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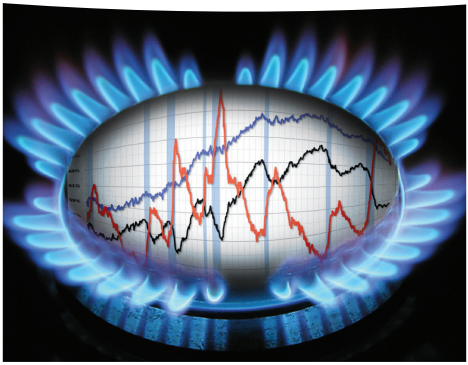

The Danube Region Gas Market Model

Identifying Natural Gas Infrastructure Priorities for the Region

NEW SZÉCHENYI PLAN

PREPARED BY

REKK

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THE DANUBE REGION GAS MARKET MODEL AND ITS APPLICATION TO IDENTIFYING NATURAL GAS INFRASTRUCTURE PRIORITIES FOR THE REGION

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1 ABSTRACT

The paper introduces the Danube Region Gas Market Model, a network and contract constrained multi-country competitive equilibrium model and applies it to estimate the impacts of new gas infrastructure investments on market integration, social welfare and supply security in the countries of Central and South East Europe. Individual projects, project packages (e.g. the North-South gas corridor for Central and Eastern Europe) and international pipeline projects (like Nabucco West) are evaluated according to the Regional Cost Convergence Index. Estimates on price spill-over effects of new infrastructures are also presented. The model can support cost benefit analyses foreseen by the proposed European Infrastructure Package to identify EU projects of common interest.

Keywords: Natural gas, Security of supply, Gas market modelling

2 INTRODUCTION

New EU member states and the wider Central and Southeast European region (from this point forward the Danube Region or DR[2]) suffer from specific gas industry problems. The most serious of them is the lack of sufficient interconnectivity which impedes gas supply source diversification for the DR, reduces the scope for gas market integration and supply security improvements at the regional level.[3]

Since the shock of the 2009 January gas crisis, European energy policy has been attempting to remedy the above mentioned gas industry problems of the DR and Energy Community countries alike. A prominent example is the gas supply security regulation 994/2010 of the EU. The new European Infrastructure Package (EIP)[4] intends to identify and provide Union level support for gas infrastructure projects that will positively impact interconnectivity and market integration[5] in the region. The EIP identifies certain priority corridors, which in the case of gas includes linking the Baltic, Black, Adriatic and Aegean Seas. The development of north-south interconnections in Central and Eastern Europe and Southeast Europe forms an important element of this corridor. In 2011 the EC commissioned a "High Level Group"[6] with the mandate to devise an action plan for the development of interconnections in gas, electricity and oil by the end of 2011. The High Level Group published its action plan in December 2011. In 2012 this work continues with a similar High Level Group activity for the Energy Community countries.

Finally, in October 2011, the EU approved the European Union Strategy for the DR that foresees a strengthened cooperation in a wide range of areas, including energy policy. Its Action Plan[7] states that for a secure and well-functioning natural gas market in the DR;

'…the interconnections between national markets have to be improved and countries in the region need to gain access to new external sources. Reinforcing gas transmission infrastructure will be key for preventing potential supply disruption in the future. Well-functioning networks, interconnections and interoperability are needed for energy security, diversification and effective energy operation.' (EC 2011, p. 18).

While an agreement seems to emerge that gas infrastructure development is the key to improve gas market integration and supply security for the DR, no solid methodology has yet been developed to assess the impacts of the proposed projects or project packages on regional gas market integration, security of supply, competition and sustainability. Moreover, while the proposed Regulation foresees the application of energy system-wide cost-benefit analysis for the evaluation of promoted projects, such a methodology is still to be developed – in the case of gas by the European Network of Transmission System Operators for Gas (ENTSO-G).

The study by Kantoor Management Consultants (2012) develops a methodology to establish priorities for regional gas infrastructure developments in support of the North-South gas working group, but the proposed methodology still leaves many problems unsolved. Its basis is a physical flow model, with country-level analysis, focusing mostly on security of supply issues. The gas market representation is rather

[2] The 14 Danube Region countries are: Austria (AT), Bosnia and Herzegovina (BA), Bulgaria (BG), Croatia (HR), the Czech Republic (CZ), Germany (DE), Hungary (HU), Moldova (MV), Montenegro (MNE), Romania (RO), Serbia (SB), Slovakia (SK), Slovenia (SL) and Ukraine (UA).
[3] The price, supply security and political risks of a lock-in situation with dominant Russian import dependence for the DR are assessed by Kaderják (2011a and 2011b).
[4] COM(2011) 658 (in the followings: proposed Regulation), SEC(2011) 1233 and COM(2011) 665.
[5] Article 4 of the proposed infrastructure Regulation defines four criteria that will apply for the evaluation of gas projects of common interest; their impact on market integration, security of supply, competition and sustainability.
[6] The High Level Group on north-south interconnections is chaired by the EC and includes Bulgaria, the Czech Republic, Hungary, Poland, Romania and Slovakia as members, and Croatia as an observer. Austria, Germany and Slovenia also became members of this group. The High Level Group also established a "working group on natural gas" (GWG) consisting of representatives of the relevant ministries, regulatory authorities and transmission system operators (TSOs) in the participating countries, except for Austria and Germany.
[7] Com(2010) 715 and SEC(2010) 1489, respectively.

simple and price formation modelling is neglected, leaving the explanation for how new infrastructure will impact market integration incomplete. On the whole, the Kantoor study provides important insights on how changes in infrastructures affect security of supply status of individual countries. However, the analysis does not specifically evaluate the impact of new infrastructure on prices, costs and benefits, or social welfare.

This paper reports on an alternative approach to the evaluation and ranking of new gas infrastructure projects in a regional gas market context. We introduce the Danube Region Gas Market Model (DRGMM) and illustrate how model simulations can be used to assess the impacts of new infrastructure or infrastructure packages on regional gas market integration and for system-wide cost-benefit and security of supply analysis. If extended to include all the EU27 gas markets, the model could help the implementation process of the proposed infrastructure Regulation. First, it could serve as a potential component of the cost-benefit methodology envisioned by the proposed Regulation.[8] Second, model estimates on the distribution of consumer and producer benefits from new infrastructure across impacted countries could also support the Agency for the Cooperation of Energy Regulators (ACER) in elaborating its decisions on cross border cost allocation for Projects of Common Interest (PCI) when national regulatory authorities could not reach an agreement.[9]

The structure of the paper is as follows: After a brief literature review on gas market modelling, we summarize the basic assumptions and characteristics of the DRGMM. Then we present several simulation results to illustrate the variety of analyses the model allows for, including market integration, cost-benefit, and security of supply analyses. Finally we reflect on the limitations of the model's present version and suggest areas for future research.

[8] See e.g. Article 12 of the proposed Regulation.
[9] See Article 13(6) on this matter.

3 LITERATURE REVIEW

Here we will provide a short review of commonly referenced, large-scale computational gas market models that have been used to analyze the security of gas supply and the impact of infrastructure developments in Europe.

The main focus of the EUGAS model (Perner and Seeliger, 2004) is to analyze the prospects of gas supplies to the European market in the coming decades. It assumes perfect competition among market players and contains an extensive infrastructure representation. The objective function and the constraints of this model are linear across a five year horizon, and the annual gas consumption is split seasonally into three different load periods.

Contrary to the EUGAS model, most of the gas simulation models depict the strategic interaction between the suppliers. The GASTALE model (Boots, 2004) was the first attempt to apply successive oligopoly conditions in natural gas production and trading in a large-scale simulation model. The model has a two-level structure, in which producers engage in competition a la Cournot, and each producer is a Stackelberg leader with respect to traders, who may be Cournot oligopolists or perfect competitors.

The extended, dynamic versions of the GASTALE model (Lise and Hobbs, 2008 and 2009) include investments in scarce infrastructure (such as pipelines, storages and LNG infrastructure), but they assume market power only for producers.

GASMOD (Holz et al., 2008) is similar in spirit to GASTALE, similarly structuring the European natural gas market as a two-stage-game of successive oligopolies; imports to Europe (first stage, upstream) and trade within Europe (second stage, downstream). As the model's main focus is to examine the possible effects of liberalization on trade, the geographical coverage of the model is wide. On the demand side it includes all European markets and on the supply side it includes all major exporters to Europe.

Egging et al. (2008) presented a more detailed complementary model of the European natural gas market which accounts for the market power of exporters and of the globalization of natural gas markets with LNG trade. The market structure that their model constructs is different from that of GASMOD and the static GASTALE model, marked by the assumption that only traders can exert market power by playing the Cournot game against each other, with other players assumed to be price takers.

Based on their previous work (Gabriel et al. 2005a, b) Egging et al. (2010) presented the World Gas Model. It is a multi-period mixed complementarity model for the global natural gas market, which contains more than 80 countries and regions and covers 98% of worldwide natural gas production and consumption. It also includes a detailed representation of cross-border pipelines and constraints imposed by long-term contracts in the LNG market. The model operates with five year periods and two seasons (peak and off-peak). Similar to the previous models, it accounts for market power in the upstream market between traders using both pipelines and LNG deliveries. It allows for endogenous capacity expansions and seasonal arbitrage by storage operators.

The NATGAS model (Mulder and Zwart, 2006) assumes an oligopolistic producer market where a small number of strategic natural gas producers are facing price-taking traders in the downstream market. The main focus of the model is to compute long-term effects of policy measures on future gas production and gas prices in Europe. It contains 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).

Abada et al. (2012) developed a dynamic Generalized Nash–Cournot gas market model (GaMMES model). In the applied oligopolistic market structure they take into account long-term contracts in an endogenous way, which makes the model a Generalized Nash Equilibrium problem. Their demand representation is specific because it captures the possible fuel substitution that can be made between the consumption of oil, coal, and natural gas in the overall fossil energy consumption.

4 THE DANUBE REGION GAS MARKET MODEL

The Danube Region Gas Market Model has been developed by REKK to simulate the operation of an international wholesale natural gas market in the Central and South-East European (CSEE) region.[10] Figure 1 shows the geographical scope of the model. Country codes denote the countries for which we have explicitly included the demand and supply side of the local market, as well as gas storages. Large external markets, such as Germany, Italy or (indirectly) Russia, are represented by exogenously assumed market prices, long-term supply contracts and physical connections to the CSEE region.

Figure 1 The geographical scope of the Danube Region Gas Market Model

All map outlines are based on the maps of Daniel Dalet, source: http://d-maps.com/m/europemax/europemax09.svg

Given the input data and subject to constraints represented by the physical gas infrastructure and contractual arrangements specific for the Danube Region, the model calculates a dynamic competitive market equilibrium, resulting in the market clearing prices, along with the production, consumption and trading quantities, storage utilization decisions, and long-term contract deliveries.

Model calculations refer to 12 consecutive months, with a default setting of April to March.[11] Dynamic connection between months are introduced by the operation of gas storages ("you can only withdraw what you have injected previously") and long-term take-or-pay (TOP) contract constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual "make-up").

The Danube Region Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) TOP contracts; and (7) spot trading. We will describe each of them in detail below.

[10] For an initial description and application of REKK's Regional Gas Market Model see Kaderjak, P. 2011a, 121-147.
[11] The start of the modelling year can be set to any other month.

4.1 LOCAL DEMAND

Local consumption refers to the amount of gas consumed in each of the local markets in each month of the modelling year. It is, therefore, a quantity measure.[12] Local demand, on the other hand, is a functional relationship between the local market price and local consumption, similarly specified for each month of the modelling year.

Local demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases by 0.1 €/MWh, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example).

The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.

4.2 LOCAL SUPPLY

Local *production* is a measure of quantity similar to local consumption, so the corresponding counterpart to local demand is local *supply*. Local supply shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price.

In the model, each supply unit (company, field, or even well) has a constant marginal cost of production (measured in €/MWh). Supply units operate between minimum and maximum production constraints in each month, with the constraints being independent across months.[13] Therefore production decisions in October, for example, have no direct effect on production possibilities in any other month.

Any number of supply units can be defined for each month and each local market. As a result, local supply will be represented by an increasing step-function for which the number and size of steps can be chosen freely.

4.3 GAS STORAGE

Gas storage facilities are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system's supply-demand balance can be positive or negative, depending on whether gas is withdrawn from or injected into storage. Each local market can contain any number of storage units (companies or fields).

Storage units have a constant marginal cost of injection and a separate cost of withdrawal. In each month, there are upper limits on total injections and total withdrawals. There is no specific working gas fee, but the model contains a real interest rate for discounting the periods, which automatically ensures that foregone interest costs on working gas inventories are taken into account.

There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.

[12] All quantities are measured in energy units within the model.
[13] Minimum production levels can be set to zero. If minimum levels are set too high, a market clearing equilibrium may require negative prices, but this practically never happens with realistic input data.

4.4 EXTERNAL MARKETS AND SUPPLY SOURCES

Explicitly modelled local markets are limited to the countries of the CSEE region (including the DR), but their gas sectors are by no means closed to the outside world. There are comparatively large external markets and supply sources neighbouring the region, which can serve as import sources (e.g. Russia, LNG markets), export destinations, or both (e.g. Germany, Italy).

Prices for external markets and supply sources are set exogenously (i.e. as input data) for each month, and they are assumed not to be influenced by any supply-demand development in the local markets. As a consequence, the price levels set for outside markets are important determinants of their trading direction with the CSEE region. When prices are set relatively low, CSEE countries are more likely to import from the outside markets, and vice versa.

4.5 CROSS-BORDER PIPELINE CONNECTIONS

Any two markets (local or outside) can be connected by any number of pipelines, which allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which corresponds to the presence of dedicated transit pipelines.

Cross-border pipelines are unidirectional, but physical reverse flow can easily be allowed for by adding a parallel connection that "points" into the other direction. Each pipeline has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee.

Virtual reverse flow ("backhaul") on unidirectional pipelines can also be allowed or restricted for each connection and each month. The rationale for virtual reverse flow is the possibility to trade "against" the delivery of long-term TOP contracts, being that the reduction of pre-arranged gas flow can be considered the same type of commercial transaction as selling gas in the reverse direction.

We disregard from modelling the internal gas transmission systems of local and external markets.

4.6 LONG-TERM TAKE-OR-PAY (TOP) CONTRACTS

A TOP contract is an agreement between an outside supply source and a local market concerning the delivery of natural gas into the latter. The structure of a TOP contract is the following; each contract has monthly and annual minimum and maximum quantities, a delivery price, and a monthly proportional TOP-violation penalty. Maximum and minimum quantities (monthly or annual) cannot be breached. If the purchase of deliveries are below the monthly minimum, the monthly proportional TOP-violation penalty must be paid for the gas that was not delivered.

Any number of TOP-contracts can be in force between any two source and destination markets. Monthly TOP-limits, prices, and penalties can be changed from one month to the next.

The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract, but they can also be changed month to month. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions.

4.7 SPOT TRADING

The final building block, spot trade, serves to arbitrage price differences across markets that are connected with a pipeline. Typically, if the price on the source-side of the pipeline exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the pipeline is reached.

Physical flows across a pipeline equal of the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become "negative" (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow on a pipeline.

4.8 EQUILIBRIUM

The DRGMM algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, adhering to all the constraints detailed above.

In short, the equilibrium state (the "result") of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders.[14]

Local consumers decide about gas utilization based on the market price. This decision is governed entirely by the local demand functions we introduced earlier.

Local producers decide about their gas production level in the following way: if market prices in their country of operation are higher than unit production costs, then they produce gas at full capacity. If prices fall below costs, then production is cut back to the minimum level (possibly zero). Finally, if prices and costs are exactly equal, then producers choose some amount between the minimum and maximum levels, which is actually determined in a way to match the local demand for gas in that month.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about long-term contract deliveries in each month, based on contractual constraints (prices, TOP quantities, penalties) and local supply-demand conditions.

Second, traders also utilize storages to arbitrage price differences across months. For example, if market prices in January are relatively high, then they withdraw gas from storage in January and inject it back in a later month in such a way as to maximize the difference between the selling and the buying price. As long as there is available withdrawal, injection, and working gas capacity as well as price differences between months exceeding the sum of injection costs, withdrawal costs, and the foregone interest, the arbitrage opportunity will be present and traders will exploit it.[15,16]

Finally, traders also perform spot transactions based on relative prices in local and outside markets based on the available cross-border transmission capacities to and from those markets, including countries such as Russia, Germany, Italy, Turkey, or LNG markets which are not explicitly included in the supply-demand equalization.

[14] When assessing welfare effects, we omit storage operators, since injection and withdrawal fees are set exogenously, and stock changes are determined by traders.
[15] Traders also have to make sure that storages are filled up to their pre-specified closing level at the end of the year, since we do not allow for year-to-year stock changes in the model.
[16] A similar inter-temporal arbitrage can also be performed in markets without available storage capacity, as long as there are direct or indirect cross-border links to countries with gas storage capability. In this sense, flexibility services are truly international in the simulation.

5 SIMULATION RESULTS

This chapter presents an application of the DRGMM to assess the likely impact of all known gas infrastructure development project proposals on regional gas market integration in the DR. The types of projects we analyse are inter-region pipelines (interconnectors, including reverse flow projects), underground storage sites, LNG terminals and international long distance pipelines providing new sources of gas supply for the DR.

For this purpose we create and run a reference scenario with 2011 input data and additional assumptions discussed below. Next we add, one by one, the proposed projects to the reference case infrastructure ceteris paribus and compare model outcomes to the reference case. Thus the outcome of regional gas trading and infrastructure operations can be measured according to the differences in outcomes from the 2011 reference case. When adding new infrastructure to the reference case, we disregard the cost and timing of infrastructure investment, so the model is established 'overnight' and the tariffs paid by infrastructure users for transmission, storage or LNG terminal services remain unchanged. However, for the purpose of cost-benefit analysis we collected available project related investment cost data.

After analysing individual projects one by one, we repeat the same procedure for project packages like the proposed project list of the north-south gas working group. Finally, the likely impact of new long distance pipelines on the regional gas market is assessed in the context of a 2020 reference scenario.

5.1 INPUT DATA

Table 1 contains the dimension and sources of technical input data used for the simulations. In order to create the 2011 reference scenario, we used estimated data when 2011 data was still not available (e.g. consumption data due to delayed publication). The actual data used to create the 2011 and 2020 reference scenarios is summarized in the country profiles in Annex 1.

Data		Source	
Category	Unit	Actual data	Forecast / Planned
Consumption	Annual Quantity (bcm) Monthly distribution (% of annual quantity)	Eurostat, EnC data	N-S study, EnC data, Eurostat, ENTSO-G, own estimation
Production	Minimum and maximum production (mcm/day)	EUROSTAT, EnC data	N-S countries: N-S study, EnC data, ENTSO-G GRIPs, TYNDP,
Infrastructure			
♦ Pipeline	daily maximum flow	ENTSO-G, EnC	TSOs, N-S action plan, TYNDP, GRIPs, EnC
♦ Storage	Injection (mcm/day), withdrawal (mcm/day), working gas capacity (mcm)	GSE	
♦ LNG	Capacity (mcm/day)	GLE	
TOP contracts	Yearly minimum maximum quantity (mcm/year) Seasonal minimum and maximum quantity (mcm/day),	Gazprom, National Regulators Annual reports, Platts	

Table 1 Summary of input data structure and sources

EnC: Energy Community Regional Energy Strategy Task Force data; N-S Study: Kantor Management Consultants (2012)

For the 2020 annual consumption and production forecast we rely on a critical review of the forecasts of institutions listed in Table 1. The monthly distribution of gas consumption for the analysed countries was estimated using historic data (see Figure 2).

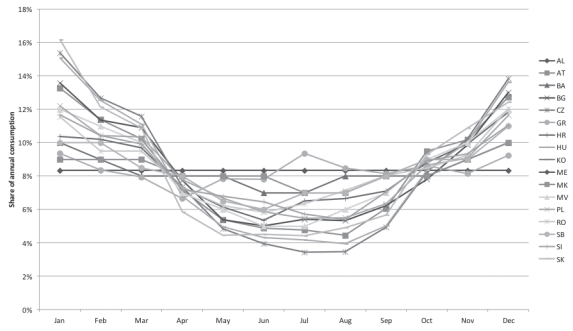

Figure 2 Estimated monthly distribution of consumption in the modelled countries (% of annual consumption)

The pipeline infrastructure of the region for the 2011 reference scenario is depicted on Figure 3.

Figure 3 Interconnector topology used for the 2011 reference scenario. Arrows show the possible physical flow direction and the daily maximum capacity (mcm/day)

Finally, in order to run the model, we also have to assume TOP and spot prices for external markets and tariffs paid by infrastructure users for transmission and storage (injection and withdrawal).

Table 2 contains external gas product prices we use for simulation purposes in this paper. With regard to TOP contracts we assume a mixed pricing regime with a 20% weight for spot and 80% weight for oil indexed pricing, which reflects the European gas industry's ability to renegotiate Russian TOP contracts in recent years due to the economic crisis.[18] The assumed tolerance for TOP annual contracted quantity is ±15%. For the simulations with the 2020 reference scenario, we assume the renewal of the long term contracts expiring between 2011 and 2020, but also assume a 20% decrease in their annual contracted quantity.

Market	Price in €/MWh
Western Europe (TTF spot)	24.2
Russia (TOP)	34.2
Italy (spot)	28.0
Turkey (TOP)	31.6
LNG	24.2
LNG BG, RO	31.6

Table 2 External market price assumptions (€/MWh)

Transit contracts are taken into consideration only as far as they use infrastructure within the DR. In case of Germany and France we assume 50% of their Russian imports will come through Nord Stream from 2013, thus 2020 flows are reduced accordingly. Furthermore, in the case of Germany we assume that 50% of the transit requirements pass through the Yamal pipeline. For Turkey, we take into account only those Russian import contracts that are transmitted through Romania and Bulgaria. For Italy, Russian contracts

go through Slovakia and Austria.

We do not have a realistic representation of local market transmission tariffs for the DRGMM, so we set them close to zero in this paper. We think that disregarding from transmission tariffs will not distort our conclusions because the unit transmission cost for a MWh of gas is negligible compared to its product price.[19] Another argument is that although significant differences in transmission tariffs across the region might distort cross-border arbitrage opportunities, including the utilization of gas storage assets, the advancement of EU-wide gas market regulation and integration is expected to level-off transmission tariffs for the region. Nevertheless, this is a point for further model development.

Data on gas storage tariffs (injection and withdrawal fees) were gathered from storage owners or national energy regulators. Besides direct storage costs, we also account for the foregone interest costs on holding working gas inventories. The real interest rate for calculating the interest costs of gas inventories is set at 5%.

5.2 MARKET INTEGRATION MEASURES

The first set of our project related analyses deals with regional gas market integration and the impact of new interconnectors or LNG stations.[20] Since market integration is a multi-dimension concept and difficult to measure per se, we have developed variations of a simple measure of market integration. Our Regional Cost Convergence Index (RCCI) is based on the assumption that an advance in market integration results in price convergence across the countries concerned and towards cheaper gas supply sources. Thereby in the 'Danube Region 2011' reference, a new piece of gas infrastructure will improve market integration by reducing local oil-indexed prices closer to continental spot price levels.

Formally,

$$RCCI = \frac{\sum p_i \cdot q_i}{p_{spot} \cdot Q} - 1$$

, where

i is an index for the DR countries, i = 1…k;
p_i is the annual weighted average gas price on local market i, calculated by the model;
q_i is the annual gas consumption on local market i, calculated by the model;
Q is the amount of DR gas consumption (sum of qi over k), calculated by the model;
p_{spot} is the continental spot price.

The RCCI is the excess gas purchase cost (a percentage), which is the amount that the DR pays for its gas consumption over the same amount at a continental spot price. The RCCI for the 2011 reference scenario is 21.5%. Figure 3 shows the modelled 2011 reference scenario with local prices (€/MWh, white boxes) and trade flows (arrows), assuming external market prices (included in the grey boxes). White arrows represent non-congested and grey indicates congested interconnections.

[19] REKK has recently carried out a survey of gas transmission tariffs for an 80 MW gas fired power plant for 10 of the modelled countries and found a € 1.87/MWh average value for this group. This is 5.5% of the oil indexed and 7.7% of the German spot price we use in this study.
[20] A positive impact on gas market integration is the singularly most important criterion a PCI should meet according to Article 4 of the proposed infrastructure Regulation.

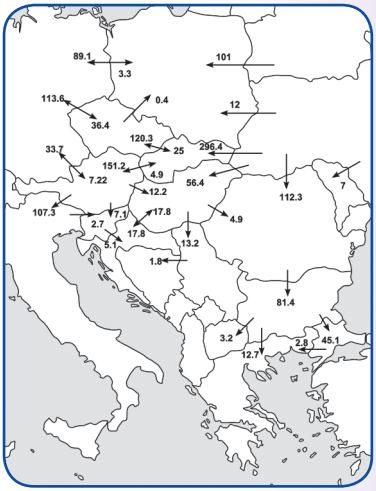

Figure 4. Reference scenario: 2011 current infrastructure ($RCCI_{ref}$ = 21.5%)

ANALYSIS OF INDIVIDUAL PROJECTS CASE BY CASE

To calculate the project RCCIs, we added the proposed gas infrastructure projects to the 2011 reference scenario one at a time, holding everything else constant. No single gas storage project had a significant regional market integration impact. Table 3 contains the pipeline simulations and Table 4 lists the LNG projects, in the order of increasing RCCI values. Those projects with lower RCCI save more gas purchase cost for the region than those with higher values, while the distribution across individual countries will vary. For example, in the 2011 reference scenario, consumers of the Danube Region pay 4700 million € more than what they would pay for their consumption on a Western European spot market price.

We identified seven pipeline and five LNG projects which alone can have a significant and beneficial regional impact on gas prices and purchase costs. While the rest of the pipeline projects do not have a significant regional impact individually, there are some that actually result in higher RCCI values (that is, increasing gas purchase cost for the region). The latter results might seem counter-intuitive, but they are actually consistent with the workings of the market. The market equilibrium maximizes total welfare, i.e. the aggregate welfare of all market players, i.e. consumers, producers, storage and interconnector, operators etc. Therefore while the addition of a new infrastructure element will never decrease short-term social welfare, it may well result in a welfare loss for one or more groups of market players.

Pipeline	RCCI (ref:21,51%)	Pipeline	RCCI (ref:21,51%)
CZ-PL2	17,10%	PL-SK	21,51%
SK-HU	18,35%	BG-RO	21,51%
GR-BG	21,13%	PL-CZ	21,51%
TR-BG	21,29%	HR-IT	21,51%
RS-BG	21,39%	MK-GR	21,51%
RS-RO	21,42%	HR-HU2	21,51%
RO-MD	21,47%	RS-MK	21,51%
BA-RS	21,50%	RS-HR	21,52%
MK-AL	21,51%	BA-HR	21,52%
HR-RS	21,51%	MK-RS	21,55%
HR-BA	21,51%	RO-HU	21,56%
HU-SK	21,51%	BG-RS	21,56%
MK-XK	21,51%	RO-RS	21,56%
AT-CZ	21,51%	MK-BG	21,56%
HR-SI	21,51%	MD-RO	21,57%
RS-BA2	21,51%	SI-HU	21,67%
HU-SI	21,51%		

Table 3 Individual pipeline project ranking by RCCI

	RCCI (ref:21,51%)
LNG-PL	16,94%
LNG-PL2	17,04%
LNG-HR	20,03%
LNG2-RO	20,40%
LNG2-BG	21,29%
LNG-GR2	21,51%

Table 4 Individual LNG project ranking by RCCI

According to RCCI, the best ranking pipeline project for the region is an upgrade of the Czech-Polish interconnector from its present 0.4 mcm/day to 8.6 mcm/day capacity. A new Slovak-Hungarian interconnector ranks second, followed by three projects that reduce relatively high Bulgarian prices, and lastly an interconnection from Romania to Moldova. The best ranking LNG projects are on the Polish and the Croatian territories.

However, project ranking by RCCI alone can be misleading from a regional perspective since it is neutral with regard to the distribution of price changes and cost savings across the countries. Impacts of some projects might be limited within those parties that are directly involved while benefiting others across the region. Our Regional Spill-over Index (RSoI) measures by how much the addition of a new piece of infrastructure will change the 2011 reference RCCI when we exclude the countries directly affected by the new project[21] from the RCCI calculation. Table 5 contains the results for those interconnector projects that produce part of their cost reduction effects beyond the borders of the project countries.

[21] One country in the case of LNG, and two in the case of a new interconnection

Pipeline project	Reduction, %
SK-HU	1.59%
GR-BG	0.51%
RS-BG	0.11%
MD-RO	0.02%
TR-BG	0.01%

Table 5 The reduction of regional gas purchase costs by individual pipeline projects in peripheral countries, %

We can see that the impacts of two of the top ranking projects by RCCI, the Czech-Poland and the Serbia-Romania interconnectors (see Table 3), are strictly limited to the involved countries, (their RSoI is 0). In contrast, the majority of benefits are generated beyond the borders of the project countries (Slovakia-Hungary and Greece-Bulgaria). We can identify similar differences in the case of LNG projects. The benefits of a Polish LNG receiving terminal, without additional cross border pipelines put in place, is strictly limited to Poland itself. At the same time a Croatian LNG project could bring reduced prices and purchase costs not only for itself but also for Slovenia, Hungary, Serbia and Bosnia and Herzegovina without any supplemental infrastructure.

ANALYSIS OF PROJECT PACKAGES – THE NORTH-SOUTH GAS CORRIDOR

The DRGMM model can also be used to carry out similar assessment of regional gas market integration for project packages. In recent years a number of proposals have been put forward to develop a set of infrastructure projects to improve gas market interconnectivity of the DR. The two prominent ones were the New Europe Transmission System (NETS) project (a European priority project under the EU's TEN-E program) and the recently developed North-South gas corridor for Central and Southeast Europe. Since the present status of the NETS project does not allow for the breakdown and identification of its individual infrastructure projects, we used the North-South corridor project list that was published by the Commission in December 2011 (EC, 2011).

Adding the 17 projects of the North-South corridor to the 2011 reference case lowers the RCCI index from 25.1% to 6.8%. This translates into an annual gas purchase cost savings of 2827 million € for the DR (see Figure 5).

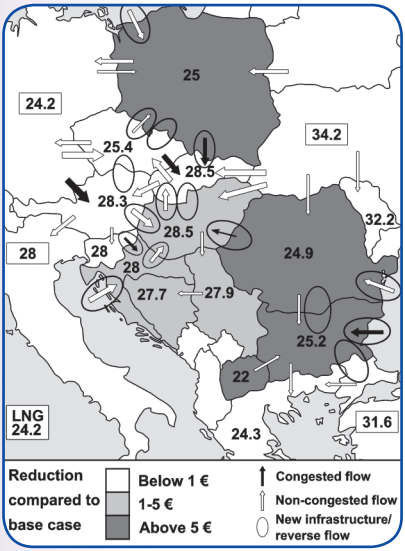

Figure 5 The impacts of the North-South corridor (RCCIref = 21,5%)

All countries except for the Czech Republic seem to enjoy a significant drop in wholesale gas prices in the modelled countries. The implementation of the entire project seems to bring the Western part of the region very close to the German / Italian markets and the South-Eastern part to the Greek market, as four LNG terminals provide significant new supply sources for the region.

Second, the empty black circles on Figure 4 stand for projects that are built but not utilized by market participants according to the model. An interesting issue for future analysis is how the package could be reduced while still preserving its benefits for the region. This requires an in-depth analysis due to the abnormal trading patterns of the region that are a result of significant TOP obligations and spot trading opportunities supported by a robust infrastructure and new LNG supply sources. We can observe several trade flows from high to low priced countries (e.g. Bulgaria exporting to Greece or Hungary exporting to Serbia) or a lack of trade between countries with a price differential (e.g. an empty pipeline between Slovenia and Hungary).

THE IMPACTS OF NEW INTERNATIONAL GAS PIPELINES ENTERING THE REGION

Up to now we have investigated the impacts of intra-regional projects and project packages on market integration. However, in recent years discussions about how to increase gas supply source diversification of the DR have manifested in South Corridor gas pipeline project alternatives, e.g. Nabucco, Nabucco West, South Stream, TAP. Now we seek to analyse the potential impacts of new pipeline supply sources entering the DR according to the model.

For this analysis we first create a 2020 reference scenario. Compared to the 2011 reference case, three major changes are made to the model: first, only new infrastructure under construction in 2011 are

added; second, load data is modified according to best available 2020 forecasts; third, we assume that TOP contracts expiring between 2011 and 2020 will all be extended again but at a reduced rate of annual contracted capacity (80% of the former contract). External price assumptions are unchanged compared to the 2011 reference scenario. The RCCI index for the 2020 reference case is 29.9%

New pipelines are represented schematically, by assuming that new gas entering the region is under a TOP regime. TOP is priced at Russian price minus 5%, with the Russian price 80% oil and 20% spot indexed.

We compare the impacts of two pipeline business models under two different intra-regional network configuration alternatives (four cases). The first pipeline brings 10 bcm to the Turkish-Bulgarian border and then ships all of it to Baumgarten via Bulgaria, Romania and Hungary. Spot trading of this gas is then allowed (Project 1). This pipeline business model considers the DR as primarily a transit area. Alternatively, Project 2 brings again 10 bcm to the Turkish-Bulgarian border but some of the gas is distributed along the way: 1 bcm for the Bulgarian and Romanian markets, 2 bcm for the Hungarian market, and the remaining 6 bcm reaches Baumgarten. Sufficient additional pipeline capacities are assumed to bring these amounts to the affected markets. We estimate the impacts of Projects 1 and 2 on RCCI both with the assumption of a complete and incomplete North-South corridor. The corresponding RCCI figures are summarised in Table 6.

	With North-South package	Without North-South package
2020 base scenario	19.16%	29.86%
V1 (10 bcm TOP to AT)	16.89%	29.54%
V2 (10 bcm distributed along the route)	16.73%	27.38%

Table 6 The impact of alternative 10 Bcm South Corridor projects on RCCI under alternative intra-regional network topology

We conclude that the bulk of the improvement in RCCI is due to improved intra-regional interconnectivity along with the addition of LNG sources to the DR – representing the implementation of the North-South corridor projects. The more regionally diversified pipeline business model performs slightly better than the transit model.

ALLOWING VIRTUAL REVERSE FLOW (BACKHAUL) TRANSACTIONS ON EU-EU BORDERS OF MAJOR TRANSIT PIPELINES

Because of the apparent counter-incentives of transit pipeline owners, in the foregoing we have disregarded from allowing backhaul transactions on all transit pipelines, shipping Russian gas to Western and South Europe crossing the DR. However, one might argue[22] that instead of building new infrastructure, the addition of a bi-directional component to existing infrastructure would significantly improve the integration of the DR with West European gas markets.

In order to estimate the potential impact of backhaul transactions on the DR's gas purchase costs, we allowed for virtual reverse flow transactions to happen at all EU-EU borders as – including Coatia[23] – along the transit pipelines. However, no backhaul transactions are allowed at EU-third country borders (EU-RU, EU-TR and EU-EnC[24]).

[22] The authors thank Pierre Noel for raising their attention to this point.
[23] Croatia will be member of the EU from 01.07.2013
[24] Allowing backhaul transactions on the EU-EnC borders does not significantly change the result, RCCI would be 25,01%

Table 7 contains the results of our simulations.

Backhaul option	not allowed (base case)	allowed on all EU-EU borders	Annual savings on regions gas bill compared to base case
2011	21.51%	17.20%	823 million €
2020 base scenario	29.86%	25.13%	1181 million €

Table 7 The impacts of virtual reverse flow options on RCCI

The figures in Table 7 lead can be used to calculate an annual savings of € 823 – 1181 million in gas purchase cost for the region.

The realization of a new Czech-Polish interconnector (map on the left) has very similar results on a regional scale to the free backhaul option (map on the right). However prices in the Czech Republic remain unchanged in the first case while they increase significantly in the second.

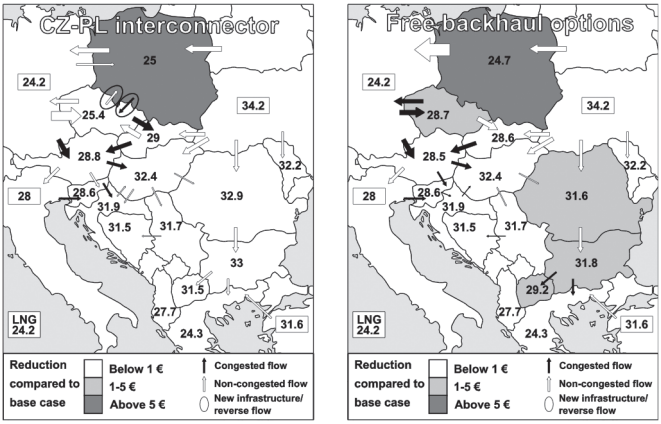

Figure 6 Effects of a new CZ-PL interconnector compared to free backhaul options

5.4 USING THE MODEL FOR COST-BENEFIT ANALYSIS: AN ILLUSTRATION

Up to this point we have concentrated on market integration and price impacts of projects and project packages and ignored project related costs. However, the consideration of project related investment cost coupled with calculated savings from the model allow for a more economically significant measurement and evaluation than the RCCI or the RSoI alone. Since the availability of investment cost data for future natural gas infrastructure projects is very limited,[25] we often used international benchmarks for this purpose. In this regard the following analyses is based on some cost estimations.

First we calculate a *regional payback period* for the projects by dividing the project related investment cost with the estimated annual purchase cost reduction. Table 8 contains the results of the calculations and also compares project rankings by RCCI against the payback period.

[25] Investment costs are gathered from the project home page, from investors in the case of pipelines and a benchmark for LNG.

	Project	RCCI (ref:21.51%)	Annual saving on gas bill (million €)	Estimated investment cost (million €)	Pay-back period (year)
Individual pipeline	CZ-PL2	17.10%	841.75	28	0.03
	SK-HU	18.35%	598.51	150	0.25
	GR-BG	21.13%	73.49	160	2.18
	TR-BG	21.29%	41.77	75	1.80
	RS-BG	21.39%	22.98	95	4.13
	RO-MD	21.47%	7.73	50	6.46
LNG	LNG-PL	16.94%	872.30	470	0.54
	LNG-HR	20.03%	281.39	240	0.85
	LNG2-RO	20.40%	205.51	470	2.29
	LNG2-BG	21.29%	41.77	470	11.25

Table 8 Individual project ranking by RCCI and regional payback period

The results indicate that the four best pipeline projects could cover investment costs *for the region* within just 3 years, with the two best (CZ-PL and SK-HU) within a few months. The regional payback period for the Polish and Croatian LNG projects is also less than a year. Surprisingly, the differences in the regional payback period changes the RCCI ranking only slightly, e.g. the TR-BG project becomes more lucrative than the GR-BG pipeline.

Thus the question is why these projects are not being built, or if they are planned why they proceed slowly when they are profitable and provide tangible benefits to the region? Part of the answer to this question relates to the positive network externalities of new interconnectors that are non-internalized because of the system of regulated third party access. The revenue from a new interconnector is based on investment and operation costs of the pipeline company. These costs are typically shared and paid by the consumers of those member states directly involved in the project through the regulated transmission tariffs. A new pipeline might include more dispersed additional costs and benefits for producers and consumers across a wider geographic area.[26]

We can illustrate this point by simulating the likely impacts of building one of the top ranking projects, the Greece-Bulgaria interconnector. This project ranks third in RCCI and its estimated cost is € 160 million. By adding this interconnector to the 2011 reference case, we can identify ten countries where the new line leads to a measurable change in annual weighted average wholesale gas prices and improvement in social welfare. Table 9 summarizes the results of this simulation.

Aggregate welfare rises by € 190 million annually, with Greece and Bulgaria the most significant beneficiaries. In the meantime, Romania and Hungary suffer sizeable welfare losses. With regard to market players, TSOs and consumers are the beneficiaries of the project while DR gas producers and TOP contract holders suffer losses. In this scenario, excess demand for the new pipeline capacity results in significant congestion revenues for the participating TSOs.. A gas price decrease, on the other hand, adversely affects local producers and TOP gas holders (TOP gas is crowded out by cheaper Greek LNG sources, leaving TOP holders with a significant loss in all countries except for Greece). Since gas prices increase in Greece relative to the reference case (cheaper LNG flowing now to the North), consumers suffer a significant welfare loss while producers and TOP traders make gains.

[26] Part of the benefits could be captured by tendering pipeline capacity, e.g. an open season procedure.

	Net consumer surplus	Producer surplus	Storage operation profit	Net profit from long-term contracts	TSO auction revenues	Total social welfare
GR	-76.8	41.0	0.0	43.9	114.9	122.9
BG	60.3	-8.2	0.0	-46.7	103.8	109.2
RO	94.8	-98.8	0.0	-24.5	-7.5	-35.9
HU	1.7	-0.4	0.0	-1.2	-7.6	-7.5
MK	3.2	0.0	0.0	-2.6	0.0	0.6
SI	0.0	0.0	0.0	0.0	-0.1	-0.1
AT	0.0	0.0	0.0	0.0	-0.1	-0.1
HR	0.6	-0.4	0.0	-0.2	-0.1	0.0
RS	0.3	-0.1	0.0	-0.2	0.0	0.0
BA	0.1	0.0	0.0	0.0	0.0	0.0

Table 9 Changes in welfare measures due from Greece – Bulgaria interconnector (million €)

We think that model simulations of this kind might help structure the debates surrounding new gas infrastructure projects for the DR by identifying their distributional impacts. Within the EU context, ACER could potentially make use of such results in preparing for its decisions on cross border investment cost allocation (see Article 13 of the proposed infrastructure Regulation).

5.5 USING THE MODEL FOR SUPPLY SECURITY ANALYSIS: ANOTHER ILLUSTRATION

The DRGMM model can also support sophisticated gas supply security analyses at the regional level. As we have noted before, the DRGMM model uses a fully dynamic solution algorithm over 12 consecutive months, in which we assume that traders optimize their use of storage assets and the flexibility of the delivery of TOP contracts. As a result, the model produces monthly forward prices for the entire year, which are "right on the spot" in the sense that if there are no subsequent changes in the input data, then all the outcomes (including prices) will turn out as predicted as the year unfolds.

Of course, in reality, supply and demand conditions will deviate from forecasts throughout the year. To capture this, the model allows for the possibility of intra-year runs in which any input variable pertaining to the upcoming months can be changed.

Given that the gas year runs from April to March the initial model run will have to include forecasts for supply-demand conditions in each of the 12 months, otherwise it would be impossible to input optimal storage and contract delivery decisions in the beginning of the year.[27] Taking the forecast as given, we can then calculate how each of the 12 months will "play out".

Now let us suppose that a supply disruption occurs in January. For the sake of the example, it could be another gas dispute between Russia and Ukraine that results in zero Ukrainian transits through the whole of January. In the model, we would represent this incident by setting the maximum transport capacity of the pipelines through Ukraine (to Romania, Moldova, Hungary, and Slovakia) to zero for a month.

An important question is, in which month do market participants know that interconnectors crossing Ukraine will be unavailable in January? If they already know it in April, they will likely have enough time to stock up gas to better adjust to the crisis. But, if it takes them by surprise, the price effects will be much more severe.[28] One can therefore imagine that the actual effects will be highly dependent on the length of time that is available for preparation.

[27] The key decision variables here are those with inter-temporal consequences.
[28] Since the model employs market mechanisms only, negative supply shocks will present themselves as price jumps in the affected areas.

Fortunately, the DRGMM model allows for a full exploration of these issues. Taking the start-of-year run as a reference for how market events occur naturally, it is possible to "stop" the year in any month (e.g. just before January), re-set the input parameters of the model for the rest of the year (e.g. interconnector capacities in January, and probably also the yearly TOP minimum constraints), and re-run the optimization procedure while taking the outcomes of the past months (e.g. storage utilization from April to December) as already given. The model results will then reflect the consequences of regional market-based responses to the supply shock, including the spillover effects on countries not directly affected by the shut-down of the pipeline (Serbia or Bulgaria in this case).

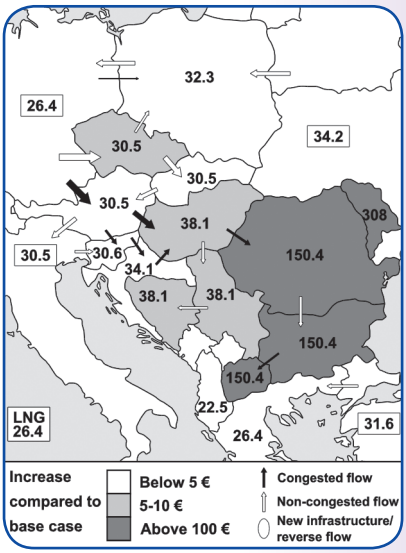

Figure 7 The effect of an unexpected supply disruption of all pipelines through Ukraine in January (prices in €/MWh)

Figure 7 shows the results of the crisis situation that we outlined above. The coloring of the markets indicates the extent of the price rise in January and the seriousness of the supply disruption if the market equilibrium is restored via mandatory consumption cuts.

Light grey colored markets experience a price rise of about 4-5 €/MWh for the crisis month, whereas the dark grey colors indicate a price rise beyond 10 €/MWh. As the actual numbers show, the supply disruption is quite severe in the Eastern part of the Balkans, whereas it seems to be more manageable in Hungary, Serbia, and Bosnia and Herzegovina. Interestingly, the Czech Republic is also affected through the decrease in SK→CZ pipeline flows.[29]

As a final point, we note that the regional (and country-level) supply security effects of various policies and new infrastructure elements can also be assessed using this methodology. One would simply carry out the supply shock analysis, such as the one above, with and without the policy or the new infrastructure and compare the outcomes.

[29] The same crisis situation turns out to be almost fully manageable (except in Moldova) when market players start preparing for it in April, instead of only reacting to the events as they take place in January.

6 MODEL LIMITATIONS AND FUTURE RESEARCH DIRECTIONS

The DRGMM is a unique analytical tool that represents the natural gas industries of Central and South East Europe in a detailed and consistent manner. In this paper we have described the assumptions and logic of the model and presented several simulations to measure and analyse effects on market integration, cost-benefit, and security of supply. However, the model has limitations that need to be addressed.

The first of these limitations is the model geography. At present, only the 17 countries from Figure 1 are represented in detail as 'local' markets in the model, leaving a significant part of the EU labelled as an 'external' market. An extension of the model to present 'external' EU markets could result in a detailed representation of the entire interconnected EU natural gas wholesale market.

Second, the model lacks a sensible representation of the EU's outside suppliers' pricing behaviour. In its present form, the pricing of external markets to supply the DR is static; a combination of oil product price and spot price indexation by Russia, relative pricing from Turkey, and spot pricing in Germany, Italy and LNG. Yet in the last four years there were several instances of supply/demand shocks that shifted heavily oil-indexed contracts more towards spot price indexation (Stern and Rogers, 2011). We can also assume that a stronger internal and East-West integration of DR gas markets, promoted by a significant change in network topology in the DR, could create a basis for a more dynamic and market based gas pricing system in the region compared to a present, very rigid oil indexation. Thus, developing a more realistic representation of outside supplier pricing behaviour is a key future model development task.

Third, the representation of gas transmission and storage access prices and pricing in the model requires refinement. This is made difficult by the lack of a consistent data, particularly well-documented benchmarking of gas infrastructure access costs across Europe. Nevertheless, since the magnitude of transmission and storage access tariffs in comparison to product prices is marginal, we can argue that a more accurate and detailed representation of infrastructure access tariffs and rules are not likely to significantly change model results and in fact might disrupt model algorithms.

Finally, one could argue that the representation of the DR gas market as existing in perfect competition under network and TOP contractual constraints is an unrealistic assumption. Beyond TOP constraints, national gas wholesale markets are often dominated by players with significant market power. The assumption of efficient utilization of cross border pipeline capacities is somewhat flawed because existing capacity allocation rules are far from market based mechanisms (see REKK, 2011 on a Hungarian example). Nevertheless, the world represented by the model is the vision of the European Union, including its south-eastern region, for a restructured gas industry. The model thus provides for a normative reference case in a European spirit and allows for an important assessment of the impacts, changes and distortions of projects relative to a baseline case.

ANNEX 1: THE LIST OF THE ANALYSED PROJECTS

Cross-border interconnections

Pipeline	Maximum flow (mcm/day)	Estimated start-up
BG-RO	14.00	2012
RO-BG upgrade	4.11	2012
RO-HU	4.79	2013
BG-RO upgrade	4.11	2013
GR-BG	8.22	2014
TR-BG	13.70	2014
HU-SK	13.70	2015
SK-HU	13.70	2015
RS-BG	4.93	2015
PL-SK	13.70	2016
TR-BG upgrade	10.96	2017
CZ-PL upgrade	8.22	2017
PL-CZ	8.22	2017
AT-CZ	13.70	2017
HU-SI	3.56	2017
SI-HU	3.56	2017
HR-SI	31.78	2017
RS-BA upgrade	3.29	2018
HR-BA	6.85	2018
BA-HR	6.85	2018
HR-IT	41.10	2018
HR-RS	7.40	2018
RS-HR	7.40	2018
MK-BG	1.23	2018
MK-GR	2.74	2018
MK-AL	2.47	2018
MK-KO	1.37	2018
MK-RS	2.19	2018
RS-RO	4.38	2018
RO-RS	4.38	2018
BA-RS	3.29	2018
RS-MK	2.19	2018
MD-RO	2.74	2018
RO-MD	2.74	2018
GR-BG upgrade	5.45	2020
HR-HU upgrade	12.98	2020

Storage facilities

Market	Injection capacity (mcm/day)	Withdrawal capacity (mcm/day)	Working gas capacity (mcm)	Estimated start-up
CZ	3.9	3.9	290	2012
PL	0.54	2.36	180	2012
RS	10	10	350	2012
PL	5.7	5.7	150	2013
SK	3	2.5	250	2014
AT	1	1.2	84	2014
AT	5.71	8.57	685	2014
AT	2.9	2.9	100	2014
PL	0.28	0.41	35	2014
SK	3	2.5	250	2014
RO	15	15	1 600	2015
PL	7	10.8	675	2015
GR	5	4	360	2015
CZ	0.87	0.87	350	2016
HR	8.256	8.256	510	2017
CZ	1.7	1.7	195	2017
BG	10	10	550	2017
RO	4	4	300	2018
RO	2	2	250	2018
BG	9	9	600	2018
AT	2.8	2.8	225	2018
AT	17.3	17.3	900	2018
AT	24.5	24.5	1600	2018
RS	10	10	350	2018
PL	20.6	20.6	422	2020

LNG terminals

Country	Maximum flow (mcm/day)	Estimated Start-up
LNG-HR	16.44	2014
LNG-PL	13.7	2014
LNG2-RO	21.92	2015
LNG2-BG	6.85	2015
LNG-GR2	5.76	2015

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