O,\ c \in C,\ p \in P \tag{7}$$

Firm profit (equal to sales revenue minus costs of gas transport, liquefaction and production) is constrained by the mass balance of sales and transport (3), production and transport (4), the liquefaction capacity (5), production capacity (6) and nonnegativity (7).

3.2.2. TSO model

Price-taking behaviour of TSO simulates efficient allocation of scarce transmission capacity to the most highly valued transmission services. The objective function includes terms for the value (net of shipping costs) associated with pipeline and LNG shipments. Inter-region flows are subject to upper bounds (9), while regasification capacity is also constrained (10) and variables are nonnegative (11):

$$\max_{z_{kp}} \sum_{p \in P} D_p \left[\sum_{k \in K} (wt_{kp}^* z_{kp} - CZ_k(z_{kp})) \right] + \sum_{p \in P} D_p \left[\sum_{o \in O} \sum_{c \in C} (wtl_{ocp}^* x_{ocp} - CX_{oc}(x_{ocp})) \right] \tag{8}$$

subject to

$$z_{kp} \leqslant Z_k \quad (\psi_{kp}) \quad \forall k \in K,\ p \in P \tag{9}$$

$$\sum_{o \in O} x_{ocp} \leqslant TL_c^{in} \quad (\gamma_{cp}^{in}) \quad \forall k \in K,\ p \in P \tag{10}$$

$$z_{kp}, x_{ocp} \geqslant 0 \quad \forall o \in O,\ c \in C,\ k \in K,\ p \in P \tag{11}$$

Note that it is unnecessary to explicitly enforce mass balances at the network nodes for z_{kp}, as these will automatically be satisfied because of (4) and the market-clearing constraints below.

3.2.3. SSO model

Similar to transporters of gas, storage providers are assumed to be competitive. The SSO's profit is the difference between the selling and purchase price, minus storage costs:

$$\max_{\substack{i_{cp} \\ e_{cp}}} \sum_{p=2,3} D_p \sum_{c \in C} p_{cp}^* e_{cp} - \sum_{p=1} D_p \sum_{c \in C} (p_{cp}^* i_{cp} + CS_c(i_{cp})) \tag{12}$$

subject to

$$i_{cp=1} \leqslant SC_c \quad (\lambda_c) \quad \forall c \in C \tag{13}$$

$$\sum_{p=2,3} D_p e_{cp} \leqslant \sum_{p=1} D_p i_{cp} \quad (\sigma_c) \forall c \in C \tag{14}$$

$$e_{cp}, i_{cp} \geqslant 0 \quad \forall c \in C, p \in P \tag{15}$$

Storage is constrained (13), total extraction must be less than total injection (14) and variables are nonnegative (15).

3.2.4. Market-clearing and consistency conditions

$$p_{cp}^* = P_{cp}\left(\sum_{f \in F} s_{fcp} + e_{cp}|_{p=2,3} - i_{cp}|_{p=1} \right) \quad \forall c \in C, p \in P \tag{16}$$

$$z_{kp} = \sum_{f \in F} \sum_{o \in O} \sum_{c \in C} GTC_{ock} t_{focp} \quad (wt_{kp}^*) \quad \forall k \in K, p \in P \tag{17}$$

$$x_{ocp} = LTC_{oc} \sum_{f \in F} tl_{focp} \quad (wtl_{ocp}^*) \quad \forall o \in O, c \in C, p \in P \tag{18}$$

The first market-clearing condition (16) is simply the definition of inverse demand function of consumption sectors within a region as a function of supply to the market, including net supply from storage. The second condition (17) says that the TSO's transmission flows match the transmission services demanded by producers. Condition (18) equates the LNG transmission services provided by the TSO to the LNG services demanded by producers.

3.3. Investments

Here, we consider four types of endogenous investments, namely expansion of liquefaction, regasification, pipeline and storage capacity.

One way to treat investments is to formulate a multiyear model in which all years are simultaneously considered, and variables are defined that represent capacity additions with an appropriate cost term in the objective. Such a model would imply perfect foresight on the part of investors regarding prices. Our model represents a more heuristic investment process within a recursive model structure. Additions to capacity are made once every 5 years, assuming that the marginal value of capacity after 5 years (i.e., the congestion prices in the next period) will apply indefinitely to all future years. This is equivalent to comparing annualised cost (including interest and depreciation) with the expected annual benefits of reducing congestion.

3.3.1. Variables for investment decisions

Z_{ky}^{new} investment in upper daily mcm limit for flow on pipeline arc k in 5-year period y

TO_{foy}^{new} investment in daily mcm LNG liquefaction capacity of producer f at o in 5-year period y

TI_{cy}^{new} investment in daily mcm LNG regasification capacity at c in 5-year period y

SC_{cy}^{new} investment in upper daily mcm limit for storage capacity at c in 5-year period y

Coefficients for investment decisions:

V_k^Z	investment cost in €/m^3 for additional daily pipeline capacity in mcm limit on arc k
V_{fo}^{TO}	investment cost in €/m^3 for additional daily LNG liquefaction capacity in mcm of producer f at o
V_c^{TI}	investment cost in €/m^3 for additional daily LNG regasification capacity in mcm at c
V_c^{SC}	investment cost in €/m^3 for additional daily storage capacity in mcm at c
Δ	depreciation rate (5 yearly; i.e., 1/half decade) for pipeline, liquefaction and regasification capacity
δ^{SC}	depreciation rate for storage capacit
B	real interest rate (5 yearly)
ρ	discount factor ($\rho = 1/(1+\beta)$) (5 yearly)

3.3.2. Investment in pipeline capacity

Concerning investments in pipelines, the time horizon of the TSO is extended 5 years ahead to the next y. TSOs will try to maximise their discounted payoff by choosing the amount of transmission services to deliver after 5 years and the investment cost to be borne in the current year. In a hypothetical multiyear version of the TSO model (8)–(11) with perfect foresight, the TSO would choose values of new capacity (Z_{ky}^{new}) as well as flows (z_{kpy}) in order to maximise the present worth of revenues minus supply and capacity costs over the entire time horizon:

$$\max_{z_{kpy}, Z_{ky}^{new}} \sum_{y \in Y} \rho^y \sum_{k \in K} \left[\rho \sum_{p \in P} D_p (wt^*_{kpy+1} - CZ'_k) z_{kpy+1} - V_k^Z Z_{ky}^{new} \right] \tag{19}$$

The variables in this optimisation function are defined as before, while an index for 5-year periods is added (y). The costs and profits in the future are discounted with discount rate ρ. To have an optimal level of capacity available in the next period, investment costs have to be incurred in the current year. Hence, the investment decision of the TSO in the current period depends on the expected market outcome in the next period. That is why we assign the prices, transmission service and transmission capacity to the next period ($y+1$). Parameter V_k^Z represents the investment costs, while Z_{ky}^{new} denotes the amount of new transmission capacity on arc k.

However, the model we actually implement assumes that firms do not have such perfect foresight, but instead make decisions in a more heuristic manner. We base the investment decisions on the so-called feedback information structure (e.g. [19]). This means that TSOs make their investment decision in every period based on the most recent information, which we assume to be perfect forecasts of just the next period's prices. (Alternatively it is also possible to consider open-loop and closed-loop information structures, see, e.g. [20].) The feedback information structure can be expressed as an identity; leading to Eq. (20) for the transmission flow restriction, which is an extension of (9) and where capital is depreciated at rate δ, where the current level of pipeline capacity also can be expressed as the sum of depreciated past investments:

$$z_{kpy} \leqslant (1-\delta)^{y-1} Z_k + \sum_{\varphi=1}^{y-1} (1-\delta)^{y-1-\varphi} Z_{k\varphi}^{new} \quad (\psi_{kpy}) \forall k \in K,\ p \in P,\ y \in Y \tag{20}$$

From (19) and (20), an optimality condition for the hypothetical multiperiod equilibrium with perfect information can be derived, the left side of which holds as an equality if new capacity additions are being made:

$$0 \geqslant \left\{ -V_k^Z \rho^y + \rho^{y+1} \sum_{\varphi=y+1,\dots} [\rho(1-\delta)]^{\varphi-y-1} \sum_{p \in P} D_p \psi_{kp\varphi} \right\} \perp Z_{ky}^{new} \geqslant 0, \quad \forall k \in K,\ y \in Y \tag{21}$$

(The perpendicular "⊥" symbol indicates that the two terms on either side of the symbol have a product of zero.) Hence, if investment is positive, the present worth of the investment cost equals the sum of the depreciated and discounted shadow prices in subsequent years.

The above condition for the perfect information model can be the basis for a rule for investment in our heuristic model. We would like that rule to be based on an estimate of just the duals for the next 5-year period (and not the whole time horizon, as (21) presently requires). Such a rule can be derived as follows. First, let us assume that demand is growing such that once the model begins adding capacity, the optimal solution is to add capacity in every 5-year period after that year. That means that the left condition of (21) will hold as an equality in y. Now consider the left condition for two adjacent 5-year periods y and $y+1$ in which additions are being made:

$$-V_k^Z \rho^y + \rho^{y+1} \sum_{\varphi=y+1,\dots} [\rho(1-\delta)]^{\varphi-y-1} \sum_{p \in P} D_p \psi_{kp\varphi} = 0 \tag{22}$$

$$-V_k^Z \rho^{y+1} + \rho^{y+2} \sum_{\varphi=y+2,\dots} [\rho(1-\delta)]^{\varphi-y-2} \sum_{p \in P} D_p \psi_{kp\varphi} = 0 \tag{23}$$

These can be rearranged as follows:

$$-V_k^Z \rho^y + \rho^{y+1} \sum_{p \in P} D_p \psi_{kpy+1} + \rho^{y+1} \sum_{\varphi=y+2,\dots} [\rho(1-\delta)]^{\varphi-y-1} \sum_{p \in P} D_p \psi_{kp\varphi} = 0 \tag{24}$$

$$-V_k^Z \rho^{y+1} + (1-\delta)^{-1} \rho^{y+1} \times \sum_{\varphi=y+2,\dots} [\rho(1-\delta)]^{\varphi-y-1} \sum_{p \in P} D_p \psi_{kp\varphi} = 0 \tag{25}$$

Using (25), (24) can be re-expressed as (26), which after rearrangement yields (27):

$$-V_k^Z \rho^y + \rho^{y+1} \sum_{p \in P} D_p \psi_{kpy+1} + \rho^{y+1} V_k^Z (1-\delta) = 0 \tag{26}$$

$$-V_k^Z(\beta+\delta)+\sum_{p\in P} D_p\psi_{kpy+1}=0 \quad (27)$$

In words, the annualised cost (where $(\beta+\delta)$ is the annual cost of capital, adjusted for depreciation) of capacity equals the *sum* of the shadow prices in *all seasons* after 5 years.

This suggests a heuristic rule for investment. If the shadow prices *in this year* (weighted by the lengths of each demand period) equal or exceed the annualised cost of the investment (accounting for depreciation), then some investment are worth making. Note that the investment decision is not a Cournot game; instead, investors are taking future prices as fixed and so are acting as a Bertrand (price-taking) player. Moreover, this dynamic game model can be viewed as a series of short-run equilibria linked by investment decisions made by investment rules, which are implemented in a myopic way in that the investors do not look further ahead than 5 years.

This rule is implemented in GASTALE by adding a capacity variable Z_{ky}^{new} to the right side of constraint (9) of the TSO model, and then subtracting its annualised cost $V_k^Z(\beta+\delta)Z_{ky}^{new}$ from the profit objective. GASTALE is then solved recursively, once every 5 years, starting in 2005. In each year, the model solves for both the short-run equilibrium and for the incremental investments assumed to come on line in that year. Following the recursion logic, the fixed part of the right side of (9) in each subsequent 5 years is defined as the previous year's fixed capacity (minus depreciation) plus new additions made in that previous year.

3.3.3. *Investments in regasification, liquefaction and storage capacity*

Following the same reasoning, we have also derived recursive investment models for the three other types of investment decisions.

4. Results

To demonstrate the scope of the GASTALE model, we present model results concerning the impact of strategic behaviour on future gas prices and investments in the EU. The results are presented in terms of wholesale prices under the assumption of two extreme types of producer behaviour: (1) producers are price takers (PTs, *competitive case*) and (2) producers are fully exercising market power (*Cournot case*). Here the producers who provide "World LNG" are assumed to be able to coordinate their strategies and exercise market power as a joint firm. These two scenarios form two (extreme) possibilities of the liberalised EU gas market, while the reality is likely to be somewhere in between. A third scenario is considered wherein we assume Russia is a PT both in the EU15 and the CEEC10, while all other firms exercise market power as in the Cournot case (*Russia PT case*). This scenario is of interest since Russian profits are actually higher than in the Cournot case, and is therefore arguably more realistic.

4.1. *Prices*

Figs. 3–5 show the wholesale prices for the competitive, Russia PT and Cournot cases. The price is most sensitive to uncertainties in price elasticity, which can be shown by applying a basic sensitivity analysis via permutation, whereas other uncertainties in sales, storage and extraction have a relatively minor impact on the value of calculated prices.

Considering first the competitive case, the figure reveals that the low–high season price differential in 2005 is 30 €/kcm, and rises steadily to about 40 and 43 €/kcm in 2030 for CEEC10 and EU15, respectively. The difference between low and high season prices reflects the marginal cost of storage and the cost of storage congestion, which results from the assumed price-taking behaviour of the storage operator. The congestion costs at most equal the

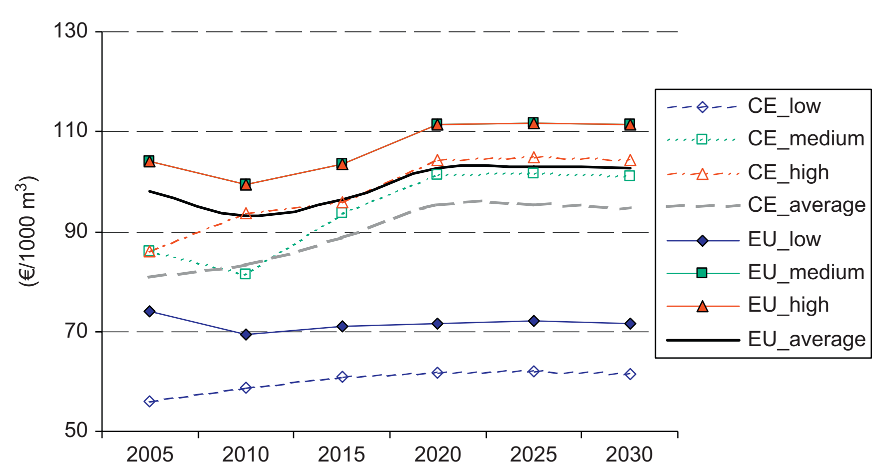

Fig. 3. Wholesale prices in the competitive case.

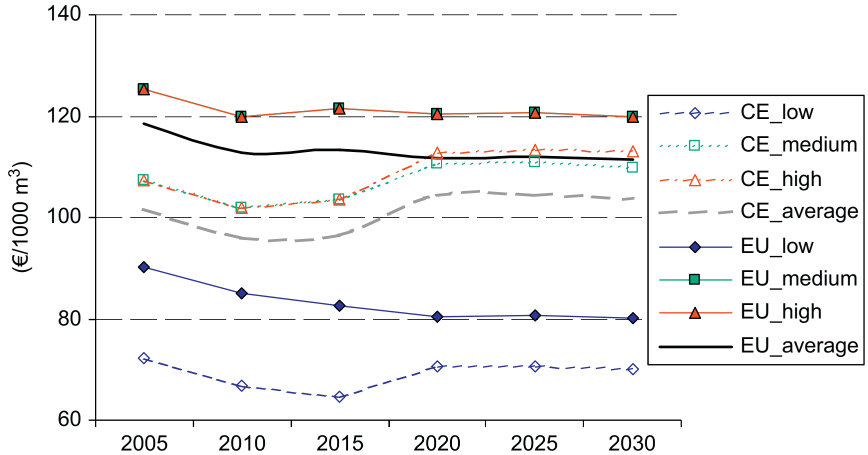

Fig. 4. Wholesale prices in the Russia PT case.

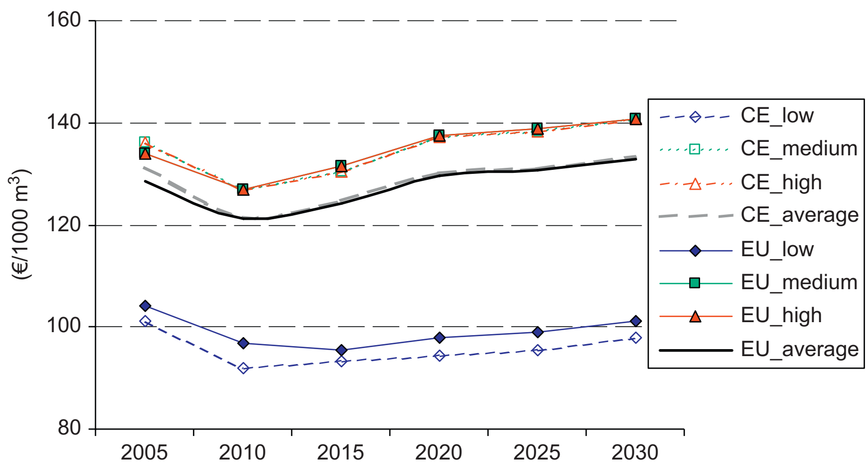

Fig. 5. Wholesale prices in the Cournot case.

additional costs for constructing new storage facilities per unit stored, because the capacity expansion portion of the model automatically adds capacity if congestion costs are sufficient to cover the expense of investment. The congestion component is positive when the storage capacity is limiting (from 2010 onwards in CEEC10 and from 2015 onwards in EU15). Furthermore, the price is substantially higher in EU15 than in CEEC10, although the difference decreases from 17 €/kcm to 8 €/kcm over time due to addition of new pipeline capacity. The lower price region is a transit point for flow of gas from Russia to the EU15; so by the equilibrium conditions, its price must be lower than the EU15 price.

Examination of Figs. 4 and 5 yields similar conclusions concerning the relationship among seasonal prices. Prices in the EU15 remain higher than in the CEEC10. It is worth noting that the Russia PT case leads to near-constant prices over time, in contrast to the increase in competitive prices between 2010 and 2020. The reason why competitive prices rise is that the cheapest options are already used in that case, while in the Russia PT case, TSO investments improve market competitiveness over time. In the Cournot case, prices actually drop by 7–10 €/kcm between 2005 and 2010. This shows that the TSO's investments enhance competitiveness by eliminating the most extreme congestion, allowing competing supplies to enter and lower prices.

But in the Cournot case, Russian market power offsets any advantage that the CEEC10 might have by being closer to Russia's supplies. In the Cournot case, prices are substantially higher due to producer exercise of market power. Moreover, in 2005, mark-ups relative to the competitive case in the EU15 (30 €/kcm) are lower than in the CEEC10 (between 45 and 50 €/kcm). One of the reasons for this difference is that EU15 has substantial production capacity of its own. The mark-ups are roughly halved once Russia becomes a PT (Russia PT case) and the mark-ups become equal in the EU15 and the CEEC10. In the Russia PT case, the prices are lower in the CEEC10 than in the EU15 market, indicating that CEEC10 benefits most from a price-taking Russia, given that all other producers remain Cournot.

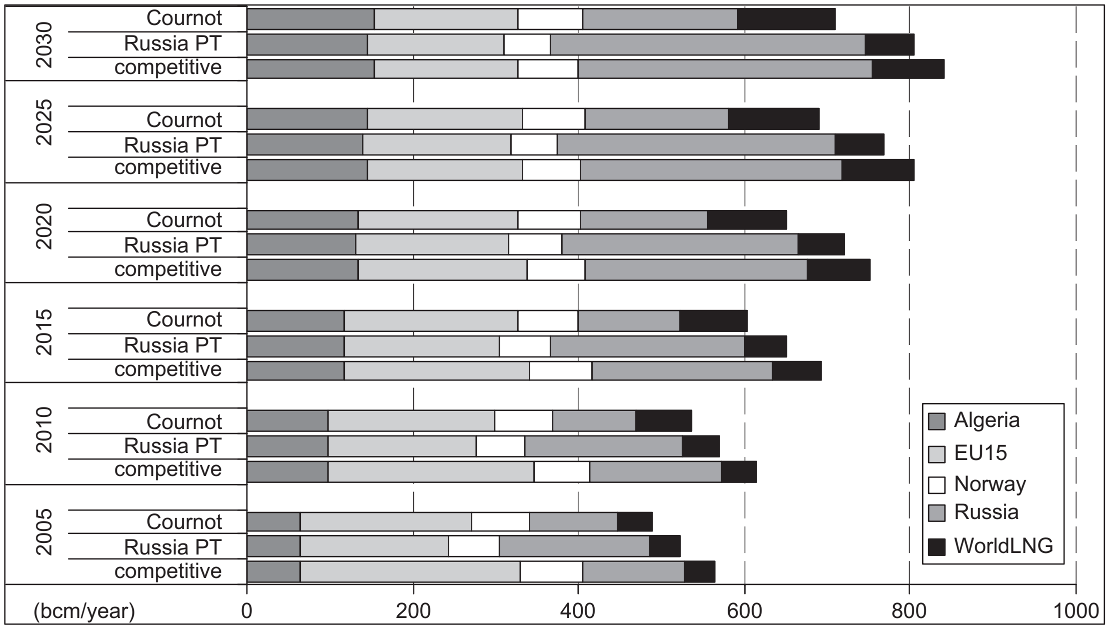

Fig. 6. Production over time in five regions for three cases (in bcm per year).

4.2. Production and supply security

Fig. 6 shows production over time. It reveals an overall production drop in going from the competitive to the Cournot case. This holds for EU15 and Russia, while production in Algeria stays the same (at full capacity). On the other hand, production increases somewhat in Norway and World LNG. Thus, consistent with the Cournot model, large strategic producers see a reduction in their market share when behaving strategically, while small producers with spare capacity instead expand their production to take advantage of the higher prices caused by withdrawal of capacity by large producers. In the Russia PT case, Russian production is higher than the competitive case because higher prices motivate more output, while it is higher than under Cournot by an even greater amount because Russia no longer behaves strategically.

The role of production constraints in the model is as follows. In general, production is at its upper bound for more countries in the competitive case than in the Cournot case, because no one withholds capacity. For non-Russian producers they are more likely to be binding in the Cournot case than in the PT case, because in both cases non-Russian producers withdraw capacity a la Cournot. In the PT case, Russia expands its output as a price taker, resulting in reductions in output by other producers. On a country-by-country basis, the results are as follows. Production constraints are always binding in Algeria in all considered cases. They are fully binding in the competitive case in the EU15 and binding under high and medium demand in EU15 from 2015 onwards in the Cournot and Russia PT cases. They are binding in Norway only in 2015 in the competitive and Cournot cases, while never binding in the Russia PT case. They are binding from 2020 onwards for World LNG in the Cournot and competitive case and never binding in the Russia PT case. Russian capacity is fully binding under medium and high demand in the Russia PT and competitive case, but never binding in the Cournot case. Hence, except for Algeria all other producers provide swing production from time to time. Capacity constraints are mainly binding under medium and high demand, except for the most expensive producers, namely Norway and World LNG (2005–2015).

Demand and price increases spur production growth. In 2005, the total quantity demanded in the Russia PT case is 8% lower than the competitive case, but is 7% higher than the Cournot case. By 2030, these differences become, respectively, 4% and 12%. EU15's contribution to production falls over time in the competitive case. This is due to our assumption of decreasing production capacity in EU15 over the period 2005–2030, in which EU15 produces in the competitive case. EU15 production is much lower in other cases, but shows an increasing trend over time, unlike the competitive case, because more favourable prices stimulate production and the availability of spare capacity to accommodate demand growth.

Table 8
Outcomes in terms of security of supply, EU15 production as share of EU15 consumption

	2005 (%)	2010 (%)	2015 (%)	2020 (%)	2025 (%)	2030 (%)
Competitive case	56	49	40	34	30	27
Russia PT case	41	38	36	32	29	27
Cournot case	49	45	42	36	34	31

The security of supply in EU15, defined as the share of local production in the total consumption is going down from about 50% in 2005 to about 30% in 2030 (Table 8). The exact level of security of supply depends on the ability of firms to exercise market power. In 2005 the security of supply is the highest under perfect competition (56%), while in 2030 the security of supply is the highest under Cournot competition (31%). A steady supply from Russia could reduce the speed of depletion of indigenous gas sources.

4.3. Investments

In order to gain insight into dynamic changes in the liberalised EU gas market, we now consider investment behaviour. Table 9 presents the projected investments for the three studied cases for the years 2005 through 2030, including totals for storage, pipelines, liquefaction and regasification. For each corridor, the actual flow, new investments and total capacity are presented. The capacities of 2005 cannot be altered by new investments, which commence from 2010 onwards.

Table 9 yields several insights. First of all, it shows the extent to which capacities are congested. It turns out that storage capacity is fully used only in 2015 or afterwards. As a result storage investment commences in 2020. Investments are the highest in the Cournot case, followed by the Russia PT case and the lowest in the competitive case. This is because the ability of price-taking SSOs to invest in storage moderates the ability of producers to exercise market power.

Second, pipeline, liquefaction and regasification capacities are not binding during some seasons. Thus, existing corridors must be able to deliver during the highest demand, and a part of this capacity is not needed during low demand; thus, no congestion rents would be able to contribute to fixed costs at those times. Also the degree of utilisation differs among the three considered scenarios. In 2030, 150 billion cubic meters (bcm) of pipeline capacity is unused in the competitive case, 95 bcm of pipeline capacity is unused in the Russia PT case, while only 72 bcm is unused in the Cournot case. The same pattern applies to LNG facilities. The higher use of pipelines and LNG facilities in the Russia PT case is due to a competitive Russia's desire to increase market share. Note that we assume that Russian exports utilise both pipelines and LNG facilities, which is not presently the case but could be so in future.

Third, Table 9 provides a variety of insights into TSO and SSO investment decisions. For instance, the Norway to EU15 (N_EU) interface expands in all scenarios, but by the lowest amount in the Russia PT case, because Russian gas

Table 9
Usage, investments and capacity of storage, pipeline transport, liquefaction and regasification (in bcm/year)

	Competitive case						Russia PT case						Cournot case					
	2005	2010	2015	2020	2025	2030	2005	2010	2015	2020	2025	2030	2005	2010	2015	2020	2025	2030
Storage																		
Total stored	49.9	46.5	57.2	61.0	64.4	61.5	63.9	58.5	59.2	65.3	74.7	76.8	62.5	59.9	59.2	71.6	82.9	90.8
Storage capacity	70.5	64.6	59.2	61.0	64.4	61.5	70.5	64.6	59.2	65.3	74.7	76.8	70.5	64.6	59.2	71.6	82.9	90.8
Total new investments		0.0	0.0	6.7	8.5	2.5		0.0	0.0	11.0	14.8	8.3		0.0	0.0	17.3	17.2	14.7
CEEC10		0.0	0.0	0.2	2.2	2.5		0.0	0.0	0.0	2.2	2.4		0.0	0.0	1.0	4.6	8.3
EU15		0.0	0.0	6.5	6.3	0.0		0.0	0.0	11.0	12.6	5.9		0.0	0.0	16.3	12.6	6.4
Pipelines																		
Total transported	263.4	284.8	319.3	355.1	390.6	427.1	415.4	381.1	323.4	328.0	353.5	380.0	329.0	385.9	367.4	353.7	349.5	350.7
Pipeline capacity	622.3	585.0	551.2	545.5	558.7	577.8	622.3	585.0	522.5	476.2	468.4	474.4	622.3	585.0	522.5	473.6	440.8	422.7
Total new investments		66.6	63.8	86.4	104.3	112.4		66.6	35.2	40.9	71.8	84.2		66.6	35.2	38.4	46.3	55.5
A_EU		66.6	35.2	38.4	31.5	33.1		66.6	35.2	38.4	31.5	33.1		66.6	35.2	38.4	31.5	33.1
EU_CE		0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0	6.2
N_EU		0.0	0.0	0.7	16.2	15.8		0.0	0.0	0.0	0.0	8.6		0.0	0.0	0.0	14.8	16.3
R_CE		0.0	28.7	47.4	56.5	63.5		0.0	0.0	2.6	40.2	42.5		0.0	0.0	0.0	0.0	0.0
Liquefaction																		
Total liquefied	65.9	87.2	148.7	194.1	225.3	240.9	65.3	98.6	179.1	245.7	279.2	305.1	69.7	69.5	124.7	182.4	219.1	244.2
Liquefaction capacity	71.5	153.2	209.3	256.3	285.1	312.0	71.5	138.3	220.5	289.2	321.5	350.5	71.5	102.3	158.2	213.1	259.3	291.7
Total new investments		93.6	81.7	81.9	71.6	74.5		78.8	105.3	105.5	80.6	82.7		42.7	73.0	81.3	81.8	75.6
Russia		44.4	55.1	44.4	43.6	45.0		52.5	83.4	83.9	59.9	66.0		0.0	41.4	49.7	48.8	46.0
World LNG		49.2	26.6	37.5	28.0	29.5		26.2	21.9	21.6	20.7	16.8		42.7	31.6	31.6	33.0	29.7
Regasification																		
Total regasified	65.9	87.2	148.7	194.1	225.3	240.9	65.3	98.6	179.1	245.7	279.2	305.1	69.7	69.5	124.7	182.4	219.1	244.2
Regasification capacity	71.2	136.2	195.2	244.5	275.3	303.8	71.2	113.7	200.0	272.1	307.8	339.4	71.2	77.7	137.7	197.1	246.0	280.5
Total new investments		76.9	81.7	81.9	71.6	74.5		54.4	105.3	105.5	81.1	83.1		18.4	73.0	82.3	81.8	75.6
CEEC10		0.0	0.0	0.0	0.0	0.0		0.0	1.0	8.8	6.4	6.4		8.5	7.2	10.6	11.1	13.2
EU15		76.9	81.7	81.9	71.6	74.5		54.4	104.3	96.8	74.7	76.7		9.8	65.9	71.7	70.7	62.4

displaces Norwegian gas in the EU market while Norwegian suppliers strategically withhold supply. Russian exports (through both pipelines and LNG terminals) increase, and World LNG producers are also expanding their liquefaction capacities. The matching regasification capacities are expanded the most in the EU15, with relatively little to no additional investment in the CEEC10.

The share of LNG in total transported gas (pipelines + LNG) increases from 20%, 14% and 17% in 2005 in the competitive, Russia PT and Cournot cases, respectively, to 35%, 45% and 41% in 2030. Hence, LNG is an increasingly important alternative to pipeline transport, especially for transport over longer distances, where LNG has a strong cost advantage.

Our investment model assumes a heuristic decision process in which a given year's investments consider only prices 5 years hence. We therefore compare results with a perfect foresight model in which all periods are solved simultaneously. Under perfect foresight, investments would be higher and earlier than under our heuristic decision process. Investments in pipelines are higher over the whole time horizon, while investments in storage and LNG are lower from 2020 onwards. The reason for these earlier and higher investments in the case of perfect foresight is that all future expected congestion are taken into account and investors make sure that investments are undertaken at the time of highest net profit.

5. Conclusions

This paper has presented a dynamic model of the liberalised European gas market, including investment in storage and transport facilities. After describing the model formulation and parameterisation, we undertook an analysis of the effect of market imperfections on prices and supply security in the European gas market. This analysis illustrates the capabilities of this model relative to previously proposed gas market models. In particular, our model simulates endogenous investments over multiple years, a capability not available in previously published oligopolistic models of the gas market.

This paper has shown the need to consider market imperfections in the European gas market; in particular, market power significantly affects prices and flows. From an investment perspective, the model indicates that extending the pipeline between Algeria and Western Europe, as well as LNG liquefaction of gas produced by Russia and other importers to Europe, appear attractive, especially if Russia acts competitively while other producers exercise market power. Market imperfection also plays a role in European security of supply, where a steady supply from Russia could reduce the speed of depletion of indigenous gas sources.

In addition the model analyses in this paper lead to the following conclusions:

- in the Cournot case, prices drop by 7–10 €/kcm between 2005 and 2010, showing that the TSO's investments enhance competitiveness by eliminating the most extreme congestion, allowing competing supplies to enter and lower prices;
- the Russia PT case is preferred over the Cournot case by three parties, where CEEC10 benefits from lower prices, Russia benefits from higher profits due to more sales and EU15 benefits from lower prices and keeping a high amount of indigenous gas stocks;
- consistent with the Cournot model, large producers see a reduction in their market share when behaving strategically, while small producers with spare capacity expand their production;
- capacity constraints are mainly binding under medium and high demand, except for the most expensive producers, namely Norway and World LNG (2005–2015);
- investments are the highest in the Cournot case, followed by the Russia PT case and the lowest in the competitive case; the ability of price-taking SSOs to invest in storage moderates the ability of producers to exercise market power;
- regasification capacities are expanded the most in the EU15, with relatively little to no additional investment in the CEEC10, which is close to abundant Russian gas sources;
- The share of LNG in total transported gas increases from 14% in 2005 to 45% in 2030 in the Russia PT case. Hence, LNG is an increasingly important alternative to pipeline transport, especially for transport over longer distances, where LNG has a strong cost advantage.

The results of this paper also suggest several areas for future work. First, future work will develop a more detailed version of this model to represent individual geographic markets within the EU15 and CEEC10 countries to study effects of delivery interruption and market power on prices and investment decisions [21]. Second, the TSOs and SSOs considered in this paper could be represented as strategic rather than regulated price takers, so that they could exercise market power with respect to investments and possibly obtain higher profits. We expect that this would lead to a delay in investments, which is clearly observed already in the current European market. Treatment of this issue would, however, be complex and is beyond the scope of the current paper. Third, in order to obtain a realistic base case, it is also possible to impose certain investment decisions in the model as boundary conditions, for instance the construction of the Baltic pipeline connecting Russia directly to Germany, which would not be built based on the economic fundamentals considered in this paper. Fourth, long-term contracts that last beyond the first 5-year period should also be represented, as they would dampen the incentive for contracting producers to restrict supply.

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Appendix. KKT optimality conditions of GASTALE

Equilibrium conditions for the gas market is characterised by the following Karush–Kuhn–Tucker (KKT) conditions for producers, TSO, and SSOs, together with market clearing. The static model consists of Eqs. (28)–(48), while in the dynamic model, equations (37), (40), (41), (43) are replaced by their dynamic equivalent conditions for investments, as denoted in Eqs. (49)–(56). The KKT conditions are expressed as complementarity conditions.

Producers:

$$\forall q_{fop}: \quad 0 \leqslant q_{fop} \perp [-CQ'_f(.) - \mu_{fop} + \theta^P_{fop}] \leqslant 0 \tag{28}$$

$$\forall q^{peak}_{fop}: \quad 0 \leqslant q^{peak}_{fop} \perp [-D_f - \mu^{peak}_{fop} + \theta^P_{fop}] \leqslant 0 \tag{29}$$

$$\forall t_{focp}: \quad 0 \leqslant t_{focp} \perp \left[\theta^S_{fcp} - \sum_{k \in K} GTC_{ock} wt^*_{kp} - \theta^P_{fop}\right] \leqslant 0 \tag{30}$$

$$\forall tl_{focp}: \quad 0 \leqslant tl_{focp} \; [\theta^S_{fcp} - LTC_{oc} wtl^*_{ocp} - \theta^P_{fop} - \gamma^{out}_{fop}] \leqslant 0 \tag{31}$$

$$\forall s_{fcp}: \quad 0 \leqslant s_{fcp} \perp [p^*_{cp} + MU_{fcp} B_{cp} s_{fcp} - \theta^S_{fcp}] \leqslant 0 \tag{32}$$

$$\forall \theta^S_{fcp}: \quad \theta^S_{fcp} \perp \left[s_{fcp} - \sum_{o \in O} (t_{focp} + tl_{focp})\right] = 0 \tag{33}$$

$$\forall \theta^P_{fop}: \quad \theta^P_{fop} \perp \left[-q_{fop} - q^{peak}_{fop} + \sum_{c \in C} (t_{focp} + tl_{focp})\right] = 0 \tag{34}$$

$$\forall \mu_{fop}: \quad 0 \leqslant \mu_{fop} \perp [q_{fop} - 0.9 \times Q_{fop}] \leqslant 0 \tag{35}$$

$$\forall \mu^{peak}_{fop}: \quad 0 \leqslant \mu^{peak}_{fop} \perp [q_{fop} - 0.1 \times Q_{fop}] \leqslant 0 \tag{36}$$

$$\forall \gamma^{out}_{fop}: \quad 0 \leqslant \gamma^{out}_{fop} \perp \left[\sum_{c \in C} tl_{focp} - TL^{out}_{fo}\right] \leqslant 0 \tag{37}$$

TSO:

$$\forall z_{kp}: \quad 0 \leqslant z_{kp} \perp [wt^*_{kp} - CZ'_k(.) - \psi_{kp}] \leqslant 0 \tag{38}$$

$$\forall x_{ocp}: \quad 0 \leqslant x_{ocp} \perp [wtl^*_{ocp} - CX'_{oc}(.) - \gamma^{\text{in}}_{cp}] \leqslant 0 \tag{39}$$

$$\forall \psi_{kp}: \quad 0 \leqslant \psi_{kp} \perp [z_{kp} - Z_k] \leqslant 0 \tag{40}$$

$$\forall \gamma^{in}_{cp}: \quad 0 \leqslant \gamma^{in}_{cp} \perp \left[\sum_{o \in O} x_{ocp} - TL^{in}_c\right] \leqslant 0 \tag{41}$$

SSO:

$$\forall i_{cp}: \quad 0 \leqslant i_{cp} \perp [-p^*_{cp} - CS'_c(.) - \lambda_c + \sigma_c] \leqslant 0 \tag{42}$$

$$\forall \lambda_c: \quad 0 \leqslant \lambda_c \perp \left[\sum_{p=1} i_{cp} - SC_c\right] \leqslant 0 \tag{43}$$

$$\forall e_{cp}: \quad 0 \leqslant e_{cp} \perp [p^*_{cp} - \sigma_c] \leqslant 0 \tag{44}$$

$$\forall \sigma_c: \quad 0 \leqslant \sigma_c \perp \left[\sum_{p=2,3} D_p e_{cp} - \sum_{p=1} D_p i_{cp}\right] \leqslant 0 \tag{45}$$

Market clearing:

$$\forall p^*_{cp}: \quad p^*_{cp} = P_{cp}\left(\sum_{f \in F} s_{fcp} + e_{cp}|_{p=2,3} - i_{cp}|_{p=1}\right) \quad \forall c \in C, p \in P \tag{46}$$

$$\forall wt^*_{kp}: \quad z_{kp} - \sum_{f \in F} \sum_{o \in O} \sum_{c \in C} GTC_{ock} t_{focp} = 0 \tag{47}$$

$$\forall wtl^*_{ocp}: \quad x_{ocp} - \sum_{f \in F} LTC_{oc} tl_{focp} = 0 \tag{48}$$

Dynamic investment decisions (*an index for years is added*):

$$\forall Z^{new}_{ky}: \quad 0 \leqslant Z^{new}_{ky} \perp \left[\sum_{p \in P} D_p \psi_{kpy+1} - (\beta + \delta) V^Z_k\right] \leqslant 0 \tag{49}$$

$$\forall \psi_{kpy+1}: \quad 0 \leqslant \psi_{kpy+1} \perp [z_{kpy+1} - (1-\delta) Z_{ky} - Z^{new}_{ky}] \leqslant 0 \tag{50}$$

$$\forall TO^{new}_{foy}: \quad 0 \leqslant TO^{new}_{foy} \perp \left[\sum_{p \in P} D_p \gamma^{out}_{fopy+1} - (\beta + \delta) V^{TO}_{fo}\right] \leqslant 0 \tag{51}$$

$$\forall \gamma^{out}_{fopy+1}: \quad 0 \leqslant \gamma^{out}_{fopy+1} \perp \left[\sum_{c \in C} tl_{focpy+1} - (1-\delta) TL^{out}_{foy} - TO^{new}_{foy}\right] \leqslant 0 \tag{52}$$

$$\forall TI^{new}_{cy}: \quad 0 \leqslant TI^{new}_{cy} \perp \left[\sum_{p \in P} D_p \gamma^{in}_{cpy+1} - (\beta + \delta) V^{TI}_c\right] \leqslant 0 \tag{53}$$

$$\forall\gamma^{in}_{cpy+1}:\quad 0\leqslant\gamma^{in}_{cpy+1}\perp\left[\sum_{o\in O}x_{ocpy+1}-(1-\delta)TL^{in}_{cy}-TI^{new}_{cy}\right]\leqslant 0 \tag{54}$$

$$\forall SC^{new}_{cy}:\quad 0\leqslant SC^{new}_{cy}\perp[D_{p=1}\lambda_{cy+1}-(\beta+\delta^{SC})V^{SC}_{c}]\leqslant 0 \tag{55}$$

$$\forall\lambda_{cy+1}:\quad 0\leqslant\lambda_{cy+1}\perp[i_{cp=1,y+1}-(1-\delta^{SC})SC_{cy}-SC^{\mathrm{new}}_{cy}]\leqslant 0 \tag{56}$$

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