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SECURITY OF ENERGY SUPPLY IN CENTRAL AND SOUTH-EAST EUROPE

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CORVINUS UNIVERSITY of BUDAPEST

SECURITY OF ENERGY SUPPLY IN CENTRAL AND SOUTH-EAST EUROPE

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1.1. Introduction

The objective of this paper is to briefly review the existing concepts of energy supply security in the context of the Security of Gas and Electricity Supply in Central and South-East Europe (henceforth: SoS-CSEE) project. Based on this survey we are to propose a set of security of supply (SoS) measures that could regularly be quantified and compared for various regions, across countries and over time. Such comparisons will hopefully contribute to the evaluation of changes in regional energy supply security that might be of interest for private investors as well as policy makers.

Energy supply security studies investigate the ability of the sector's value chain to meet consumer demand at the required time and place of consumption according to a predefined level of service quality. While the definitions of supply security usually include a reference to price and contractual conditions,[1] its central theme is continuity. Economic loss in the form of lost production or consumption opportunities is caused by discontinuity or disruption of the service and the consequent loss of load. Thus the primary objective for security of supply policy is to reach the level of loss of load probability where the marginal benefit of a further reduction in this probability would equal its marginal cost[2]

Note that consumer demand characteristics have to be accounted for eventually in security of supply studies. Certain customers do not per se demand electricity or gas, but rather those services (heat, lighting, cooking, etc) that are provided by them. Continuity of consumption of these final services might temporarily be maintained even during times of electricity or gas supply disruptions. One example of that is when the district heating plant switches from gas to oil or coal so as to maintain heat supply for household customers during a gas supply disruption. The installation of an uninterruptible power supply can also mitigate the impact of a short term electricity supply cut for the customer.

We assume the elasticity of gas consumption to be significantly higher than that of electricity consumption, due mostly to storage options and a higher level of substitutability. The implication is that demand side variables will play a more important role in defining the prevailing level of supply security in the case of gas than in electricity.[3]

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[1] According to the IEA (2001), energy security is defined as the availability of a regular supply of energy at an affordable price. In the case of electricity we can further specify this concept by using a definition provided by EURELECTRIC:
"Security of electricity supply is the ability of the electrical power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner, relating to the existing standards and contractual agreements at the point of delivery."

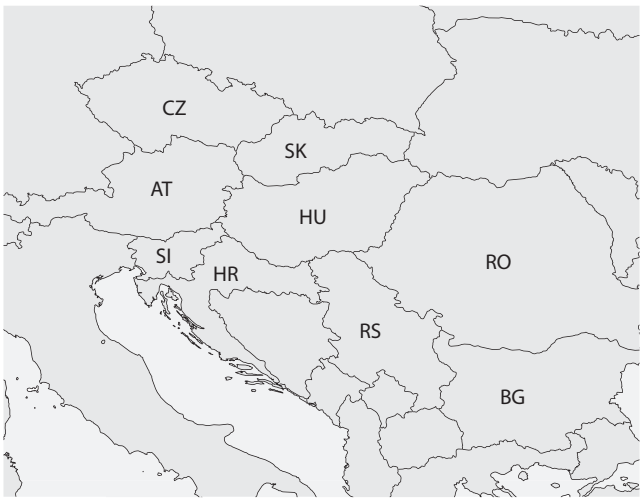
[2] The empirical investigation of the economic value of lost load is the subject of a forthcoming study of this project.

[3] Investigating the role of demand side response in energy supply security will be included at a later stage in the SoS-CSEE project.

1.1.1. Geographical scope

We cover the countries named and depicted in Figure 1.1, which we will refer to as the Central and South-East European (CSEE) region for the purposes of the study. Occasionally, we will also extend the analysis to neighboring countries (such as Ukraine or Bosnia and Herzegovina) on a case-by-case basis as needed.

Figure 1.1. Countries analyzed in the SoS-CSEE project



1.1.2. Supply security from an EU perspective

The increasing import dependency of the European countries coupled with the import gas supply disturbances of the last years placed the issue of security of supply high on both the EU and the national political agendas. Besides promoting energy efficiency measures and the harvesting of available domestic energy sources, most notably renewables, the EU makes considerable efforts to induce member state cooperation on diversifying transport routes and suppliers, and to encourage interconnection capacities despite the fact that energy security is not a community policy, unlike energy market liberalization and environmental regulation of the energy sector.[4] Member states still maintain their national competence over security of supply, hence currently the mandate of the Union is more of coordination and setting policy frameworks. The EU seeks similar cooperation with South-East European states in the Energy Community.[5]

Current EU legislation with regard to the safe supply of natural gas is a framework that induces member states to define their own measures and requires them to report regularly to the Commission on their own parameters such as new long-term contracts for

[4] Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions - Second Strategic Energy Review: an EU energy security and solidarity action plan (COM/2008/0781 final)

[5] Council Decision 2006/500/EC of 29 May 2006 on the conclusion by the European Community of the Energy Community Treaty

imports from third countries, the existence of adequate liquidity of gas supplies, the level of working gas in storage and of the withdrawal capacity of gas storage and the interconnection capacities towards other Member States and their regulatory framework to induce new investment to gas infrastructure.[6] The Member States are required to build up and constantly maintain minimum stocks of petroleum products equal to 90 days of the average daily internal consumption during the previous calendar year (corrected with domestic production up to 25%).[7] Member states are required to secure electricity network security, to create transparent policy environment to future investments and to balance supply and demand so that market compatible measures would suffice even in case of disturbances.[8]

The measurement of security of supply is an essential informational tool not only for national policy makers but also to the neighboring community of states (within and outside the EU) as the emergence of regional energy markets increases the interdependence of states.

1.1.3. Regional focus

In this paper we wish to develop SoS measures that to some extent reflect on the specific, most pressing energy security problems of the region. These specifics are the contradictory regulatory climate of energy infrastructure investments and unilateral natural gas import dependence.

Regulatory risks

Countries in the region (with the possible exception of Austria) seem to be characterized by a relatively high risk environment for private energy infrastructure investors. Part of this risk is related to the prevailing macroeconomic conditions, the other part is specific to the regulatory environment of energy markets.

While the penetration of private investment is significant in the region's energy sector, after-privatization regulatory conflicts are common phenomena (LaBelle and Jankauskas, 2009). Several countries are in the process of implementing the European model of gas and electricity sector restructuring, but are still at half-way. Sizable regulated market segments in electricity and gas are still common, while the credibility and transparency of price regulation are often questionable. Cross-subsidization is still a widespread practice, licensing procedures for new generation and network development are lengthy and costly. All these regulatory risks might result in lower-than optimal private investment activity that, in turn, undermine the immediate quality of energy services and also longer term energy supply security.

The negative effects of relatively high regulatory risk on private investment could be offset by sufficient investment of publicly owned energy companies or by the implementation of specific investment support schemes (grants, obligatory feed-in schemes).

[6] Council Directive 2004/67/EC of 26 April 2004 concerning measures to safeguard security of natural gas supply

[7] Council Directive 2006/67/EC of 24 July 2006 imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products

[8] Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment

However, unfavorable public finance conditions (high budget deficit and indebtedness) will reduce the possibility of public investments to replace private efforts.

In sum, our energy supply security measures will reflect on the issues of country and regulatory risks and their likely impact on energy infrastructure investments.

Unilateral gas import dependence

In their review of the energy supply security issues regarding the member states joining in 2004, Cameron et al (2008) and Kaderják et al (2007) demonstrated that the single most important energy supply security issue for several Central and South-East European countries was their unilateral gas import dependence on a single supplier country, Russia. The vulnerability of the region's countries in this respect include combinations of components like their high (above EU average) economic dependence on gas, high import dependence, limited diversity in import supplies, high share of gas-based electricity production and very limited gas infrastructure interconnectivity for the region.

The gas crisis of January 2009 demonstrated that the region under study is vulnerable to short run gas supply shocks in an asymmetric manner: while the impact of a gas supply cut had a significant impact on end customers in the region, this impact was negligible in the rest of old EU member states.

1.1.4. Desirable characteristics of SoS indicators

There are several characteristics by which to judge the success of certain supply security measures. We are looking for indicators that have the following features:

(i) Be quantitative and meaningful, facilitating comparisons across countries and years.

(ii) Minimize subjective elements (i.e. expert judgment) that are often used in assigning weights to subcomponents.

(iii) Balance between excessive data requirement and simplicity, leaning towards the later.

(iv) Limit itself to factors/variables that poses supply security problems in real life and ignore those that are only theoretical issues in this region.

While the majority of traditional supply security measures are descriptive of past developments, we also wish to make a specific effort to establish leading indicators for longer term supply security. We shift the focus of the indicators from foreign trade (import dependency) to risks and investment climate. This is especially relevant in the case of the electricity sector, since all the countries under study are well interconnected UCTE members. The exception is the already mentioned issue of unilateral gas import dependence.

Note that in this paper we implicitly assume that less reliance on imported fuel and more diversity in fuel sourcing will "ceteris paribus" increase supply security. Regarding infrastructure, we associate higher capacity or capacity reserves both in networks and electricity generation with a higher level of supply security.

1.1.5. Outline of the study

In Section 1.2, we propose a framework to guide our thinking about gas and electricity supply security and the development of specific indicators. In Section 1.3, we survey the literature on supply security measurement, and position our efforts relative to the cited body of work.

In Section 1.4, we turn to collecting short, medium and long-run security of supply indicators in the electricity sector, while in Section 1.5, we do the same for natural gas. Finally, in Section 1.6, we provide a first approach to measuring regulatory risk in the energy sector of the countries within the region of the SoS-CSEE project.

1.2. Framework for energy supply security

There are several possible definitions of security of supply depending on the type, extent, probability or duration of adverse events that one considers disruptive for household consumption or economic activity. Although we could attempt to provide an extensive definition of our own choosing, the multi-dimensional nature of energy security would necessarily make that an incomplete and sometimes also a misleading one. Instead, we will choose a framework into which most of the topics related to the security of electricity or gas supply fit.

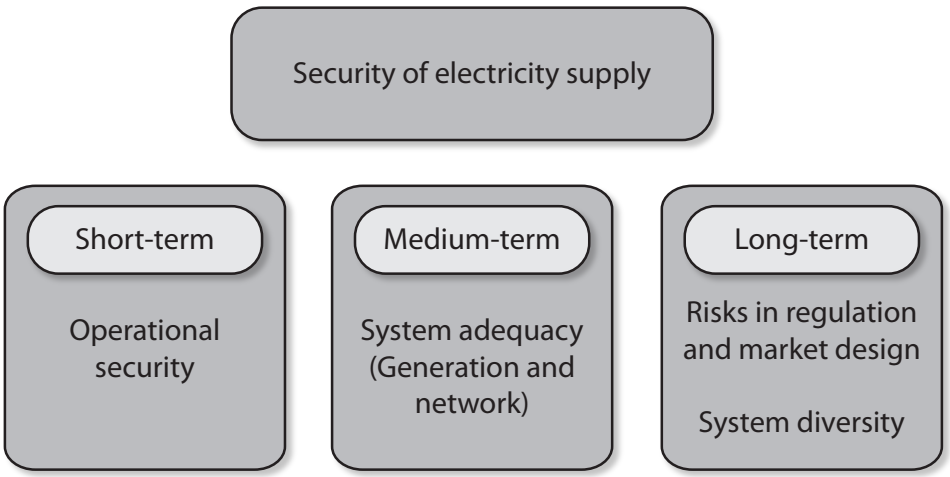
1.2.1. Framework for electricity

Figure 1.2 shows the main elements of an electricity supply security framework according to the typical time frame over which the disruptive events materialize and can be resolved:

1. Short-term: supply disruptions that can usually be resolved within hours or days, at most.
2. Medium-term: the potential for recurring, more chronic supply shortages in the foreseeable future (within the typical investment cycle of around 3-5 years).
3. Long-term: systemic vulnerabilities to hard-to-quantify disruptive events beyond the investment cycle.

Within each time frame, Figure 1.2 displays the typical security risks that our analysis concentrates on.

Figure 1.2. Framework for the security of electricity supply



Short-term security

For short-term supply disruptions, the main concern is the operational security of the electricity distribution networks, and to a smaller extent, of the transmission network as

well. Moreover, we may worry about the availability of dispatchable reserve generation to deal with unplanned imbalances in the system.

Short-term electricity outages do sometimes originate from the transmission network, but these events are both very rare in the UCTE network and also rather unpredictable. For these reasons, they pose hard-to-quantify and certainly limited supply security risks. Accordingly, we will not address them in the current paper.

Likewise, potential reserve inadequacy also causes very few problems from a security of supply point of view. The UCTE sets clear reserve requirements for the individual TSO-s in the synchronized system, which – supposedly – handle supply security problems arising from potential imbalances in the appropriate manner.

Therefore, our investigation of short-term electricity supply problems will center around the operational security of the electricity distribution networks.

Medium-term security

We think of the length of the medium term as a typical investment cycle of new generation or new transmission network elements, especially cross-border connections. The reasons are simple: this is the future time interval over which we can predict with reasonable accuracy whether the development projects that are already in the pipeline provide adequate extensions to the existing infrastructure to satisfy growing consumer demand at reasonable prices. If this is not the case, then under-investment will potentially cause supply security issues in the form of prohibitively high prices, or – more likely – recurring electricity shortages.

Naturally, medium-term supply security indicators will not be reliable too far into the future. The fact that the current and the actually planned new infrastructure will not be able to cover demand in 10-15 years time does not mean that we have a supply security crisis in the making; it simply means that those investments do not need to start yet.

Long-term security

The long-term time frame in this classification starts where our information about specific future infrastructure investments ends. Even though we cannot assign actual numbers to measure the seriousness of potential supply shortages, we can still indicate the potential for supply security problems by applying two different approaches.

The first, and more important, approach is to assess the investment climate of a given country by devising indicators that reflect the risks inherent in the regulatory environment and market design of the country. We argue that necessary future investments are more likely to materialize if investors are more assured of their return.

The second approach, measuring the diversity of the electricity generation portfolio, is suited to test the long-term resilience of the existing system against unforeseen disturbances. Valuing diversity is based on the general risk mitigation idea of not putting all of one's eggs into a single basket. Arguably, a long-term security assessment based on the idea of diversity is better suited, for example, to biological systems, but economic applications – especially in case of power generation – are also prevalent.

1.2.2. Framework for natural gas

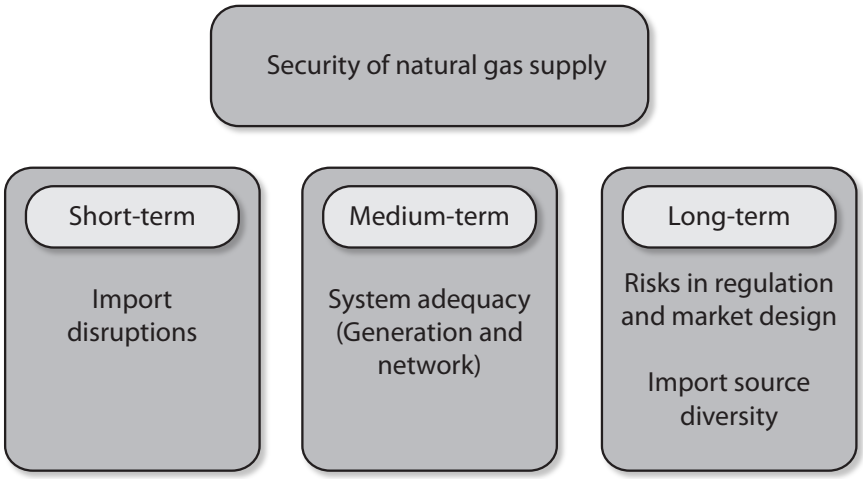
Our framework for evaluating the security of gas supply is shown in Figure 1.3. We still distinguish between three different time horizons, but they have slightly different meanings due to the differences between the two industries:

(i) Short-term: supply disruptions (mainly) in gas imports that are resolved within 2-3 weeks at most.

(ii) Medium-term: current and future adequacy of the transportation and storage infrastructure to deal with the trend and seasonality of consumption.

(iii) Long-term: systemic vulnerabilities to hard-to-quantify disruptive events beyond the investment cycle.

Figure 1.3. Framework for the security of natural gas supply



Short-term security

As opposed to the electricity sector, the distribution network is generally not a significant source of short-term supply disturbances, and neither is the domestic transmission grid. The main cause of short-term supply interruptions in Central and South-East Europe – as witnessed repeatedly in recent years – has been a discontinuation of Russian gas imports flowing through Ukraine for 1-2 weeks. Since gas-related disputes between the two countries are likely to resume in the future as well with similar consequences, our short-term supply security indicators will concentrate on the gas systems' resilience against a typical loss of import in times of high (winter) demand.

Medium-term security

Medium-term supply security problems in the gas sector are similar to those in electricity. We will again compare the current and projected capabilities of the infrastructure (transportation and storage) to the expected increases in demand.

Long-term security

As in the electricity sector, long-term supply security issues of the region also depend on the general investment climate, most prominently the riskiness of regulation and market design in each country. The diversity of import sources (instead of generation technologies, as in electricity) is also a useful indicator of the gas sector's long-term exposure to a single supplier.

1.3. Existing Literature on supply security indicators

1.3.1. Short-term security

Short-term security of supply measures by our classification fall into the category of quantifying disruptions in the distribution system, which is one dimension of service quality measurement. The measurement itself is usually carried out by the distribution system operators and published by the energy regulatory office of each country in which such measures are recorded.

The Council of European Energy Regulators (CEER) publishes regular benchmarking reports on the quality of electricity supply (the latest, 4th report came out in 2008), which provides a comparative survey of service quality indices for the countries that take part in the assessment.

1.3.2. Medium-term security

Medium-term supply security indicators are essentially about system adequacy to serve load under various conditions. These indices can be computed from primary data and from predictions about future demand growth and planned investments. One prominent source of such medium-term assessments in the electricity sector is the UCTE System Adequacy Report, published yearly. Kaderják et al (2008) also developed similar measures for the Central and South-East European region.

1.3.3. Long-term security

Most of the work in developing security of supply indicators has been carried out with an eye on long-term security. Kruyt et al (2009) provide an exhaustive survey, classifying long-term indicators into the following 10 + 5 categories. (A few relevant papers are cited after each in parentheses.)

Simple indicators

1. Resource estimates: quantifying the total amount of energy sources "left in the ground". (United States Geological Survey, 2000, among others).
2. Reserves to production ratios: how many years of consumption are left at current rates until exhaustion (Feygin and Satkin, 2004).
3. Diversity indices (Stirling, 1999; von Hirschhausen and Neumann, 2003; Jansen et al, 2004; Grubb et al, 2006; Frondel and Schmidt, 2008).
4. Import dependence: net imports as a percentage of total consumption (Alhajji and Williams, 2003).
5. Political stability of supplier and transit countries (IEA 2004, 2007; Jansen et al, 2004).
6. Energy price as an indicator of relative shortage.
7. Mean-variance portfolio theory: quantifying the optimal trade-off between risk and cost in electricity generation (Awerbuch and Berger, 2003; Awerbuch, 2004; Roques et al, 2008).

8. Share of zero-carbon fuels (Asia Pacific Energy Research Centre, 2007).
9. Market liquidity (IEA 2004).
10. Demand-side indicators: such as fuel intensity or share of energy expenditures (Kendell, 1998).

Composite indicators

1. Shannon index and its modifications (see Diversity indices).
2. The IEA's energy security index.
3. S/D index (Scheepers et al, 2007).
4. Willingness to pay for security of supply (Bollen, 2008).
5. Oil vulnerability index (Gupta, 2008).

As we can see, there is no shortage of indicators for long-term supply security problems, even though many of them have been developed specifically for oil and may not be directly applicable to natural gas or electricity.

In our long-term assessments, we will mainly rely on diversity based indicators (such as the Shannon-Wiener or Herfindahl-Hirschman indices) and political stability measures. In addition, we will suggest ways to quantify the risk in the regulatory environment which may preclude necessary investment in infrastructure to take place, endangering the security of energy supply in the long term.

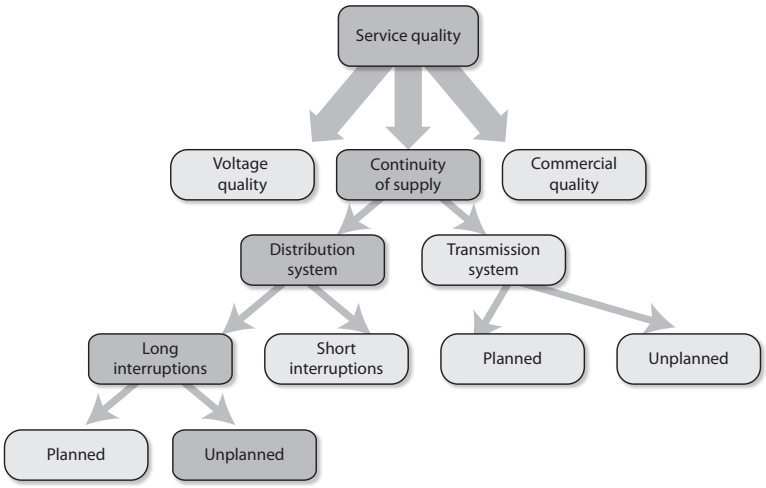
1.4. Security of supply in electricity

1.4.1. Short-term indicators

As we discussed in the framework for electricity supply security, our short-term measures concentrate on service disruptions originating in the distribution network. The idea itself is not new: distribution *service quality* indicators are routinely calculated in several countries and they usually include some form of measurement for unserved load.

The notion of service quality encompasses several dimensions, only one of which refers to discontinuities of electricity distribution. Figure 1.4 provides a schematic overview of service quality elements. We have highlighted the service quality dimensions which we believe to be relevant for measuring short-term security of supply in the electricity sector.

Figure 1.4. Dimensions of electricity service quality



Interruptions that last less than 3 minutes are classified as short, whereas anything beyond 3 minutes counts as long.[9]

Measures for long interruptions

There are a number of measures for the severity of long interruptions. Table 1.1 provides a short overview of the most important ones.

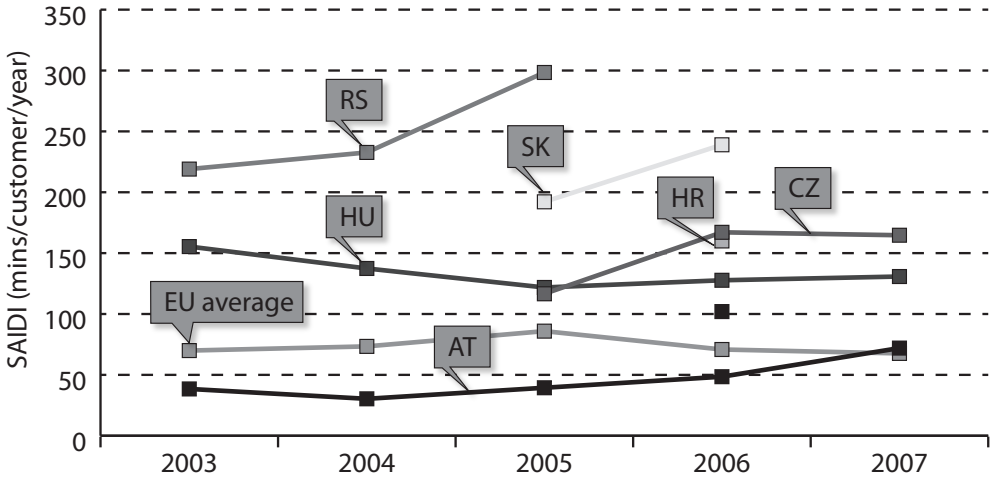
[9] There is also a third category, transient interruptions, which is reserved for events that last less than 1 second.

Table 1.1. Measures of long interruptions in distribution networks

Name	Short form	Units of measurement	Availability in CSEE
System Average Interruption Duration Index	SAIDI	Minutes per customer per year	AT, CZ, HR, HU, RS, SI, SK
System Average Interruption Frequency Index	SAIFI	Interruptions per customer per year	AT, CZ, HR, HU, RO, RS, SK
Customer Average Interruption Duration Index	CAIDI	Minutes per interruption	AT, CZ, HR, HU, RS, SK
Energy Not Supplied	ENS	GWh	-

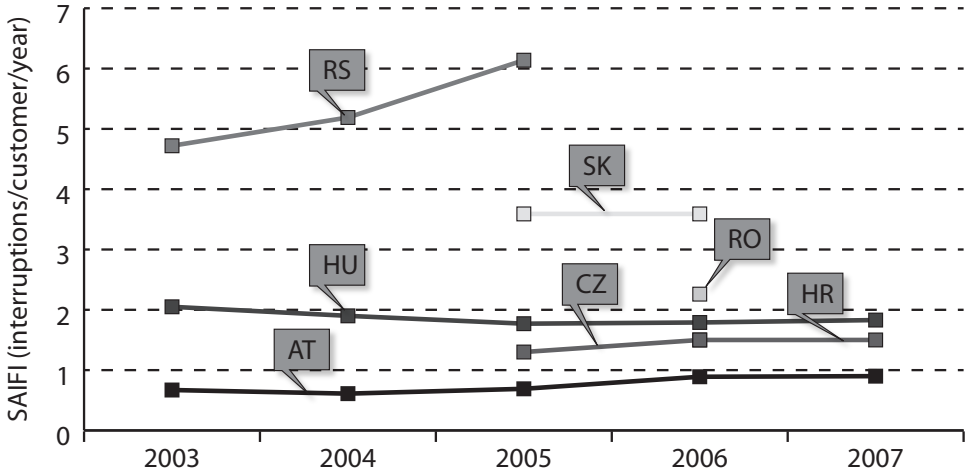
The column "Availability in CSEE" lists those countries in the CSEE region for which we were able to find indicator data for at least some of the past 5 years. Figure 1.5 and Figure 1.6 show the evolution of the two most often calculated measures, SAIDI and SAIFI, over the examined period.

Figure 1.5. System Average Interruption Duration Index in CSEE countries



Source: CEER (2008), National Energy Offices' Reports

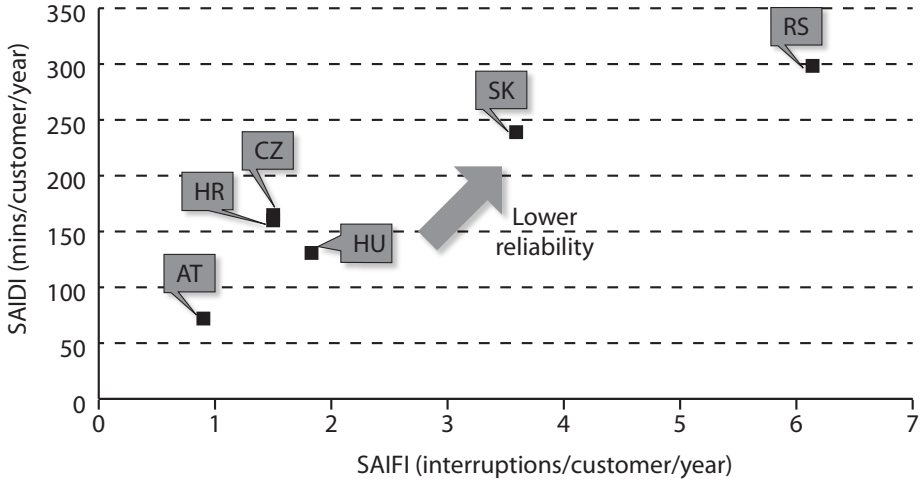
Figure 1.6. System Average Interruption Frequency Index in CSEE countries



Source: CEER (2008), National Energy Offices' Reports

As the charts show, data availability on disruptions is unfortunately far from exhaustive (information on Bulgaria is missing altogether). In order to provide a better comparison of countries, we have combined the two indices for the most recently available years in Figure 1.7.

Figure 1.7. Combined short-term security of supply measurement in CSEE



Source: CEER (2008), National Energy Offices' Reports

The closer each data point is to the origin in Figure 1.7, the better situation the given country is in from a short-term security of electricity supply perspective. Distribution networks in Austria are outstanding in this respect, with Hungary, Croatia and the Czech Republic being somewhat behind in the comparison. Slovakia, and especially Serbia, are in considerably worse situation.

1.4.2. Medium-term indicators

As we have determined earlier, we will use generation and (transmission) network adequacy measures to quantify electricity supply security in the medium term. The general methodology is comparing available generation capacities to consumption: the higher the available capacities are compared to likely demand, the better the security of supply situation is. This ratio is also connected to the price of electricity. The higher the excess capacities are, the lower the probability of a very high price level in the peak hours, because more power plants can produce electricity in peak hours.[10]

In this subsection, we show how to calculate the availability of capacities according to both the definitions of the UCTE (System Adequacy Reports) and to our assumptions about generation availability during peak hours. We will determine two sub-indices: both of them compare the available capacity to peak consumption, but with different formulae and also somewhat different results, as we will see.

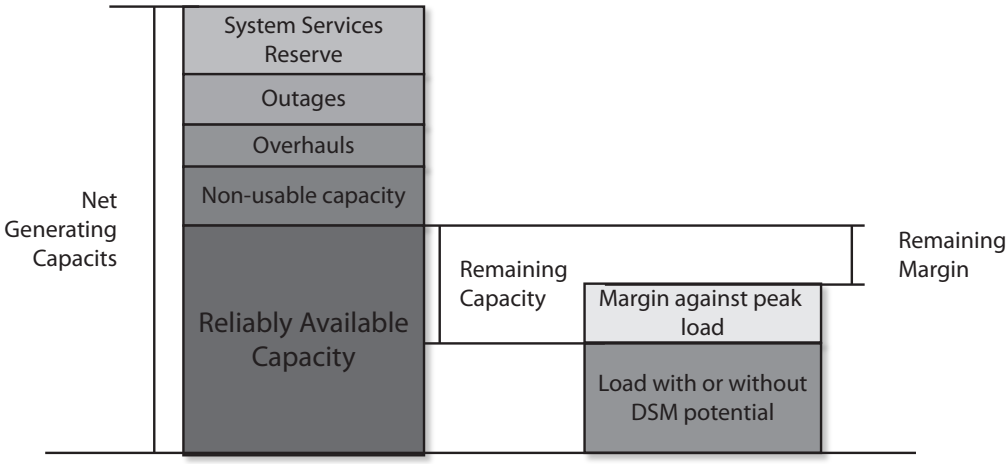
UCTE adequacy index

The most commonly used index measuring security of supply in the electricity sector in what we defined as medium term is based on UCTE methodology (System Adequacy

[10] Naturally, prices in a competitive market are determined by the unit costs of the marginal plant. However, with more excess capacity during peak hours, these costs are likely to be lower.

Report). The basic idea of the adequacy index is to compare the reliably available capacity to peak consumption. The setup of the index is shown in Figure 1.8.

Figure 1.8. Generation adequacy in UCTE



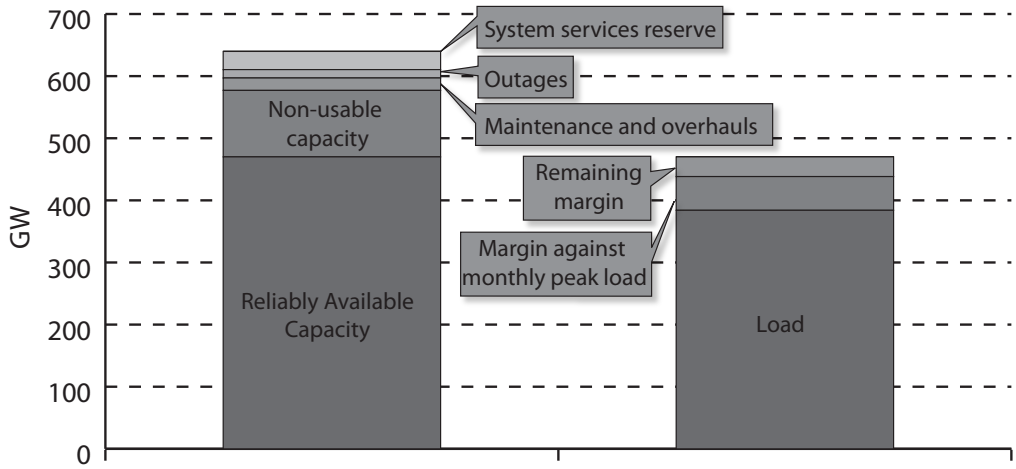
Source: UCTE, SAR 2007

Net generation capacity is the maximum power that a power plant can produce in a longer period in normal conditions. Decreasing this number by the system services reserves, outages, overhauls and non-usable capacities, we get the reliably available capacities. Remaining capacity is the difference between reliably available capacity and the load, in which we also include network losses.

Finally, margin against peak load means the difference between the representative load hour in a period and the peak load hour. If we decrease the reliably available capacity by the peak load, we get the remaining margin. According to UCTE methodology, we should compare the remaining margin to the reliably available capacity. If the remaining margin is below zero in a system, then the power balance requires import, while if it is positive, then the internal capacities are enough to cover peak consumption.

Figure 1.9 shows the these values for the whole UCTE system in 2007. The positive remaining margin signals that in this geographical aggregate the internal capacities are adequate to cover peak consumption.

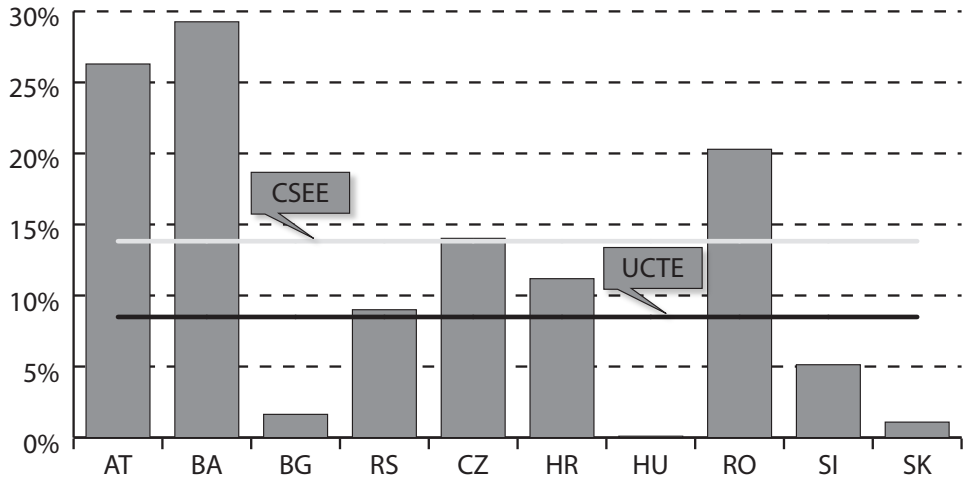
Figure 1.9. Generation adequacy in the UCTE system, 2007



Source: UCTE, SAR 2007

UCTE compares the remaining capacity to the net generating capacities year-by-year for all of the UCTE members. In Figure 1.10, we depict the analyzed countries in the Central and South-East European region (CSEE), and also the UCTE average.

Figure 1.10. Remaining margin/net generation capacity, 2007



Source: UCTE, SAR 2007

All values are positive, meaning that the internal capacities are enough to cover the peak consumptions in these countries. Hungary, Slovakia and Bulgaria are in the worst situation, because these figures are below 2%. The highest values belong to Bosnia and Herzegovina, Austria, and Romania.

REKK index

The UCTE index (remaining margin/net generation capacity) does not take into consideration the availability capacity of different technologies. It assumes, for example, that hydro and thermal power plants operate at the same utilization rate. It does adjust for non-usable capacity, but irrespective to the technology mix. We calculate an alternative index with the following technology specific availability values that includes maintenance and system service reserves as well.

Table 1.2. Assumed availability of power plants during yearly peak hours

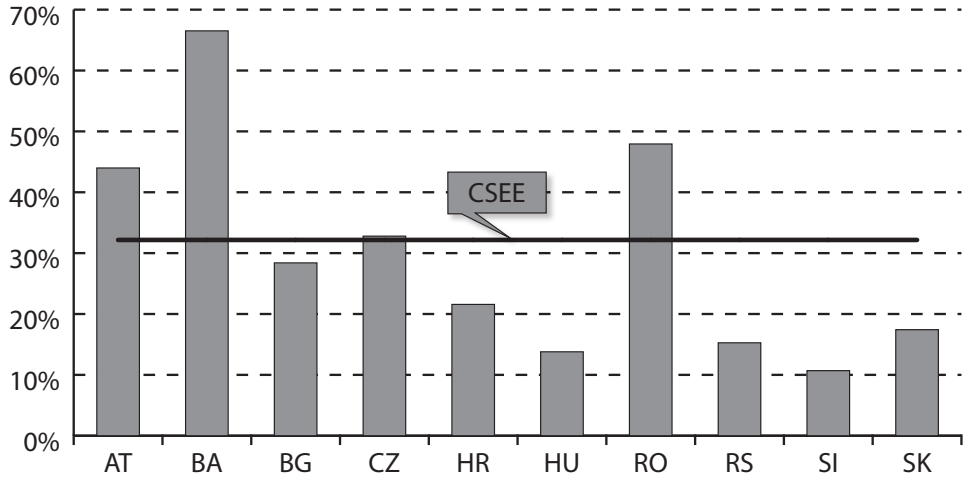
Technology	Assumed availability in peak hours
Pumped storage	100%
Other hydro	Last six year country average
Wind	Last six year country average *
Nuclear	100%
Thermal	90%
CCGT	90%

Source: REKK estimate

**Because both a wind generator's and a hydro power plant's marginal costs are close to zero, their utilization depends only on the weather.*

We assume that in peak hours pumped storages can produce at their maximum capacities, while weather dependent plants can produce at their yearly average utilization rate. The availability of nuclear power plants in the peak hours is 100%, while all the others assumed availability is 90%, taking into consideration both unplanned outages and regulation reserve services. Net capacities are calculated by decreasing the installed capacity of a plant with a technology-dependent self-consumption parameter, ranging from 0 to 13 percent. Applying the UCTE methodology to our data, i.e. comparing remaining margins (= reliably available capacity – peak consumption) to net capacities, we get the following figure.

Figure 1.11. Remaining margin divided by net capacities in the CSEE region in 2008

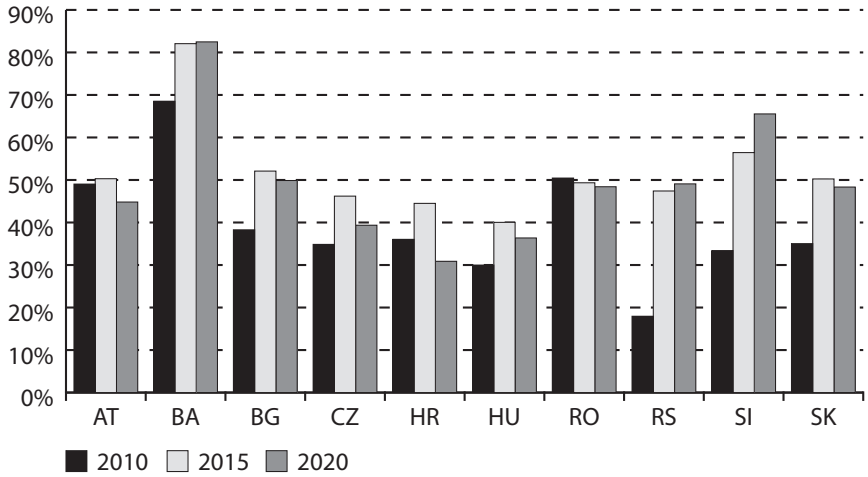


Data source: UCTE, Eurostat

All countries are above 10 percent, which means that their electricity systems can supply the countries absolute peak consumption, given our assumptions about instantaneous availability made in Table 1.2. The countries in the best shape are still Austria, Bosnia and Herzegovina, and Romania, as in Figure 1.10. The CSEE average is above 30%, meaning that the region as a whole is well-endowed with electricity generation capacity.

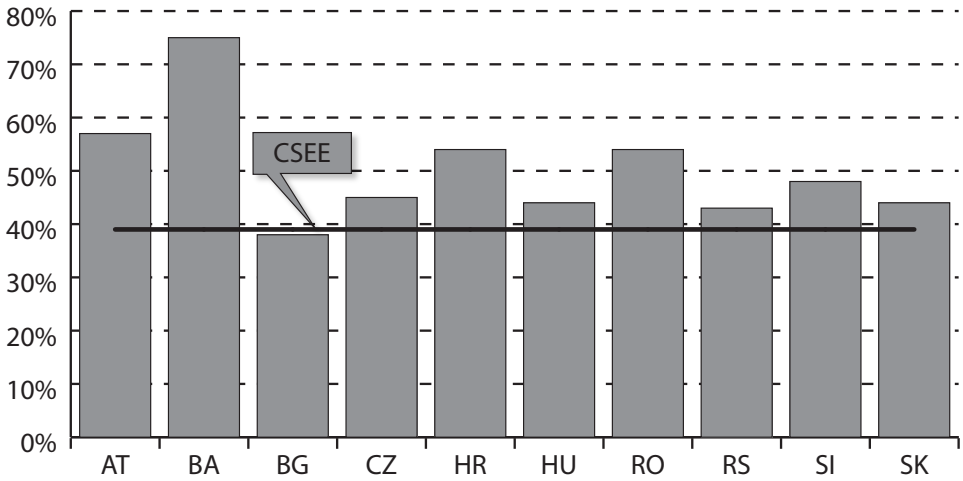
It is also instructive to project the values of this adequacy index into future years by forecasting peak loads and expected new power generation units, as well as the decommissioning of old power plants. Figure 1.12 shows the results of this exercise until 2020 for the CSEE region. As we can see, most countries can expect an improvement in medium-term electricity supply security, especially those that aren't performing extremely well in the present (e.g. Hungary or Serbia). In addition, a large part of this improvement (due to new generation assets) will likely happen within the next five years.

Figure 1.12. Remaining margin divided by net capacities in the CSEE region (forecast)



Data source: UCTE, Eurostat

Figure 1.13. (Available capacity + import capacities – peak consumption) divided by net capacities in the CSEE region in 2008



Data source: UCTE, Eurostat, ETSO

There is one other important factor that we have not taken into consideration. Import capacities can decrease the vulnerability of a country. Including import capacities among available generation assets, we get the numbers shown in Figure 1.13.

As Figure 1.13 shows, all of the analyzed countries indices are close to or above 40%, which means that they can easily satisfy peak consumption with indigenous capacity and imports.

1.4.3. Long-term indicators

We take two different approaches to assessing the long-term security of electricity supply in a given country. First, we compute two different diversity measures regarding the electricity generation portfolio of CSEE countries. Second, we look at measures of regulatory risk, trying to compare how countries fare against each other in terms of long-term investment climate. Since regulatory risk concerns the investment climate of the energy sector in general (both electricity and gas), we devote a separate section to its discussion at the end of the study.

1.4.4. Measuring diversity

The usual way of measuring long-term security of supply in the electricity sector is assessing the diversity, or concentration, of generation sources. The general argument in favor of diversity indices as long-term indicators follows the research agenda of Stirling (1999). Stirling argued that the long-term resilience of biological, technological or socio-economic systems against yet unquantifiable disturbances can be measured by the degree of diversity within the system.

Diversity, in Stirling's interpretation, consists of three, more basic properties: variety, balance and disparity. *Variety* refers to the number of categories into which we can divide the quantity in question (e.g. how many separate primary energy sources or technologies does a country have to generate electricity). *Balance* captures the relative share of these categories within the whole system (e.g. how evenly electricity generation is spread across energy sources). Finally, *disparity* is intended to capture the inherent similarities or dissimilarities in the categories (e.g. is lignite as a fuel more similar to hard coal than to natural gas?).

Diversity is generally measured with concentration indices, such as the Shannon-Wiener index (and its extensions) or the Herfindahl-Hirschman index. These are defined as follows.

Shannon-Wiener index:

$$SWI = -\sum_{i=1}^{I} p_i \cdot \ln(p_i)$$

where I is the number of categories (variety) and p_i is the proportion of each category within the whole (that is, $0 < p_i \leq 1$). The minus sign in front ensures that the index remains nonnegative. It takes its minimum of 0 when there is only a single category in the entire system (perfect concentration).

Herfindahl-Hirschman index:

$$HHI = \sum_{i=1}^{I} p_i^2$$

where I is again the number of categories (variety) and p_i is the percentage share of each category within the whole (that is, $0 < p_i \leq 100$). Perfect concentration is denoted by a maximum value of 10,000. In general competition policy applications, an HHI value

above 1800 is usually regarded as a sign of a concentrated market – although the applicability of this threshold to diversity measurement is arguable.

Of the two indices, we currently chose to apply the Herfindahl-Hirschman index, mostly because it is a more customary choice in economic applications. We will compute two separate indicators: one for the diversity of primary energy sources ("technology") and one for the diversity of ownership.

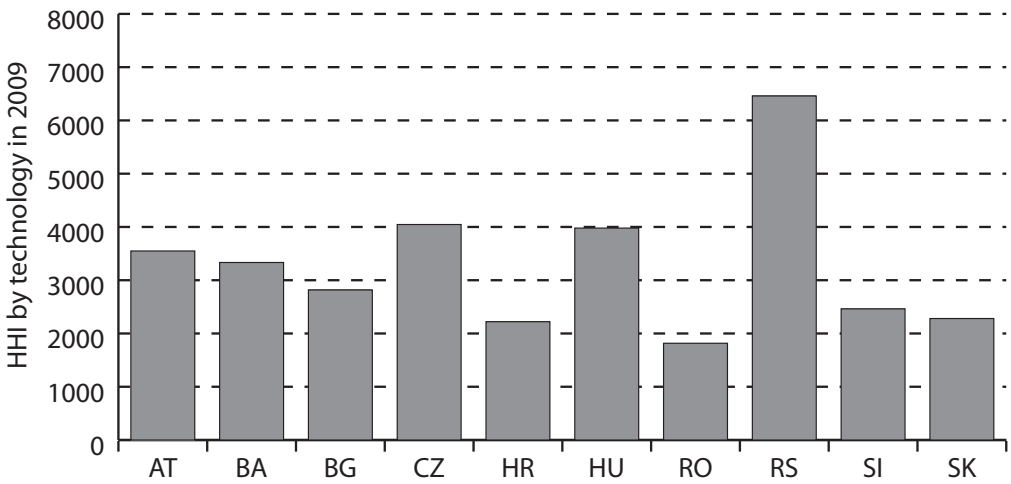
Intuitively, the more diversified the installed capacities are, the more secure the country seems in the long term. All of the technologies have disadvantages from security of supply aspects. In the case of coal power plants, a stricter regulation on pollutants such as CO_2 or SO_2, may induce a higher price. The same problem can occur in oil and gas-fired power plants. On the other hand, hydro and wind power plants are dependent on the weather. More variety and better balance among energy sources means that any single, unforeseen shock disturbs a smaller proportion of the total generation capacity.

The second concentration index reflects the ownership patterns of power plants. Again, we can argue that dependence on more producers increases security via decreasing the benefits of practicing strategic behavior (withholding capacity from the market).

Technological diversity

We differentiate between eight technologies (or fuel types): wind, hydro, lignite, hard coal, oil, natural gas, nuclear and biomass. Figure 1.14 shows the HHI for the analyzed countries.

Figure 1.14. Technology HHI in the analyzed countries



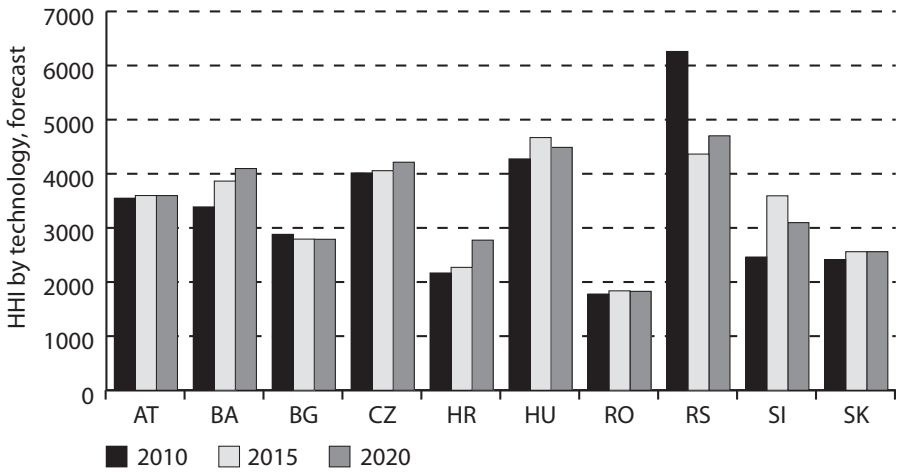
Data source: UCTE

As we can see, the most concentrated country by technologies in the CSEE region is Serbia, while the least concentrated one is Romania, meaning that from a long-term perspective, Romania has a better balanced electricity generation sector.

In Figure 1.15, we also depict projected values for fuel source diversity based on current estimates of new capacities that are likely to come online in the next decade. The

main noticeable development is an improved balance in the Serbian generation portfolio, bringing the country's diversity index in line with those of the Czech Republic and Hungary. There is a slight loss of balance in case of Croatia and Slovenia, but these countries will still be close to (or even below) the regional average.

Figure 1.15. Technology HHI, forecast until 2020

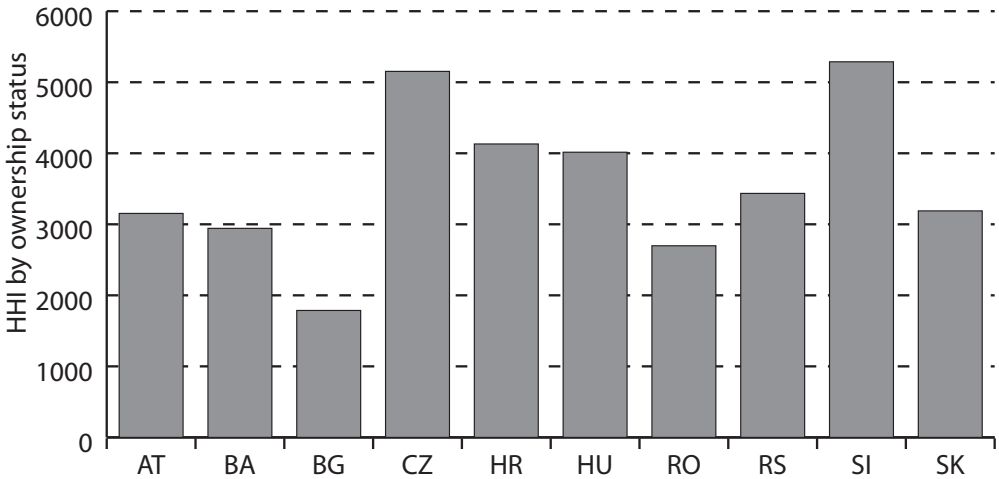


Source: REKK calculations

Ownership diversity

Calculating the HHI by generation ownership status, we get the following results.

Figure 1.16. Ownership HHI in the analyzed countries



Source: REKK calculations

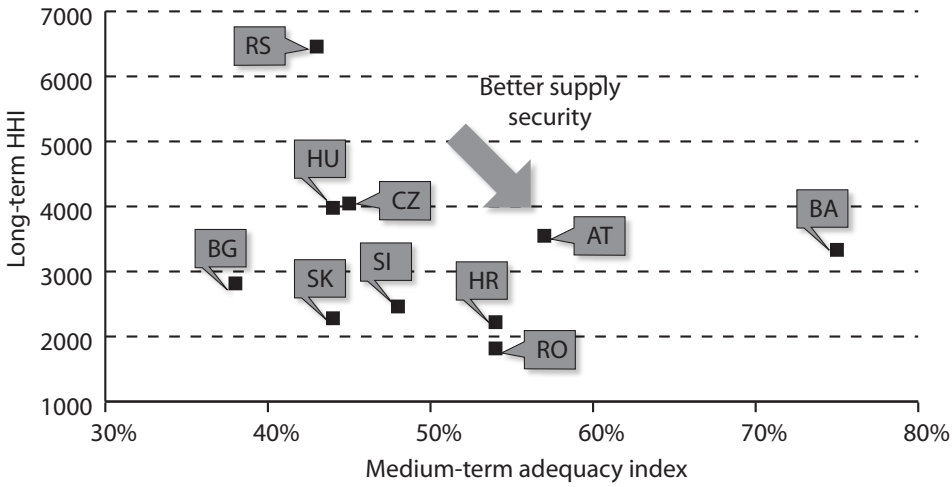
Only in the case of Bulgaria is the HHI below 2000, in all other countries the index is much higher. The most concentrated countries in terms of generation ownership are the

Czech Republic and Slovenia. We must emphasize, however, that by assessing ownership status, we assumed no centralized coordination among different state-owned companies, treating them as if they belonged to separate ownership groups (hence the low HHI value for Bulgaria).

1.4.5. Comparison of medium- and long-term indicators

In the previous two sub-sections we calculated several indices for medium- and long-term security of electricity supply. Figure 1.17 below summarizes the most important results: the countries' positions according to HHI by technology and the REKK adequacy index.

Figure 1.17. Indicators for medium- and long-term security of electricity supply



As the figure shows, the forerunners regarding medium and long-term electricity supply security are Bosnia and Herzegovina, Austria, Croatia and Romania, whereas Bulgaria, Hungary, the Czech Republic, and especially Serbia are in a considerably worse shape witin the CSEE region.

1.5. Security of supply in natural gas

1.5.1. Short-term indicators

We develop two short-term indicators to measure the supply security risk posed by a sudden, short-duration discontinuation of imports: a daily peak exposure indicator and a residual supply index.

Daily peak exposure indicator

We can quantify daily peak exposure (*EXP*) to gas imports with the following formula:

$$EXP = \frac{C_{peak} - P_{dom} - S_{ext} - L_{ext}}{C_{peak}}$$

where C_{peak} is daily peak consumption, P_{dom} is daily domestic production, S_{ext} is daily storage extraction and L_{ext} is daily LNG extraction (re-gasification).

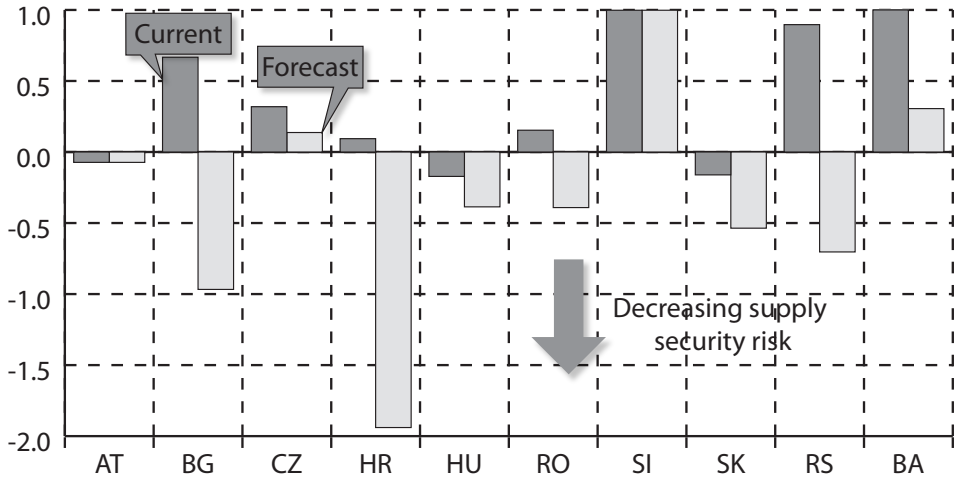
Due to the lack of a consistent data on true daily peak consumption, we used average daily winter consumption figures that are – by definition – below the peak consumption. The index reflects that domestic production and storage are considered to be less risky than import transported in pipelines. Similarly, LNG supply is more flexible to react to sudden demand changes due to number of potential suppliers and the short-term contract conditions characterizing the LNG market. (Currently, none of the countries involved in the research has LNG extracting capacity.)

The higher the index, the more vulnerable the country is to import supply. Its maximum value (=1) means the total lack of domestic supply sources (production and storage). Consequently uninterrupted consumption is based purely upon the reliability of import supply.

On one hand, as Figure 1.18 shows, Austria, Hungary and Slovakia can cover an average winter consumption day purely from domestic sources (negative value for exposure) which is mainly attributable to their large storage capacities. At the other extreme, Bulgaria, Slovenia, Bosnia and Serbia are very vulnerable as they have virtually no domestic production and none of them possess storage.

Forecast values for the exposure index, taking into account expected new storage and LNG capabilities within countries show a considerable improvement in short-term gas supply security.

Figure 1.18. Daily peak exposure indicator



Source: REKK calculations

It is important to consider – however – that this index is invariant to the geographic spread of major consumers (industrial users supplied from transmission lines) relative to the flow direction of imported gas pipelines. The gas import disruption experienced in Europe in January 2009 revealed that albeit Slovakia has large storage capacities and has – in theory – good security of supply position, it was unable to redirect the flow from its storages (located in the Western part of the country) to the major in-country exit points in the East to substitute the import gas entering the country from Ukraine. As a result, ensuring the future reverse flow capability of gas transmission lines is an important direction of European supply security policy.

Residual supply index

Our second short-term indicator is the Residual Supply Index (RSI), which is a structural indicator originally used for measuring market power of a single supplier. As opposed to the HHI, it is a tool that incorporates the demand side of the market as well. We apply the RSI in our analysis to show whether the outage of a single import pipeline causes major supply disruptions.

The formula for calculating the RSI is the following:

$$RSI = \frac{P_{dom} + S_{ext} + L_{ext} + I_{total} - I_{largest}}{C_{peak}}$$

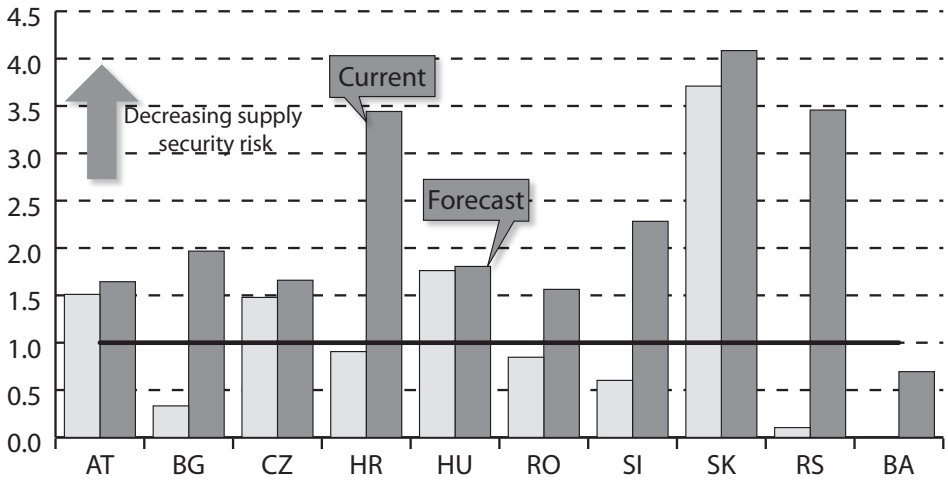
where C_{peak} is daily peak consumption, P_{dom} is daily domestic production, S_{ext} is daily storage extraction, L_{ext} is daily LNG extraction, I_{total} is the total pipeline import capacity and $I_{largest}$ is the import capacity of the largest single pipeline.

When the index equals 1, then in case of a complete outage of the biggest pipeline (no gas delivery at all) the other sources of supply (both domestic and pipeline import) are just sufficient to cover consumption. If the index is above 1, then the country has more supply resources than demand, and conversely, if it is below 1, then a disruption definitely causes a supply problem.

Our results in Figure 1.19 show that again Bulgaria, Slovenia and Serbia are risking the most with their current pipeline interconnection system, whereas Romania and Croatia are quite on a narrow margin as well. Slovakia's outstanding value shows again that its enormous storage extraction capacity can manage short term supply disruption (of course only until storage technical capacity lasts, and if the East-West problem we mentioned earlier can be solved). The rest of the countries are around or above 1, so that their consumption can be considered covered.

Figure 1.19 also shows the expected future improvements in the RSI value, which are especially market in the case of Bulgaria, Croatia, Slovenia and Serbia.

Figure 1.19. Residual supply index, current and forecast



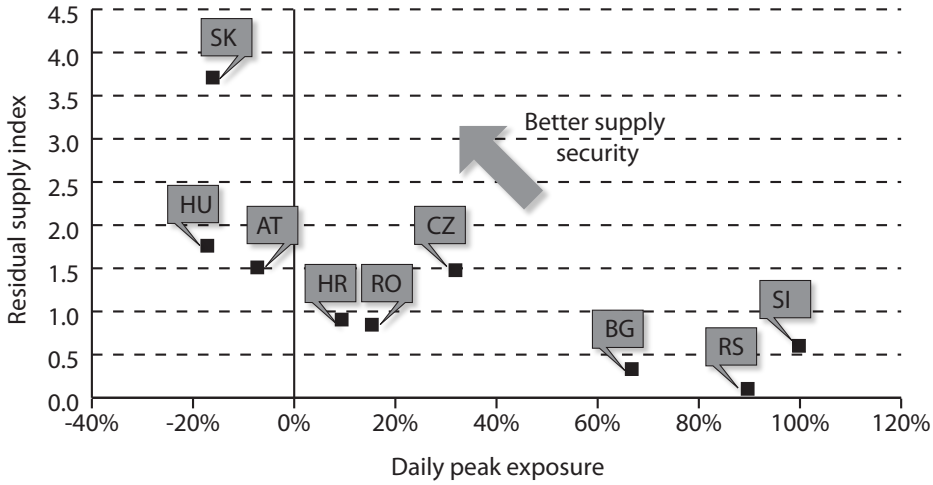
Source: REKK calculations

The combination of the two short-term gas supply indices in Figure 1.20 creates three rather distinct group of countries. The "safe side" group (characterized by low exposure and high RSI values) consists of Austria, Hungary and Slovakia. They have enough domestic sources (dominantly storage capacity) to substitute for import disruptions.

The second cluster of countries characterized by high exposure and low RSI values) is at the other extreme of a virtual short term security of supply continuum. Bulgaria, Serbia and Slovenia all have little storage and virtually no domestic production (Serbia

has some). The rest of the countries (Croatia, Romania and the Czech Republic) are in a middle position.

Figure 1.20. Summary of short-term gas security indices



Source: REKK calculations

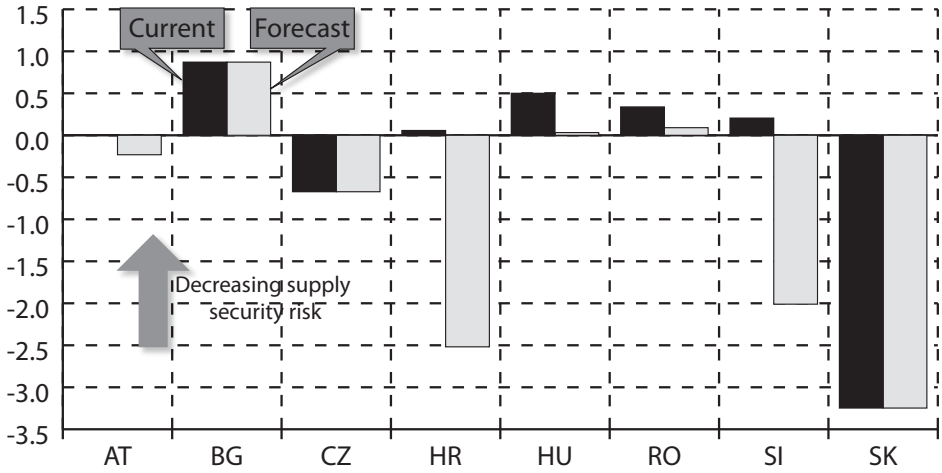
1.5.2. Medium-term indicators

We employ a medium-term indicator that takes into account the current capabilities of the infrastructure to satisfy demand, much like in the short-term case. Instead of daily peak capacities, however, we will look at a medium-term adequacy (MTA) measure over a full year, according to the following formula:

$$MTA = \frac{C - P - I_{total} + I_{largest}}{C}$$

where C is annual consumption, P is annual domestic production, I_{total} is the total annual pipeline import capacity and $I_{largest}$ is the annual import capacity of the largest single pipeline.

Figure 1.21. Medium-term adequacy indicator in the CSEE region



Source: REKK calculations

The value of the ("in")adequacy indicator can rise up to 1. A negative value means that the country in question is not dependent on any single import pipeline. Import is diversified and the largest pipeline can be substituted by the other(s). Whereas if the index value is in the positive range, then at least the largest pipeline is pivotal in satisfying annual consumption (most notably in Bulgaria, Hungary, Romania and Slovenia).

The index at this stage is still insensitive to the economic risk associated with the contractual setting such as the length of the supply contract or the supplier (EU versus non-EU state), and possibly also the transit route country risk.

1.5.3. Long-term indicators

As in the electricity sector, long-term supply security issues also depend on the general investment climate, most prominently the riskiness of regulation and market design in each country. We will examine this question in the final section of the study.

Regarding the diversity of import sources (instead of generation technologies, as in electricity), most countries in the CSEE region are unilaterally dependent on imports controlled by Russia. This is a unique supply security risk that should most likely be analyzed with the tools of political science, rather than economics. Therefore, we will not delve into the issue in the current study.

1.6. Assessing regulatory risk

Macroeconomic and regulatory risks might result in lower-than-optimal private investment activity that, in turn, undermines the immediate quality of energy services and also longer-term energy supply security. In the current subsection, we list those indicators of increased risk to private investment that are in line with the characteristics we described in section 1.1.4.

1.6.1. Macroeconomic risks

Our aim in this study is to focus on energy sector specific risks and mention other factors only when it is necessary. Undoubtedly, macroeconomic risks play important role in investment decisions. However, there are no specific macroeconomic indicators for the energy sector. Therefore we list three well-known indicators of macroeconomic risk without discussing them in detail.

- Aggregate economic country risk indicators (Monthly reserves, trade balance, inflation rate, exchange rate risk if applicable)
- Indebtedness of the country (debt to GDP, fiscal deficit to GDP)
- Credit ratings (S&P, Fitch)

1.6.2. Energy sector specific regulatory risks

Some perceive regulatory risks are more important than any other risk. They identify regulatory policy changes as the key challenges to prepare for. Although macroeconomic indicators also have important role in risk assessment, with firm regulatory framework this role could be easily played down. Jamison et al [2005b: p.36.] cites the East Asian financial crisis as a relevant example. When the crisis stuck in some Asian countries, the electricity sector investors were allowed to recover their investment costs, while in other countries the promises were broken and governments behaved opportunistically, regulating the prices in favor of gaining political support from their electorate.

Regulatory risk lies in the juridical framework and legislature. It occurs when laws, regulations, contracts are changed in an unpredictable and unfavorable way for the investors. While need for change is not always a question, the way of its implementation or frequency can lead for financial losses for private participants. In this subsection we will focus on different angles to assess the regulatory risks.

In case of regulatory risks first of all we have to look at the regulatory environment. Has the government set up a regulatory authority for energy sector or it regulates the sector through its ministries? Direct governmental control notably raises political risk and means that policy decisions are made in line with political aims. Therefore a separate regulatory authority is more likely to make professional decisions and consider policies that can lead to an efficiently functioning sector. Political risk can be significantly reduced if the authority's status is well settled in the legal system and respected.

Almost all of the CSEE project countries have their own regulatory authority, the only exception is Serbia. However, their obligations, duties and rights vary from country to country, as national law or statutory law sets their status. It is not the aim of this study to provide a legal analysis of the national regulatory authority's rights. Especially, in some

cases the aim of the law might differ from the way of its implementation. Therefore we propose to measure the regulatory authority's current status and related risk factors on an empirical basis. This would provide an overview on the current regulatory practice in CSEE project countries.

Viable and effective regulatory arrangements encourage private investment. But how can these regulatory frameworks resist political and economic constraints? (e.g.: elections, macroeconomic crises) What indicators allow the measurement of viability and effectiveness?

The existing literature states good governance is the key to achieve these aims. Thereafter our assumption is that good regulatory governance means low regulatory risk. First, and probably the most important factor of good governance is independence. High level of independence minimizes political intervention in the sector's affairs and reduces the chances of political corruption. It is a key factor of a professional, sector-specific policy making that can guarantee a well functioning market.

Regulator's independence assessment can be broken down into two levels: financial and political independence. The available resources from non-state budgetary sources, like license fees or other levy assessed on regulated entities can assist financial independence. It is also important to measure whether the available financial resources are sufficient to regulate the market actors. This indicates that the regulator has all means to have a competent staff and at the same time has the opportunity to avoid brain drain by providing competitive wages, education and training.

The measurement of political independence is not trivial. Law determines the regulatory authority's activities, rights and obligations. Nevertheless, the implementation of the law may vary from the lawmaker's intention. Occasionally the rule of law is so weak, that there are few opportunities to enforce its implementation. Political science has its tools how to measure these institutional frameworks or the strength of the law. For example by looking at the origins of law (is it part of the constitution, changes in law require simple majority vote or absolute majority, etc.) or the chairman's appointing mechanism (who is appointing – president, prime minister – is there a parliamentary vote on the appointment or not, etc.)

In theory these are very well founded tools, however, in a cross-country comparison this assessment requires a country by country analysis, and experts' opinion. As we tried to avoid such a complicated mechanism, we propose an indicator on empirical basis: **Average term of the Chairman / Commissioners of the Energy Commission in the last 10 years (or since the establishment of the Commission)**.

Short Chairman terms suggest frequent political intervention or pressure on the regulator's activity, while long served terms can guarantee coherent continuity in policy making. Unfortunately the Commissioners' persons cannot always guarantee cohesion as pressure can be exercised indirectly, thus enforcing policy changes. Therefore it might be relevant to look at **the policy changes per commissioner.** The latter can measure not only political independence, but also serve as a sign for predictability in policy change. Predictability is a relevant requirement of good governance, as unforeseen changes can seriously affect the rate of return on investment.

In the following table we have collected data on average term of the Chairman in the CSEE region.

Table 1.3. Number of Chairmen since the establishment of the Commission

Country	Established	Number of chairmen	Average term (2008)	Term of the current (last) chairman
Austria	2001	1	7	>5
Bulgaria	1999*	4	2,25	(>5)***
Croatia	2001**	2	4	4
Czech Republic	2001	2	5	5
Hungary	1994	5	2,8	(>5)****
Romania	1999	7	1,5	<1
Serbia	n.a.	n.a.	n.a.	n.a.
Slovakia	2002	4	2	<2
Slovenia	2001	2	4	2

Source: National Regulator Agencies' Annual Reports

* Established as State Energy Regulatory Commission, since 2005 State Energy and Water Regulatory Agency
** Established as Croatian Energy Regulatory Council, since 2005 Croatian Energy Regulatory Agency
*** Chairman term recently (2009 autumn) ended
**** Chairman recently (2009 autumn) withdrew from his position

Table 1.3 shows that almost all energy regulator agencies in this region were established during 1999-2002. Among them Hungary is the only exception, establishing its agency rather early, in 1994.

Based on the number of chairmen in office, the highest regulatory risk – in sense of predictability, possible policy change and political dependence – exists in Romania, where in 10 years time, 7 chairmen were appointed. This data can be slightly balanced with the fact that in some cases the ex-chairman continued to work as vice-chairman, therefore maintaining some level of continuation in policies. There were precedents that ex-chairman returned to this position after few years. However, this does not change the fact that there was no chairman in Romania who could serve its full term. This suggests high political influence in the authority's work.

The second highest result is shown in Bulgaria. Admittedly, this result can be a bit misleading, as the first three chairman changes happened in the first three years since SEWRC establishment. In reality, Bulgaria's chairman position was as stable as the Austrian, having only one chairman during 2001-2009.

Hungary has a delicate situation, its first two chairmen were appointed for indefinite time. The first chairman passed away, the second was revoked by the Minister. Since then, none of the Chairmen have served a full term.

In regional comparison, Slovakia has slightly higher risk than its neighbors, as its chairmen changes happened more often than scheduled. In Croatia, Czech Republic and Slovenia chairmen served their full term, although never as long as in case of Aus-

tria. Based on this method in these four countries there is a relatively low risk to policy change or direct political interference.

Secondly, good governance depends on the market design. The regulator is in charge to set the framework of the market and make amendments in case of malfunctions. Indicators listed in the following section are directly related to risks that are caused by the regulator's policy itself.

Primarily, we have to assert the importance of the regulator implemented tariff regime. Regulators following different policy aims may frequently interfere in the market, with the aim to frame market mechanisms in a manner that allows serving public interests. The public interest in this case is having a reliable supply for competitive prices. The most obvious solution to measure competition is to look at the **share of publicly owned equity to total equity**.

High share of publicly owned equity may signal high market concentration in the government hands that makes the sector sensitive for political issues, like political gains or elections. High public share may also lessen competition, raises the risk of market intervention in an indirect way.

However, the scale of obligatory feed-in can influence competition in prices therefore it is also important to look at the **share of obligatory feed-in generation in total generation (given year).** Obligatory feed-in regimes serve policy aims to support different generation types. Nevertheless, they narrow competition. Obligatory feed-in indicates that the product has to be let into the system and paid a given price. This means that other market actors have less demand to supply and compete for. While from the consumer point of view, a certain share of the consumption comes from a "non-competitive price source".

Other indicator on the tariff regime can be given by the **local wholesale / retail prices relative to benchmark power exchange prices**.

The tariff regime also sets the limits for investors to recover their costs. Investors' interests are that the tariff regime allows them to plan investment with stable prices or predictable price changes, in line with inflation and exchange rates. The Californian electricity crises have shown that for investors market design is crucial. This can be measured by the **share of generation under tariff regulation or long-term regulated contracts** and by the **share of customers entitled to purchase at regulated tariffs (G/E, wholesale, retail)**.

Table 1.4. Share of customers entitled to purchase at regulated tariffs

Country	Share of customers entitled to purchase at regulated tariffs
Austria	n.a.
Bulgaria	~70%
Croatia	80%(household) 50%(medium) 20%(industry)
Czech Republic	
Hungary	40-45%
Romania	~57%
Serbia	100%
Slovakia	n.a.
Slovenia	n.a.

Source: National Regulator Agencies' Annual Reports and own calculations

We have not addressed the criteria of good governance such as transparency, accountability and public participation. However, we assume that the above discussed indicators will signal risk levels sufficiently and the latter three will not provide us with new information on regulatory risk.

Finally, on regional scope national regulatory authorities with license fees and procedures can directly influence decisions on investment. These can be measured in the following ways.

(i) Estimated licensing cost of 1 MW installed generation

Licensing costs mean all expenses that are required by the regulatory authority for capacity installation.

Table 1.5. Estimated licensing cost of 1 MW installed generation

Country	Estimated licensing cost of 1 MW installed generation
Austria	n.a.
Bulgaria	~ 38 € + 10 €/year* + 0.055 percent of annual revenues
Croatia	~137 €**
Czech Republic	38 €
Hungary	n.a.
Romania	~ 25 € + annual contribution of 0,035% of the turnover
Serbia	n.a.
Slovakia	more than 1 up to 5 MWe 33,00 € / 1 000 Sk - more than 5 up to 50 MWe 1 659,50 € / 50 000 Sk - more than 50 MWe 2 489,50 € / 75 000 Sk
Slovenia	n.a.

Source: National Regulator Agencies on license fees[11]

* estimated calculation for an average 200 MW capacity (Total: 7600 € + 2000 €/year max: 50000 €) renewable energy production has much more favorable conditions

** estimated calculation for an average 200 MW capacity (Min. ~27500 € (200000 HRK))

(ii) Estimated time requirement of licensing (new generation, transmission, distribution E/G)

Only licenses issued by the Regulatory Authority are included in this indicator. License is a technical and legal document, granted by the Competent Authority, which, following an application submitted by a foreign natural/legal person, enables the latter to commercially operate electricity or electricity and heat cogeneration capacities and to ensure the efficiency of the electricity market, respectively.

(iii) Number of licenses / authorizations needed to start energy infrastructure investments

Investment tendencies, on the other hand, can serve as sign how the above mentioned risk factors are perceived. Investment flows, or lack of them, can signal the general investment climate. This can be assessed either by **new investment applications by capacity / total installed capacity** or **new investment applications / started investments**. High values could indicate acceptable level of regulatory risk comparing with the opportunities of the market. While low results may indicate high administrative burden or other regulatory barriers that can be eliminated by good governance.

[11] Czech Republic Act No. 634/2004 on Administrative Fees; Ministry of Economy Croatia Regulation on Conditions for Carrying Out an Energy Activity (Official Gazette 6/03) Regulatory Office for Network Industries of Slovakia – License Tariff scale Romanian Government Decision No. 540/April 7th, 2004 and No.553/June 6th, 2007; Tariff of Fees to Be Collected from State Energy and Water Regulation of Energy Law (SG. 41 2007)

The definition of new investment application may vary in many sophisticated ways. For example a new investment application can be defined as the first submitted application for any kind of permission that is related and needed for the project realization. However, better solution would be if only those cases are counted were the authority have issued the permit. Third example could be, when new investment application is counted only when all the required permissions are obtained.

The same applies for the definition of started investment. It can be said that a started investment counts when on site works have been started. An alternative definition on started investment can be a signed memorandum of understanding between the parties and finished feasibility studies.

Observation of investment tendencies can be further developed by recognizing the average age of the energy infrastructure that indicates the scale of ongoing modernization or contrary the lack of investment. In case of an old infrastructure it has to be examined why needed investments have not occurred? What are the drivers behind the ageing? Are the regulatory or other obstacles withholding investment?

Table 1.6. Average age of CSEE region power plants

Country	Average age of power plants 2009* (in years)
Austria	22,5
Bulgaria	30,0
Croatia	21,7
Czech Republic	27,6
Hungary	23,6
Romania	24,0
Serbia	27,4
Slovakia	20,0
Slovenia	22,8

Source: REKK calculations
** hydro power excluded*

The result in Bulgaria shows old infrastructure where new production capacities are needed urgently. It indicates that in the past years no significant production sites were added to the Bulgarian power generation system. Theoretically it is in line with the low average term of the Chairman (2.25 years) and these two indicators together sign relevant regulatory risk. However, it was noted that there were no change in Chairman position in the last seven years. This suggests problems in the market setting and/or in the regulatory environment. The Serbian and Czech generation capacities average age also sign need for new power plant investment. While the other countries in the region somehow manage to coordinate system upgrades in an acceptable time frame.

It is interesting to point out that Croatia while has one of the lowest average age of its power plants in the region has a perilously old network system. Most of the lines are over 30 years old, which means they are close or at the end of their life-time [Majstrović 2009].

The latest section of indicators can be examined in another way by looking at the yearly tendencies in the share of investment (or FDI) in energy sector comparing to the total investment (or FDI) level. This gives us a general picture on mid or long term tendencies in the energy sector investments. Implementations of new capacity installation requires years. The increase in the investment flow to the energy sector might indicate new opportunities and favorable changes in the sector.

To sum up, a variety of regulatory risk indicators have been given in this subsection to address such relevant issues as regulatory independence, predictability or indicators for risks that unfold from the regulator's policy itself, that directly or indirectly affects investment decisions. We have assessed risks that unravel from tariff regime, license procedures and investment applications.

1.6.3. Other indicators for investment climate

Besides the mentioned macroeconomic and regulatory risk indicators we have to supplement indicators that address the questions of rule of law and corruption. These indexes are very difficult to be measured, but they are extremely important to get an overall picture on the investment climate, the stability and predictability of the regulatory authority, and policy transparency.

One of the most well known indicators of this type are the Worldwide Governance Indicators (WGI) of the World Bank. The WGI is an aggregate of 35 data sources provided by 33 different organizations that are coming from public, private and NGO sectors. It gives us an overview on six dimensions of governance over the period 1996 – 2008, providing the opportunity of a cross country comparison.

The six dimensions are the following:

1. *Voice and Accountability (VA)* – capturing perceptions of the extent to which a country's citizens are able to participate in selecting their government, as well as freedom of expression, freedom of association, and a free media.
2. *Political Stability and Absence of Violence (PV)* – capturing perceptions of the likelihood that the government will be destabilized or overthrown by unconstitutional or violent means, including politically-motivated violence and terrorism.
3. *Government Effectiveness (GE)* – capturing perceptions of the quality of public services, the quality of the civil service and the degree of its independence from political pressures, the quality of policy formulation and implementation, and the credibility of the government's commitment to such policies.
4. *Regulatory Quality (RQ)* – capturing perceptions of the ability of the government to formulate and implement sound policies and regulations that permit and promote private sector development.
5. *Rule of Law (RL)* – capturing perceptions of the extent to which agents have confidence in and abide by the rules of society, and in particular the quality of contract enforcement, property rights, the police, and the courts, as well as the likelihood of crime and violence.

6. *Control of Corruption (CC)* – capturing perceptions of the extent to which public power is exercised for private gain, including both petty and grand forms of corruption, as well as "capture" of the state by elites and private interests.

There are different types of methodologies to measure corruption. To provide a wider perspective on this issue we turned to other well established and citied indicator, the Transparency International's Corruption Perception Index (CPI). It measures perceived levels of corruption by expert assessments and opinion surveys. It is interesting that despite the fact that CPI overlaps with some sources of the WGI CC (in 7 cases out of 13), the differences in results are visible. CPI shows higher corruption in a 10 grade scale, that we converted to percentages to provide an opportunity to compare it with WGI CC. (Margins of error are applicable)

Table 1.7. Worldwide Governance Indicators and Corruption Perception Index 2008

Country	Word Bank						Transparency International
	Voice of Accountability	Political Stability and Absence of Violence	Government Effectiveness	Regulatory Quality	Rule of Law	Control of Corruption	Corruption perception
Austria	94	95,7	94	94	99	94	81
Bulgaria	66	58,9	58	73	51	52	36
Croatia	60	66,5	70	67	55	62	44
Czech Republic	82	78,9	82	82	77	67	52
Hungary	78	67,9	73	88	76	72	51
Romania	59	56	50	68	54	57	38
Serbia	55	28,2	48	47	41	53	34
Slovakia	75	78,5	77	85	67	69	50
Slovenia	82	84,7	83	75	82	80	67

Source: Transparency International, World Bank

Table 1.7 shows that despite EU membership Bulgaria and Romania has one of the weakest results in Rule of Law (51% and 54% respectively) and different corruption indicators. With very similar results (RL 55%) much the same investment climate is described in Croatia that has started accession talks with the EU. The worst performer in the region is Serbia that needs to make serious efforts to catch up with its neighbors in fight of corruption and enforcing rule of law. The Czech Republic, Hungary and Slovakia have performed the average results of the region, while Austria serves as a benchmark of

the Western European average. Slovenia has the best results among the former socialist states, thus approaching the Western European results.

Our proposal for alternative measurement of the rule of law relevant to the energy sector would be an indicator of the average annual number of international arbitrations in the energy sector in the last 10 years (or since the establishment of the Commission). Broken or renegotiated contracts, sometimes changes in legal framework may serve basis for international arbitrations. This indicator could show: firstly, if the parties are able to resolve legal disputes in the national judiciary or not. High value indicates that disputes cannot be resolved on national scale for some reasons, indirectly indicating the weakness of the rule of law in the given country. Secondly, this indicator could measure indirectly the effectiveness of the regulator. Clear market rules, policy aims without sudden changes allow to avoid such legal disputes. Unfortunately, this indicator serves for a cross country comparison. For a sole country it could not be effectively interpreted.

In this section we have set up a framework that can address the complexity of macroeconomic, regulatory and legal-social risks assessment. Considering energy sector investment these factors cannot be dealt separately. It was shown that although mutual leverages are obvious, other risk types, mentioned in this section, could be successfully addressed by high standards of regulation. The arranged indicators allow us to measure regulatory risks on an empirical basis.

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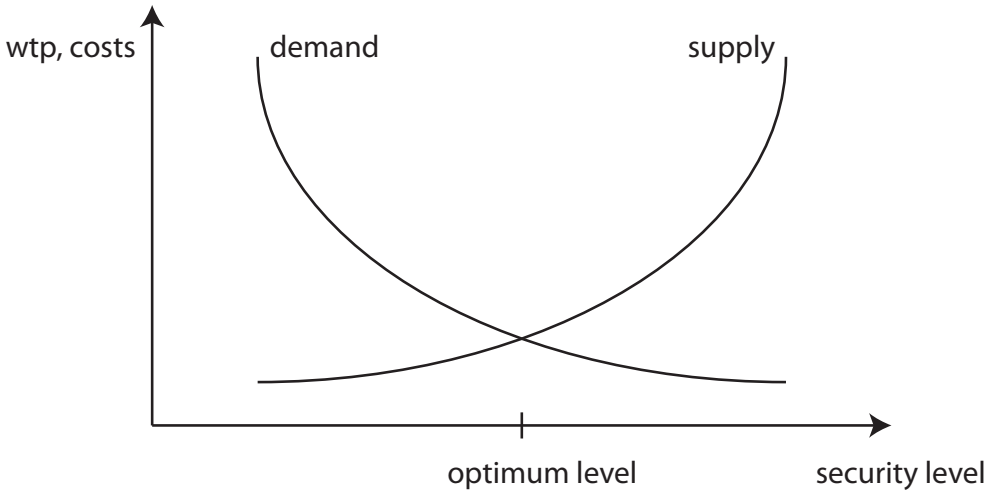
The economic value of increased supply security

2.1. Introduction

All electricity and gas supplying systems provide a certain level of security. Whether this level of security is adequate or not is however not easy to assess. There is a trade-off between security and costs as higher levels of security can only be reached with greater investments, while a less secure system is also less costly. Achieving an adequate level of security of supply needs the balancing between the benefits of increased security and the additional costs needed to realize it.

The theoretical optimum level of supply security is where the demand for security equals its supply. Supply of security can be characterized by the costs of investments that are needed to provide extra security. Raising the level of security in the beginning can be attained by more simple, less costly investments, while in case of an already highly-secure system providing extra security would demand more complicated measures. Therefore the supply curve could be illustrated with an upward sloping curve which is close to flat at low levels of security and it becomes very steep at very high levels. On the other hand demand for security can be defined in the form of willingness to pay of consumers for extra security. As higher the level of security, the less consumers are willing to pay for extra security which is characterized by a downward sloping curve which is steep at low levels of security and is close to flat at high levels. Optimal level of security is thus where these two curves intersect. Above this level, the costs of extra security are higher than what consumers would pay, while below this level consumers would be willing to pay more for extra security than its costs.

Figure 2.1. The theoretical optimum level of supply security



If there would exist perfectly competitive and perfectly informed markets for security this optimum would be reached as a result of individual decisions. However in case of natural gas and electricity markets this is not the case mainly because security is not a pure private good. For example small consumers receive the service collectively, without

individual real time metering it is in practice impossible that consumers from the same network enjoy different levels of security. Thus small consumers' individual willingness to pay remains unrevealed. This is partially also the case for large consumers. There are some possibilities to alter their security level from the system's especially in case of electricity but the range of security levels that can be obtained with these additional possibilities is very limited.

This way the willingness to pay of consumers does not appear on the energy markets and the security level as a second best solution is determined through centralized decision of the authorities on behalf of the consumers. The task of the regulator in this respect is to aim at providing the theoretical optimal level of security. For this however besides the costs of investments (the supply side) the regulator needs to be familiar with the demand curve for security as well, the valuation of consumers. But while in practice there are many decisions made regarding investments that affect the level of security the regulator in Hungary and also in the region has not paid much attention to the demand side. This suggests that the current security levels could be far from the theoretical optimal one.

This paper aims to mitigate this problem by providing details and information on the demand side of security making calculations on the value of lost load for consumers in the natural gas market. The results of the paper could be used to evaluate investments and/or regulatory decisions that affect the level of security of supply, directing it closer to the theoretical optimal.

The structure of the paper is the following. In section 2.2 we briefly introduce the four main methods for estimating consumers' valuation on security of supply, section 2.3 discusses our estimation for the Hungarian consumers, section 2.4 provides an application, a cost-benefit analysis of the Hungarian strategic storage site, and finally the Appendix contains the estimations for the remainder countries in the CSEE region.

2.2. Estimation methods

For the estimation of the value of supply security for consumers we will use as a tool the value of lost load (VOLL) indicator which is frequently applied in the electricity sector and shows the value (€) consumers place on energy not supplied to them (m^3).

As we have described it in the introduction there is no market price for security of supply therefore for the estimation of VOLL alternative ways are used. There are many types of categorizations for these estimation methods, we will discuss them briefly in the following four categories: proxy methods, revealed preference methods, surveys (stated preference methods), and finally case studies.

2.2.1. Proxy methods

These are the simplest estimation methods trying to provide an approximation for the VOLL value with primarily macroeconomic statistical data. The biggest advantages of the proxy methods are their simplicity and small data need while their greatest drawback is that these only provide aggregated average values, and do not tell anything about the variation of VOLL within a consumer group or its variation over time. The most popular proxy method is the GVA method, which is based on gross value added and consumption data. This method estimates VOLL as the lost GVA due to a halt in production. Other proxy values are simply the price of the analysed energy products and for the valuation of residential consumers the average wage which is considered as an approximation for the value of the leisure time that was interrupted by the supply problem.

2.2.2. Revealed preference methods

Revealed preference methods provide an estimation based on actual decisions of consumers on markets which are connected to energy consumption and consumption interruption. The advantage of this method is that in this case VOLL is estimated from real decisions of consumers therefore it should reflect true valuation of those analysed, its drawback is its complexity, and great data need. A further problem of the revealed preference method is that only a small segment of the consumers can be analysed this way, as most energy users do not reveal their preferences on alternative markets. Therefore these values cannot be used to reflect the valuation of the whole society.

An example for this estimation method is the analysis of the market of backup generators in case of electricity, and the analysis of alternative fuels' markets to which some consumers can easily switch in case of natural gas.

2.2.3. Surveys (stated preference)

In case of surveys the consumers are asked about their valuation in a hypothetical situation of a supply disruption. With the carefully fabricated questionnaire the interviewer simulates the missing market of supply security to find out as much about the consumers' valuation as possible. The advantage of this method is that this way we can arrive at an estimation for the valuation of all kinds of consumers and for all kinds of supply interruptions, thus we would learn a lot more about the distribution of VOLL than with

the other valuation methods. The greatest drawback of the surveys is that the results cannot fully be treated as real valuations, since consumers can state anything they want. Unlike in the case of the revealed preference method here consumers do not have to pay the actual value they state therefore we never can be fully certain about the validity of the answers. It could be the case that the interviewed consumer exaggerates its cost on purpose, but it could also happen that the consumer did not fully understand the situation described in the question and therefore provides a false value. Furthermore many studies have showed that the answers are very dependent on how the questionnaire is written.[1]

Thus since the answers cannot be enforced, the values estimated this way could always be questioned.

2.2.4. Case studies

Case studies similarly to the previous method are delivered by asking consumers but in this case in-depth interviews are made with few people instead of postal or telephone surveys with a thousand people or more. The aim here is to estimate the costs of a given supply interruption that has been suffered by the approached consumers instead of the costs of a hypothetical, future situation. Its advantage is that consumers know and understand exactly what they are asked, they will not have trouble in calculating the costs, however consumers might be tempted to exaggerate what they have suffered in hope for compensation. The main disadvantage is that based on the case studies we will learn about one exact supply disruption case but due to the specifics of the analysed disruption it cannot fully be used for deriving general values.

2.2.5. Experience of measurement and use of VOLL values in the natural gas sector

Estimating and using consumers' valuation of supply security in the natural gas sector is relatively a new area. While in case of electricity there is an ample literature dating back to the 1970s in case of natural gas only a few valuations and applications have been made and these pertain to only two countries Australia and the United Kingdom.

In Austrialia a VOLL value is used as an overall price ceiling in the Victorian natural gas wholesale market. The value is also applied for long-term planning analysis of the reliability of the gas transmission system. It was first calculated and introduced in 1997 and since then it is being updated and refined. The latest comprehensive survey of the VOLL value was conducted in 2005.[2] Gas powered generators and industrial consumers of different curtailment groups were asked to assess their costs in a hypothetical setting of gas supply interruption, i.e. stated preference method was used for the estimation. Based on that the current VOLL price ceiling in the wholesale natural gas market is 800 AUD.

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[1] Carson, R. – Flores, N. – Meade, N. (2001): Contingent valuation: controversies and evidence. Environmental and resource economics, vol. 19. (2)

[2] MMA report to Vencorp: The value of customer reliability for gas, 2005

In the UK cost of unserved gas values were used by the Department of Trade and Industry to determine the economic implications of a gas supply interruption to UK industry,[3] and VOLL values were also used in long-term security of gas supply analysis, where strategic storage and other options were assessed and valued against their benefits.[4] The estimations were made with the simple GVA proxy method.

[3] ILEX Energy report to DTI: Economic implications of a gas supply interruption to UK industry, 2006

[4] ILEX Energy report to DTI: Strategic storage and other options to ensure long-term gas security, 2006

2.3. Calculation of costs of unserved gas for Hungary

2.3.1. The focus of the estimation

In our next analysis we will start out from the simplest proxy method applying it to the industry, then will gradually refine our estimation for the different consumer groups with different methods.

Since the VOLL value varies according to consumer groups and also according to the size of the disruption and its length, instead of estimating a single VOLL value for the country which would be hard to interpret and use for cost-benefit calculations we will make separate estimations of VOLL values for the different consumer segments and will incorporate these into a cumulated cost curve for the economy. The curve will follow an optimum path of curtailment, assuming that in a supply disruption first those are curtailed which assume the least cost. This way we will have cost estimations also for disruptions with different size and length.

Our estimations of a cumulated cost curve therefore could be used as a benefit – avoided cost assessment for evaluating different types of investment opportunities that aim to increase security of supply.

We will estimate the cumulated cost curve for one winter day, as a supply interruption is most likely and would have the most sever impact in winter, when consumption is the highest.

Including January 2009

Our aim is to construct a cumulated cost curve for the Hungarian natural gas supply system that provides an indicative estimation of possible losses a future supply disruption could result in and therefore shows the demand for increased supply security. In 2009 Hungary along with other Eastern-European countries had already suffered a major supply disruption which provides a good insight of what a supply crisis could cause.

A brief summary of the 2009 crisis is given below. [5]

> *The Russian-Ukrainian gas dispute started at the end of 2008 resulted in a curtailment of transit supplies through the Ukrainian pipeline to the Western gas routes. The list of effected countries is long, as supplies to Slovakia which is the main entry point of Russian supplies to Western Europe were also ceased. The most directly hit countries were Slovakia, Romania, Bulgaria, Bosnia and Herzegovina, Serbia, Croatia, Czech Republic, Hungary, Slovenia, Italy and Austria. The curtailment had different effect on these countries based on their alternative possibilities for supply. Hungary within this group was moderately hit the largest consumers had to reduce consumption for several days. The companies that were ranked in the first curtailment category were curtailed between January 6 and 15 while those companies that were ranked in the second curtailment group also had to curtail their consumption for*

[5] For a detailed discussion please see the related EU Commission staff working document: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SEC:2009:0977:FIN:EN:PDF

around 24 hours between January 7 and January 8. The crisis in Hungary resulted in a consumption curtailment of around 7 Mcm/day (I^{st} category) and on the most severe day it went up to 9 Mcm (I^{st} and IInd category) while the consumption of the rest of the consumer groups during the crisis was not effected and varied between 57 – 64 mcm/day.

The 2009 supply crisis provides a good opportunity for estimating costs of an exact supply disruption, and naturally comes the idea to use this gas crisis as a baseline for future events. Thus the paper could focus on estimating the exact costs that the 2009 gas crisis caused. However we think that due to the peculiarities of this crisis like the coincidence with the financial crisis and the extraordinary relation of the oil and natural gas prices that were in effect during that period, the costs of this given crisis would not be a right indication of the costs of a possible future supply disruption. Therefore we will not aim at directly estimating the costs of this supply crisis but will rely on conclusions that can be derived from this 2009 experience and will also use the 2009 crisis as an example to illustrate the estimations we make.

Structure of the analysis

The following estimation for Hungary will be structured as follows. Our analysis will start out from the simple GVA method. Then for the different consumer segments, this first estimation will be gradually refined. In case of gas fired power plants we will replace the GVA estimation by the revealed preference method, calculating the power plants' switching cost to alternative energy. In case of other industrial players we will include the experience that can be learned from the case studies we conducted on the 2009 gas crisis. Finally in case of the service sector we will use the results of a survey conducted among small and medium enterprises. As a result we will obtain a revised cumulated cost curve for Hungary that reflects in a fairly detailed way the costs of the economy in case of a supply disruption, the demand for supply security.

2.3.2. Basic values – proxy estimation

The proxy method we use for the basic estimation is the GVA method which assumes that the costs a supply disruption causes are the loss of profit due to the hold up in production. Naturally this method can mainly be used for the assessment of costs incurred by the industry.

Data used

Data published by Eurostat have been used to measure the impact of a gas supply interruption on the economy. We use gross value added at basic prices for the quantification. Gross value added is defined as the net result of output valued at basic prices less intermediate consumption valued at purchasers' prices, i.e. the value of goods and services less the value of the products used to make them. For the proxy estimation we calculate with average daily gross value added, for which we simply transform the yearly GVA to non-weighted average daily GVA, assuming that the sectors produce evenly throughout a year.

Data published by the Hungarian Energiaközpont KHT was the principal source of energy usage. Energaiközpont KHT provides the most detailed breakdown of the yearly natural gas consumption to sectors. For the estimation we use average daily consumption by sectors, which is transformed from the yearly consumption value to a weighted average daily value. We use weighted average as we are interested in the costs a supply disruption causes on a winter day. Natural gas consumption is typically not spread evenly across the year, total winter consumption due to the Hungarian climate is around three times higher than summer consumption. For this reason based on 2007 and 2008 monthly consumption data of the small, medium, and large consumers, and the electricity and heat producing sector, in case of industrial sectors we have multiplied the average daily consumption by 2, in case of the public administration and the services sector we have weighted the simple average by 2.7 and in case of the electricity, gas, steam and hot water supply sector we have multiplied the average by 1.1.[6]

Combining the two database

Since the data published by the two sources are not broken down to the same categories, Eurostat GVA data is more detailed than the energy usage data of Energiaközpont Kht, we have aggregated the GVA data to the level of the energy usage data.

The latest data published for energy usage is for the year 2008, therefore our estimations will be based on this year's values. Altogether we find 2008 data a better basis for estimation of future costs than an estimation based on 2009 values due to the serious impact of the economic crisis on this year's energy consumption. It would probably provide a biased estimation for the future years without economic crisis.

Assumptions

In case of GVA method we define the impact of a supply crisis with the loss of gross value added. For this we use the GVA/day and energy usage/winter day indices. However it has to be mentioned that this quantification method implies many simplifying assumptions due to which the real costs of a supply problem could greatly differ to both directions. When evaluating the results of this analysis this always should be taken into consideration. The most important and relevant simplifying assumptions are:

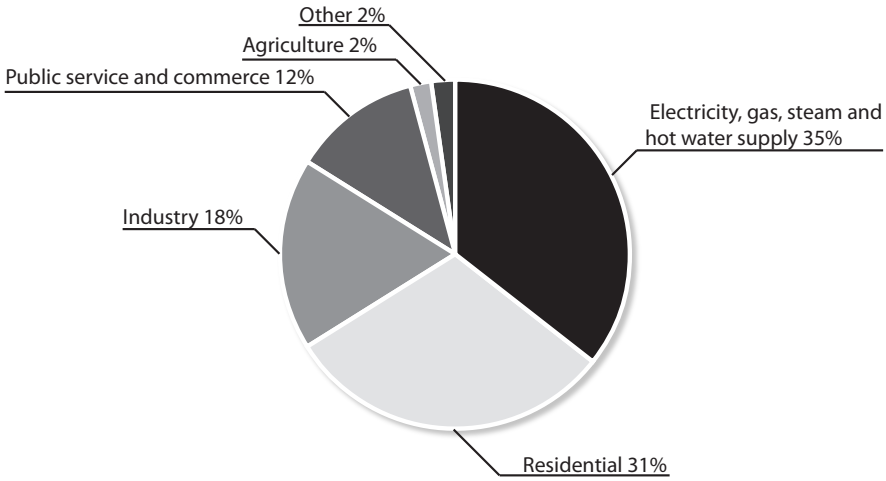
- Natural gas is a substantial input - without natural gas production cannot continue even not partially
- The cost is the lost profit:
  - there is no further costs e.g. damage in stocks and equipment
  - the loss cannot be decreased for example by making up for the lost production later.
- The gross value added is spread evenly during the year
- Gross value added and natural gas consumption is spread evenly within a sector

[6] The Hungarian Energy Office publsihed monthly consumption data for 2007 and 2008 for the consumer segments below 20m^3/h, between 20 m^3/h and 100 m^3/h, between 101 m^3/h – 500 m^3/h, and above 501 m^3/h. Eurostat publishes monthly natural gas consumption data of power stations.

Gas reduction

The breakdown of the gas usage of the economy shows which sectors are the energy intensive ones, providing the most potential for gas reduction during a supply problem. Besides the industry the residential and public services and commerce are also large consumers of natural gas, however these sectors are curtailed at latest, therefore in the majority of cases the primary costs emerge at the industry.

Figure 2.2. Structure of the Hungarian natural gas consumption, 2008, total: 13,103 mcm

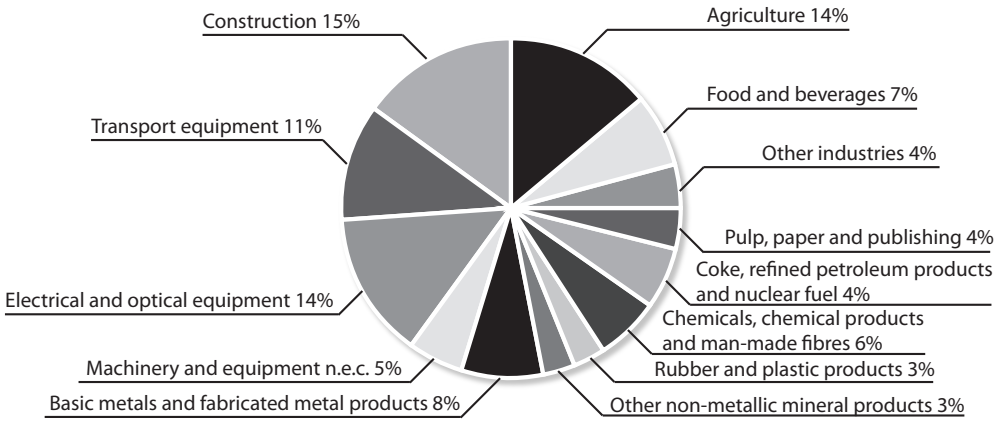


Source: Energiaközpont Kht

Financial impacts

Figure 2.3 shows the distribution of GVA among the natural gas consuming industrial sectors based on 2008 data.

Figure 2.3. Structure of the Hungarian industrial GVA, 2008, total 27,512 million euros



Source: Eurostat

Cumulated cost curve

During a gas supply interruption currently the most important ranking parameter which is considered is the energy that could be saved when curtailing an industrial sight's consumption. However it is also important what costs it causes to the economy. With the GVA method we assume that the costs incurred by a sector are the costs of lost production. A curtailment that provides the least cost to the economy therefore would follow a ranking that puts in order the gas use which is needed to produce one unit of GVA.

This ranking can be seen in Table 2.1. While construction provides an important contribution to the economy, it consumes relatively little natural gas, curtailing this sector – according to the GVA method - would result in a very small saving of gas while a very large loss in economic terms. The most gas could be saved during an energy crisis with the least cost by curtailing the electricity producing industry.

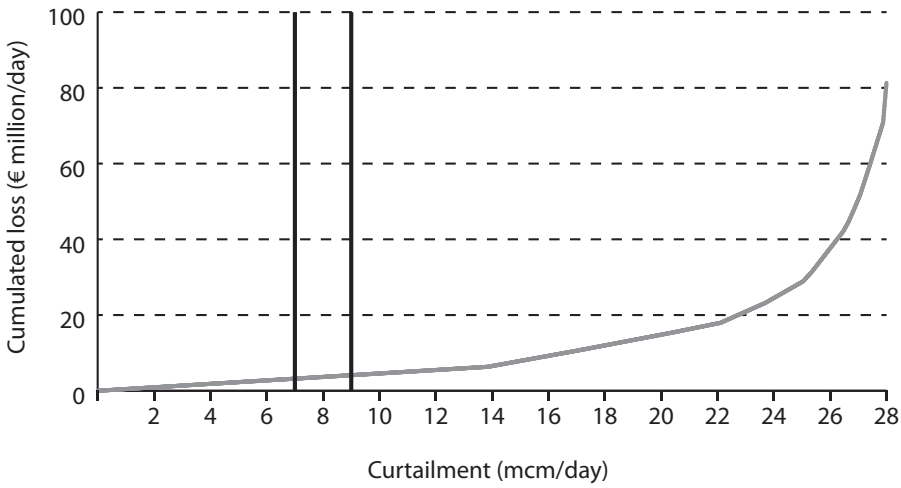
Table 2.1. Optimal curtailment ranking

	gas use/winter day (mcm)	GVA/day (€mill)	gas use/winter day / GVA/day	VOLL (€/m^3)
Electricity, gas, steam and hot water supply	14.09	6.33	2.23	0.45
Coke, refined petroleum products and nuclear fuel	3.27	4.32	0.76	1.32
Chemicals, chemical products and man-made fibres	3.45	4.79	0.72	1.39
Other non-metallic mineral products	1.7	2.52	0.67	1.48
Food and beverages	1.61	5.24	0.31	3.25
Basic metals and fabricated metal products	1.36	5.68	0.24	4.18
Pulp, paper and publishing	0.33	2.68	0.12	8.12
Agriculture	1.12	10.53	0.11	9.40
Rubber and plastic products	0.19	2.46	0.08	12.95
Machinery and equipment n.e.c.	0.25	4.11	0.06	16.44
Other industries	0.18	3.16	0.06	17.56
Transport equipment	0.36	8.14	0.04	22.61
Electrical and optical equipment	0.46	10.81	0.04	23.50
Construction	0.13	10.94	0.01	84.15

By assuming that those sectors are curtailed first which can be curtailed the cheapest we result at our first estimation of the cumulated daily cost curve of a supply disruption. Figure 2.4 shows the total GVA loss per day of a disruption for a given supply loss per day. The slope of the curve in a given point is actually the VOLL value of the industry curtailed on the margin.

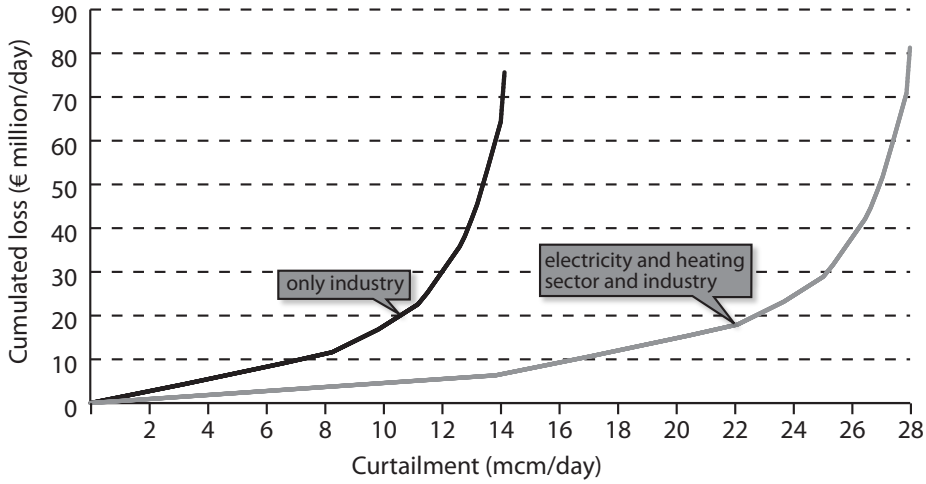
As an example of how this curve can be used for estimating costs of a supply disruption we have included in Figure 2.4 the parameters of the 2009 gas crisis. In Hungary the supply crisis resulted in a consumption curtailment of around 7Mcm daily and for one day it increased to 9 Mcm (black vertical lines). According to the GVA proxy method therefore, the costs per day of the crisis to the economy were between €3.15 and €4.05 million, for the total 8.5 day crisis around €27.7 million.

Figure 2.4. Cumulated cost curve for a given day, Hungary, based on GVA estimation, industry and electricity and heat producing sector, €million



The cost curve's shape is very important. As it can be seen, for the first few million cubic meters it is relatively flat, then it becomes steeper and around 20 mcm it is almost vertical. The relatively flat part is due to the cheapest curtailable sector the electricity and heat producing sector. If this sector could not be curtailed then the costs of a gas supply disruption would be much larger which is illustrated by Figure 2.5 below.

Figure 2.5. Comparing the cumulated cost curve with and without the curtailment of the electricity and heating sector, €million

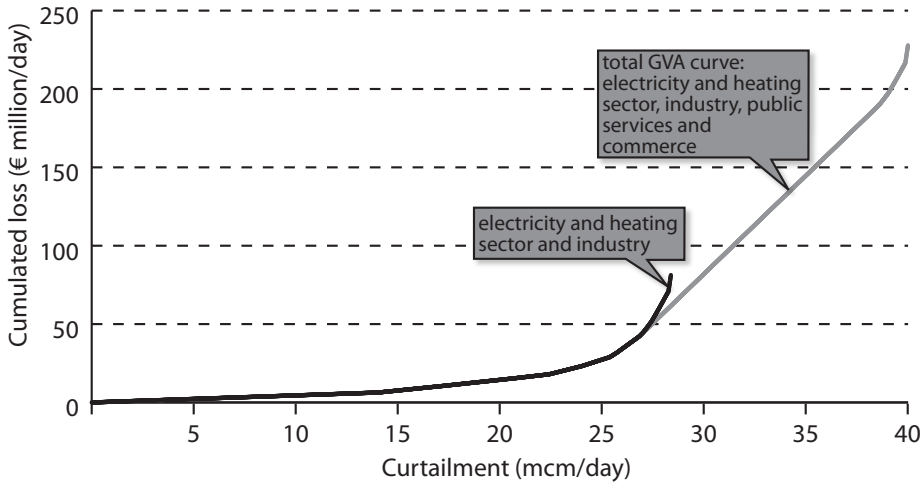


During the 2009 gas crisis, actually around 6 mcm per day was curtailed from the electricity and heating sector and the rest of the curtailment was provided by industrial players. Using the two curves instead of the one that illustrates the optimal path, the GVA method for the total costs of the 2009 gas supply crisis estimates a cost around €36.8 million.

The complete cost curve constructed with the GVA method includes besides the industry and the electricity and heat production sector also the public service and commerce segment. This sector consumed 1,576 mcm in 2008 our estimation for the sector's winter daily consumption is 11.66 million m^3. Regarding the valuation of supply disruption, since in this sector natural gas is mainly used for heating and not as an input for production, the low gas consumption but high value added (€145.85 million/day) results in a relatively high VOLL value of 12.5 €/m^3 which is significantly higher than the costs of the majority of industrial branches.

The GVA method in this respect supports the current curtailment ranking of the sectors, which ranks the services sector into a later curtailment group than industry.

Figure 2.6. Total GVA method based cumulated loss curve, including the public services and commerce sector, €million



Our total cumulated cost curve estimated with the GVA method shows an estimation of the costs of a supply disruption up to a size of 40.14 million m^3 loss per day. This curve does not cover the total daily consumption of the country. For example household is another large consumer segment with an average daily winter consumption of around 22 mcm. Thus our curve covers around 60% of the average daily winter consumption of the country.

Since our aim is to provide a cumulated cost curve that can be used as an input to cost-benefit analysis for future investments and decisions we do not need to construct a curve that covers a larger share of daily consumption as consumption parts above 40 mcm are not likely to be affected by new investments. Furthermore the valuation of the costs of households and other delicate segments that we will consider later is a field less objective and measurable, and therefore the values derived would be less reliable. Accordingly, our cost curve should be considered as a first part of a total cumulated cost curve where the remaining part is a strictly ascending continuation of our curve.

Summarizing our estimations so far, we have resulted at a cumulated cost curve constructed with the simple GVA method to estimate the possible costs of a supply disruption for Hungary. This type of GVA curve was used for example by the Department of Trade and Industry of the UK to value the benefits different investment options could provide to increase the country's security of supply.[7]

In the following sections we will refine this curve at those places where the assumptions of the GVA method discussed above are found to be less valid compared to other methods' premises.

[7] ILEX Energy report to DTI: Strategic storage and other options to ensure long-term gas security, 2006

2.3.3. *Electricity and heat producing sector – switching cost*

The GVA method is although the most popular provides a very rough estimate with many assumptions that are sometimes too rigid to be able to capture the real circumstances. We start refining our estimation with the costs incurred by the electricity and heat production sector for which the GVA method estimated a VOLL value of 0.45 €/m^3.

In order to gain a better insight of the costs of this sector we have interviewed two electricity generation companies which were curtailed during the 8.5 days of the 2009 gas crisis. According to the interviews, due to a Hungarian regulation that obliges the gas fired power plants over 50 MW installed capacity to store alternative fuel,[8] oil, the gas fired large power plants in case of a natural gas supply disruption can change their fuel within a short period of time and can continue producing using alternative fuel. Thus a natural gas consumption curtailment does not result in the disruption of electricity production, the affected power plants are able to continue producing although with increased input costs. Therefore in Hungary the GVA method is not adequate to estimate the costs of the electricity and heat producing sector during a gas crisis, the costs of the large gas fired power plants is not the loss of production, instead it is related to the difference between the prices of the two fuels, natural gas and fuel oil. Therefore we will replace our GVA estimation for these large power plants in the cumulated cost curve with the average price difference of the two fuels used.

In order to make an estimation for the average price difference we have to have an estimation for the fuel oil and the natural gas prices the power plants pay and we have to define an estimation method for the *average* price difference as well.

Oil prices

According to the interviews, these power plants depending on the technology either switch to Light Fuel Oil (LFO) or to Gas Turbine Oil (GTO). There is a significant price difference between these two oil products, GTO is almost twice as expensive as LFO. To provide a conservative estimation therefore we will calculate the cost with the more expensive fuel, GTO. The Hungarian power plants buy fuel oil from the sole domestic provider, MOL. The exact prices on which the power plants buy oil from MOL are considered confidential information, however according to MOL representatives MOL's LFO and GTO pricing is based on the Rotterdam daily quotations from Platt's for the fuel oil with 1% sulfur content and for gasoil with a sulfur content of 0.1%. Therefore we will use these prices for the cost calculation.[9]

[8] 85/2005(X.21.)GKM rendelet Az 50 MW és annál nagyobb teljesítményű erőművek energiahordozókészletének legkisebb mértékéről és a készletezés rendjéről szóló 44/2002 (XII.28.) GKM rendelet módosításáról. 85/2005(X.21.) decree of the Ministry of Economy and Transport: Decree modifying the 44/2002 (XII.28.) decree on the minimum size and order of energy stocks for power plants over 50 MW installed capacity.

[9] In case of the gasoil prices the Rotterdam price is only available from october 2007, however we will make calculations from January 2005. Gasoil price data between January 2005 and September 2007 are taken from IEA Statistics: Energy prices and taxes. Quarterly statistics. Third quarter 2010.

Natural gas prices

In case of the natural gas prices again the best data would be the prices at which the power plants buy their fuel. However these are also considered as confidential information. Furthermore there is no transparent Hungarian wholesale price for natural gas. Therefore we decided to use as an approximation for the wholesale price an estimation of the average import price based on the formula published in ministerial decrees that refer to the recognized average import procurement costs in the regulated prices.[10] Since around eighty percent of Hungary's consumption is supplied from import and the price of domestic production is also linked to the import price, the average import price in absence of a liquid hub could be considered as a relatively good estimation of the wholesale price.

The import price is set for 3 months and its evolution is linked to the previous 9 months average price of two oil products, the fuel oil with 1% sulfur content FOB Med quotation of Platt's, and until July 2009 the gasoil with 0.2% sulfur content, since July 2009 the gasoil containing 0.1% sulfur FOB Med quotation of Platt's.

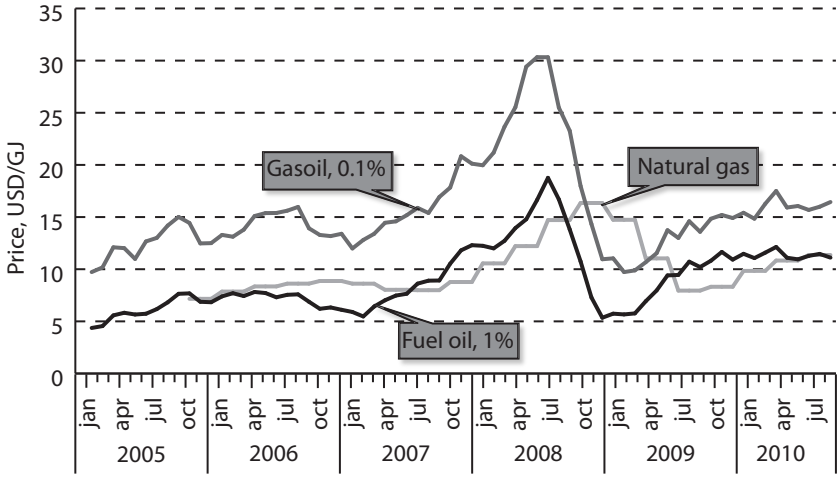
As it can be seen the natural gas price is based on almost the same oil prices as the price of fuel oil which is relevant for the Hungarian power plants in case they have to switch their fuel. This is of course not just a coincidence, the price of natural gas in the 20 – 30- year-long long term contracts, which are also dominating the market in Hungary, is linked to the prices of the alternative fuels, in order to preserve its competitiveness during the 20 or 30 years these natural gas procurement contracts are set.

Therefore the natural gas prices of Hungary according to the construction of the formula will closely follow the movements of the prices of the oil products, it will mainly be below these prices and due to the 9 months averaging, it will have a smoother shape.

In our calculations we will use the Platt's Rotterdam prices from 2005 also for the estimation of the natural gas prices. The monthly average oil and the estimated gas prices are shown in Figure 2.7 below.

[10] Ministerial decrees: 105/2005. (XII. 25.) GKM and 29/2009. (VI. 25.) KHEM

Figure 2.7. Monthly average fuel oil and gasoil prices and the estimated monthly natural gas price, USD/GJ, January 2005 – September 2010



Source: Platts, EIA, REKK estimation

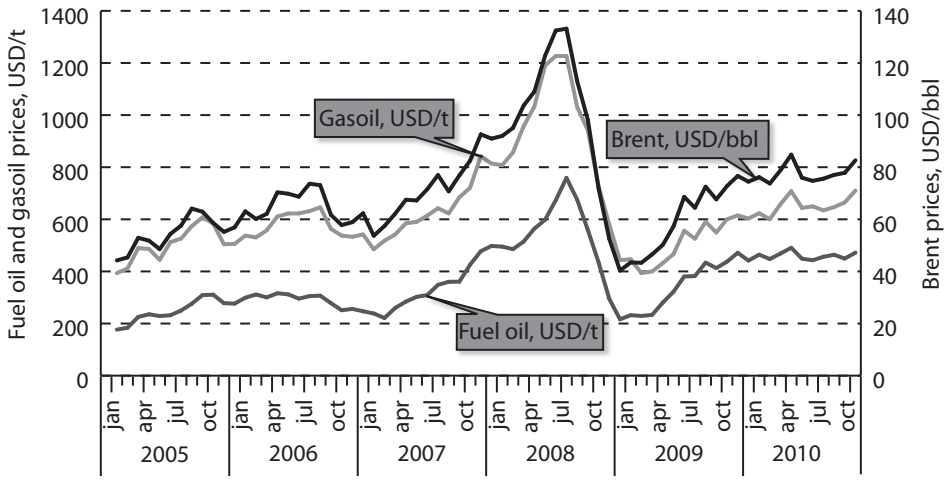
Average price difference

Figure 2.7 also illustrates the evolution of the price difference between the gasoil and the natural gas prices (the difference between the yellow and blue line) between January 2005 and September 2010. The gasoil is in most cases much more expensive than natural gas, however due to the extraordinary effect of the financial crises on the oil prices and the 9 months delay in the natural gas import formula, during some months from the end of 2008 until the first quarter of 2009 the spot price of gasoil was lower than the import price of natural gas. This means that during this period a fuel switch would not have resulted in extra costs.

As it could be seen, the price difference we intend to estimate has varied significantly in the recent past. The size of the difference does not only depend on the relation of the spot prices but due to the structure of the natural gas price formula it depends also on the evolution of the oil prices in the preceding 9 months, the shape of the time series. Therefore to provide a reliable estimate we will have to know how the 9 months time series of the gasoil and fuel oil prices and their relation to the spot prices look like in the majority of the cases, i.e. what is the distribution of the price difference. Since the

oil products' prices are dependent on the movement of the brent prices, we will base our calculation on the brent prices, and this way could use the historical data of the brent prices to generate a larger data set for the price difference we intend to estimate.

Figure 2.8. The evolution of the brent price compared to the prices of the oil products, January 2005 – September 2010



Source: Platts and EIA

Figure 2.8 shows how the two oil products' prices follow the movement of the brent prices. Based on these data we estimated the statistical relationship between the brent and the fuel oil and between the brent and the gasoil prices.[11] Then using a longer time series of the brent prices, January 1990 – September 2010,[12] based on the relationships between the brent and the oil products' prices we have generated a longer time series for the oil products' prices. Using the estimated oil prices in the natural gas formula we have also estimated possible natural gas prices. This way we have generated a larger set (240) in Figure 2.9 of possible gasoil and natural gas price differences that are based on actual historical brent price data, the distribution is shown in Figure 2.10 below.

[11] Brent – fuel oil: R^2=0.87, Brent -gasoil: R^2=0.95

[12] By using monthly US inflation we have converted the nominal time series of brent prices to a real time series to the level of 2010 September prices.

Figure 2.9. The evolution of the gasoil – natural gas price difference estimated from brent prices between October 1990 – September 2010

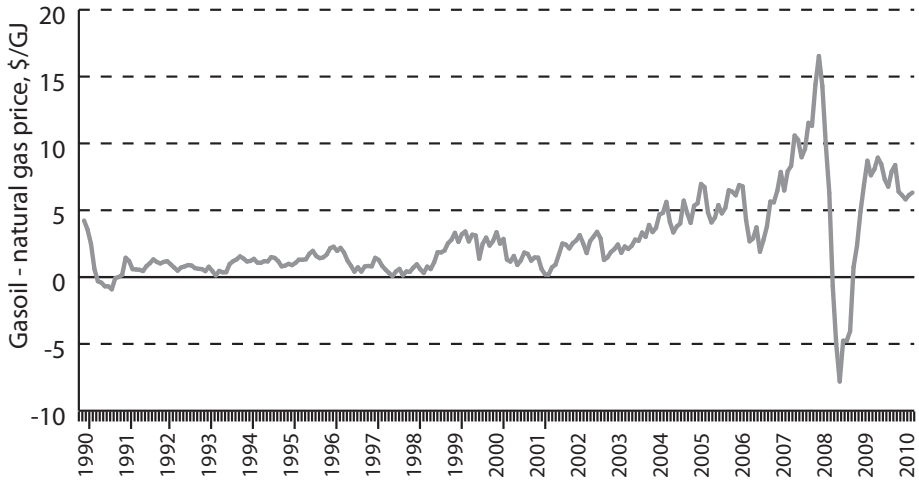
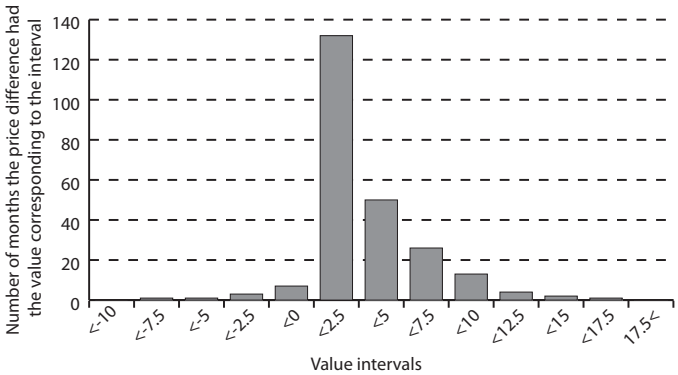


Figure 2.10. Distribution of the gasoil – natural gas price difference



minimum	-7.82
under 0	5%
D1	0.38
Q1	0.84
Median	1.81
Average	2.73
Q3	3.79
D9	6.79
maximum	16.54

According to the estimated data, there are only two occasions when the natural gas price due to the extraordinary movement of the oil prices exceeds the gasoil price (negative price difference) for a few months, the February - July 1991 and the already mentioned October 2008 – March 2009 periods. Besides these two occasions which amount to 5% of the months analysed, in all the rest of the cases the natural gas price is below the gasoil price leading to a costly fuel switch for power plants in case of a natural gas supply disruption. The average price difference is 2.73 $/GJ while the maximum is 16.54 $/GJ. 75% of all differences is below 3.79 $/GJ while 90% of all differences is below 6.79 $/GJ. It is a question which value should be used to estimate future possible switching costs. Since our estimation is intended to be a conservative one - we find underestimation more problematic than overestimation – therefore we decided to use the ninth decile value as the VOLL of the electricity and heating industry, 6.79 $/GJ.

Additional costs

Naturally, besides the fuel switch cost power plants could have additional administrative or other costs as well. However we predict these to be negligible and also very different from one generation company to the other, and therefore will only add one more truly objective cost item that could generally emerge during a fuel switch, the additional CO_2 costs that have to be paid because of burning oil instead of the cleaner natural gas. Since Hungary as a European Union Member State is also participating in the EU's Emission Trading Scheme (ETS) power plants must possess EU Allowance Units (EUA's) that cover their CO_2 emissions of burning fossil fuels.

The number of EUA's needed to produce 1 MWh of electricity depends on the type of fuel used and the efficiency of fuel energy conversion into electricity (unit heat rate and self-consumption). Table 2.2 below shows the CO_2 emission factors of the two fuels. The emission factor difference corrected with efficiency shows how much more CO_2 is emitted on average when oil is burnt instead of natural gas to produce 1 MWh of electricity.

Table 2.2. Emission factors and emission factor difference corrected with efficiency, kg/GJ

CO_2 emission factor of the input fuel	kg/GJ
Natural gas	55.8
Oil average	75.4
Difference	19.6
Difference corrected with efficiency	43.4

Source: UNFCC

In order to derive the cost this yields, we will have to multiply this difference with a CO_2 price. EUA's are traded in exchanges and have a transparent price that has lately fluctu-

ated around 14-15 €/ton (for December 2010 delivery, see Figure 2.11). For forecasting purposes therefore we will calculate with an EUA price of 15 €/ton.

Figure 2.11. EUA price for December 2010 delivery

Source: ECX.EU

As a result the additional cost for switching to a more pollutant fuel during a gas supply disruption is 0.651€/GJ[13].

Summarizing the above, we have calculated the cost that emerges at the electricity and heat producing sector during a natural gas supply crisis. The estimation was based on the cost of switching to oil from natural gas. Our conservative estimation of the price difference between gasoil and natural gas is 6.79 $/GJ while also additional cost arises from the CO_2 emission surplus that corresponds to 0.651 €/GJ. Thus altogether our estimation for the switching cost of the electricity and heat producing sector is 5.68 €/GJ[14] which is 0.19 €/m^3. This is almost 60% less than the VOLL value of 0.45 €/m^3 calculated with the GVA method.

Quantity

The quantity that we will replace in our cumulated cost curve with this value is the quantity consumed by large power plants (above 50 MW installed capacity). The consumption of these plants in 2008 accounted for 10.62 mcm/ winter day[15] out of the total 14.09 mcm/winter day consumed by this sector.

The remaining 3.47 mcm/day will still be estimated with the GVA method, as without the alternative fuel the plants will not produce, and therefore the loss of profit is a good approximation. However refining the previous GVA estimation is also adequate here, since calculating with the total GVA of the electricity and heat producing sector would result in an overestimation of the losses as the GVA of for example the nuclear power plant is also included in this case, while its production is evidently not disrupted in a

[13] 0.651 €/GJ= 0.0434 t/GJ*15€/t.

[14] 6.79 $/GJ/1.35$/€+0.651€/GJ=5.68 €/GJ

[15] Estimated from annual data published in HEO Annual Report and Energiaközpont Kht database

natural gas supply crisis. Therefore only the GVA of the natural gas consuming power plants should be used. Although there is no such data available an approximation for this value could be to calculate only with a given share of the sector's GVA which equals the share of natural gas in the sector's total energy consumption. Although such approximation carries very rigid assumptions, this still seems to be a more realistic estimation than using the whole sector's GVA. In 2008 this share was 33.8%,[16] which means that the VOLL value for the remaining 3.47 mcm/day is 0.15 €/m^3.

Thus the new cumulated cost curve of a supply disruption for one winter day which includes the switching cost method for the electricity and heat industry is the following.

[16] Estimating from Energiaközpont KHT data: yearbook 2008

Figure 2.12. Comparison of the new cumulated cost curve with switching cost

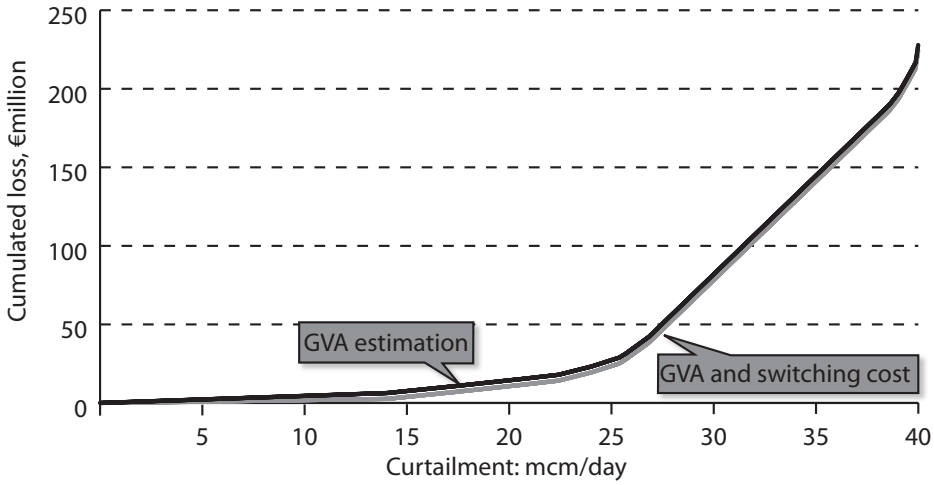
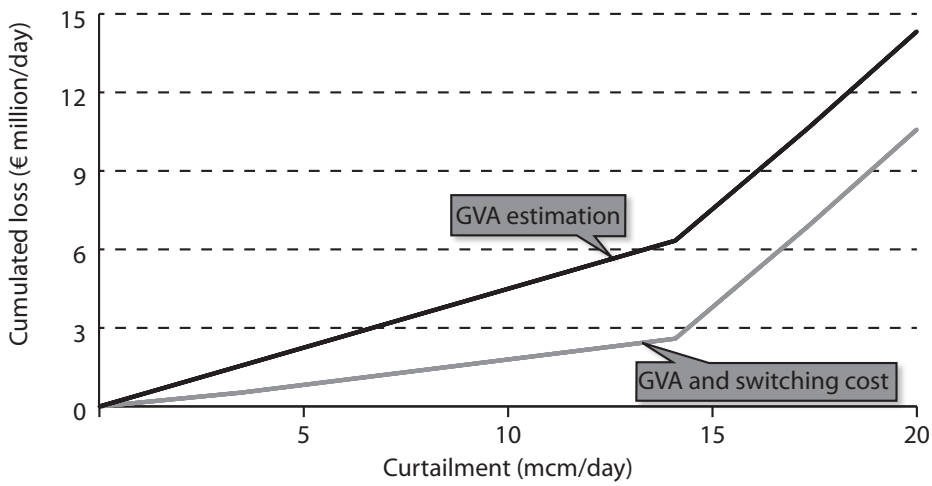


Figure 2.13. Comparison of the new cumulated cost curve with the cost curve constructed purely with the GVA method



Continuing our example of the 2009 gas crisis according to the refined cumulated cost curve a crisis with such a supply loss size (i.e. 9 Mcm for one day and 7 Mcm for 7.5 days) would cost for the economy €10.7 million instead of the previously calculated €27.7 million. If we consider that in the actual crisis around 6 mcm per day was curtailed from the electricity and heating sector and the rest of the curtailment was provided by industrial players then the losses due to the crisis according to our VOLL estimation would be €22.54 million instead of the €36.8 million calculated with purely the GVA method.

However if we look at the 2009 January value of the gasoil – natural gas price difference on the Figure 2.9, it can be seen that interestingly the gas dispute occurred during the extraordinary time when due to the 9 months averaging in the natural gas formula and the previous fluctuation of the oil price natural gas was more expensive than oil. Thus the real costs suffered by power plants in the 2009 January gas crisis might be lower than what we estimate for future values. One of the interviewed power generation companies has confirmed that due to these extraordinary circumstances they did not suffer losses with the fuel switch, however other power plants have claimed to have suffered serious losses, although they have also confirmed that the switching cost calculation method is adequate to measure their losses in a supply disruption.

In the following we further refine this new cumulated cost curve by reconsidering the costs the industrial sector bares.

2.3.4. Industrial sector – case studies

The 2009 gas crisis provided a good opportunity for us to conduct case studies on the effect of a natural gas supply disruption on the industrial sector. Before this crisis companies had little or no experience at all with gas curtailment which could also be seen in how unprepared some of them were when the crisis came.

We have approached those industrial players that were ranked in the Ist curtailment category and among the large industrial consumers have conducted four interviews. In the following we will present a brief summary of these interviews and then derive conclusions that could be useful for our country-wide cost curve estimation.

Carfactory

The carproducing factory has a maximum contracted consumption of 4,500 m^3/h, however due to the decreased demand for automobiles since the start of the economic crisis their maximum hourly consumption by the end of 2008 decreased to 3,500 m^3. Natural gas is used for steam production that is needed for car washing and cleaning before the coloring, it is also used for stabilizing the temperature in the painting plant, furthermore it is used in the furnaces that dry the painting.

Curtailment effects

If there is a total consumption curtailment, then although mainly only the coloring process is held up, due to the just-in-time method used, the whole production stops. Furthermore a total curtailment would cause serious damages in the equipment therefore not just the loss of production but also serious asset costs would emerge.

If there is a partial curtailment, i.e. the company is allowed to consume at least 500 m^3/h then 'only' production stops, damages to the equipment can be avoided, thus the costs of curtailment would be the lost profit and the energy cost of maintenance.

January 2009 gas crisis

The company's 4,500 m^3/h contracted consumption was ranked into curtailment categories the following way: 1,500 m^3/h in the Ist category, 1,000 m^3/h in the IInd category, 2,000 m^3/h in the IIIrd category. When on 6 January the TSO asked them to lower their consumption according to the amount they were participating with in the Ist category, it did not cause a great problem, as they already were consuming around 3,000 m^3/h. However on the next day the company also had to curtail the amount that it had in the IInd category, an additional 1,000 m^3/h which actually resulted in a total shut down of production. The company only maintained the consumption level that was necessary for avoiding damages in the equipment and halted production for three days. After the three days production restarted and consumption level went up to 3,000 m^3/h, the company's consumption did not exceed this level until the curtailment of the Ist category remained in effect. Due to the economic crisis therefore for the car company the curtailment 'only' meant the loss of three days' profit and the energy cost needed for maintenance during these three days. However if the economic crisis had not been so severe during that time period, costs due to the curtailment would have been much higher.

After the crisis the company started an investment that helps avoiding serious costs in case of gas consumption curtailments and also results in lower network capacity payments. They build an on site synthetic gas producing facility with two containers to store the liquid gas (LPG) which is turned into natural gas by the facility. This way the company can reduce its contracted network capacity from 4,500 m^3/h to 2,500 m^3/h. And in winter time when its consumption exceeds 2,500 m^3/h it supplements its natural gas offtake with natural gas produced on-site from LPG. Furthermore in time of gas curtailment it can continue production by using its own converted gas. This way although the converted gas is more expensive, due to the saving on network tariffs and the benefits of increased supply security this investment has a positive net present value. Thus in the future this company will not suffer serious costs in a supply disruption, its cost will be the amount with which the natural gas converted from LPG is more expensive than the natural gas bought from the pipeline.

Company from the food industry

The company is a large consumer with an hourly consumption that varies between 13,000 and 15,000 m^3, its maximum contracted consumption is 16,500 m^3/h which is to cover the coolest winter day's consumption needs. Natural gas is used in the drainers and its two small (13 MW and 15 MW) gas turbines. They have very limited possibility to switch to alternative fuel.

Curtailment effects

In the production process the maintenance of temperature is very important. If heating stops due to a curtailment and the equipment cools down the system becomes contaminated and the whole equipment has to be replaced resulting in an asset loss around €18 million. However if natural gas consumption is only partially reduced, and there is partial heating amounting to a consumption around 8,000 m^3/h then the damage to the assets can be saved, and the costs are reduced to the loss of profit due to the stop in production and the cost of energy needed for maintenance.

January 2009 gas crisis

The company thought – based on its contract with its trader - that they were ranked in the IIIrd curtailment category, and were surprised to hear it on January 6 from their trader and then from the TSO that they were actually reported in the Ist category, and they have to reduce all their consumption to zero by 20:30 that day.

They tried to buy oil that they could burn in the furnaces, however it took time and therefore the company started burning alcohol products (that they had on-site) and had reduced their natural gas consumption to 2,000 m^3/h. I.e. they did not comply with the obligation to shut down all their consumption due to the enormous damages a total curtailment would cause to the company. In the same time they have started negotiations with the Hungarian Energy Office and as a result the company was allowed to increase its consumption up to 6,600 m^3/h. With this amount although they could not produce they could avoid the damages to the assets and therefore reduced their costs to the level of lost profits and the energy costs of the reduced level consumption.

After the crisis the company had renegotiated their categorization in the curtailment order which was revised by the HEO also in response to the experience of the crisis. In the new curtailment ranking there is a separate curtailment group - group number VIII – for food industry. They could rank 8,500 m^3 of their consumption in this category while the rest was allocated to the categories VII, IV, and II.

The company to increase its preparedness for future curtailments also began to hold an oil stock on-site. And they are also planning to build a biomass furnace which would - among other benefits - help reduce the costs in case of a gas crisis.

Lime producing company

The company's maximum contracted consumption is 2,500 m^3/h, which is used in the furnace that burns limestone and produces lime. There is no possibility to use alternative fuels.

Curtailment effects

If there is a total consumption curtailment, then the burning of limestone stops, the furnace cools down, the whole lime production procedure stops. The walls of the furnace would be damaged, its repair takes around 3 – 3.5 months which

means that a total curtailment comes along with loss of profit of 3 – 3.5 months and the costs of repair furthermore the costs of loosing the company's consumers in the future due to the bad reputation such an occasion causes.

If natural gas consumption is only partially reduced, and there is enough gas supplied for the maintenance of the temperature that is needed for the furnace to avoid damages then within three days production can be restored. The cost of curtailment in this case is the loss of profit and the cost of energy and raw material needed for maintenance.

January 2009 gas crisis

The company's entire 2,500 m^3/h consumption was ranked in the Ist category. They were notified on January 6 to stop consuming. The company started negotiating with the Hungarian Energy Office and the TSO and as a result they were allowed to consume 1,500 m^3/h which was enough to maintain the needed temperature in the furnace. They remained at this consumption level until January 15, and could produce good quality lime by January 19. This way their costs of the crisis was 14 day's lost profit and the energy cost of the reduced level consumption and the cost of raw material that had to be burnt for the maintenance.

It has to be mentioned that the company had reduced its production from the 2007 and 2008 level by 25% just before the January gas crisis due to the economic crisis' effect on lime consumption. This entails a lower cost of gas curtailment than it would be the case during normal economic circumstances.

During the crisis the company tried to negotiate with another consumer which was on the same exit point of the pipeline system, to provide the 1,000 m^3/h curtailment by curtailing this other company's consumption instead of theirs, since this latter company could switch to alternative fuel and would have lower costs than the lime producing company. However due to the rigidity of the curtailment system this opportunity could not be exploited.

After the crisis the company has renegotiated its categorization in the curtailment order and now they are listed in the IInd category.

Cement producing company

The company has a maximum contracted consumption of 3,000 m^3/h out of which 500 m^3/h is used for heating the workplace while the other 2,500 m^3/h is needed for firing up the kiln. After they have reached the required temperature in the kiln maintaining the temperature level is made by alternative fuels. Thus natural gas is only needed for 2 days in a month in the production process however at that time it is very important to have it available.

Curtailment effects

If natural gas is not available when firing up the kiln becomes necessary then production is halted until they receive natural gas again. Thus the loss is the lost profit.

2009 January gas crisis

When the gas crisis came the company's 2,500 m^3/h consumption was ranked in the Ist category while 500 m^3/h was ranked in the IInd. During the crisis they actually needed gas for firing up the kiln, they have negotiated with the Hungarian Energy Office and as a result were granted the 2,500 m^3/h for 2 days, which was enough for them to start production. Thus at the end, for this company the gas crisis did not cause any costs.

These four stories have important common features that help us understand better how costs emerge at industry sights during a supply disruption. Firstly from the interviews it turns out that companies were not really prepared for such a situation. Some of them were not aware of their curtailment categorization others just simply did not care about it before, and let all their consumption be ranked in the Ist category, while it would have caused serious problems for them to be fully curtailed. Once the companies faced the problem, realized how important it is for them to be able to consume a certain level of natural gas, and started lobbying to avoid full curtailment, at which they were all successful. This also shows the unpreparedness of the whole curtailment system, but it also reveals the fact that the 2009 gas crisis could have resulted in much larger costs if the real time management of the crisis would have not been as flexible as it was. After the crisis these companies - becoming more conscious consumers - have renegotiated their curtailment categorization and the government had also revised the whole curtailment system.

Regarding the costs of a supply disruption the most important conclusion this experience holds is that at most industrial consumers there is a minimum consumption, a threshold level, that if during a curtailment consumption can be reduced only partially, and the company can consume around this threshold level, then the loss equals the loss of profit and the cost of the inputs that are needed for maintenance. On the other hand, if consumption is curtailed below the threshold level then the costs of the companies increase radically due to the damages caused in the equipment. Applying this observation to our calculations we can say that curtailment above the threshold level in the industry results in costs that are approximately equal to the gross value added, thus the previous GVA value could be used for this quantity as well. On the other hand the costs of a curtailment that goes beyond the threshold level are much higher than the lost profit.

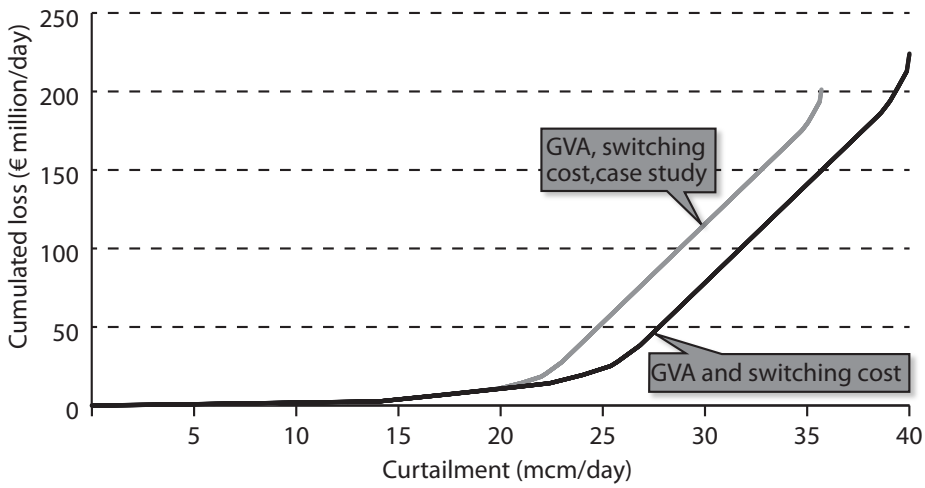
Thus to refine our previous estimation which was simply the GVA of each industrial sector for the curtailment of their entire natural gas consumption, we need to define this threshold level. Actually in the four stories above this level varied significantly between 0% - 60% of total consumption, therefore we will have to define an average threshold value subjectively. In our calculations we will set this threshold level at 30% keeping mind however that its actual value could be much higher or lower.

By this the 70% of the sectors' daily consumption remains represented by the cost equal to the daily GVA, while the rest 30% should be moved to the end of the cumulated curve given a very high value. We will represent this latter by not including this part of the industries' consumption in our curtailment curve. If there is a crisis and there is

possibility for partial curtailment, then this consumption should not be curtailed. Including any value for this equipment cost part would be too subjective while on the other hand would be of little importance for our cost-benefit evaluation purposes.

Thus in the refined cumulated cost curve we reduce the quantities of the industrial sectors that could be curtailed to 70% of the original values, while will leave out the rest 30%, ranking it among the latest consumptions to be curtailed. This new cumulated cost curve compared with the previous one is illustrated in Figure 2.14 below.

Figure 2.14. Comparison of the new cumulated cost curve including the experience of case studies and the previous cost curve



The costs of the 2009 gas crisis with this new curve only change slightly compared to the previous estimation. If we consider that in the actual crisis around 6 mcm per day was curtailed from the electricity and heating sector and the rest was provided by industrial players then the losses due to the crisis according to our new estimation would be €22.59 million instead of the €22.54 million calculated earlier.

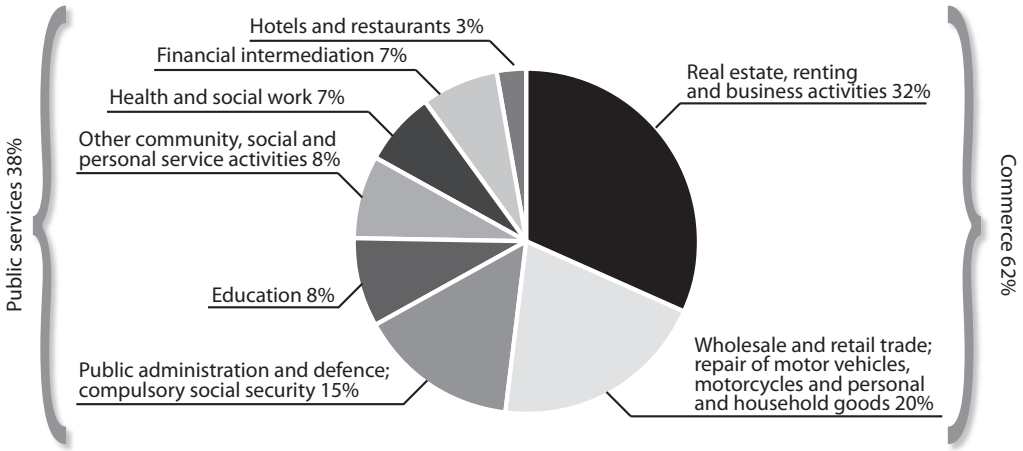
2.3.5. Public services and commerce sector - surveys

In this section we will refine our estimation of the public services and commerce segment. This sector's VOLL value with the GVA method was 12.5 €/m^3 which was significantly higher than the majority of industrial users' valuation. However since natural gas is not directly used for value creation here, it might be possible to conduct the services without natural gas, therefore the GVA method seems to provide an overestimation.

The other problem of the GVA estimation is the too high level of aggregation. Public services and the market based commercial sector are put together in this method into one big sector due to the absence of more detailed natural gas consumption data. However these two sectors could have very different costs due to their very different activity and goals.

The GVA of the two sectors within the aggregated public services and commerce sector has the following structure.

Figure 2.15. The structure of the GVA of the public services and commerce sector, 2008, total €53,238 million



Source: Eurostat

Unfortunately, without distinct natural gas consumption data we cannot objectively separate the two segments. However for further calculations we need to construct a separation which we will do by assuming that the two sectors have the same share within the gas consumption as they have within the GVA production. This way the GVA proxy method yields for the two segments the proxy estimation of the aggregated public services and commerce sector: 12.5 €/m^3. Thus in the following we will refine our estimations starting out from this value however it has to be noted that our separation of the segments lies on an assumption that could be distinct from the real circumstances.

Commercial sector – stated preference

In case of the commercial sector we apply a new estimation method, the stated preference method, i.e. the use of large representative surveys. We have conducted a survey in the autumn of 2008, just before the January 2009 gas crisis among 600 small and medium enterprises from the commercial services sector in Budapest. The average yearly gas consumption of the representative sample was 3,100 m^3, and 88% of the companies used natural gas only for heating purposes.

In the survey – among other topics - we have asked the interviewees about their valuation using two different methods: direct costing (dc) and willingness to pay (wtp) method. First we have asked them to estimate their costs that would emerge if there would be a five- hour, one-day, five workday or a 20-day-long supply disruption. Later we have

asked them how much they would be willing to pay for a service that allows them to consume even in times when other consumers would be curtailed for five hours, a day, five workdays or 20 days. Theoretically the two amounts should be equal.

The answers to the two questions are summarized in Figure 2.16 and Figure 2.17 below.

Figure 2.16. Direct costing survey question to the actors in the commercial sector: How much loss would your business incur in case of a ….-long gas disruption?

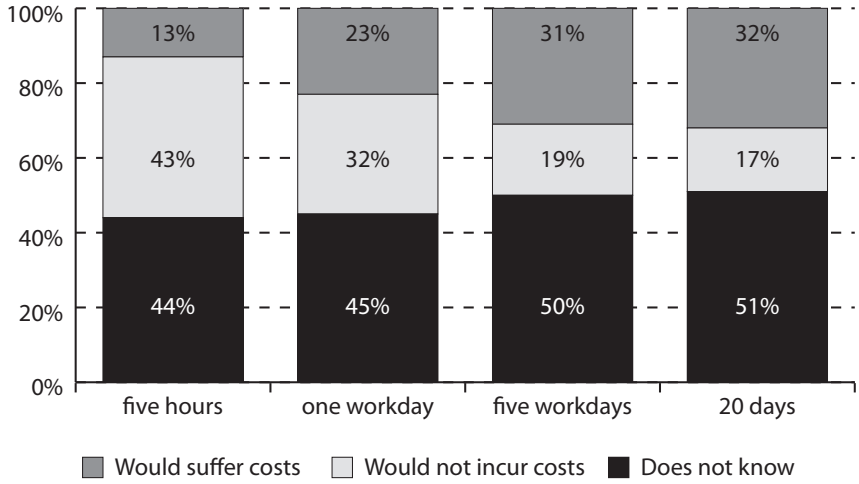
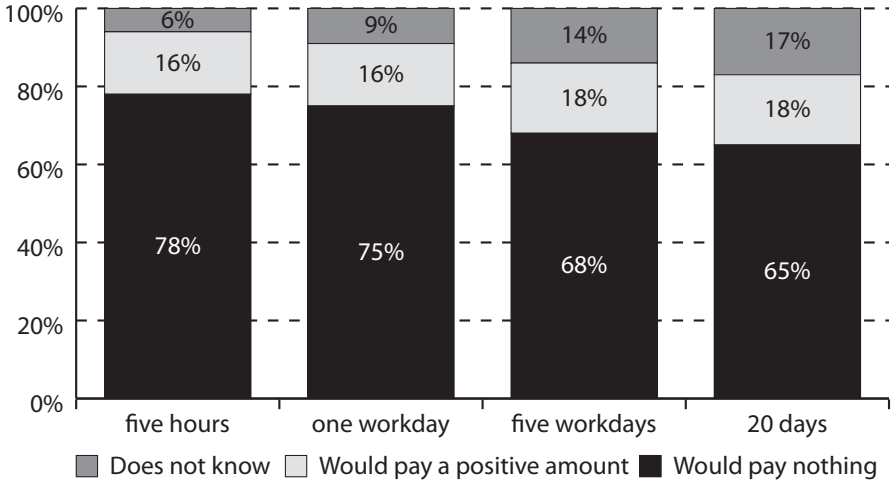


Figure 2.17. Willingness to pay survey question to the actors in the commercial sector: How much would you pay for a service that protects you from a ….-long gas distruption?



From the answers the problems of the stated preference method clearly stand out. The share of the consumers who cannot assess their possible costs is at least 44% in case of direct costing and is at least 16% in the case of wtp method. This already questions the

validity of the results. Even more embarrassing is the fact that the answers to the two questions diverge greatly providing inconsistent results.

Thus although the simple GVA method provides a result that holds too many rigid assumptions and therefore could be questioned, the stated preference method which requests a lot more resources and goes directly to the source asking consumers' valuation still does not provide a reassuring estimation. Nevertheless in the following we will use the results of the survey, as there is no possibility to gain more valid data on consumers' valuation.

The values that the survey provided are summarized in Table 2.3 below.

Table 2.3. Results of the survey conducted among small and medium enterprises in Budapest, 2008, n=600

	5 hours		1 day		5 days		20 days	
	direct costing	wtp	direct costing	wtp	direct costing	wtp	direct costing	wtp
average cost of a supply disruption of those who claimed a positive amount (€)	36.9	13.19	292.7	21.7	287.8	92.9	1242.0	288.0
average cost of a supply disruption of those who had answered either 0 or a positive amount (€)	8.9	0.91	123.1	2.3	180.6	16.0	816.6	60.3
normalized VOLL for those who claimed a positive amount €/m^3	13.40	0.21	22.2	1.6	4.4	1.4	4.7	1.1
normalized VOLL for those who had an answer either 0 or a positive amount €/m^3	3.22	0.01	9.3	0.18	2.7	0.24	3.1	0.23

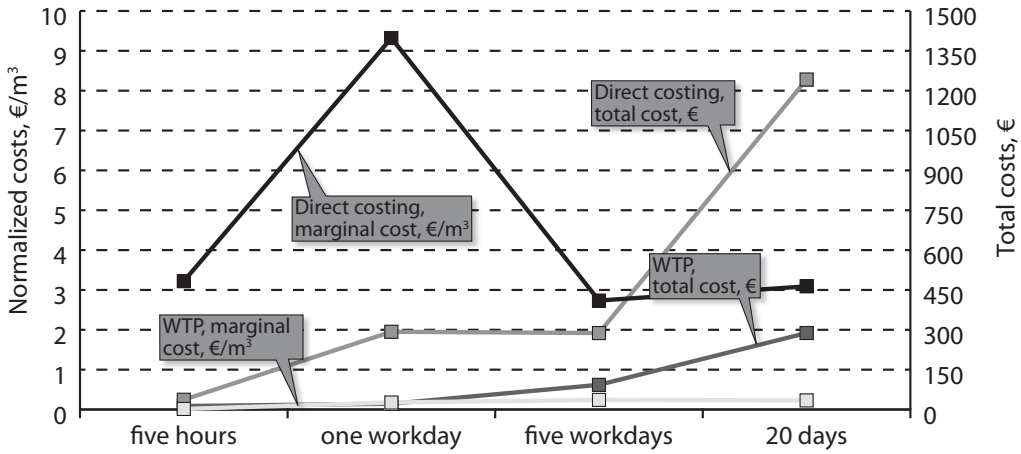
Raw data are expressed in absolute values, euro cost or wtp per the given interruption. In order to make it comparable, we normalized this value to an €/kWh VOLL measure.[17]

From Table 2.3 we can see that people report to suffer costs with one order of magnitude higher than what they would pay to avoid these costs. This remains true in the case when we convert the daily values to costs/wtp suffered per 1 m^3 loss and also weight the values with the share of consumers who reported positive figures. From these latter VOLL values one characteristic of VOLL that has been reported also in other studies that tried to assess consumers' valuation through questionnaires can be observed: the valua-

[17] Using the average 3100 m^3 yearly consumption and also accounting for the seasonality in consumption.

tion is not constant in the function of the lost quantity. The VOLL value in the beginning increases as the duration and size of supply disruption becomes larger, a 5 hour disruption does not have such a serious impact even on average, as a 1 day interruption would have. Then it reaches its maximum value, and begins to decrease as the time interval further widens. Of course the total overall costs increase with the length of the disruption, but the average costs (VOLL) become lower. This is illustrated in Figure 2.18 below.

Figure 2.18. Total and average costs with the direct costing and with the WTP method



Our aim is to construct a cumulated loss curve for the commercial sector for a day when natural gas supply is disturbed. Therefore from the above values we will use the ones referring to a 1 day loss. Out of these we decided to use those average values where also the zero answers are included and will use the average of the wtp and direct cost values instead of using one of them. Thus according to the questionnaire the VOLL value of this sector is 4.75 €/m³ instead of the GVA method based VOLL value of 12.5 €/m³.

Thus within the cumulated cost curve we will replace the public services and commercial sector's part which refers to the commercial segment (7.21 mcm/day) with this new value of 4.75 €/m³.

Public services

As for the valuation of the public services sector, we can say that if there is no natural gas then most public institutes - like schools - close their offices.[18] However there are some, which are necessary for everyday life - like hospitals - which remain open and continue consuming natural gas from the limited strategic stock, or if they have switching possibilities they use alternative ways for heating, oil or electricity. For the costs of those public services which can close during a gas crisis, the GVA method seems to be an adequate approximation, as the loss is the loss of the value of their activity for one

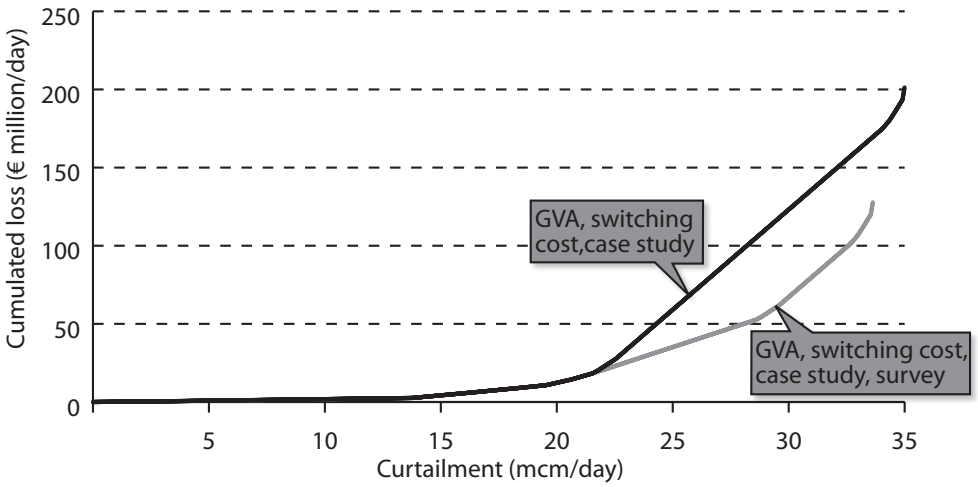
[18] Like they did during the gas crisis in Bulgaria.

day, further losses, like damages in equipment or material are not likely to emerge here. For the part of services which remain producing due to their indispensable nature their valuation if there is no switching possibility must be extremely high.

Thus, the GVA method seems to be a right estimation method for a part of the public services consumption while the other part has to be put to the end of the curtailment curve just like in the case of industrial equipment costs earlier. To determine the size of the part of public services that could be suspended during a gas crisis we do not have detailed data, again we will make a subjective estimation. Out of the four public services categories illustrated in Figure 2.19 we think that 100% of *education*, 50% of *public administration and defense, compulsory social security,* 50% of *other community, social and personal service activities,* and 10% of *health and social work* could be considered as a suspendable service during a gas crisis, i.e. 3.05 mcm/day could be valued with GVA while the remaining 1.40 mcm/day will be put at the end of the country cumulated cost curve, not represented in our analysis.

The new cumulated cost curve which incorporates the above changes in the valuation of the commercial sector and the public administration sector is illustrated in Figure 2.19 below in comparison with the last cumulated cost curve we have estimated earlier.

Figure 2.19. Comparison of the final cumulated cost and the previous one



We have reached the end of our curtailment cost analysis. Starting out from the simple GVA method we have refined our estimation reconsidering each large consumer segment's valuation and applying different estimation methods that are used in the VOLL literature. We now have a cost curve that estimates the costs of Hungary during a supply disruption.

To show how this curve could be used for cost-benefit analysis of security of supply investments we will provide an application below, the valuation of the strategic storage site built in Hungary in response to the 2006 gas dispute between Russia and Ukraine.

2.4. Valuation of the Hungarian strategic storage site

The decision of building a strategic storage site was made in the beginning of 2006. Russia in a Russian - Ukrainian gas price dispute on 1st of January has decreased the quantity supplied to Ukraine which resulted in the lowering of pressure in the transit pipeline that supplies Europe. The supply crisis only lasted until the night of January 2nd and the parties have declared that the security of supply was not damaged nevertheless the Hungarian politicians suddenly realized Hungary's vulnerability and have responded very quickly and drastically.

The parliament has voted the act on security stockpiling in the middle of February.[19]

The act founded the Hungarian Hydrocarbon Stockpiling Association (MSZKSZ) of which all producers, traders, suppliers and importing consumers had to become a member. The members of the association have to pay each year a member fee set in a ministerial decree based on the heat content of the natural gas they supply to final consumers. MSZKSZ has the role to build and make available the strategic storage site.

The size of the storage site was also set in the act, the working gas volume was determined at a volume that would be enough to supply households and communal consumers for 45 days in a row, i.e. 1.2 bcm. The withdrawal capacity was set at 20 mcm/day. The stored gas could only be used if the minister in a dedicated ministerial decree permits it, furthermore, this ministerial decree would also individually appoint the suppliers that are entitled to use the strategic stock. The act declares that the strategic stock is primarily reserved for the households and communal users and those other consumers that cannot switch to alternative fuel.

Regarding the timeframe, the law declared that by 1st of January 2010 the strategic storage site had to be built. Thus during the January 2009 gas crisis this site was not yet available, only that 300 mcm which was stored in the existing storage sites of E.ON ordered by the act as a temporary solution until the strategic storage site is built.

MOL won the tender of MSZKSZ for the construction, it had used as a basis one of its depleted gas fields – Szőreg-1 -, and had founded the MMBF Storage Zrt, of which it owns 62% and MSZKSZ has the remaining 38% share. The storage site built this way is eventually larger than the parameters that were set out for strategic storage in the act. The working gas capacity of Szőreg 1 storage site is 1,900 mcm while its withdrawal capacity is 25 mcm/day. The 700 mcm working gas and the 5 mcm/day withdrawal capacity that are in addition to the 1,200 mcm working gas and 20 mcm/day withdrawal capacity of the strategic storage are considered as commercial storage capacities that can be freely marketed.

Thus Hungary from 2010 January is endowed with an own strategic storage site to secure itself from the consequences of future gas supply crisis. In the EU there is no other country that has built a dedicated storage site for strategic storage reasons others have opted for alternative solutions.[20] Whether this unique solution was an economically sound one, we will analyse it in the following section by comparing the costs and the benefits of the site.

[19] 2006. (febr.13.) évi XXVI. törvény a földgáz biztonsági készletezéséről (Decree on natural gas security stockpiling XXVI./2006.)

[20] For a detailed description of the strategic storage solutions of the EU country please see DG TREN

2.4.1. Costs of the Hungarian strategic storage site

The total cost of the strategic site is not exactly known, according to newspaper articles published on the site of MSZKSZ the cost of development and filling was around €530 million and the cost of an additional pipeline that had to be built for its filling up from Ukraine was an additional €245 million.[21] The cost of maintenance is not known. The real costs for the consumers comes directly from the MSZKSZ member fee, which is currently around €6.68 per thousand cubic meter,[22] thus in this year alone consumers pay around €87 million for the strategic storage site.

2.4.2. Benefits

To be able to evaluate the decision of building a strategic storage site for Hungary besides its costs we also need to know the benefits the site provides. Using our cumulated cost curve we will estimate what would be the costs caused by a gas crisis if there would be no strategic storage site at all, thus what costs the country avoids by having the storage site.

For this analysis we will have to define what we consider as a supply disruption and also we have to calculate what would be the supply gap in case of a supply disruption.

We define supply disruption in line with the N-1 rule of the Security of Supply Regulation of the EU[23] as a drop out of the largest infrastructure, but in case of import the drop out of the largest import direction. Thus we will consider the case for Hungary when the supplies from the Ukrainian border are fully curtailed.

Table 2.4 below lists the peak parameters of the supply infrastructure of Hungary, the 2006 status, when the decision on strategic storage was made and the current 2010 status. We have made two scenarios, Scenario 1 shows the size of possible supply in case the largest import direction fails and there is no strategic storage. Scenario 2 shows the case when the largest import direction drops out but there is the strategic storage to secure supply. Although the strategic storage act declares that the strategic storage site is primarily dedicated for the use of households in our calculations we will assume that the strategic storage site is used whenever a consumer group would be curtailed, since this seems rational. Regarding the size of the strategic storage facility in case of the 2010 analysis we use 25 mcm/day, because although the strategic storage is only 20 mcm/day, but the additional 5 mcm/day commercial capacity would not have been built without the building of the strategic part.

C1: Study on natural gas storage in the EU. October 2008

[21] http://www.husa.hu/_userfiles/image/pdf/Rolunkirtak/20100427_index_evi24milliardforintertvanstrategiaitarolonk.pdf

[22] http://www.husa.hu/ugyfeltajekoztato/hozzajarulasi-dij/index.html

[23] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC

Table 2.4. Peak and remaining peak infrastructure data with and without strategic storage. 2006 and 2010

		Peak infrastructure data 2010		
		base case, mcm/day	Scenario 1, mcm/day	Scenario 2, mcm/day
Strategic Storage (MSZKSZ, MOL)	Strategic storage (MSZKSZ) - strategic part	20	-	20
	Strategic Storage - commercial part	5	-	5
	Strategic Storage total	25	-	25
E.ON	E.ON Storage Zsana	28	28	28
	E.ON Storage Pusztaederics	3.1	3.1	3.1
	E.ON Storage Hajdúszoboszló	20.8	20.8	20.8
	E.ON Storage Kardoskút	3.2	3.2	3.2
	E.ON Storage total	55.1	55.1	55.1
Domestic production		10.7	10.7	10.7
Import direction Austria		12.1	12.1	12.1
Import direction Ukraine		56.3	-	-
Total infrastructure		159.2	77.9	102.9

Source: E.ON Földgáz Storage homepage and MOL FGSZ Annual report 2009

		Infrastructure data 2006		
		base case, mcm/day	Scenario 1, mcm/day	Scenario 2, mcm/day
Strategic Storage decision		-	-	20
E.ON	E.ON Storage Zsana	21	21	21
	E.ON Storage Pusztaederics	2.9	2.9	2.9
	E.ON Storage Hajdúszoboszló	19.2	19.2	19.2
	E.ON Storage Kardoskút	2.6	2.6	2.6
	E.ON Storage Maros-1	1.8	1.8	1.8
	E.ON Storage total	47.5	47.5	47.5
Domestic production		10.2	10.2	10.2
Import direction Austria		12.1	12.1	12.1

	Infrastructure data 2006		
	base case, mcm/day	Scenario 1, mcm/day	Scenario 2, mcm/day
Import direction Ukraine	30		
Total infrastructure	99.8	69.8	89.8

Source: MOL FGSZ Annual report 2006

The supply gap that emerges in case of a supply disruption is the difference between the daily consumption and the supply the infrastructure without the Ukrainian border can deliver. Here we assume that the remaining infrastructure can deliver at its peak value, thus there are enough gas in the storage sites, production can go on at its maximum capacity and there are enough import possibilities from Austria that allow the maximum import flow from that direction. In case of the January 2009 crisis this assumption was valid, all remaining infrastructures provided the possible maximum supplies. From Table 2.4 it can be seen that the size of the remaining infrastructure in 2006 was 69.8 mcm/day while in 2010 due to investments of E.ON in further commercial storage capacities and a small increase in production capacities increased to 77.9 mcm/day.

We also need an estimation of daily consumption distribution during wintertime. For this we have used the actual data of the previous years starting from the 2003/2004 winter, the beginning of market opening. Table 2.5 below shows the yearly peak consumptions of the previous years.

Table 2.5. Historical peak consumptions

Year	Peak consumption, mcm/day
1998	71.4
1999	69.6
2000	74
2001	79.4
2002	79.6
2003	83
2004	81.9
2005	89.9
2006	88.9
2007	76.3
2008	79.1
2009	73.9

Peak consumption was highest in 2005 and 2006 in these years it almost reached 90 mcm, however since then due to milder temperature and economic decline the yearly peak did not reach 80 mcm, this lower consumption was the case also in the years prior to 2005.

From the historical data of daily consumption starting from the winter of 2003/2004 till the last winter of 2009/2010 we will calculate what the costs would have been if there would have been a supply disruption on the Ukrainian border during all wintertime thus will provide a high-end estimate of possible benefits. We use the historical data as possible distributions of the winter daily consumptions and with that we result at possible outcomes of supply disruption costs. For the 2008/2009 winter, the winter of the supply crisis we use the actual data of the crisis and the cost that we have estimated in the previous section.

Table 2.6 below illustrates our calculations for the 2003/2004 winter. Only those days are shown which had a consumption higher than the remaining capacity of 2006, 69.8 mcm, since in the rest of the days there would have been no supply problems even during a supply disruption on the Eastern border. The costs are calculated using our estimated cumulated cost curve, for each day the cost is the curve's value for the given supply gap. For the rest of the years we provide the aggregated numbers that were derived the same way as the 2003/2004 case.

Table 2.6. Hypothetical costs of a supply disruption on the Eastern border during the 2003/2004 winter

Winter 2003/2004					
Date	consumption, mcm	Gap 2006, mcm	Gap 2010, mcm	Cost 2006 €million	Cost 2010 €million
2003.12.27	70.2	0.4	0.0	0.06	0.00
2004.01.04	72.8	3.0	0.0	0.46	0.00
2004.01.05	80.7	10.9	2.8	1.96	0.42
2004.01.06	82.6	12.8	4.7	2.34	0.77
2004.01.07	81.7	11.9	3.8	2.16	0.58
2004.01.08	80.8	11.0	2.9	1.99	0.44
2004.01.09	81.3	11.5	3.4	2.08	0.51
2004.01.10	73.9	4.1	0.0	0.66	0.00
2004.01.21	70.6	0.8	0.0	0.13	0.00
2004.01.22	78.5	8.7	0.6	1.54	0.09
2004.01.23	80.3	10.5	2.4	1.89	0.37
2004.01.24	77.2	7.4	0.0	1.29	0.00
2004.01.25	74.0	4.2	0.0	0.68	0.00
2004.01.26	77.9	8.1	0.0	1.42	0.00
2004.01.27	77.7	7.9	0.0	1.38	0.00
2004.01.28	75.7	5.9	0.0	1.00	0.00
2004.01.29	75.4	5.6	0.0	0.94	0.00
2004.01.30	75.4	5.6	0.0	0.94	0.00
2004.01.31	73.0	3.2	0.0	0.49	0.00
2004.02.12	77.6	7.8	0.0	1.37	0.00
2004.02.13	75.6	5.8	0.0	0.99	0.00

Winter 2003/2004					
Date	consump-tion, mcm	Gap 2006, mcm	Gap 2010, mcm	Cost 2006 €million	Cost 2010 €million
Total	21 days	147.2	20.5	25.7	3.2

Table 2.7. Summary of hypothetical costs of an Eastern-border supply disruption

Winter	number of days	GAP 2006, mcm	Cost 2006 million €	GAP 2010, mcm	Cost 2010 million €
2003/2004	21	147.2	25.7	20.5	3.2
2004/2005	48	313	79	77.5	13.3
2005/2006	33	206	56.9	52.9	9.3
2006/2007	0	0	0	0	0
2007/2008	20	60.3	9.8	1.2	0.2
2008/2009	the crisis: € 22.54 million				
2009/2010	7	20.1	3.1	0	0
Total	-	-	174.5	-	26

What we can see from Table 2.6 and Table 2.7 is that out of the 7 years analysed in one there would have not been any problems, if the Eastern border dropped out for the winter, even in the coldest period even with the 2006 infrastructure. Since by now the peak capacity of the remaining infrastructure is higher than the 2006 level calculating with the current infrastructure capacities, two out of the seven winters analysed would not have been affected by an import supply disruption. In the remaining cases the greatest cost that would be suffered with the 2006 infrastructure is around €79 million which along with the cost suffered with 2010 infrastructure – €13.3 million -, is below the cost Hungarian consumers pay per year in 2010 for the strategic storage (€87 million).

The other important conclusion from the above calculation is that in the seven previous years the yearly cumulated consumption gap, i.e. the consumption that has to be supplied from the strategic storage did not go above 320 mcm with the 2006 infrastructure and did not go above 80 mcm with the current 2010 infrastructure. This suggests that the size of the strategic storage site, 1,200 mcm might have been a little overshot. Maybe policymakers have realized this by now since there is a new initiative to lower the strategic stock's size to 600 mcm. Of course the question arises then what will be the function of the freed 600 mcm in the future.

This simple analysis suggests that building this exact strategic storage site might not have been an economically sound decision.

It has to be mentioned however that during the calculations we have made some assumptions without which the costs of a supply disruption could be higher. One important assumption is that the remaining infrastructure during a drop out of an import direction could supply at its maximum capacity. For this to be true it has to be assured that production goes at the maximum level and the import contracts on the remaining

borders work well. Furthermore in the commercial storage sites there should be enough natural gas for the maximum supply. For this latter to be true further regulation might be needed. This could be similar to French example where they impose an obligation on the public service provider to book 85% of the storage capacity rights associated with their domestic and selected public services consumers in the existing commercial storages for security reasons.[24] This kind of strategic storage solution while ensures the availability of maximum supply from storages during a crisis, is much cheaper than a construction of an additional storage site.

The other important assumption we have made is that when calculate the costs using our estimated cumulated cost curve we assumed that the actual curtailment follows the optimum path, i.e. those are curtailed which suffer the least cost and also only the needed amount is curtailed, i.e. the size of the gap. However, currently the curtailment system is not that flexible. Curtailment is delivered administratively and by large categories. So if there would be a curtailment need of 1.2 mcm and another with a size of 3 mcm the same consumers would be curtailed, those that are ranked in the Ist curtailment category and all the consumption is curtailed that is ranked in this category, the size of which in the January 2009 crisis was around 7 mcm. Since this means a great difference in curtailment cost compared to our estimation, we include this phenomenon in our calculations[25] by assuming that if there is any curtailment need at all, then at least 7 mcm is curtailed, and so on.[26] We again show our calculations for the 2003/2004 winter and then the summary table of the rest of the results.

Table 2.8. Hypothetical costs of a supply disruption on the Eastern border during the 2003/2004 winter with non-continuous curtailment

Date	consumption, mcm	GAP 2006, mcm	Curtailment	GAP 2010, mcm	Curtailment	Cost 2006 €million	Cost 2010 €million
2003.12.27	70.2	0.4	7	0	0	1.21	0
2004.01.04	72.8	3.0	7	0	0	1.21	0
2004.01.05	80.7	10.9	11	2.8	7	1.99	1.21
2004.01.06	82.6	12.8	16	4.7	7	5.11	1.21
2004.01.07	81.7	11.9	16	3.8	7	5.11	1.21
2004.01.08	80.8	11.0	16	2.9	7	5.11	1.21
2004.01.09	81.3	11.5	16	3.4	7	5.11	1.21

[24] DG TREN C1: Study on natural gas storage in the EU. October 2008. p. 165.

[25] However we think that accepting this inflexibility for the future would be a great mistake. The difference of costs the two table shows only result from the rigidity of the curtailment system and not from the supply problem. Therefore we think that great savings could be made just by reconsidering and improving the curtailment system.

[26] It is not known in advance how much mcm could be saved by curtailing one category. Regarding the size of the categories only the sum of the contracted capacity that has been ranked in each category is known. For example in the Ist category around 11.8 mcm/day capacity was ranked but during the January 2009 crisis when the Ist curtailment category was curtailed the TSO estimated that around 7 mcm was curtailed, since not all consumers were consuming at their maximum level and also as we have shown with the case studies some consumption that belonged to the Ist category was not curtailed after all. Therefore the values we use here are estimations based on the experience of the crisis.

Date	consump-tion, mcm	GAP 2006, mcm	Curtail-ment	GAP 2010, mcm	Curtail-ment	Cost 2006 €million	Cost 2010 €million
2004.01.10	73.9	4.1	7	0	0	1.21	0
2004.01.21	70.6	0.8	7	0	0	1.21	0
2004.01.22	78.5	8.7	9	0.6	7	1.60	1.21
2004.01.23	80.3	10.5	11	2.4	7	1.99	1.21
2004.01.24	77.2	7.4	9	0	0	1.60	0
2004.01.25	74.0	4.2	7	0	0	1.21	0
2004.01.26	77.9	8.1	9	0	0	1.60	0
2004.01.27	77.7	7.9	9	0	0	1.60	0
2004.01.28	75.7	5.9	7	0	0	1.21	0
2004.01.29	75.4	5.6	7	0	0	1.21	0
2004.01.30	75.4	5.6	7	0	0	1.21	0
2004.01.31	73.0	3.2	7	0	0	1.21	0
2004.02.12	77.6	7.8	9	0	0	1.60	0
2004.02.13	75.6	5.8	7	0	0	1.21	0
Total	21 days	147.2	201	20.5	49	44.55	8.49

Table 2.9. Summary of hypothetical costs of an Eastern-border supply disruption with non-continuous curtailment

Winter	number of days	Curtailment 2006, mcm	Cost 2006 €million	Curtailment 2010, mcm	Cost 2010 €million
2003/2004	21	201	44.55	49	8.49
2004/2005	48	464	124.04	145	29.96
2005/2006	33	306	84.80	79	16.31
2006/2007	0	0	0.00	0	0.00
2007/2008	20	144	25.02	7	1.21
2008/2009	the crisis: 22.54 million €				
2009/2010	7	49	8.49	0	0
Total	-	-	286.91	-	55.97

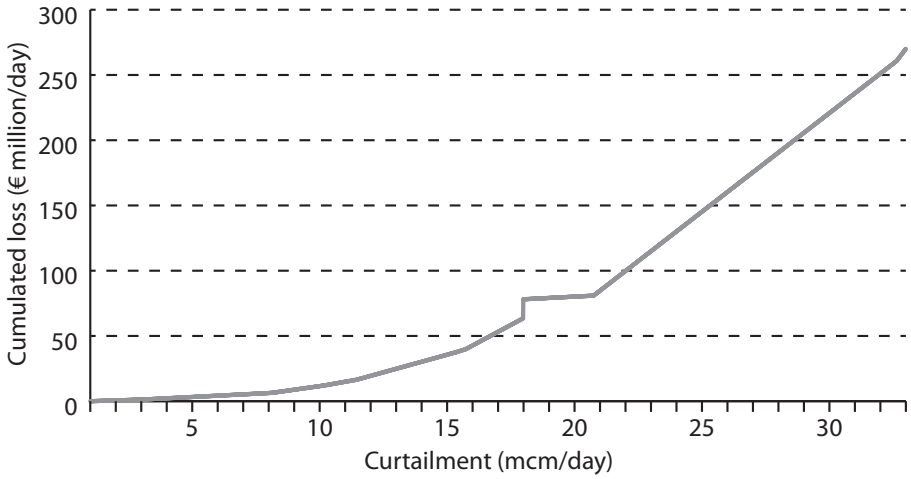
When we account for the inflexibility of the curtailment system we result at costs that are 1.5 – 2.5 times higher than the costs that a flexible system would yield. But even with these costs we can say that costs of a crisis only exceed the payments of the Hungarian consumers for the strategic storage once, and there is one more year when the two values are almost equal. Finally we mention that the costs that we have calculated refer to cases when there is a supply disruption during the whole winter, thus each day of the year is included in which consumption is high enough to cause a supply gap. Thus our estimations from this point of view can be considered to be very conservative estimations as the chance to have a supply crisis for such long time is pretty low.

Summarizing our results, according to our simple analysis the investment into a strategic storage site seems to have larger costs than benefits, consumers' demand for security does not surely justify this investment. Thus the Hungarian strategic storage site might be providing a security level that is higher than the theoretical optimal one.

2.5. Appendix

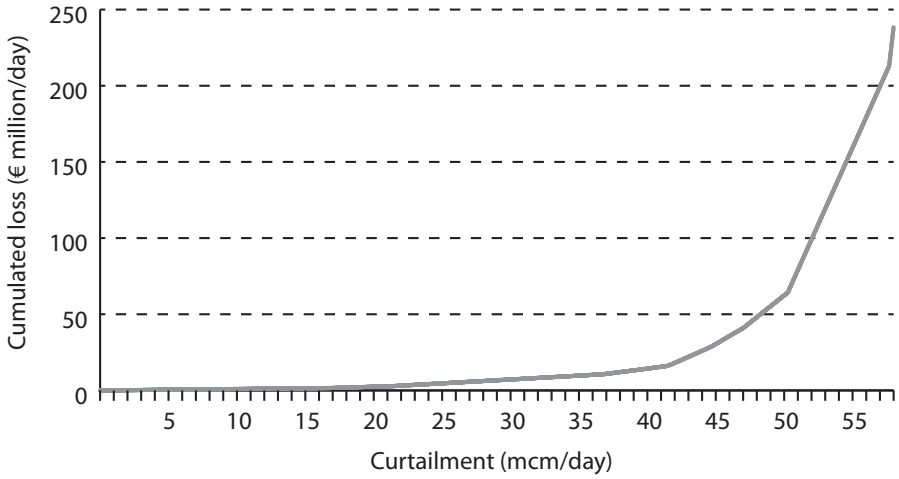
Here we present the cumulated cost curves of the other countries of the CSEE region where data were available to calculate the VOLL values. The curves are estimated using the GVA method.Data is gathered from Eurostat for the year 2008.

Figure 2.20. Cumulated cost curve of Czech Republic, 2008



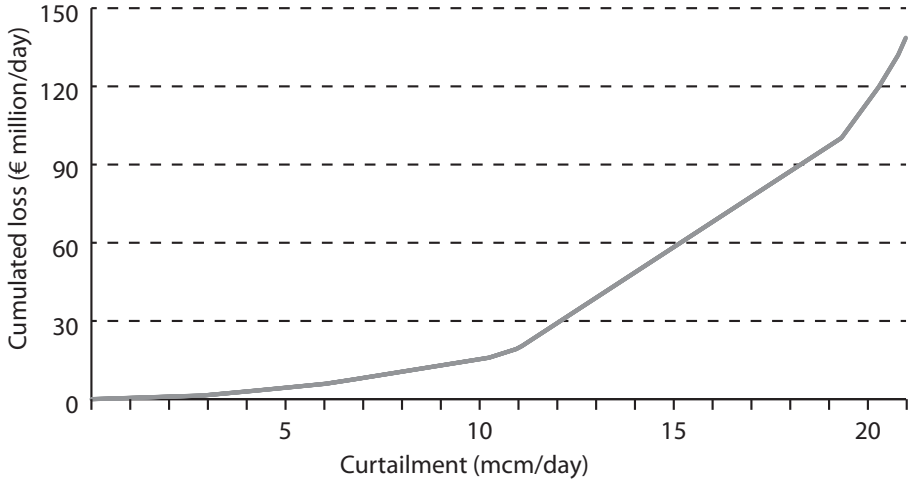
Source:Eurostat

Figure 2.21. Cumulated cost curve of Romania 2008



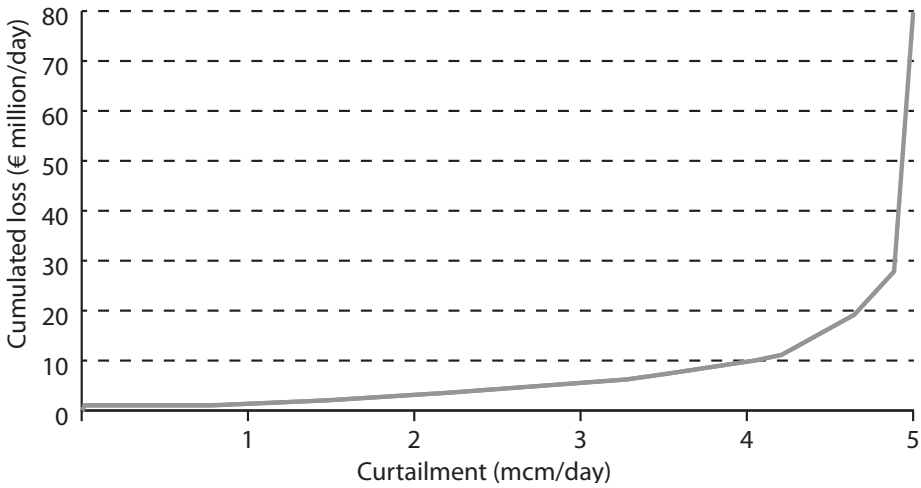
Source:Eurostat

Figure 2.22. Cumulated cost curve of Slovakia, 2008



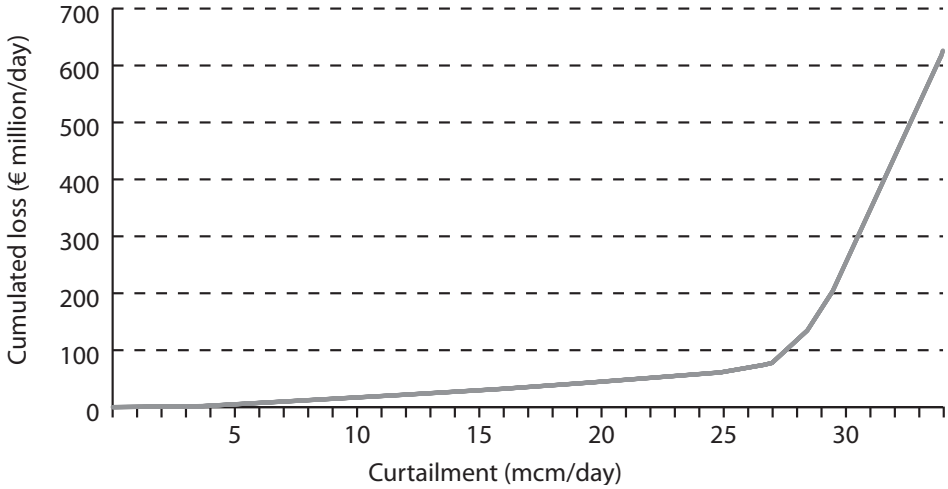
Source:Eurostat

Figure 2.23. Cumulated cost curve of Slovenia, 2008



Source:Eurostat

Figure 2.24. Cumulated cost curve of Austria, 2008



Source:Eurostat

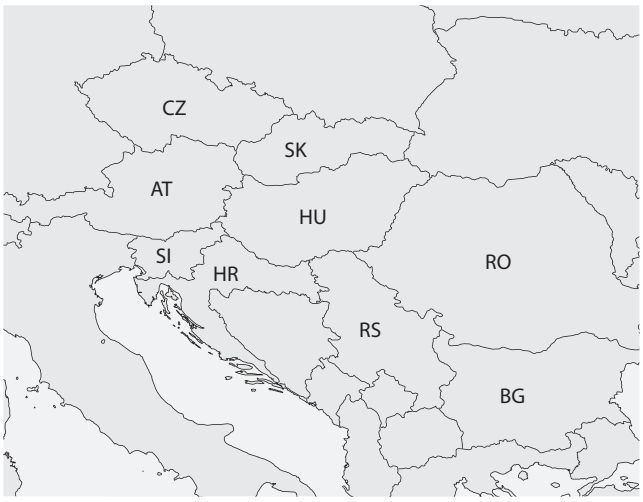
Forecasting demand for electricity and natural gas in Central and South-East Europe

3.1. Introduction

The objective of the current study is to outline and apply a simple forecasting methodology for electricity and natural gas consumption in the countries covered by the Security of Gas and Electricity Supply in Central and South-East Europe (henceforth: SoS-CSEE) project. In addition to describing the forecasting methods and their pitfalls, we will also introduce the available data and show the results of our calculations.

We cover the countries named and depicted in Figure 3.1, which we will refer to as the Central and South-East European (CSEE) region for the purposes of the study.

Figure 3.1. Countries analyzed in the SOS CSEE project



The intended time frame of the forecasts is the period between 2010 and 2020, with the understanding that predictions for years further into the future are inherently more uncertain. Nevertheless, investment decisions in the energy sector do require some level of foresight over at least a ten years' period, making demand forecasting such as this one an important, if imperfect, exercise.

Broadly speaking, demand forecasting can have two objectives. The first one is to predict total consumption of an energy product over a given period, typically one calendar year. Based on this knowledge (and a market model with supply side information), we can gain an understanding about the expected revenues and profitability of a given company in the future. Therefore, sales predictions are primarily interesting for investors looking to enter the market, or expand their current presence.

The second object of forecasting is some measure of system peak load. In electricity, this is usually the highest hourly load, whereas in the gas sector it is the highest daily consumption of natural gas in a given year. The main purpose of such forecasts is to aid the planning of both production and transportation capacities within the system, as well as the calculation of necessary reserve levels.

While both consumption and peak load can be interesting under different circumstances, our focus in this study is more on the long-term supply security perspective. Therefore, we will mainly concentrate on projecting total consumption and only provide a description of methodological issues for the latter.

The outline of the study is the following. In Section 3.2, we discuss demand forecasting methods in general, emphasizing both their strengths and weaknesses in relation to the data at hand. In Section 3.3, we outline our preferred approach to the present forecasting exercise. Consequently, we treat electricity consumption in Section 3.4 and consumption of natural gas in Section 3.5.

3.2. Energy Demand forecasting methods

Our discussion of the relevant forecasting methodology is based on a recent and exhaustive consultation paper by the Electricity Commission of New Zealand, as well as the practice developed for the state of South Australia, and contained in several papers in the academic literature.[1]

The main issues regarding the forecasting methodology are the following:

- Top-down vs. bottom-up approach
- Use of exogenous economic and social data
- Incorporating weather information
- Peak forecasts derived from total consumption or produced independently
- Use of information from industry participants
- Historical data period
- Prudence in forecasting
- Predicting the load duration curve and the break-down of total consumption

3.2.1. Top-down vs. bottom-up approach

In a top-down approach, the object of forecasting is the aggregate level of consumption as a single entity. There is no breakdown into separate components, or the breakdown itself is carried out after the forecast itself.

As an example, we might treat the total yearly electricity consumption of a given country as the variable to produce a forecast for. In this case, we look at the data series as a whole object, without thinking about what different subcomponents (e.g. consumption of the household, industry or services sector) it is made of.

The techniques applied to the aggregated series may be various: pure single variable time series methods, the use of exogenous economic and social variables as predictors, incorporation of weather data or information from industry participants, etc. After a forecast is produced for the variable, predictions for its different subcomponents may be derived subsequently. For example, ratios of household-to-industry consumption may be used to derive future household consumption levels from the predicted total consumption.

In contrast, bottom-up approaches decompose the object of forecasting into its various subcomponents first, and produce forecasts for each element separately – possibly using different forecasting methods for different elements. Afterwards, the separate predicted values are aggregated up to yield the overall forecast.

Whereas bottom-up approaches seem intuitively more appealing, since they may allow a deeper and more nuanced understanding of the drivers of consumption growth, they are not without limitations. First, disaggregated data is usually only available in further spaced intervals, typically once per year, whereas aggregated data is measured more frequently. As a result, the historical data series contains considerably fewer observations

[1] See the South Australian site at http://www.esipc.sa.gov.au/site/page.cfm?u=287 and the references therein.

to perform a bottom-up approach, yielding wider confidence intervals and less accurate predictions. Second, mistakes in predicting the individual elements in a bottom-up estimation may add up in a way that produces substantial bias in the aggregate. Finally, if not all elements are considered equally, biases can again result (e.g. taking into account currently existing industries, but neglecting potential future ones).

3.2.2. Use of exogenous economic and social data

In a single variable time series prediction exercise, only the variable to forecast is looked at and analyzed. The researcher tries to find a pattern in the historical data (usually a trend or recurring cycles) which seems strong enough to be assumed to continue. Once the regularity is found, it is used for prediction into the future. For example, if electricity consumption seems to have grown exponentially by 2 percent on average in the past decade, then this growth rate can be predicted for the upcoming years as well.

In contrast, past values of other variables may be used to find stable relationships between these "regressors" and the dependent variable that we wish to forecast. Examples for such variables in case of electricity and gas consumption include past GDP, population, or prices. Of course, such additional information is only useful in our prediction exercise if the relationship can be estimated relatively accurately *and* we have reliable forecasts for the regressors, which we can use to predict future values of the dependent variable.

3.2.3. Incorporating weather information

Weather data – especially temperature – is very useful information to have in case of energy demand forecasting. Weather is one of the strongest drivers of short-term demand fluctuations. When it gets colder outside, people predictably turn up the heating, and the same holds for air conditioning on hot days.

Using past information about weather, we can correct the time series to extract economically irrelevant weather effects, which may allow us to detect the underlying trend more accurately. This method is especially useful with frequent time series observations that only extend a short period into the past. The weather dependence of consumption is likely not to have changed much over a few years, and the large number of data points allow us to estimate the exact relationship.

3.2.4. Peak forecasting methodology

Peak forecasts may be derived from total consumption by analyzing the past development of the peak vs. the average load and making assumptions about this relationship based on past facts for the future. This approach keeps the consistency between the predictions for total consumption and those for peak load, while limiting the amount of forecasting effort at the same time.

A different approach would be to use separate models for peak and for total consumption forecasts, as their drivers may be different from one another. For example, a dynamic growth of air conditioning is likely to have an asymmetrically stronger effect on peak loads than on total yearly consumption.

3.2.5. *Use of information from industry participants*

In some cases, certain installations may be large enough to have a distinctive effect on total consumption or on peak load in a given country. When this happens, having more in-depth information about the future operation of these units can be valuable for forecasting purposes.

Care must be taken, however, not to introduce asymmetric biases into the prediction by considering some industrial consumers (about which data is more readily available, for example), while neglecting others. In addition, the reliability of such in-depth information provided by industry players may be questionable as well.

3.2.6. *Historical data period*

The appropriate length of the historical data period depends on data availability and quality (more data is better, but only if earlier data is of not much poorer quality), shifts in economic relationships (longer periods may contain more significant breaks), the number of exogenous variables (using more regressors requires more data) and the frequency of observations (using yearly data needs a longer time period than using monthly data).

3.2.7. *Prudence in forecasting*

Especially in case of peak load forecasting, it is important to provide information about the accuracy of the predictions, as well as their dependence on changes in exogenous variables. For capacity planning purposes, it is usual to look at extreme weather scenarios. For example, the gas industry often uses 1 in 20, or similar winter weather severity measures to determine the necessary service capacity of the system. These unusual peak load levels may also be objects of forecasting exercises.

3.2.8. *Predicting the load duration curve*

Besides peak load, a more detailed distribution of consumption levels may also be of interest. The continuous load duration curve is the ultimate object of prediction, but in practice, more coarse representations are used (such as consumption deciles). Similarly, consumption forecasts could be made for each month, week, or day.

However, given the amount of data necessary for such a detailed forecast, the practical approach is the same as in the case of peak load tied to total consumption: find the historical relationship between the object of interest and total consumption (e.g. electricity consumption in January tends to average at 10 percent of the yearly total), and use a projection of that relationship together with the total consumption forecast to predict the variable in question.

To sum up, the choice of the appropriate forecasting methodology involves a well-calculated trade-off between the level of sophistication and the associated data requirements. In practice, the applied methodology is likely to be most limited by the availability of data. It is in this spirit that we will outline our possible choices of forecasting methods in the next section.

3.3. Methodology for electricity and gas demand forecasting in Central and South-East Europe

In the current section, we will describe the data available to us, as well as the potential forecasting alternatives that this constraint allows. In the end, we shall suggest one forecasting model to proceed with.

3.3.1. Data availability

In all cases, our intention was to proceed with publicly available information. This has several advantages, as well as drawbacks. First, using public data sources decreases the cost of forecasting. Second, it makes the forecasting exercise freely reproducible. Third, it is likely to coincide with the data used by investors and companies operating in the energy sector of the region, while a fourth advantage is a gain in consistency across the analyzed region. However, the most obvious drawback is the limitation that publicly available data places on the applicable forecasting models.

Electricity

In electricity consumption, data is available on various frequencies. Hourly load values can be downloaded from the ENTSO-E website[2] for the past three-to-four years, whereas some system operators make even longer time series available at the hourly frequency. Load values are aggregated across all consumer groups.

Monthly consumption values are also available from ENTSO-E, Eurostat or individual TSO-s.[3] These go back longer in time (sometimes up to 10 years), but are still aggregated across different consumers.

Yearly consumption is currently available from 1990 to 2008 in a disaggregated form (households, different industries, agriculture, transportation, services) in the Eurostat database.

Peak loads can be derived from hourly load data for the past few years. Beyond that, they are available on TSO websites for certain countries.

Natural gas

The availability of natural gas consumption data is similar to that of electricity, except that consumption over very short frequencies (within a day) is not metered. Generally, daily consumption data is not public information either. However, from monthly consumption upwards, the type and extent of availability is the same as for electricity.

Weather information

There are two types of important weather-related information that we may use. The first is average temperature on a given day, which may exert a considerable influence on heat-

[2] European Network of Transmission System Operators for Electricity (www.entsoe.eu).

[3] A consistency issue also arises across several data sources, as they tend to cite different numbers for the same variable. Judgment by the researcher about what "looks to be correct" is unavoidable in certain cases.

ing or cooling needs. Average daily temperature data is available from the University of Dayton archives for each capital (except Ljubljana, for which we substitute the data for Zagreb), going back to around 1996. Monthly heating degree days can also be found on Eurostat starting from 1990. For the overlapping years, we found the two datasets to be largely consistent.

The second type of weather-related information is the length of daylight on a given day, which may influence electricity usage through lighting needs. Whenever we do estimation on very frequent (daily) data, we proxy the length of the day by a variable denoting the month of the year (e.g. days are short in January, but long in July).

Economic and social variables

For measuring economic activity, we variously use real GDP and an industrial production index. The first is a yearly figure, whereas the second is published monthly. The latest GDP forecasts are also available until 2020 from the Economist Intelligence Unit (EIU).

Product price availability is sparse, except for the crude oil price, which we will use to proxy the wholesale price of natural gas (through the pricing formula used by most CSEE countries for their gas imports from Russia).

Finally, we have yearly population data as a demographic variable.

Information from industry participants

As we found no feasible way of gathering consistent and reliable information from industry participants, we decided to forego the use of such information altogether in our forecasts.

3.3.2. Forecasting model

Given the level of aggregation, we found that a bottom-up approach could only be fruitfully applied to yearly data, since on shorter frequencies data is not available separately for households and industrial consumers.

A top-down approach would theoretically be possible for monthly as well as yearly data, potentially increasing the accuracy of the prediction by the multiplication of observation points. However, the problem is that most economic and social variables (most importantly: real GDP) are only available at the yearly level, making it misleading to include them in monthly regressions.

Instead, our aim is to first run an estimation on monthly (or in case of electricity: daily) data to get a precise estimate of the weather effect, which we will need to net out of the consumption data.

Assuming that temperature and other economic variables (such as real GDP) are unrelated to each other, we can then aggregate the temperature-corrected monthly series into a yearly dataset. On this data, we will carry out our top-down regression, estimating the co-movement of economic variables with the corrected consumption figures.

Once the estimation on historical data is complete, we predict future consumption values by plugging predicted values for economic variables and average values for temperature data into the estimated equation.

3.4. Electricity demand forecasting

In this section, we perform a statistical estimation and forecasting exercise for the yearly electricity consumption of 9 CSEE countries which are in the focus of the research project. During the demand forecasting exercise, we will first look at whether the effect of temperature needs to be corrected in the data, then describe the relationship between the potential explanatory variables (GDP, population) and yearly electricity consumption. Finally, the most likely path of consumption will be projected until 2020, based on our information about the expected evolution of the explanatory variables.

3.4.1. Temperature correction

We carried out the estimation of the temperature effect on daily observations between January 1st 2006 and June 30th 2009. Altogether, this is 1276 observations (3.5 years, including one leap year) for each country.

We estimated the following equation by the method of ordinary least squares for each country:

$$Cons=\alpha+\beta_H \cdot HDD+\beta_C \cdot CDD+\Gamma \cdot Dayofweek+\Delta \cdot Month+\gamma \cdot Indprod+\varepsilon$$

where the notation is as follows:

Cons	Daily electricity consumption
HDD	Heating degree day (the number of degrees by which the daily average temperature fell below 16 °C, if any)
CDD	Cooling degree day (the number of degrees by which the daily average temperature exceed 20 °C, if any)
Dayofweek	Dummy variable for each day of the week except Monday
Indprod	Monthly industrial production index
Month	Dummy variable for each month except January
α	Regression constant [MWh]
β_H	HDD coefficient; shows the effect of a 1 °C drop in average daily temperature below 16 °C on the average daily consumption [MWh/°C]
β_C	CDD coefficient; shows the effect of a 1 °C rise in average daily temperature above 20 °C on the average daily consumption [MWh/°C]
Γ	Day of week coefficients; show the average difference in consumption between the given day and Monday [MWh]
Δ	Month coefficients; show the average difference in consumption between the given month and January [MWh]

γ Coefficient of industrial production index; shows the increase in consumption resulting from a 1 point increase in the index [MWh].

In the estimation, we allowed for second degree autocorrelation in the regression error term (ε) to account for unobserved effects that persist over several day and have an effect on the total electricity consumption.

Table 3.1. Regression output for daily electricity consumption in Austria

Dependent Variable: CONS_AT

Method: Least Squares

Sample (adjusted): 3 1276

Included observations: 1274 after adjustments

Convergence achieved after 11 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	137248.3	8052.541	17.04410	0.0000
HDD_AT	768.8782	86.16522	8.923301	0.0000
CDD_AT	756.9258	257.1305	2.943741	0.0033
TUESDAY	5249.545	544.7136	9.637257	0.0000
WEDNESDAY	6267.574	637.7493	9.827645	0.0000
THURSDAY	4957.221	676.4600	7.328181	0.0000
FRIDAY	2107.567	677.3906	3.111302	0.0019
SATURDAY	-17306.49	637.6454	-27.14125	0.0000
SUNDAY	-30603.77	538.9641	-56.78258	0.0000
FEB	-3614.084	1686.553	-2.142882	0.0323
MAR	-15562.43	2556.296	-6.087882	0.0000
APR	-22550.57	2214.012	-10.18539	0.0000
MAY	-31761.69	2400.640	-13.23051	0.0000
JUN	-30431.32	2707.087	-11.24135	0.0000
JUL	-30944.00	2994.538	-10.33348	0.0000
AUG	-30207.70	2417.561	-12.49512	0.0000
SEP	-27410.63	3333.127	-8.223696	0.0000
OCT	-22576.76	3330.561	-6.778666	0.0000
NOV	-19404.35	3225.418	-6.016075	0.0000
DEC	-16246.86	2891.953	-5.617956	0.0000
INDPROD_AT	377.0819	85.79667	4.395064	0.0000
AR(1)	0.465693	0.028366	16.41731	0.0000
AR(2)	0.065210	0.028420	2.294496	0.0219
R-squared	0.900842	Mean dependent var		158787.1
Adjusted R-squared	0.899098	S.D. dependent var		20163.65
S.E. of regression	6405.005	Akaike info criterion		20.38544
Sum squared resid	5.13E+10	Schwarz criterion		20.47841
Log likelihood	-12962.52	F-statistic		516.5988
Durbin-Watson stat	2.005886	Prob(F-statistic)		0.000000
Inverted AR Roots	.58	-.11		

Source: REKK calculations

The result of the estimation is shown in Table 3.1 for a single country, Austria. We can see that all explanatory variables are significantly different from 0 at the 5 percent level (Prob. value in the last column is below 0.05).

Regarding the interpretation, we can see that a rise by 1 HDD increases daily electricity consumption by 768.9 MWh, whereas a rise by 1 CDD increases consumption by 756.9 MWh. By construction, temperature changes have no effect when the daily average is between 16 °C and 20 °C.

We have carried out the estimation seen above for several countries in the CSEE region. Table 3.2 shows the coefficient results for temperature effects. All of them are significant at the 5 percent level, except for the CDD coefficient in the Czech Republic, which is not significantly different from 0.

Table 3.2. HDD and CDD regression coefficients for various CSEE countries

Country	HDD coefficient [MWh/°C]	CDD coefficient [MWh/°C]
Austria	769	757
Croatia	204	283
Czech Republic	641	188
Hungary	242	1069
Romania	594	696
Serbia	753	424
Slovakia	239	148

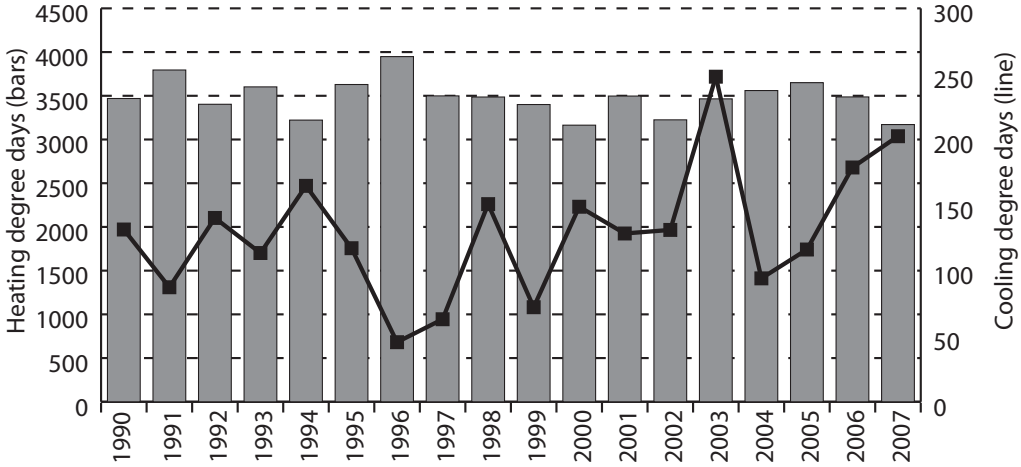
Source: REKK estimation

The estimated coefficients vary considerably across the countries. After this estimation, we can use the regression results to correct for the yearly variation in heating and cooling degree days in order to net out the temperature effect from the observed data.

Figure 3.2 shows heating and cooling degree days in Austria, starting from 1990. (Cooling degree days between 1990 and 1995 are estimated.) Assuming that the relationship between temperature and electricity consumption has not changed much over

the past two decades, we can add or subtract the difference between the average and the actual heating and cooling degree days, multiplied by the corresponding coefficients, to arrive at the temperature-corrected consumption time series.

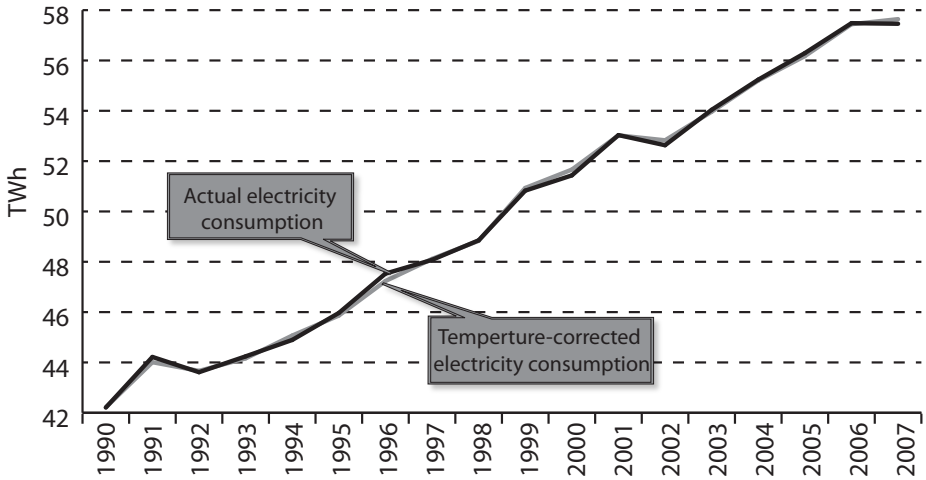
Figure 3.2. Yearly heating and cooling degree days in Austria



Source: Eurostat, NCDC, REKK estimation

Figure 3.3 shows the actual and the temperature-corrected yearly electricity consumption values for Austria between 1990 and 2007. As the two lines are barely distinguishable, we can conclude that at least in the case of this country, temperature effects do not matter too much for total yearly consumption.

Figure 3.3. Actual and temperature-corrected electricity consumption in Austria



Source: Eurostat, NCDC, REKK estimation

Moreover, since the estimated HDD and CDD coefficients in Table 3.2 are within the same order of magnitude, and the temperature variation is also similar across the CSEE countries, we can also conjecture that weather correction will not change the total yearly consumption of other countries, either. As a consequence, we use the essentially identical non-corrected yearly series in our subsequent regressions, to avoid any potential bias from previous estimations.

Even then, however, temperature correction could likely be important if we looked at peak load levels. Although the HDD and CDD coefficients will be the same, the degree days themselves will not necessarily average out for the peak load day, as they do over the entire year.

3.4.2. Estimation of economic effects

In the current section, we will look at the relationship between yearly consumption data and relevant economic variables. We also tried to include demographic variables, such as total population, but no significant relationships were found between population and electricity consumption. We look at this shortcoming as a data limitation (too few observations and not enough variation in population levels), but opt for the simpler model, nevertheless.

Therefore, we estimate the following equation for each country:

$$\log(\text{Cons}) = \alpha - \beta\log(\text{Cons}) + \varepsilon$$

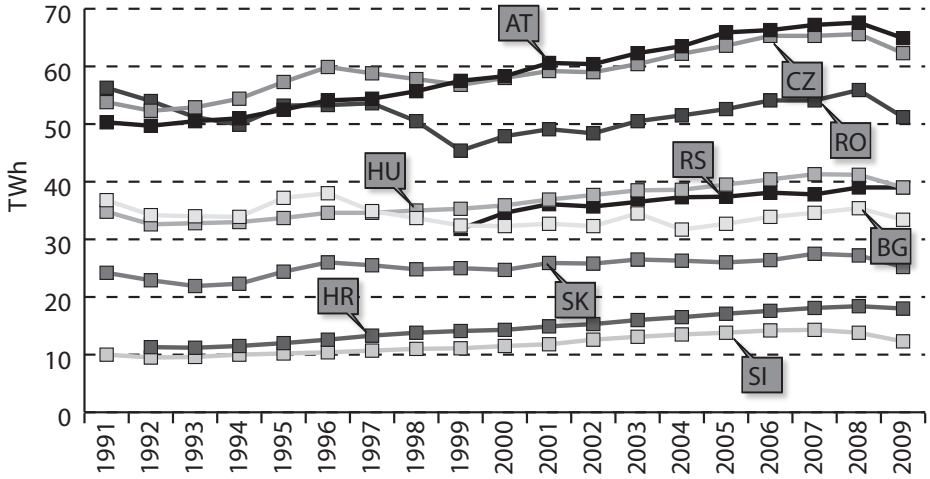
where the notation is as follows:

log(Cons)	Natural logarithm of the total yearly consumption of electricity
log(GDP)	Natural logarithm of the real GDP of the country
α	Regression constant
β	GDP coefficient; shows the percentage effect of a 1 percentage point increase in real GDP on total yearly electricity consumption[4]
ε	Regression error term.

Figure 3.4 shows the evolution of domestic electricity usage in 9 CSEE countries, which are in the focus of our investigations.

[4] We can also think of this loosely as the income-elasticity of aggregate electricity consumption.

Figure 3.4. Yearly electricity consumption in the CSEE region, 1991-2009



Source: ENTSO-E, Eurostat, national statistics

In many cases, the figure shows a consumption decrease in the first (and sometimes even the second) half of the 1990's, which was due to a massive reorganization of the former socialist economies. Heavy industry has receded to lower output levels and the energy intensity of production has also decreased.

As a consequence, we can conjecture that the aggregate income elasticity parameter has probably changed over time for many countries. To capture this change, we have run a series of regressions excluding progressively more and more years from the beginning of the dataset as long as the significance of the estimates was still convincing, and kept looking for changes in the parameters. In addition, we looked at whether the "crisis year" of 2009 affected the estimates to a considerable degree.

We present the detailed results of the most convincing estimation in Table 3.3 for Hungary. As the R^2 value shows, the explanatory power of this simple model is excellent. 97 percent of the variation in yearly electricity consumption levels can be explained by the variation in real GDP.

Table 3.3. Estimation of economic effects on electricity consumption in Hungary

Dependent Variable: LCONS_HU

Method: Least Squares

Sample (adjusted): 1999 2009

Included observations: 11 after adjustments

White Heteroskedasticity-Consistent Standard Errors & Covariance

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LGDP_HU	0.516191	0.023938	21.56356	0.0000
C	8.115466	0.111621	72.70557	0.0000

R-squared	0.971880	Mean dependent var	10.55912
Adjusted R-squared	0.968756	S.D. dependent var	0.052453
S.E. of regression	0.009272	Akaike info criterion	-6.360740
Sum squared resid	0.000774	Schwarz criterion	-6.288396
Log likelihood	36.98407	F-statistic	311.0586
Durbin-Watson stat	1.659590	Prob(F-statistic)	0.000000

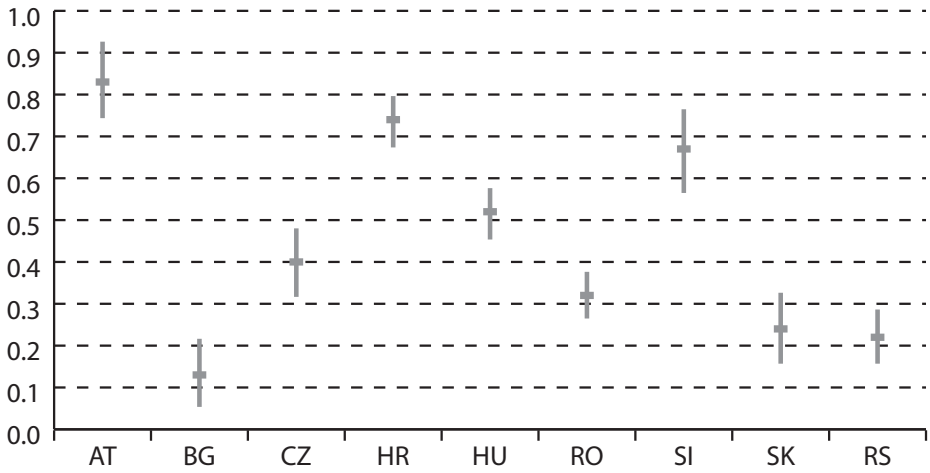
Source: REKK estimation

In addition, the parameters of the model are very precisely estimated even with 11 data points. The coefficient on log-GDP tells us that over the past two decades, a 1 *percent* increase in Hungarian real GDP meant a 0.52 *percent* increase in the country's yearly electricity consumption.

Interestingly, this coefficient varies across countries in the CSEE region. Figure 3.5 shows the collection of our best estimates based on past GDP-consumption relationships for each country. Besides the point estimates (square marks), we also present the width of the 95 percent confidence intervals as a range around the estimated coefficients (vertical lines).

The graph shows that the sensitivity of electricity consumption to GDP growth in Hungary is somewhere around the regional average. For some countries (e.g. Austria, Croatia), the estimated figure is much higher (above 0.7), and for others (e.g. Bulgaria, Slovakia, Serbia), it is much lower (below 0.3).

Figure 3.5. Estimated income elasticities in the CSEE region

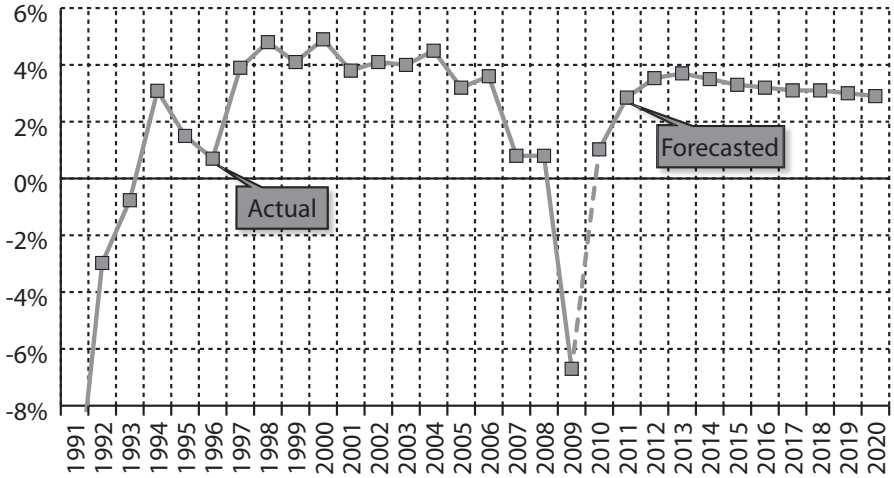


Source: REKK estimation

3.4.3. *Demand forecasting based on economic effects*

In this subsection, we show how the simple model estimated above can be used together with a GDP forecast to predict future yearly consumption values. Figure 3.6 shows past and forecasted future real GDP growth rates for Hungary, our example country.

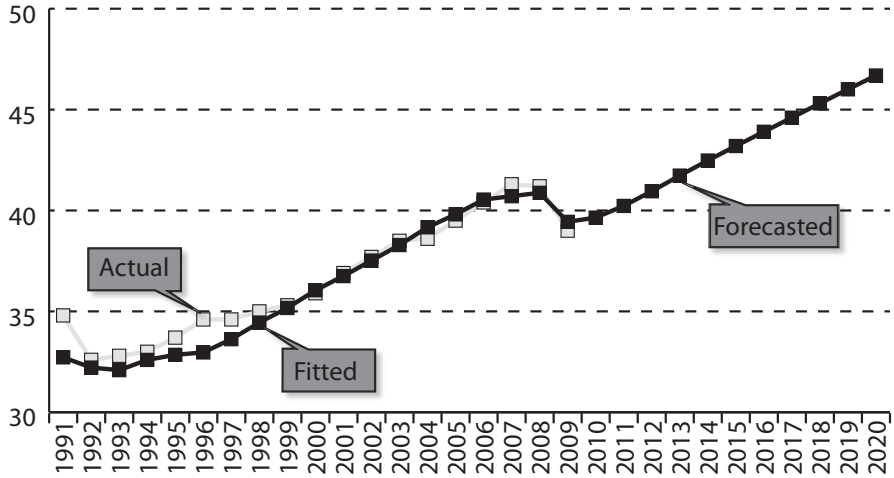
Figure 3.6. Past and forecasted future real GDP growth in Hungary



Source: IMF, MNB, Economist Intelligence Unit

We can plug the forecasted values into our estimated equation in Table 3.3 to get predicted values for total yearly electricity consumption, assuming that the relationship between the two variables stays the same in the next decade as it was during the estimation period (1999-2009). Our results for final electricity consumption are shown in Figure 3.7.

Figure 3.7. Actual, fitted and forecasted final electricity consumption in Hungary

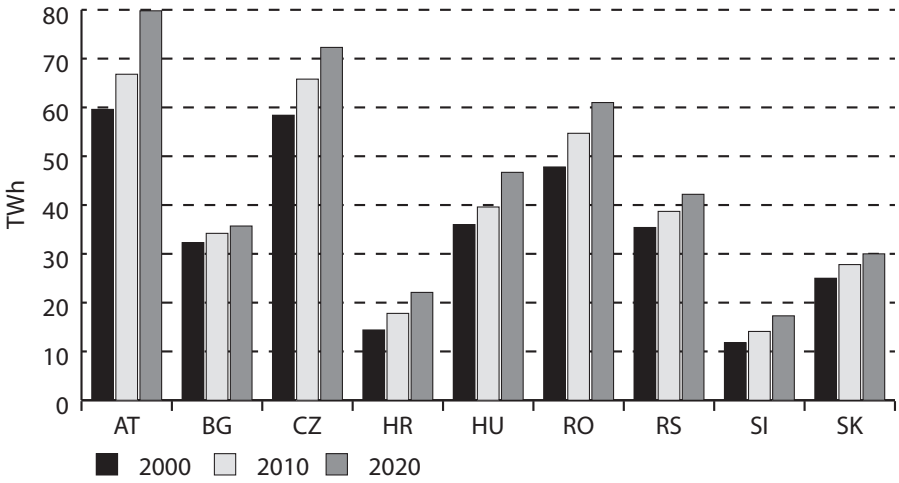


Source: HEO, REKK estimation

As the figure shows, our statistical model approximates the actual consumption values very closely for the estimation period, but does somewhat worse for the decade before. Since our focus here is on the demand projection into the next decade, this trade-off seems like a fair price for a more credible forecast for the upcoming years.

In Figure 3.8, we show the result of the estimations for all CSEE countries at 10-year intervals (2000-2010-2020). Altogether, the model predicts a growth in regional electricity demand by around 48 TWh over the next ten years, which is about 10 TWh more, than in the previous decade.

Figure 3.8. Actual and forecasted final electricity consumption in the CSEE region



Source: Eurostat, REKK estimation

3.4.4. Assessment

We can make the following points based on our investigations regarding the electricity consumption of CSEE countries.

- Available data seems to be too limited to estimate statistically significant relationships for anything beyond the simplest models.
- Although we can carry out a temperature correction based on daily observations, this does not matter much for yearly final electricity consumption, but it may impact peak load forecasting to a greater extent.
- There is a dispersion of estimated GDP-electricity consumption relationships: not all countries react the same way to a change in domestic output.

3.5. Natural gas demand forecasting

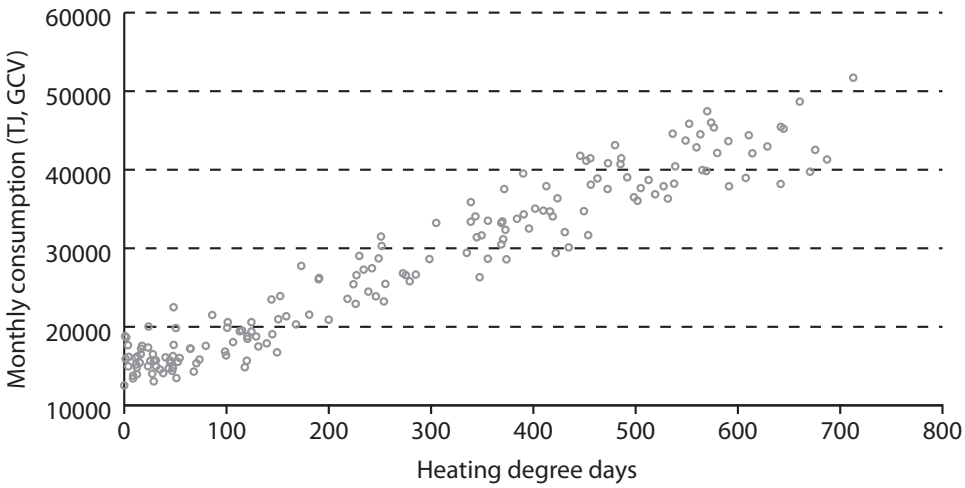
For analyzing natural gas demand, we employ a slightly different, but still top-down approach. In the current section, we show the outline of the method, along with the estimation results. Our source of data is the monthly gross inland consumption figures from the Eurostat database.

3.5.1. Temperature correction

Natural gas consumption is considerably more dependent on weather conditions than the demand for electricity. The dependence is also more asymmetric: heating degree days matter, but cooling degree days do not, as air conditioning runs on electricity, and increased demand for power does not (yet) translate into noticeable differences in aggregate gas usage (through gas-fired power plants).

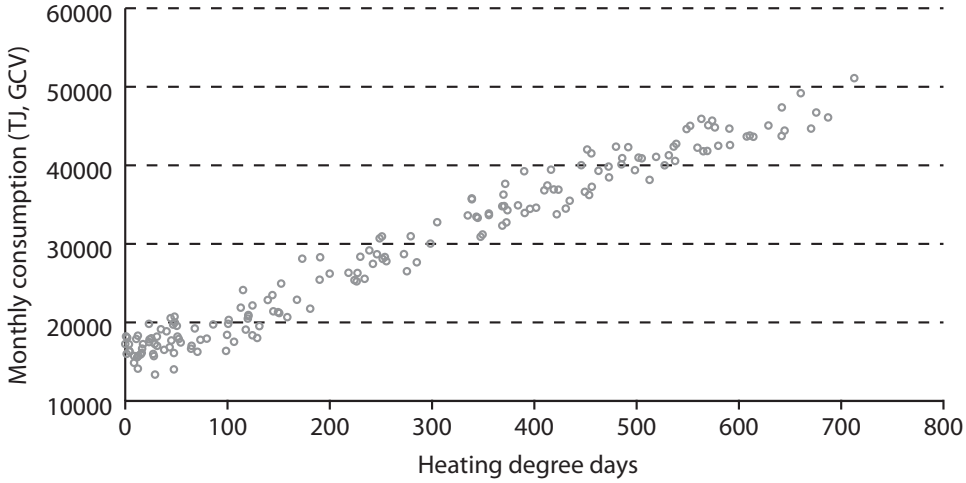
Figure 3.9 and Figure 3.10 show the relationship between heating degree days and monthly natural gas consumption in Austria. In the second figure, we have adjusted the consumption data to correct for differences in the length of the months and the number of weekend days, which yields an even tighter relationship between weather and consumption.

Figure 3.9. Heating degree days and monthly natural gas consumption in Austria



Source: Eurostat, NCDC

Figure 3.10. Heating degree days and adjusted monthly gas consumption in Austria



Source: Eurostat, NCDC

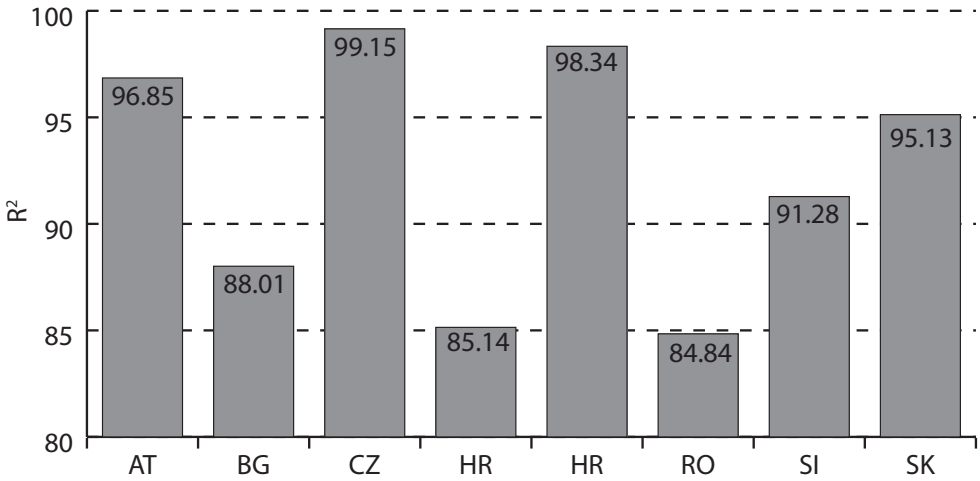
3.5.2. Estimation of economic effects

As a first approach, we have estimated the effects of relevant economic variables on the same dataset that we used for demonstrating temperature effects in the previous subsection. Therefore, the temperature correction and the structural estimation was carried out simultaneously.

We used two regressors in addition to heating degree days: the monthly industrial production index and the lagged average crude oil price. The first is a proxy for economic activity, whereas the second tries to capture the price effects.

Model fits are again rather satisfactory (see Figure 3.11), although this is mostly due to the close co-movement of heating degree days and gas consumption.

Figure 3.11. Model fits for various countries (R^2 values)



Source: REKK estimation

In Table 3.4, we display the result of one such structural regression, this time for Hungarian data.

Table 3.4. Structural estimation for monthly gas consumption in Hungary

Dependent Variable: LOG(INL_CONS_HU)

Method: Least Squares

Included observations: 55 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.003193	0.529160	13.23454	0.0000
HDD_5_16	0.002429	6.78E-05	35.84859	0.0000
LOG(INDPROD)	0.751972	0.107896	6.969445	0.0000
LOG(BRENT(-11))	-0.117112	0.037434	-3.128471	0.0029

R-squared	0.965695	Mean dependent var	10.54688
Adjusted R-squared	0.963677	S.D. dependent var	0.489180
S.E. of regression	0.093231	Akaike info criterion	-1.837527
Sum squared resid	0.443292	Schwarz criterion	-1.691540
Log likelihood	54.53200	Hannan-Quinn criter.	-1.781073
F-statistic	478.5520	Durbin-Watson stat	1.572987
Prob(F-statistic)	0.000000		

Source: REKK estimation

As Table 3.4 shows, the model fits the data very well. All coefficients are strongly significant, and in addition, they have the sign we would expect.

3.5.3. *Forecasting based on yearly data*

For the purposes of forecasting, we have estimated a similar relationship as in Table 3.4, but on data with yearly frequency. Heating degree-days have been aggregated from January to December each year. Instead of the industrial production index, we used the logarithm of real GDP, since long term forecasts are only available for the latter. In addition, Brent prices have been substituted with yearly averages.

Not surprisingly, the yearly estimations (with considerably less accurate data) have yielded weaker, but for forecasting purposes still more useful, results than the monthly ones. One of the stronger regressions is shown in Table 3.5 for Austria.

Table 3.5. Structural estimation for yearly gas consumption in Austria

Dependent Variable: AT_LCONS

Method: Least Squares

Sample (adjusted): 1990 2009

Included observations: 20 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
AT_LGDP	1.155293	0.113285	10.19807	0.0000
AT_HDD	0.000211	5.39E-05	3.925791	0.0012
BRENT	-0.001700	0.000680	-2.499918	0.0237
C	6.574451	0.593649	11.07464	0.0000

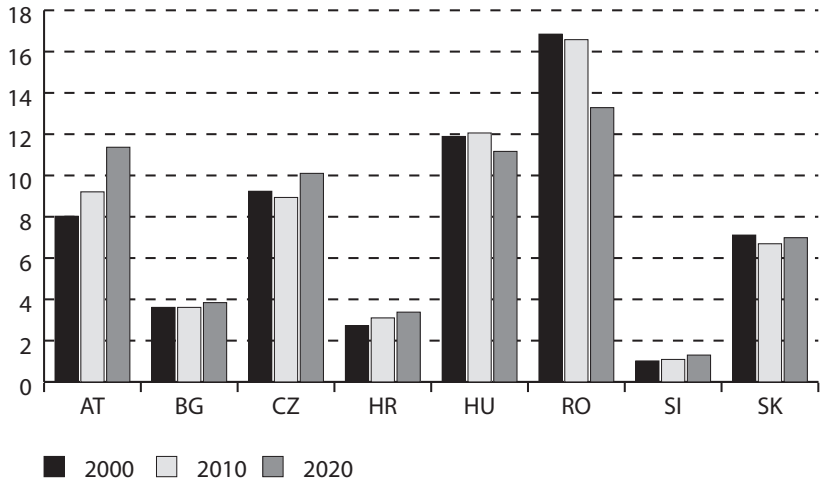
R-squared	0.897116	Mean dependent var	12.53267
Adjusted R-squared	0.877825	S.D. dependent var	0.125426
S.E. of regression	0.043841	Akaike info criterion	-3.239645
Sum squared resid	0.030752	Schwarz criterion	-3.040499
Log likelihood	36.39645	F-statistic	46.50496
Durbin-Watson stat	1.763941	Prob(F-statistic)	0.000000

Source: REKK estimation

Future values of explanatory variables have been reached the following way. For real GDP, we used the 2010-2020 forecast of the Economist Intelligence Unit, just like in the case of electricity. Heating degree-days were assumed to remain at their 1990-2009 average levels for each of the forecasted years. Finally, we assumed mildly increasing real crude oil prices, reaching 100 $/barrel in 2020.

The forecasting results are shown in Figure 3.12. Most countries in the region display a stagnating, or even decreasing expected gas consumption pattern for the next decade. Two countries stand out from this trend: Austria and Romania, although with opposite signs. Our econometric model predicts strong gas consumption growth for Austria, and considerable drops in gas usage for Romania.

Figure 3.12. Actual and forecasted final gas consumption in the CSEE region



Source: Eurostat, REKK estimation

We are inclined to treat both results as outliers, which cancel each other out on a regional level. Summing up the total expected consumption of the shown CSEE countries, we arrive at 60.5, 61.3 and 61.4 bcm for the years 2000, 2010 and 2020, respectively. In effect, our predictions imply a stagnating regional natural gas usage for the upcoming decade.

3.5.4. Assessment

We can make the following points based on our investigations regarding the natural gas consumption of CSEE countries.

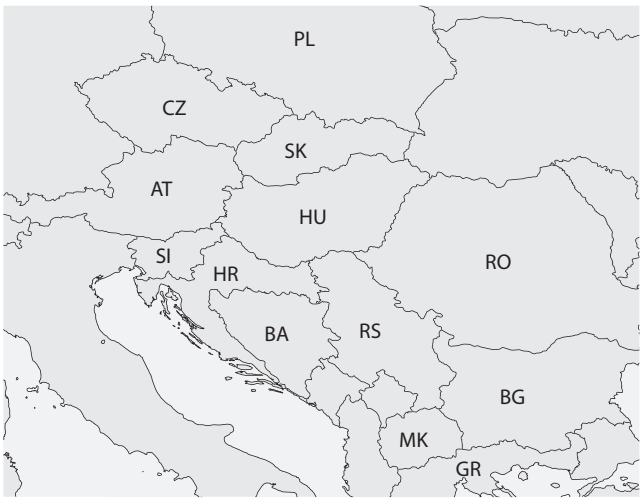
- Available data (just like in electricity) seems to be too limited to estimate statistically significant relationships for anything beyond the simplest models.
- Temperature correction based on yearly heating degree-days does matter and should be applied to the data.
- For most countries, we expect stagnating or mildly increasing gas consumption for the upcoming decade. For the region as a whole, our results imply an essentially unchanged consumption level relative to 2010.

MODELING A REGIONAL GAS MARKET IN CENTRAL AND SOUTH-EAST EUROPE

4.1. Introduction

The objective of the current study is to introduce the first version of a regional gas market model for those Central and South-East European countries, where natural gas consumption is significant. Figure 4.1 shows the geographical scope of the model; countries with country codes are explicitly included in the analysis.

Figure 4.1. The geographical scope of the regional gas model



Understanding how a regional gas market could operate is of interest for several reasons. Currently, most of these individual markets are served by Russian import sources, on which they are highly dependent. Long-term import contracts are negotiated on a one-on-one basis, highlighting permanent issues with supplier market power.

In addition, cross-border trading links are relatively weak between the markets, preventing both the access to potential alternative supplies (such as LNG, or gas from West-European markets) and the short-term efficiency-improving arbitrage of bilateral trading.

Finally, understanding the regional market is also important from the point of view of competition and regulation policy. Without source diversification and new infrastructure cooperation, price liberalization will lead to monopolistic prices on several local national markets in the region and will discredit the liberalization process. It is of paramount interest to understand the social costs and benefits of implementing certain (combinations of) infrastructure projects, even if it is recognised that such investments should primarily based on a private investment basis.

Modeling the full complexity of market behavior on a regional scale is far from being feasible, therefore we start with a relatively simple setup and aim to increase the realism of the simulations in future work.

In this study, we will describe a fully competitive market with similar technological constraints as one could find in the real world. The main difference is with respect to

the behavior of market participants. We consider every market to be devoid of dominant players, except for the Russian import segment, where prices are assumed exogenously, in line with the terms of current long-term contracts (oil-indexation). Although this simplification is unrealistic, it makes the analysis tractable and provides a useful benchmark for actual market outcomes.

Alternatively, one can also think of this study as a thought-experiment of how an ideally operating regional gas market would look like under current infrastructural conditions. In particular, the boundaries of "Eastern" vs. "Western" gas pricing influences can be sketched, and the movement of these boundaries as a result of infrastructure developments examined. In addition, we will also carry out the analysis of market-based responses to supply security disturbances, such as a temporary halt in Russian imports through a transit country.

Section 4.2 reviews previous gas market modeling efforts that are in some sense similar to ours, though none of them has the same Central and South-East European regional focus. Nevertheless, the comparisons will still be useful and allow the reader to place the current gas market model in a wider European (or world) context.

Sections 4.3 and 4.4 discuss the main elements and equilibrium mechanisms of the model in a non-technical manner. We also describe our assumptions and sources for the numerical input data.

In section 4.5, simulated market equilibrium outcomes will be shown for a reference scenario, including production, consumption, trading and storage decisions. We will also examine the effects of two alternative scenarios with the model: the installation of an LNG re-gasification terminal next to the Croatian shoreline, and an import supply disturbance of Russian gas transit through Ukraine.

Finally, we conclude the modeling exercise by discussing the limitations of the current setup and point to potentially fruitful avenues of model enhancements that are left for future work.

4.2. A short review of gas market simulation models

The European natural gas market is characterized by an increasing demand, partly driven by environmental concerns, and by decreasing domestic resources. Most countries are therefore dependent on a small number of pipeline connections to secure their supply. Hence, the need for an accurate analysis of the market situation in the region is inevitable.

The European Union, following the North American trend of liberalization, aims to implement similar legal measures for dividing the gas sellers and network operators as part of the restructuring and deregulation of the natural gas markets. The Gas Directive, implemented in 2000, has triggered considerable changes in the internal market and also led to an increased attention of economists, research centers and governmental bodies.

Complex models were developed to explain this new environment. Four such papers worth mentioning; a Complementarity Model in (Egging, Gabriel, Holz, and Zhuang, 2007), the GASTALE model (Boots, 2003), the GASMOD model (Holz, von Hirschhausen, and Kemfert, 2006) and NATGAS model (Mulder and Zwart, 2006). Although they all analyze the same issue, their focus, modeling method, geographical coverage, etc. are rather different.

Egging, Gabriel, Holz, and Zhuang (2007) present a detailed model of the European natural gas market which accounts for the issues of market power of exporters and of globalizing natural gas markets with LNG trade. The market participants being modeled include: producers, their trading arms, the so called "transmitters", pipeline and storage operators, LNG liquefiers, regasifiers, tankers, marketers (implicitly), and consumers in three sectors (residential/commercial, industrial, and power generation) via their aggregate inverse demand functions.

They assume linear demand curves by sectors, with price elasticities equal to -0.25 for the residential/commercial sector, -0.4 for industrial demand and -0.75 for power generation. Three seasons are artificially introduced to simulate real swings on the demand side; low demand, high demand, and peak.

The marketers are the only interface with the three consumption sectors and receive gas from producers via the transmitters (using pipelines) or via the regasifiers in each of the three seasons, and from the storage operators in the withdrawal seasons (2 and 3, for high and peak demand, respectively). Transmitters or regasifiers supply storage operators in the low demand season (1) when there is injection into storage. Thus, storage activities are exogenously given; not derived from the estimated prices or strategies of the players.

In all cases, except for the transmitters, players are price-takers in the production, transportation, LNG, and storage markets. The model's main focus is the representation of the global LNG market combined with the strategic behavior of the producers (via their transmitters). This requires the number of countries modeled to be large (52).

They have also designed a case corresponding to a disruption of pipeline gas to Europe via Ukraine. They do so by setting the transit capacity for the whole year equal to zero. This is a rather rough approximation of the January 2006 events, since the actual disruption lasted for a few days only. One must also keep in mind that the results of the

complementarity model are long-term equilibrium values and do not take into account short term adjustments. The only valid conclusion of this model concerning a disruption in Russian supplies to Europe through Ukraine is that it may cause a substitution effect with worldwide higher LNG consumption and prices. Clearly their approach is not appropriate to observe intra-year changes, such as modified storage activity.

GASTALE stands for: Gas mArket System for Trade Analysis in a Liberalising Europe. The goal of the analysis is to discover the effect of different assumed theoretical market structures on price developments. 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 case of Cournot traders results in a new form of energy model, that of successive oligopoly.

Considering this oligopolistic market structure, several tentative conclusions emerge. First, the model results show that successive oligopoly (so-called 'double marginalization') yields significantly higher prices and lower consumer welfare than if oligopoly exists only on one level. Second, oligopoly in the trading market (because of the high concentration of traders) results in more distortion than oligopoly in production. Third, the level of traders' profits depends on the possibilities of discrimination on the border prices. Fourth, when the number of traders increases and assuming an oligopolistic downstream structure, end-use prices converge to prices corresponding with perfect competition.

In general, the economic literature (Tirole, 1988) derives that in the case where there is both upstream and downstream oligopoly, vertical integration between upstream and downstream is favorable for consumers. This conclusion is confirmed by the results of the paper.

The difference between the competitive benchmark price and the prices derived from certain strategic models is not unambiguously relevant. Assuming oligopolistic, price discriminating traders for example results in a price difference of 1% on average in the modeled countries. The estimates also strongly depend on the assumed elasticities, which are admittedly dated (based on a study by Pindyck (1979)). The number of traders on the other hand has an obvious and significant effect.

Since the liberalization process will lead to a further increase in the number of traders present in the market, according to these results, it seems appropriate to apply the perfectly competitive model to study the natural gas market of Europe.

Their geographical coverage is limited to six countries: Austria, Belgium, France, Germany, Italy, the Netherlands, Spain and the UK. Within a country, natural gas is consumed in three main sectors; households, industry and power generation. The price elasticity of the linear demand curve for each country and sector is specified at the 1995 price-quantity pairs.

Given the paper's primary interest for market structures, it simplifies reality in many aspects. It assumes the domestic production to be an exogenous value instead of including it in the optimization and does not consider infrastructure capacity limitations, which may actually distort the outcome to quite some extent.

GASMOD is similar in spirit to GASTALE. It structures the European natural gas market as a two-stage-game of successive imports to Europe (first stage, upstream) and trade within Europe (second stage, downstream).

They chose a strictly decreasing, non-linear iso-elastic demand function. The demand elasticities are assumed to be rather low in absolute terms (-0.7 for Western Europe, -0.6 for Eastern Europe) which reflects a certain inelasticity of the natural gas demand. They assume the price elasticity to be higher (in absolute values) by 0.05 for countries where natural gas does not have a large share in energy consumption, i.e., Spain/Portugal, Sweden/Finland, Poland, Balkan, and Greece. Thus they assume that switching to alternative fuels is easier for countries where dependency on natural gas is lower.

As suggested by economic theory they find larger quantities and lower prices in the market scenarios with perfect competition compared to the Cournot scenario. This paper also claims that the liberalization of the European gas sector is supposed to lead to a competitive downstream market. The comparison with real world data indicates that the current state of the European natural gas market is better represented by a scenario of Cournot competition for most countries. Deviations for some countries (e.g., the UK, Sweden, Finland) suggest that modeling their markets with competitive behavior might be more appropriate, be it in a competitive fringe for smaller exporters or traders, or as competitive market because of limited access to the market (which leads to unrealistically high mark-ups) or in the case of the UK because of its already successful market liberalization.

It is worthwhile to note that they concentrate on the trade relations in a yearly perspective; hence, market stages such as storage which are relevant for inter-seasonal supply management are not included in the analysis.

The NATGAS model computes 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). The model is run using time periods of 5 years, extending over 10 periods. Outcomes are considered up to 30 years in the future.

Linear demand functions are assumed on the consumption side. An exogenous growth of gas demand is incorporated in the model, which affects only the slope parameter, making it time dependent. In the baseline scenario they use an elasticity of 0.25. Annual demand is distributed over winter and summer in a 65 to 35 ratio. The EU-15 countries are included separately, but the consumption of Eastern Europe only has an aggregate value.

The production sector is modeled in detail; integral long-run production costs vary from around 1 cent per cubic meter for the large Groningen field in the Netherlands, to 4-9 cents for off-shore fields in the Dutch, English and Norwegian North Sea, and over 10 cents for Russian production.

They decide not to assume a certain market structure in production, but two major influential components are introduced; the number of players and the degree of strategic interconnections. The second determinant of competition is the conjectural variations parameter (which may differ between firms), which is a generalized version of Cournot competition. In the baseline scenario, this value is put at 0.25, but as it has large implications on the model results, its variation in various scenarios are explored. Further segments of supply are competitive.

The paper's main result is a detailed price forecast for different demand elasticities (between -0.18 and -0.65), demand growth rates, conjectural variations and LNG prices.

The aforementioned four models have one issue in common; the main interest for Western Europe. Find their comparison in Table 4.1 below.

Table 4.1. Summary of existing gas market models

	Complementarity Model	GASTALE	GASMOD	NATGAS
Main focus	globalizing natural gas markets with LNG trade	analysis of theoretical merket structures	possible effects of liberalization on trade	long-term forecasting
Geographical coverage	global (52 countries)	8 Western-European countries: Austria, Belgium, France, Germany, Italy, Netherlands, Spain, UK	EU-15 countries, Poland, Czech Republic, Slovakia, Hungary, FYugoslavia, Romania, Bulagaria, Baltics, Turkey	EU-15 and Eastern Europe aggregated
Timeline	5 seasons	1 year as 1 season	1 year as 1 season	5-year-long periods
Demand	linear, sectoral	linear, sectoral	iso-elastic per country	linear by country
Market structure	mostly price-takers, exporters have harket power	oligopolies on two levels	oligopolies in two levels	generalized imperfect competition
Storage	exogeneously given	not modelled explicitly (part of the delivery cost)	not inluded	price-taking profit maximizers

The current issues of Central and South-Eastern Europe need a different approach in many aspects. Clearly, the geographical scope must be extended. Given the structural differences on the demand side among the region's countries, it is essential to incorporate three sectors: residential-commercial, industrial and power generation. We do so by calculating the average of the sectoral price elasticities, weighted by the market shares of the sectors in the given country. Having determined the aggregate elasticities, we estimate each country's monthly demand curve using a linear functional form. This method seems more adequate to describe consumers' behavior than the models published so far.

The time-line should be more detailed as well. Since the stability of supply is of main interest, monthly data are desirable to be able to show e.g. the effects of a disruption of pipeline gas to Europe via Ukraine. If one wants to see the implications of such an event on all the main players of the natural gas market, it is vital to include storage activity as an endogenous part of the model as well. Therefore, injection and withdrawal cost and capacities are incorporated into the optimization.

Many choices are available for modeling the market structure of production, transmission, storage and trade. One may even think of a multi-stage game. It is not clear though, which version of the theoretical strategies are the most appropriate. It is obvious

from the pages above that the different oligopolistic models may be close to the reality of certain countries, but they yield unrealistic outcomes for many. As the example of the UK suggests, perfect competition is the best way to estimate market outcomes in the liberalizing Europe. Effective regulation also leads to the same outcome, as it is general in the case of storage, which is typically sold under Third Party Access (TPA). Hence, we decide to use perfect competition in our model, which can serve as an important benchmark.

4.3. The Central and South-East European gas market model

We model the natural gas markets of Central and South-East Europe to be able to explain price developments in the region and the effects of possible disruptions in the pipeline network. Therefore we choose to include all important segments of the market from sectoral demand through transmission capacities till optimal storage activities.

A one-year modeling period is chosen and is divided into 12 seasons (months) so that intra-year swings in demand and changes of supply, i.e.; production, transmission and storage could be illustrated. Note that restricting the timeline to 1 year is probably with little loss of generality; since we assume storages to be full in season 1 and 12 as well, the model can be interpreted as a dynamic one due to its cyclical nature.

A linear demand curve is assumed for each country and for each season of the year. To allow for structural differences among countries, we determine the price elasticity of demand as the weighted average of sectoral elasticities, using each sector's market share as weights.

On the supply side, several constraints have to be taken into account: Producers face a maximal extraction capacity, the volume of international trade heavily depends on the pipeline grid's capacity and storage operators also have limited capacities to use for inter-seasonal arbitrage. The final price of natural gas in the market – besides demand – is obviously influenced by the costs of the supply side; such as extraction cost, transmission cost, injection cost and withdrawal cost. All these figures are explicitly included in our analysis.

Applying the structure of Table 4.1, our setup can be summarized as it follows in Table 4.2.

Table 4.2. Model characteristics

Main focus	Detailed market simulation for CSEE
Geographical coverage	13 countries and 5 main import sources
Timeline	12 months per year
Demand	Linear, elasticity is weighted average of sectors
Market structure	Perfect competition
Storage	Price-taking profit maximizers

Given our approach to model the market structure with perfect competition, the individual strategies of the players can be ignored – as suggested by microeconomic theory. Hence the market can be modeled as a whole, by maximizing the total welfare of consumers and suppliers together. This leads to a simple yet detailed regional partial equilibrium model with tractable effects of factors on the final prices and sales.

The results are derived through the behavior of the market participants. We summarize their activity in the following subsections.

4.3.1. Producers' behavior

For the interpretation of the producers' decisions, it is useful to distinguish two types; local and foreign producers. The problem of the local producers is very simple: If the market price of natural gas in the given local market is not lower than the extraction cost, it is worth increasing the production. Note, that this is constrained by the maximum extraction capacity. On the other hand, if the extraction cost exceeds the local market price, then two options are available: They either decrease their output – thereby driving up prices – or they can find a more profitable foreign market. This leads us to the problem of the foreign producers.

Selling gas into a foreign market is a more complex process than the one above. Besides market prices, physical factors and other induced costs also play an important role. First of all, cross border transmission capacities obviously limit their freedom. Furthermore, additional transmission costs and fees must also be taken into account.

Transactions are eased by traders. Their actions play a prominent role in the smooth functioning of the market.

4.3.2. Traders' behavior

The development of a single international market crucially depends on traders. As already mentioned above, we assume perfect competition; all traders operate with zero cost and at zero economic profit. They still perform the most elaborate activities among all market participants.

Producers' export decisions are greatly facilitated by traders. Their primary goal is to get information about international prices so that they can import gas from the cheapest possible sources. Again, transmission capacities and costs influence their choice.

Given their knowledge, they have the capability to use inter-seasonal arbitrage opportunities to generate higher profits. Thus, it is also their core activity to utilize storages. In the low-demand season, with lower prices, they buy gas not only to fulfill consumers' demand but also to fill up the storages. During peak demand they have the chance to use these inventories to meet higher consumption needs and sell the stored gas at a higher price.

Observe that perfect arbitrage is not possible for several reasons. First, injection into and withdrawal from the storage facilities are costly to carry out. Second, storage capacity is typically lower than the amount needed for that. Finally, storage is not only used for arbitrage but for strategic reasons as well. Hence, the difference between winter and summer prices does not disappear.

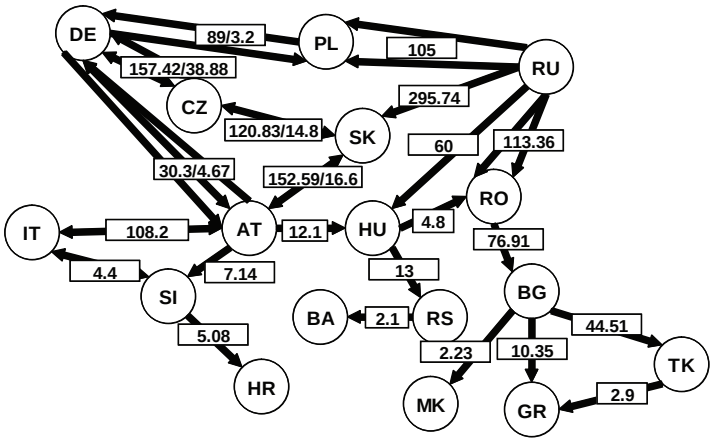
Given the strategies of the producers and traders and the demand functions derived from all sectors' needs, one can derive the equilibrium prices for all regional markets. This partial equilibrium model can then be used to simulate different market scenarios. The impact of investments into the infrastructure (such as establishing new pipeline connections or storages) or a disruption in a connection can be assessed.

4.4. Description of input data

4.4.1. Data on pipelines

The data was gathered from ENTSOG Capacity Map as of June 2010. The data was given in GWh/day it was converted to MJ given the official Net Calorific Value (NCV) at the cross-border points and switched to Nmcm/day format with reference combustion temperature 25 C. Information of cross-border point NCV was gathered from ENTSO-G Transparency Platform's Operational procedures section.

Figure 4.2. Cumulate cross-border capacities, direct/reverse flow (mcm/day)



Source: REKK data collection from various sources

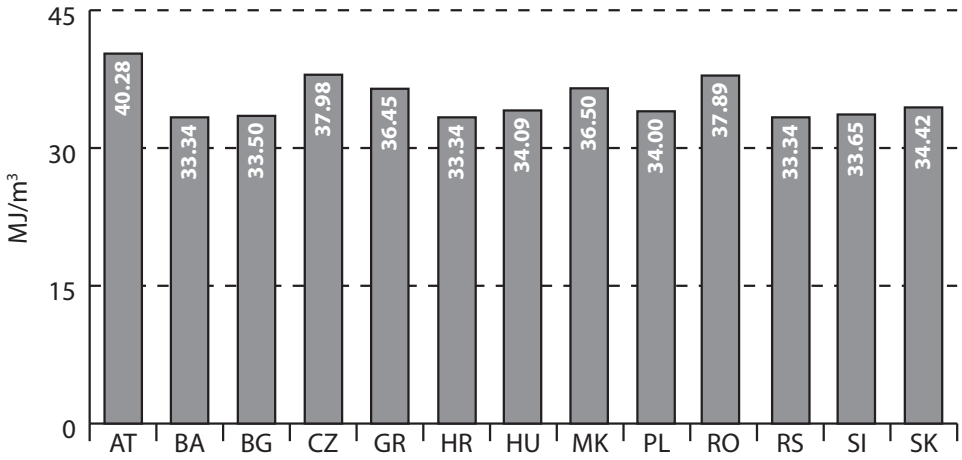
4.4.2. Net calorific values

For each country the national gas system's inner NCV was taken into account. The data was collected from national TSO, Energy Regulator publications or Ministerial decrees. In case of Macedonia the NCV value was quoted in BHPBilliton's background study, while for Croatia the data was gathered from EiHP, and considering Bulgaria ENPRO data was used.

The NCV values fall between 33.368 MJ/m^3 and 40.280 MJ/m^3, where the lowest values were observed in the gas markets of former Yugoslavia and highest values in markets closer to the Western European markets, such as Austria and the Czech Republic. Ro-

mania that covers the majority of its demand from domestic production also has a relatively high net calorific value of 38 MJ/m³.

Figure 4.3. Net Calorific Value by Country (MJ/m³)



Source: REKK data collection from various sources

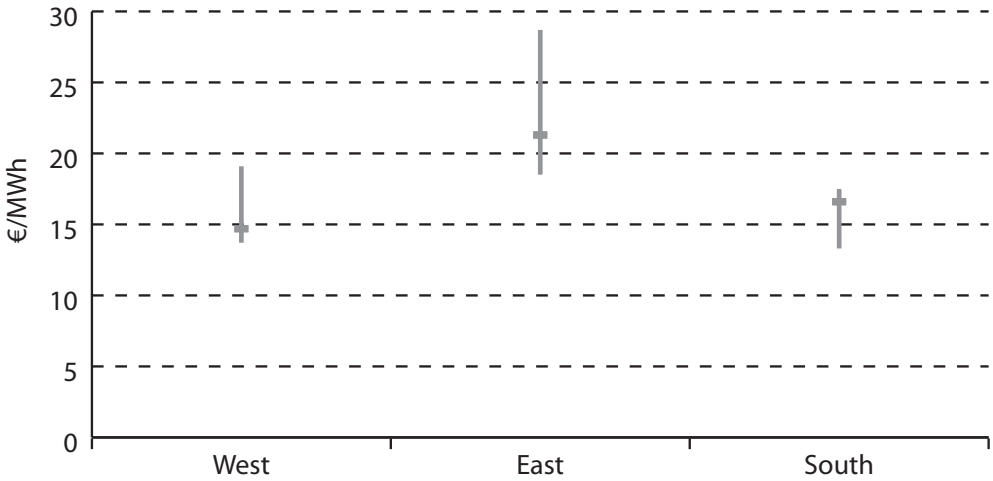
4.4.3. Import sources

The current Eastern natural gas procurement procedure is opaque. The import agreements are not public, therefore the amounts and take or pay obligations are available only through secondary sources like public and expert announcements.

Figure 4.4 shows different procurement prices. In the diagram, West stands for prices that are available on the Western border of the region from Germany and Italy. East stands for Gazprom prices to the region, while South depicts available prices from Turkey and the Greek LNG terminal. The import prices are given in €/MWh as of December, 2009. Price information was available from national regulators in Hungary, Bulgaria, and Romania in USD/mcm format, that were cross checked with IEA (USD/MBtu) and ERRA (USD/GJ) data for the mentioned period. In cases when it was necessary

cross-border net calorific values were used to convert the values in €/MWh. USD was converted to € given the 2009 Q4 average European Central Bank exchange rate.

Figure 4.4. Entry Point Import Prices December, 2009 (€/MWh)



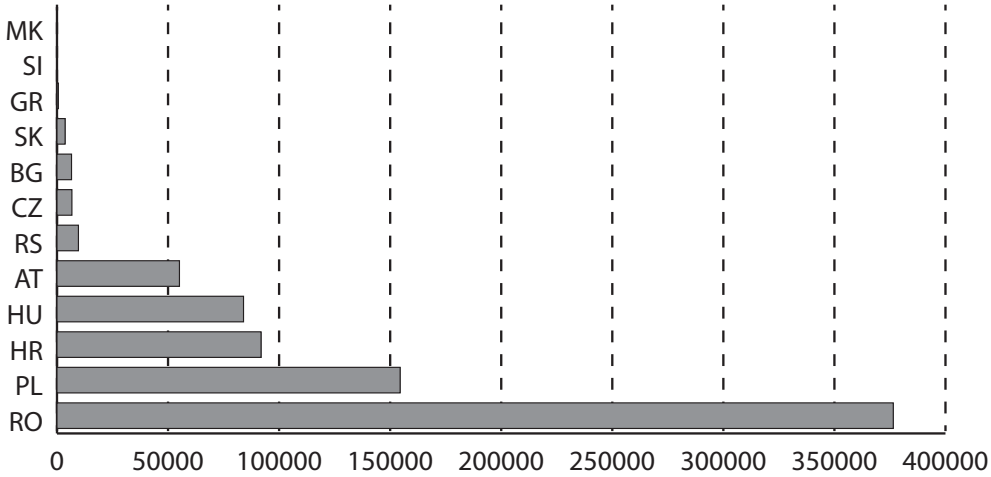
Source: REKK data collection from various sources

4.4.4. *Production data*

Natural gas production data was obtained from Eurostat database in TJ/year, NCV as of 2008. In case of non-EU members, national Statistical Bureau data was used for 2008 (Bosnia & Herzegovina, Serbia, FRY Macedonia). Only aggregated data was available, there was no information disclosed about each natural gas field production patterns (e.g. minimum and maximum capacity, operational costs), therefore aggregated data was

used for each country. It was assumed that production costs are below import costs and that domestic fields are producing at their maximum capacity (2008 total production).

Figure 4.5. Natural gas production in TJ/year (2008)



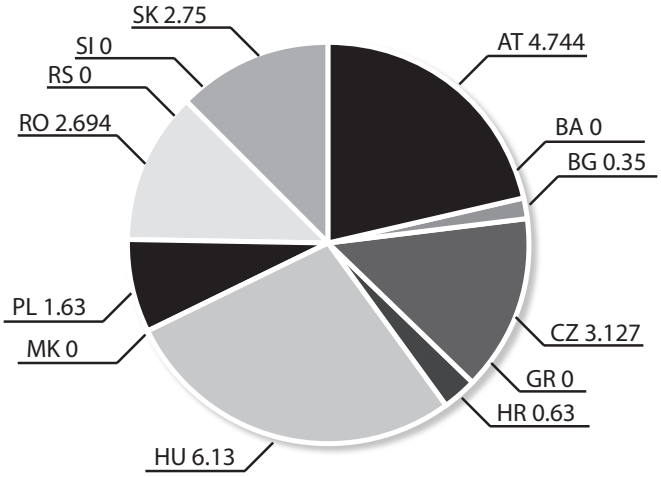
Source: Eurostat

4.4.5. Gas storage data

Gas storage working gas capacity data was acquired from GSE Map Dataset, August 2010 in mcm/day for operational capacity and bcm/year format for storage capacity. No ongoing developments were considered, only available capacities were put into the

model. Some companies did not provide a capacity breakdown for separate gas storage, just published an overall data (Czech Republic, Romania).

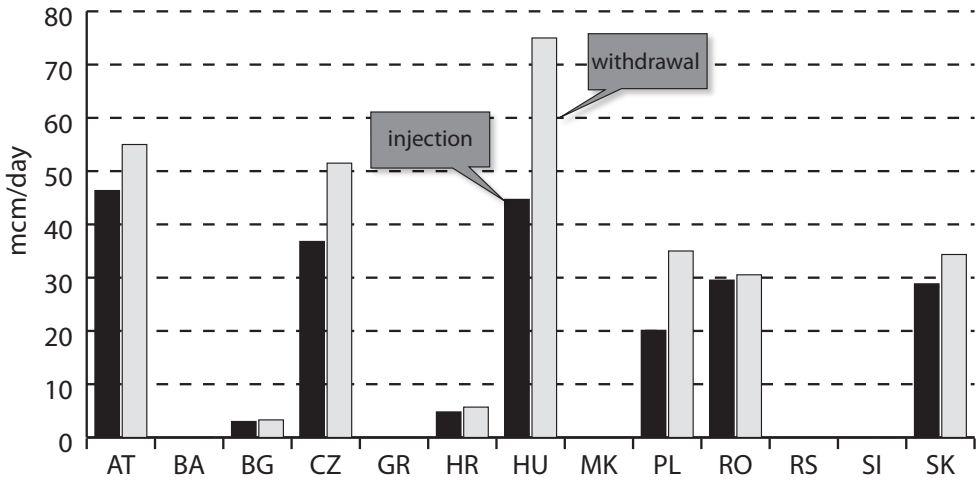
Figure 4.6. Natural gas storage capacity by country in bcm (August 2010)



Source: GIE

2010/2011 gas year injection and withdrawal costs were gathered from storage owners or national energy regulators. Capacity availability fees, storage fees, and monthly coefficient factors were not considered in general. However, in case of Slovakia, Czech Republic and Austria only accumulated price was available that included an average capacity availability fee and a yearly storage cost. In all cases the collected price data was converted to €/mcm. Mcm conversion was based on national gas network system official net calorific value. Currency conversion was based on ECB's average exchange rate of September-October 2010 period.

Figure 4.7. Aggregate gas storage injection and withdrawal capacity mcm/day (August 2010)



Source: GIE

4.4.6. Demand data

As mentioned before, we used linear demand functions to approximate the actual monthly natural gas demand of the modeled countries. The reference consumption level was that of 2008 (mostly pre-crisis), divided up to 12 months according to a typical seasonal consumption pattern. "Season 1" in the model is the month of September, as this normally the time of the year by which storages are filled up.

The monthly demand functions were anchored to the (wholesale) price of 20 €/MWh, and demand elasticity was calculated as a weighted average of three different values: -0.1 for households and services, -0.2 for industry and other segments, and -0.4 for the power sector. The weights corresponded to the consumption share of each segment in 2008, and thus were unique to each country. The weighted price elasticity parameter varied from country to country between -0.17 and -0.33, with a simple average of -0.23.

4.5. Modeling results

In this section, we discuss the results of the simulation runs. Each run returns a simultaneously optimized 12-month production-consumption-storage-trading schedule (from September to August) for all countries and import sources.

Although the structure of the model has been introduced before, it is worth repeating the essence of the optimization performed by each market player, especially with regard to its intertemporal (month-to-month) nature.

Producers operate between a minimum and maximum production constraint in each month; however, the constraints are independent across months. Therefore, their production decision in October, for example, has no direct effect on their production possibilities in any other month.

Market prices in each CSEE country and each month are such that they equalize supply and demand, taking into account stock changes of stored gas and net imports. Domestic 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 (zero in this case). 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 demand for gas in that month.

Consumers have no real decision to make in the model. Their behavior is governed by the assumed demand functions, which set a monthly consumption level as a (declining) function of the domestic market price.

Traders in the model are the ones performing the most complex optimization procedures. First, they decide about exports and imports, based on prices in each neighboring market and the available cross-border transmission capacities to and from those markets, including countries such as Russia, Germany, Italy, and Turkey, and LNG markets, which are not explicitly included in the supply-demand equalization.[1]

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 and withdrawal costs, the arbitrage opportunity will be present, and traders will exploit it.[2]

The similar intertemporal 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.

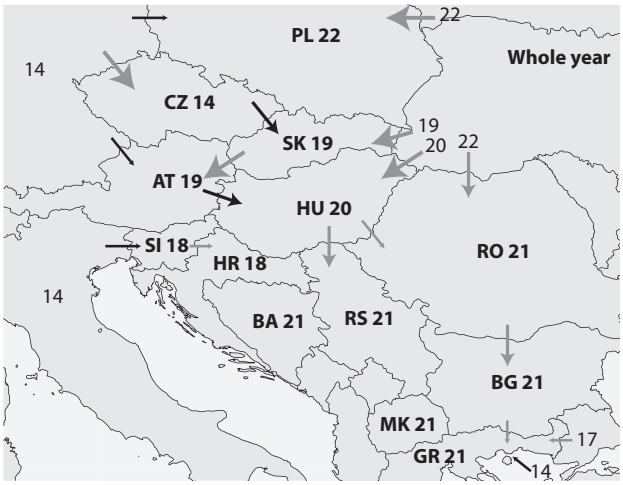
[1] For example, we allow for cross-border gas trading with Germany, but we take the German market price as given from outside the model and assume that it is not affected by gas trading with the CSEE region

[2] Traders also have to make sure that storages are filled up to their maximum level at the end of the year, since we do not allow for year-to-year stock changes in the model.

4.5.1. *Reference scenario*

In the reference scenario, all input parameters correspond to those described in the section "Description of input data". The output of the model contains a set of simultaneously determined and mutually consistent values for domestic production, consumption, market prices, storage injection, storage withdrawal, and cross-border trade for each market in each month of the year. For the purposes of the study, we will only present a selection of output data that is sufficient to demonstrate the overall picture arising from the market simulations.

Figure 4.8. Modeling outcomes for the reference scenario, yearly average prices



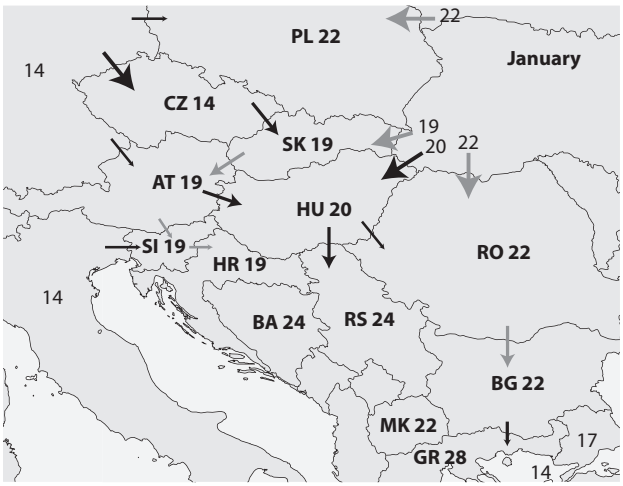
Source: REKK simulations (prices in €/MWh)

Figure 4.8 shows the yearly average results of the 12 monthly markets. The numbers in bold are the consumption-weighted yearly average prices in €/MWh. The regular numbers are the respective import prices, which are assumed to be exogenous to the model. The width and direction of the arrows represents the intensity and direction of gas trade across those borders where it is significant. Black arrows (as between Austria and Hungary) denote a bottleneck in the transmission system, whereas grey arrows (e.g. from Hungary to Serbia) are at borders with free trading capacity remaining.

As an example, let us look at the situation of Hungary. Yearly average gas prices in the country within a competitive regional gas market and the current infrastructure constraints would still correspond to the import price at the Ukrainian border, simply due to the overwhelming share of Russian imports through Ukraine. Even though gas is somewhat cheaper in Austria, the capacity of the HAG pipeline is not enough, even in its fully exhausted state, to decrease domestic prices in Hungary. It is also visible that

exports flow towards Romania and Serbia, both of them being slightly higher priced countries.

Figure 4.9. Modeling outcomes for the reference scenario, prices in January



Source: REKK simulations (prices in €/MWh)

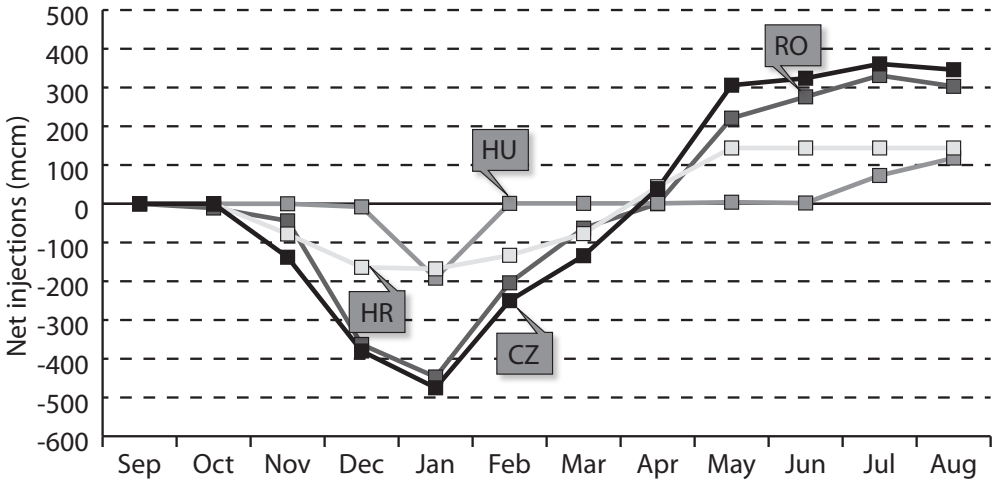
Figure 4.9 shows the market situation in January only. Prices in the Balkans tend to be higher, reflecting some relative shortage of gas. Even Slovenian and Croatian prices are close to the regional average, whereas the Czech Republic is the only country in the region that benefits from the proximity of lower priced Western European markets. All pipelines in and out of Hungary are operating at full capacity as well.

The role of gas storages for seasonal arbitrage is shown in Figure 4.9. The overall pattern of withdrawals in the winter and injections in late spring and summer are nicely illustrated in the graphs. However, the intensity of storage utilization is much lower in the simulations than in real life, for the following reasons.

First, the seasonality of consumption is modeled at the level of monthly averages, which still masks a large part of the daily and weekly winter demand fluctuation, the very reason why storages are maintained.

Second, storages are also useful for balancing unexpected demand changes, as well as performing short term arbitrage in the market (or across markets). Such uncertainty is missing from the model.

Figure 4.10. Gas storage utilization by month and country



Source: REKK simulations

4.5.2. Transit disturbance scenario

The gas crisis of January 2009 has sparked a lively debate about the security of Russian gas supply to Central and South-East European countries. The immediate cause of the crisis was a gas pricing dispute between Russia and Ukraine which resulted in a blockage of the transit pipelines towards Slovakia, Hungary and Romania. For about two weeks, natural gas flows have dried up and the region had to manage with whatever gas it could squeeze from domestic production, underground storages, and remaining cross-border capacity.

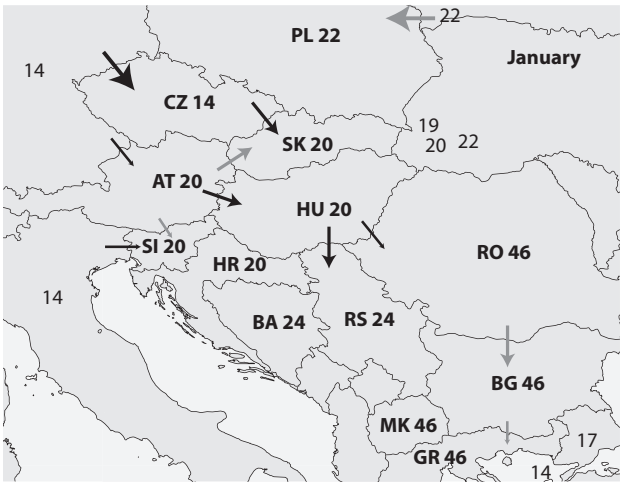
In the past 20-22 months since the end of the crisis, new infrastructure has been put into place (such as the "strategic" gas storage in Hungary with 25 mcm/day withdrawal and 1.9 bcm working gas capacity) and new EU regulations have been created to mitigate the effects of another supply disturbance in the future. Within 3-4 years, all interconnectors must have reverse flow capability and additional measures will have to be developed to comply with the "N – 1" standard.

We have run model simulations to see the effect of a month-long gas supply disruption in January in a liberalized and competitive Central and South-East European regional gas market. In effect, we took the reference scenario as the starting point and unexpectedly reduced the transmission capacity of the Ukraine-Slovakia, Ukraine-Hungary and Ukraine-Romania interconnectors for the whole of January. The term "unexpectedly" is potentially important: if large consumers had more time to prepare for the crisis, they could take measures to adjust their consumption decisions (such as a delay of holiday close-downs) which could mitigate the subsequent price effects.

The results of the simulations are shown in Figure 4.11 and Figure 4.13 for the month of January only (the market quickly returns to normal afterwards). Comparing Figure

4.9 and Figure 4.11, we see that prices in Central Europe are more or less unchanged, reflecting the resilience of the present infrastructure against disturbances. Prices rise slightly in Slovakia, Austria and the Western Balkans, and the Slovakia-Austria interconnector switches to reverse flow to supply Slovakian customers.

Figure 4.11. Modeling outcomes for a Ukrainian transit disturbance scenario in January



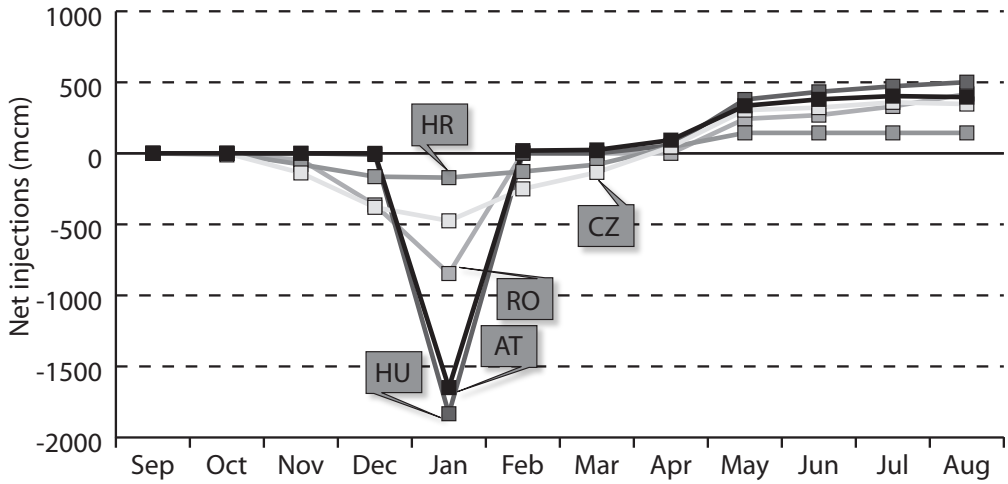
Source: REKK simulations (prices in €/MWh)

Figure 4.12 shows the reaction of the storage infrastructure to the lack of Russian imports. A comparison with Figure 4.10 is instructive: storages in Romania, Hungary and Austria are being emptied close to full capacity to serve domestic demand and to provide assistance across the border to Bulgaria, Serbia, and Slovakia, respectively.

As we can see in Figure 4.11, this is still not enough to avoid supply disruptions in the Eastern part of South-East Europe. Market prices more than double in Romania, Bulgaria, Macedonia and Greece, which is a modeling shorthand for demand curtailment

in these countries. (Higher prices lead to consumption reductions through a relationship embodied in the demand curve.)

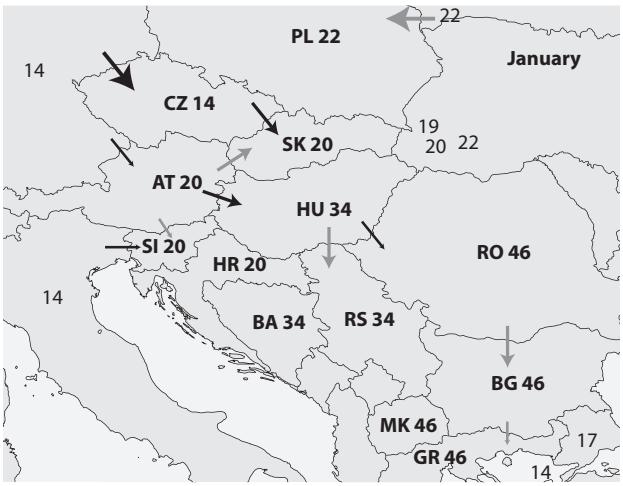
Figure 4.12. Gas storage utilization in a transit disturbance scenario



Source: REKK simulations

There is a certain lack of consensus regarding the necessity and benefits of the aforementioned strategic gas storage in Hungary, which poses an interesting modeling question. We have run the transit disturbance simulation without assuming the availability of the strategic storage, and looked at whether outcomes are any different across the region. Figure 4.13 represents the results.

Figure 4.13. Ukrainian transit disturbance scenario without strategic gas storage in Hungary (January)



Source: REKK simulations (prices in €/MWh)

As the figure shows, prices in Hungary, Serbia, and Bosnia and Herzegovina would increase considerably without the strategic storage asset. Withdrawal capacity in January decreases by 333 mcm in Hungary, necessitating the price rises to cut back on consumption by a similar amount. Due to the lack of significant interconnections, prices both in the Eastern Balkans and the Western part of the CSEE region are unchanged.

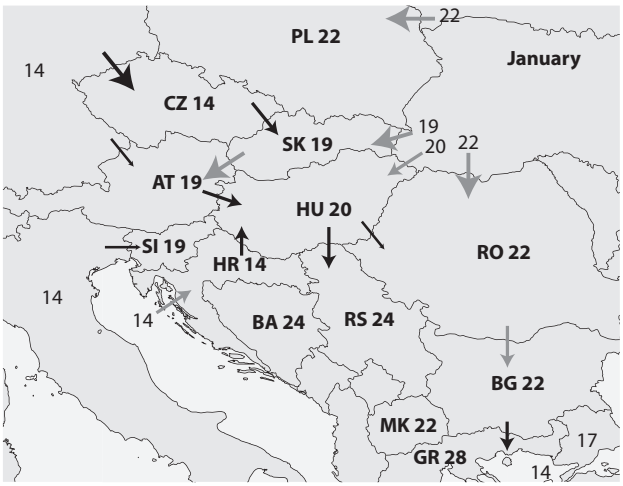
4.5.3. LNG in Croatia scenario

Another interesting infrastructure scenario is that of a new LNG re-gasification terminal in the Adriatic Sea, next to the Croatian shores. Although the Croatian market itself is relatively small to support an LNG facility, new interconnections with Hungary (and possibly onto Slovakia), for example, could facilitate the regional uptake of gas.

Consequently, we perform a market simulation with a 25 mcm/day LNG terminal in Croatia, behaving like another import source, with prices equal to West European levels (14 €/MWh). We also assume the presence of a bi-directional interconnector between

Hungary and Croatia with a 15 mcm/day transmission capacity. Modeling outcomes are presented in Figure 4.14 (January) and Figure 4.15 (entire year).

Figure 4.14. Modeling outcomes for a Croatian LNG scenario in January



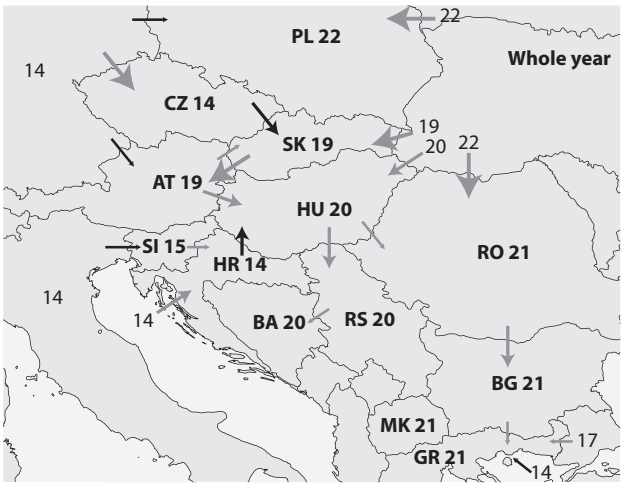
Source: REKK simulations (prices in €/MWh)

As both figures show, market prices in most countries remain unchanged throughout the year, including the highest demand month. Not surprisingly, prices in Croatia do decrease to LNG-levels, and Slovenia also derives benefits from the proximity of the additional import source.

More unexpectedly, market prices in Hungary remain at 20 €/MWh despite the low-priced Croatian imports. The intuition behind this result is simple: market prices are set by the "marginal" supplier, i.e. the most expensive one which is needed to supply demand at any given price. Even though about 5.5 bcm of natural gas could be imported

to Hungary through Croatia, Russian gas would still remain necessary to serve total demand (including exports to Romania and Serbia).

Figure 4.15. Modeling outcomes for a Croatian LNG scenario in the whole year



Source: REKK simulations (prices in €/MWh)

This explanation, however, also suggests another channel by which an alternative gas source *could* have a dynamic price reducing effect. The model works by assuming Russian import prices to be given exogenously, which might be a reasonable conjecture under current conditions, but is clearly untenable when the infrastructure changes substantially.

When faced with a 50 percent market loss due to competition from LNG, Russian prices would likely be reduced relative to the present oil-indexation formula, leading to actual reductions in gas market prices in Hungary, and to some extent, across the Central and South-East European region as well.

4.6. Conclusion and model extensions

We have introduced a numerical simulation model for the Central and South-East European natural gas market. The model captures the main features of supply, demand, transportation and storage, and produces sensible equilibrium results approximating the outcome of a fully competitive sector. In addition, it makes the analysis of various infrastructure developments possible, and it provides a market-based assessment of supply security events. Two such scenarios, a transit disruption through Ukraine and a new LNG terminal in Croatia, have been examined.

Naturally, the market model is somewhat elementary and abstracts from a large number of important real-life features at this stage. First of all, a more complex understanding of market players' behavior might be necessary, including the appreciation of strategic moves by large suppliers. Second, several cost elements (transmission, storage, production) are only "first approximations" and should be refined in later work. Finally, the time dimension of the model might need to be reconfigured to allow for sharper peak load effects on prices and infrastructure utilization.

4.7. References

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Generation Investments Under Liberalized Conditions In The Central And South-East European Region

5.8. Introduction

A key component of long term supply security in electricity is the sufficient amount of investment into electricity generation. There is an ongoing discussion about whether the market conditions that have been created in Central and South-East Europe provide the proper investment incentives or not. This study seeks to contribute to this discussion by collecting the latest publicly available information on the state of expected new investments in the upcoming decade, and critically evaluate this information in light of how much new capacity would be needed until 2020 from an economic point of view.

Our findings do not refute the claim that liberalized markets and long term supply security in electricity can coexist. We find that if anything, investment plans are overabundant in our region, and a considerable portion of them should probably be cancelled, or delayed until they are really needed.

It must be pointed out, however, that our analysis was carried out under somewhat special conditions. First, electricity consumption has taken a strong hit with the recent economic crisis, and isn't likely to recover very soon to its previous path. Second, as we will argue in detail, the 2020 renewable targets of the European Union absorb the remaining consumption growth that market-based new generation capacity could serve. If national renewable targets for 2020 will be met, there will actually be less room for the deregulated market than in 2010.

Under these conditions, new generation can at best be a substitute for retired plants. Although power plant portfolios are quite aged in many Central and South-East European countries, the decommissioning of old units is not expected to generate a large scale demand for new capacities until 2020.

The third – and final – special condition of the region is the continuing central role of the state in influencing electricity sector investments. Although the government may not be the most significant investor any more, it still has a strong effect on private investment through its regulatory actions and its long term energy sector strategy. Therefore, a purely market-based evaluation of long term regional supply security in electricity may be incomplete in the foreseeable future.

In the first part of this study, we summarize the dominant literature related to power generation investments under liberalized conditions and discuss the main controversy regarding energy-only markets, versus capacity remuneration mechanisms.

In the second part, we examine the present power capacities in Central and South-East European countries, including Austria, Bulgaria, Croatia, Czech Republic, Hungary, Serbia, Slovakia, Slovenia and Romania. We also discuss significant known power investments in the region, as well as the expected growth of renewable power generation and electricity consumption.

In the last section, we use a regional electricity market simulation model to calculate whether new fossil-fuel capacities could earn adequate return on investments under the expected market conditions as foreseen until 2020. At the end, we summarize our main results.

5.9. The investment problem and the proposed policy remedies in electricity markets

In the past decades electricity markets have started to be restructured throughout the world. This process raised many questions about the future of the industry, including whether there will be adequate investment in generation capacities without regulatory intervention. In the following, we first discuss the essence of this generation adequacy problem in the new market structure and then describe the proposed remedies.

5.9.1. The market after restructuring

In the last decades, the regulatory approach towards the electricity sector has changed in many parts of the world. The aim of this unbundling process has been to replace vertically integrated companies with a new power market structure. In the eighties, important technological advances took place (such as the advent of CCGT units), which meant that from that time on only the network was considered to be a natural monopoly. A new market participant, the system operator was entrusted with the responsibility to manage the transmission grid and maintain its reliability. One of the biggest expectations of the restructuring was that investment decisions would become more rational due to competition in the generation segment.

Previously, investment decisions were made centrally, by the government. As such, on one hand it was easier to maintain generation adequacy, but on the other, power plants were not necessarily built and operated at the lowest cost. The essence of restructuring is to move from a very reliable and expensive system to a less expensive one with the same level of reliability.

It is the duty of the system operator to guarantee short-term reliability: it contracts reserves and organizes a balancing market to achieve this goal. While generation adequacy, in other words: long-term adequacy, is expected to be provided by investors.

However, guaranteeing generation adequacy is more difficult in the restructured market, because unbundling implies more uncertainty (e.g. regarding prices) than experienced in the centrally planned structure where everything was heavily regulated.

5.9.2. Short-term reliability versus long-term adequacy

Finon and Pignon (2008) compare different capacity provision systems and define short term reliability as „the ability of the electric system to withstand sudden disturbances".[1] This is considered to be a technical aspect that should be dealt with by system operators as it is a public good possessing both distinct traits of such goods: (1) non-rivalry (everybody benefits from system reliability) and (2) non-excludability (at the moment, it is impossible to provide self-tailored reliability to everyone).

Long-term adequacy is more a question of capacity adequacy, which is „the ability of the electric system to supply the aggregated electrical demand and electricity requirements of consumers at all times".[2] Strangely, long term adequacy is considered to be

[1] pp 1, Finon and Pignon (2008)

[2] Finon and Pignon call the long-term adequacy long-term reliability problem. However, we prefer to use adequacy instead of reliability to avoid confusion. pp 1, Finon and Pignon (2008)

public good too in many cases. The main reason is that investors do not have any incentive to invest in capacities that they can never use, as they would never profit from their existence.

The solution to the short-term reliability problem is clear-cut. It is provided by the system operator who contracts the reserves that are needed to maintain system reliability. However, generators make their investment decisions based on price signals. Thus, everything that happens on the spot markets, including short-term reliability provision mechanisms, affects long-term adequacy. In the following we focus on the long-term adequacy problem in detail.

5.9.3. The problem of long term adequacy

The missing money problem

There is a wide consensus about the root of the long-term adequacy problem which in other words is the problem of inadequate investment in the long run. Hogan (2005) called it the "missing money" problem. The key idea is that when there is scarcity in the electricity system the prices will increase. However, because of the existence of price caps (imposed by regulators) prices in fact can only increase up to a certain threshold. This implies that generators fail to cash a certain amount of profit and end up having insufficient funds to cover their previously incurred investment costs.

This problem is even more severe during peak load when the opportunity cost of electricity should be reflected the most (the risk of system failure is higher in those moments, thus the demand side is more willing to pay for the electricity). As prices cannot signal this scarcity, other signals should be constructed for shortage situations.

From this reasoning it seems obvious that for Hogan the most clear-cut solution would be the suspension of price caps. Despite all of this, price caps exist. Explicit price caps are more common in the U.S. than in European markets. However, Europe is more characterized by implicit price caps. For instance when prices increase politicians tend to emphasize their high level placing pressure on regulators to introduce measures to mitigate them. Another example is the use of regulated retail prices.

As we can see, Hogan (2005) finds the roots of the long-term adequacy problem in the short-term reliability problem. According to this reasoning, in the short-term (or on the spot markets) prices do not rise high enough; therefore in the long run insufficient revenue is generated to cover costs. Thus, if short term problems would be solved, long-term adequacy problem would cease to exist as well, because the sole problem in the market design is the inappropriate short-term reliability provision. This solution is the so called energy-only market structure and its proponents provide a detailed description how these markets should be organized.

Hogan (2005) suggests that a more precise electricity demand curve should be calculated, by adding up electricity and operating reserve demand together. The reserve demand calculation should be based on engineering concerns; more precisely, engineers should determine how much reserve capacity is needed for any given level of real energy demand (the desired reliability level would be calculated using estimates of electricity's opportunity cost, or in other words on the basis of the value of lost load).

Similarly, Joskow (2006) argues that the missing money problem is relevant in the US.[3] The net revenues of generators do not cover the capital costs of investing in new capacities (in the case of a new peaking plant the net revenues cover only 40% of the annualized capital costs of the unit). Though this could be considered as a sign of too much capacity in the system, Joskow states that this idea is dismissed by many policymakers. The main reason is that system operators are worried that soon there would not be enough capacity to meet the increasing electricity demand. Joskow claims that most people link the problem back to the inadequate functioning of wholesale markets.[4]

The potential causes of the missing money problem

The causes of the missing money problem can be divided into market and government failures. First, we take a look at market failures which are price volatility and imperfect capital markets. Then we investigate the government failures that include price caps and regulatory opportunism in the energy sector.

Market failures

Price volatility

One of the biggest concerns in the restructured markets is the unpredictability of demand-supply balance. This means that prices in the electricity market are so volatile that generators simply cannot make stable calculations about their future revenues.

Furthermore, energy price fluctuation can lead to investment fluctuation on the supply side. Price spikes increase market risks, thus the investments become more risky and consequently more costly. In this situation investors would only be willing to invest if they are sure that they will recover their costs, thus take a "wait and see" approach. When there is a serious capacity shortage in the system, they invest. So the industry ends up in a cyclical investment situation. Therefore, effective means should be designed to overcome these risks related to price volatility (Stoft, 2003 and OECD, 2003).

Typical financial products cannot cover the risks of power market investments as their length is generally shorter than even the construction period of a power plant, let alone its lifetime. Long-term contracts could be useful tools for mitigating risks, for instance, certain consumer groups could have contracts with power plants covering their investment risks.

However, in many cases end-consumers do not want to have long-term contracts with electricity suppliers (the maximum contracted period is usually 2-3 years), thus suppliers are wary of having longer contracts with plants. In addition, these contracts decrease retail competition (less electricity is available for spot markets). Another solution is the

[3] Paul L. Joskow (2006), pp 27 : Competitive Electricity Markets and Investment in New Generating Capacity, Working Papers 0609, Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research

[4] Even though there are critics who claim instead that policymakers worry too much.

merger of firms, e.g. gas and electricity companies, but this can lead to less competition in the submarkets too (OECD, 2003).

Capital markets

There is a possibility that the investment deterring effects of price volatility in the electricity sector are compounded by failures in the operation of capital markets. If creditors do not see market fundamentals or regulatory risks in the proper light, they might be too worried about the feasibility of investors' business plans and demand unwarranted returns on projects. This information asymmetry might contribute to a shortfall of investment in general.

However, one must see that the argument has too sides. Just as a financier with a lack of information can exaggerate investment risk, it can also downplay it, leading to the opposite effect. Judging from the volatile spirit of capital markets, both sentiments can play a role in one period or another.

Regulatory failures

Price caps

In many regulatory regimes electricity prices are capped. Joskow (2006) explains the rationale behind this in the case of US policy practice. High prices could be a sign of scarcity, but they could be the sign of collusion among generators as well. In both cases, caps should be binding, meaning that market prices should actually hit them from time to time.

However, in the US price caps were not binding; in many cases they were never even reached.[5] Furthermore, price caps are low compared to VOLL (value of loss load) estimates. These facts suggest that not the price caps but other activities of the system operators or regulators suppress prices.[6]

Regulatory opportunism

As the sector's performance has a direct impact on the whole economy, it is difficult to make credible political commitment in energy policy. Since an electricity price increase has effects on employment and competitiveness, the sector is very prone to political interventions especially in times of price spikes. However, intervening during price spikes is very dangerous as these are the moments when investors realize their greatest incomes that could cover their previously occurred investment costs. In general, regulatory policy changes can make previously profitable projects suddenly unprofitable (OECD, 2003).

On the other hand, excessively high prices, even if they reflect shortage, cannot be maintained on the long term. They would put too high financial burden on consumers and regulators would tend to introduce price-caps to overcome this problem (Besser-Farr-Tierney, 2002 and OECD, 2003).

The success of a regulatory regime depends on commitment of policy makers. Unreasonable obligations and/or frequent regulatory changes can endanger the whole re-

[5] pp 38, Paul Joskow (2006)

[6] Such as the premature shedding of curtailable loads by system operators, or the imposition of pricing controls on dominant producers by regulators.

structuring process, creating avoidable excess uncertainty in the industry. As a result, investors might not be willing to enter the market, as they do not know when their costs can be recovered.

The possible remedies

There are two main opinions about what should be done to overcome the long term adequacy problem. According to one group of authors (Chao, Hogan, Oren, Wilson and Wolak) there is a market design problem, namely the existence of the price caps. Thus, without price caps, high prices would signal scarcity and the adequate level of investment would occur, like in other industries. This group emphasizes the basic assumption of restructuring, namely that market participants can make better decisions than market designers or regulators. This is due to the incentives that they have to face, and the fact that they are better informed to make good investment decisions.

The other group (Cramton, Joskow, Stoft) proclaims that capacity markets should be organized, because only this way can the necessary funds for financing investment in new generation be guaranteed.

There are some capacity markets in the U.S. (e.g. in the PJM market). The form of capacity markets is a procurement auction, where regulators decide about the needed capacity based on future demand forecast. Load-serving entities must procure enough future capacity to cover their expected demand, and the auction revenues go towards covering the fixed cost of available producers.

The fundamental difference between the two groups is whether they find the root of the distortion of electricity prices in the problem of short-term reliability problems, or in the entire market design. The supporters of capacity markets claim that short-term reliability is only a tiny part of the big problem, and that there are many features of market regulation which do not give proper incentives to invest, thus this problem should be addressed directly. Meanwhile those who think that there is no need of capacity payments link all the difficulties to the short-term reliability problem. If that problem would be well-treated, which means that regulation of it does not cause price distortions, then the incentives to investment would be restored, as investors would get the right price signals.

Risk mitigation in energy-only markets

As we have seen, capacity procurement auctions (capacity markets) shift some of the investment risk onto consumers (or load-serving entities acting on their behalf). However, energy-only markets also provide various means for risk sharing. Below, we discuss two such arrangements: long-term contracts and options.

Long-term contracts

Some argue that the best solution would be to motivate long term contracts because in this way generators could sell energy for large consumers or for large traders in advance. Before they were considered useful only for market power mitigation in the spot market, but they could provide good incentives for investment as well. If a new entrant gets a guarantee that for a certain period of time, his produced electricity is bought at a fixed price, his investment risks would be lower and would invest (Chao-Wilson, 2004).

Oren emphasizes the importance of VOLL calculation and price caps in promoting long-term contracts and claims that the price cap should be equal to the VOLL. First, it

would function as a penalty if someone cannot provide the previously contracted electricity. If there is a shortage of capacity, then prices would rise and those who are not available cannot profit from these increased prices.

Secondly, the price cap would decrease the expected profit of the power plants that do not enter into long-term contracts, as abstaining plants would benefit the most from nonperforming power plants. The difficulty lies in the length of these contracts (Oren, 2003). A counter argument is that in other industries investors are ready to launch more than 10 years long investment projects without long-term contracts, e.g. airplane construction (Wolak, 2004). However, the energy sector is sometimes considered to be riskier than other industries because of sudden changes in the regulatory environment.

In Hauteclocque and Glachant (2008) we find further discussion about the benefits and drawbacks of long-term contracts in the energy sector. On the one hand, these contracts can provide resources for investments and facilitate entrance to the market. Long-term contracts allow new entrants to choose high-fixed cost technologies because of the increased time span that is provided by the contracts. On the other hand, long term contracts can be considered to be means of a dominant incumbent to control the market. So, in general, competition authorities do not look favorably at them.

Another large drawback of long-term contracts is that they can extract too much electricity from the spot market limiting its liquidity. However, the details of such contracts play a crucial role in judging their effects. Apart from duration and exclusivity, there are other clauses that can increase switching costs as hence limiting competition. Still, in general, both market and contract characteristics play a crucial role in determining the effect of long-term contracts on competition (Hauteclocque and Glachant, 2008).

Options

In the debate about the proper incentives to invest in electricity generation a newly proposed mean is the introduction of option contracts. The buyers of the option would be the electricity consumers, while the sellers would be the generators. The basic option would involve a strike price and the price of the option. A strike price is a guaranteed price level at which the buyer of the option would always have access to energy, thus market prices could not exceed this price. While the price of the option would be equal to the income that could have been realized by the generator if there was not a strike price and the market price could freely rise.

Therefore the generators' expected market revenue is identical to its expected market revenue without an option contract. When the market price is below the strike price, the two markets (the one without options and another one with options) would be performing the same way. However, when the market price would be higher than the strike price, the two markets perform differently. In the case without options, the prices are rising, thus generators realize extra revenues. In the option case, the sellers cannot charge higher prices, thus they cannot realize extra revenue at that moment, but they have already realized that extra revenue in the form of the price of the option. The energy buyers' expected expense on energy is identical in the two markets, however in the case of options they do not have to face any price risks, as there is the strike price.

The idea behind the options is that based on their future demand, consumers can contract for themselves just the needed amount of electricity. While the supply side, based

on these contracts, can make investment decisions. Furthermore, different option contracts could diversify different consumer groups, thus the demand side would become less inelastic. The obligatory option contracts would make the demand side to pay for a service that they otherwise would not pay for (Hogan, 2005).

Another reason, discussed by Chao and Wilson, for introducing options is that they enlarge the time span of investment decisions so investors are able to start long-term investments. They state that the spot market supply is very inelastic, however on the long run this is not true. If there are long-term or rather option contracts, then investors will invest as they can see by when their costs will be recovered. The advantage of options is that they are not so constraining as long-term contracts: quantity and price fixed in option contracts are only applied if certain prices are reached on the spot market. Thus options solve all three problems:

- they give incentives for long-term contracting,
- provide resources for investments, and
- mitigate spot market power.[7]

Another advantage of options is that the system operator can enter on the demand side of the market and maintain reliability within the market frame and not via mandated regulatory power. Furthermore, the system operator does not have to buy electricity for balancing on the spot market. Market power issues are solved too, as power plants do not face any incentives to raise their spot prices over the option contract prices.

The disadvantage of options is that they reduce the contestability of markets. If the profits of producers decrease, there would be no incentives to enter. This means a less threatening market structure for the incumbents in the future. On the other hand, sometimes options can facilitate entry, because they serve as good collateral for creditors (Chao-Wilson, 2004).

To conclude, in Table 5.1 we can see the main differences between the capacity market and energy-only market design.

Table 5.1. The comparison of capacity market design and energy only market design

	Capacity market design	Energy only market design
Source of the investment problem	Not properly functioning spot markets (missing money)	Not properly functioning spot markets (missing money)
Proposed solution	Spot markets cannot solve alone the investment problem. Capacity holding should be remunerated.	Spot market price distortions shall be solved. (The TSO should be more active.)
Risk allocation of investments	Demand side should bear a part of investment costs.	Supply side should allocate its risk through options or long-term contracts.

[7] Chao-Wilson (2004) pp 7

	Capacity market design	Energy only market design
Role of long-term contracts or options	Another means to promote investment.	They can decrease competition (spot markets would not be liquid enough), thus regulators should be vigilant. The most important means to promote investment.
Counter argument	Capacity markets are just an administrative response to not properly working spot market design, which is a regulatory failure.	Energy only markets seem to be reliable just because they are not competitive. In an oligopolistic market structure, agents have incentives to deter entry and avoid political intervention by providing excess capacity.

Some simulation results in the European market

As restructuring is a recent phenomenon throughout the world, there are not enough data to have robust results concerning investment activity. A new line of research develops simulations or experiments to see how different regulatory regimes influence investment activity.

Laurens de Vries and Petra Heijnen (2008) investigate the effect of different market designs on investment activity. Their main question is not whether the optimal level of capacity would be installed in a power system, instead, they look at the possible development of investment cycles in the industry. The key finding is that energy-only markets are the most prone to investment cycles.

The authors assume perfect competition and the only uncertainty is future demand. They run simulations to test the energy only market design and different regimes where capacity holding is explicitly remunerated. The results show that the average electricity price is the same in all market settings. On the other hand, the standard deviation of prices and the average number of hours of shortage are the highest in energy-only markets. The regimes with capacity obligations perform the best, because such designs give a forecast for future demand, which is the only uncertainty in the system by assumption.

However, de Vries and Heijnen admit their modeling has some drawbacks. The sole source of uncertainty is future demand, they do not take into account the existence of different generation technologies, they consider individual and homogenous markets and the assumption of perfectly competitive markets is probably too strong as well.

Consequently, the authors also ran a model where an energy-only market is characterized by firms behaving in an oligopolistic way. In such a market structure, no investment cycle is present and average prices are not very different from the competitive settings. Still, the probability of shortages is higher than in any capacity mechanism.

The authors claim that the actual European energy-only market is characterized by oligopolistically behaving firms, thus there is no capacity shortage. There are two reasons why this behavior is profitable for companies. First, they can deter new entrants with their idle capacities. Second, they can minimize the possibility of political intervention with price stability and reliably functioning energy markets.

The de Vries-Heijnen article deals with very important questions and their results might provide a good explanation of the actual investment activity in European markets. However, their assumptions are very strong. The uncertainty on energy markets is not only due to future demand, there are many other factors e.g. generation technologies, input markets, taxation. Furthermore, these factors are strongly related. For instance, different technologies are taxed differently (carbon pricing) or certain generation technologies are promoted due to political reasons (e.g. security of supply). These considerations imply strong government presence and likely political intervention.

5.9.4. Moving forward

As we can see, theoretical arguments are abundant on both sides of the investment debate. In the following section, we will look at the issue from a practical point of view in the Central and South-East European power markets.

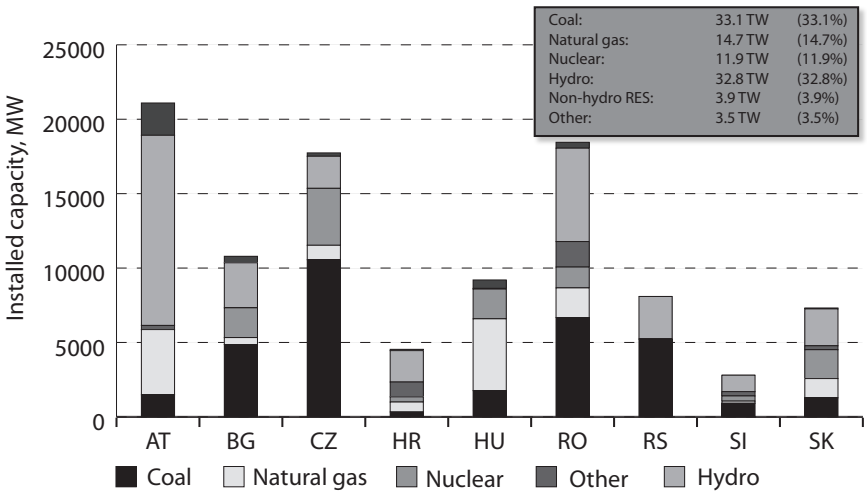
5.10. Present and expected installed power capacity in the region

In this chapter we give a short overview of the installed capacity in the Central and South –East European countries. In our study we examine seven EU Member States (Austria, Bulgaria, Czech Republic, Hungary, Slovakia, Slovenia and Romania) and two non-EU Member States (Croatia and Serbia). After describing the present situation we also investigate the role of renewable generation in this region. In the last part of this chapter we summarize the expected power plant investments in the analyzed countries.

5.10.1. Present installed capacities

In the analyzed region 36.8 % of the total installed capacities are based on renewable sources, most of them are hydro (mainly in Austria and Romania). About one third of installed capacities are coal-based, especially domestic lignite. Due to the fact that coal-fired power plants are so called "base load power plants", they have an important role in the wholesale electricity market. The largest coal-based capacities operate in the Czech Republic, Romania, Bulgaria and Serbia. Although the total installed capacity of natural gas-fired power plants are quite small, but in some countries (e.g. Hungary and Austria) they are very important. In most of the countries gas-fired plants are combined heat and power (CHP or cogeneration) plants, so they produce heat as well. In six (or seven) countries nuclear power plants operate as well, with 11.8 TW net installed capacity, which gives 11% of the total installed capacity in the region.[8]

Figure 5.1. Net installed capacity in 2010, MW



Source: REKK data collection

Reserve margin equals the ratio of the installed capacity and the absolute peak load in a given country minus one. According to expert analysis the necessary reserve margin

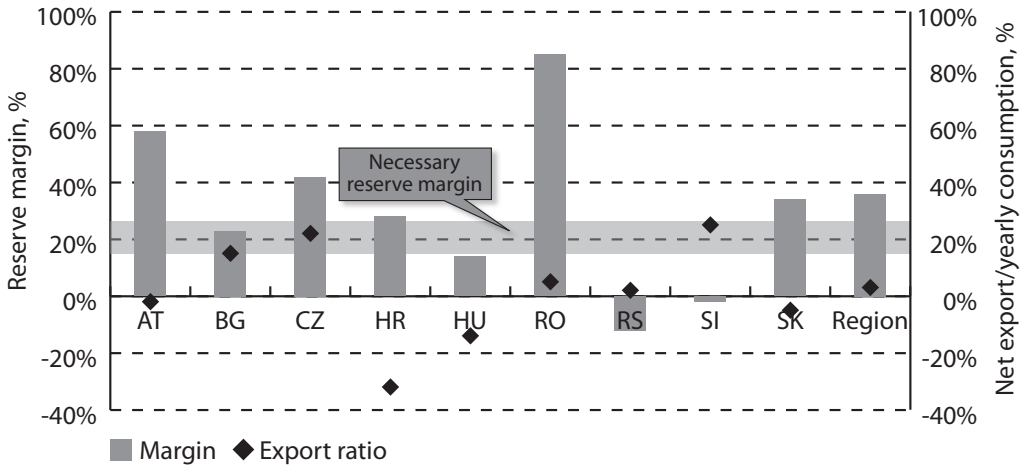
[8] It dependents on how Krsko power plant is calculated. Geographically it is situated in Slovenia but half of its installed capacity is operated by the Croatian incumbent company.

should be between 15 % and 25 %.[9] This data is based on the loss of load probability, e.g. in the USA the value of LOLP equals one blackout in every ten years, from which the reserve margin can be calculated.

On one hand, if this ratio is below zero, then the domestic capacities are not enough to satisfy the absolute peak load, so the country has to import electricity in these hours. On the other hand, a very high ratio can indicate two things: installed capacity is too high and there are non-used capacities, or the given country is a large exporter at least in the peak hours.

Figure 5.2 depicts the reserve margins and the net export in 2009 in the analyzed countries. In our calculation, we take into account the renewable capacities only with 30 % (except hydro power stations with storage and pumped storage power plants) because these capacities cannot reliably produce at full capacity. This number is an average figure for renewables, which is based on the assumptions that the average utilization of wind turbines is 20%, the utilization is around 30% in hydro capacity and above 50% in biomass.

Figure 5.2. Reserve margin in 2009



Source: ENTSO-E, REKK collection

In the CSEE region, the average reserve margin is around 36 % which is above the necessary range and in aggregate these countries are large exporters. Slovenia and Serbia is in a tight situation because they cannot satisfy their peak load with domestic capacities. Austria and Romania seems to have a lot of unused capacity as their reserve margins are quite high and they are not large exporters.

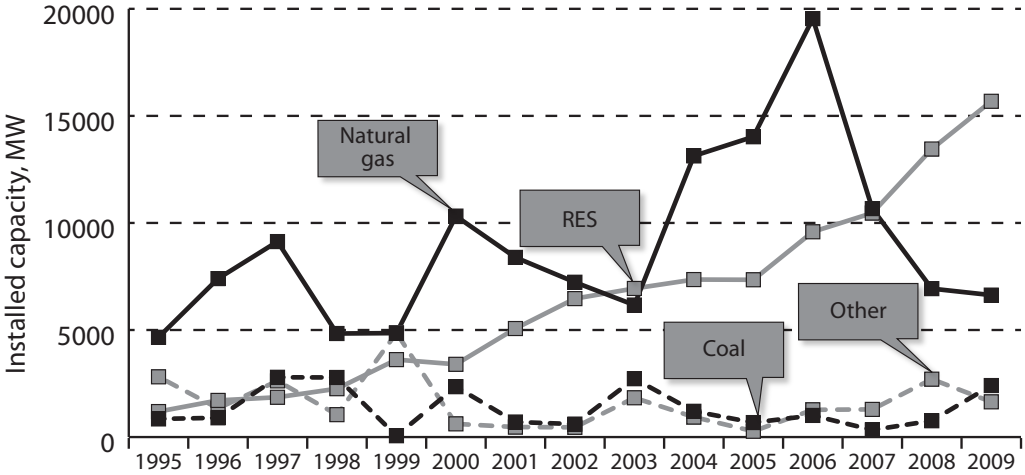
To forecast future investment, it is important to analyze historical investments as well. Between 1995 and 2009 the most popular type of newly commissioned power plants in the European Union was natural gas-fired plants. Only in the last two years did the renewable capacities spread faster than gas-fired power plants.

RES capacity has a definite increasing trend which probably will continue in the following years as well. In the last ten years only 5.4 % of the newly commissioned capac-

[9] NERC (2009), OECD (2002)

ity was nuclear or oil-fired power plants, another 6 % were coal-fired plants, while 40 % were renewable (of which 80 % was wind power). 48.5 % of the total newly installed capacity was gas-fired power plants.

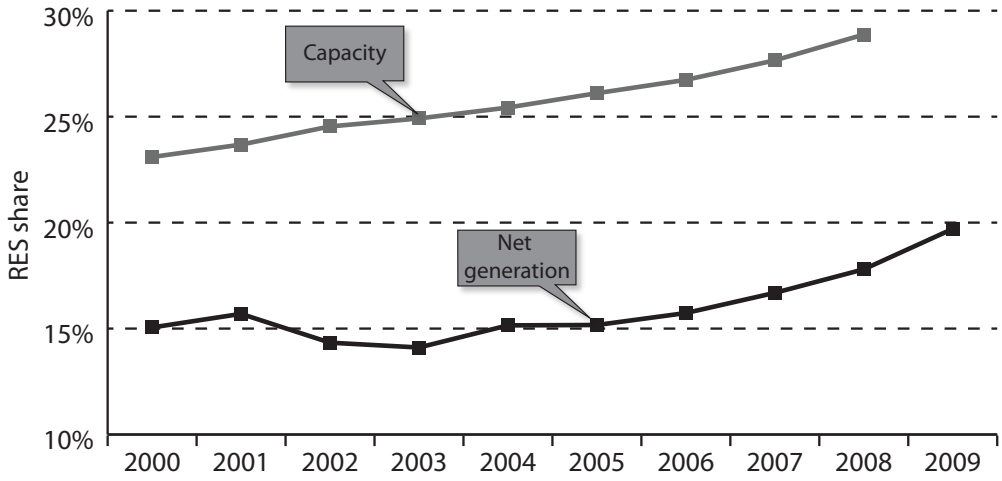
Figure 5.3. New power generating capacities, MW



Source: EWEA (2009) and EWEA (2010)
1995-2005 data refer to EU15, 2005- 2007 to EU25, from 2007 to EU27

In the last ten years the percentage of renewable generation has increased from 15% to 20% in the total electricity generation, in the meantime RES installed capacity has grown from 23% to nearly 30%. From that figure it can be seen that power production from renewable energy sources has lower utilization than the non-RES power plants. Wind (and solar) power generation cannot be predicted exactly which implies that more back-up reserve and/or a well-working balancing market is necessary. These reserves have to react fast, which is only feasible by gas-fired, pumped storage or hydro power plants with storage.

Figure 5.4. Share of renewable power generation and capacity in the EU27 between 2000 and 2009



Source: Enerdata

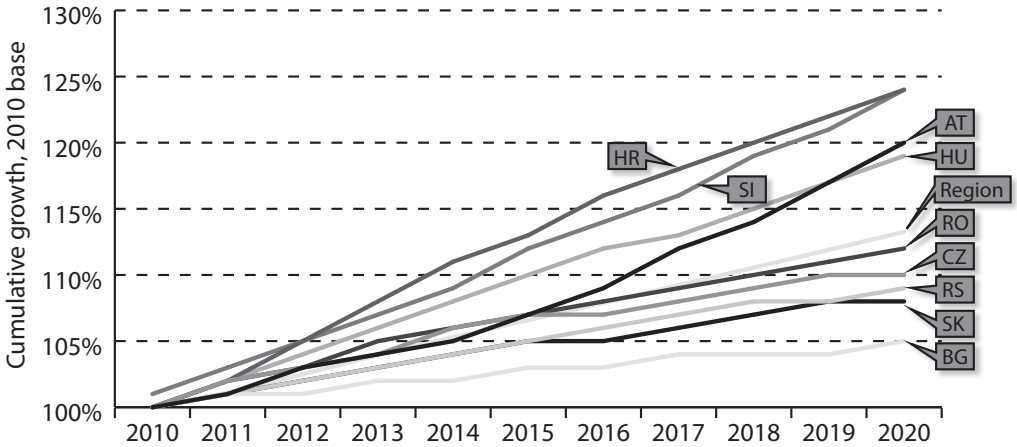
5.10.2. Expected consumption growth and RES capacities in the analyzed countries

In the forthcoming section we discuss demand and RES production forecasts separately from other, non-RES production. The reason behind is that we assume that RES production will follow the scenarios of National Renewable Action Plans with a somewhat higher certainty than the materialization of non-RES generation capacity announcements. The newly built RES, on the other hand, influences the power market and hence potentially has an impact on other generation investments.

Before we analyze the expected new power capacities, we have to demonstrate the consumption growth between 2010 and 2020 in this region, because it has the most important effect on new capacities. According to REKK calculations, the expected electricity consumption in the analyzed countries can be seen in Figure 5.5. The expected consumption growth is based on the relationship between the GDP and the yearly electricity consumption data in the past. The effect of GDP on electricity consumption is country specific, e.g. in Hungary 1% increase in real GDP means 0.52% increase in consumption. This figure combined with the expected real GDP growth gives an estimate for future electricity demand.[10]

[10] Real GDP growth estimates are taken from the Economist Intelligence Unit.

Figure 5.5. Cumulative electricity consumption growth between 2010 and 2020



Source: REKK (2010a)

In the region the average cumulative electricity growth between 2010 and 2020 is around 13%. The highest increase is in Croatia, Austria, Slovenia and Hungary, the smallest in Bulgaria and Slovakia.

As we have discussed before, RES plays an increasingly dominant role in new capacities and its future deployment is set in advance. According to the Renewable Directive (2009/28/EC) 20% of the overall energy consumption will have to be based on renewable sources. Each country has its own target depending on its GDP per capita and the share of renewable energy in final consumption in 2005. In the transport sector all Member States have to meet at least 10% share of renewables, while in the case of other sectors (electricity and heat) there are non-binding targets.

Member States had to prepare a National Renewable Action Plan (NREAP), in which they clarify how to meet their targets and have to set non-binding targets for each sector.[11] According to the National Renewable Action Plans, RES electricity generation will be the following in 2010 and 2020.

Table 5.2. Renewable power generation, 2010 and 2020

	2010	2020	Growth, GWh	Growth, %
AT	45383	52378	6995	15%
BG	3879	7536	3657	94%
CZ	5071	11679	6608	130%
HU	2856	7088	4232	148%
RO	17094	31388	14294	84%
SI	4510	6127	1617	36%
SK	5139	7500	2361	46%

[11] Some countries have not submitted the document to the European Commission yet. As this group includes Hungary, this paper uses the figures of the draft NREAP.

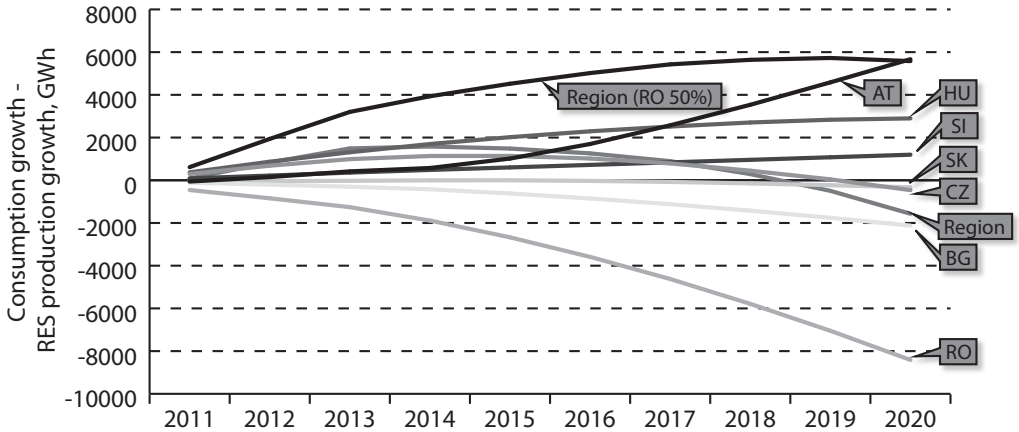
	2010	2020	Growth, GWh	Growth, %
Region	83932	123696	39764	47%

Source: National Renewable Action Plan, ECN (2010)

As Table 5.2 shows, the most ambitious targets are in Hungary and in the Czech Republic. In these countries renewable electricity generation doubles in a decade while the average growth in the region is only 47%. It is important to note that although Romania has a moderate increase in percentage but the absolute figures are extremely high (14 TWh).

Subtracting RES generation growth from the increase of total net electricity consumption we get the following picture.

Figure 5.6. Electricity consumption growth decreased by cumulative RES-E generation between 2010-2020



Source: REKK calculation based on REKK (2010a) and National Renewable Action Plans

The most important result is that if all the analyzed Member States meet their non-binding RES electricity targets then the growth of electricity consumption by 2020 is fully covered by new renewable capacities. This implies that no new non-RES capacity is needed beyond the replacement of retired non-RES capacities. Although, new capacities could produce in lower marginal cost than existing capacities, but their fixed cost is higher due to the higher CAPEX.

We added an alternative RES scenario for Romania assuming that only half of foreseen new RES capacity will be put into operation. In this case the expected consumption growth is 6 TWh higher than RES production growth. This figure – however – is still quite small; e.g. a single 1000 MW coal-fired plant with 70 % utilization rate can satisfy this excess demand.

5.10.3. *Expected new power plant investments*

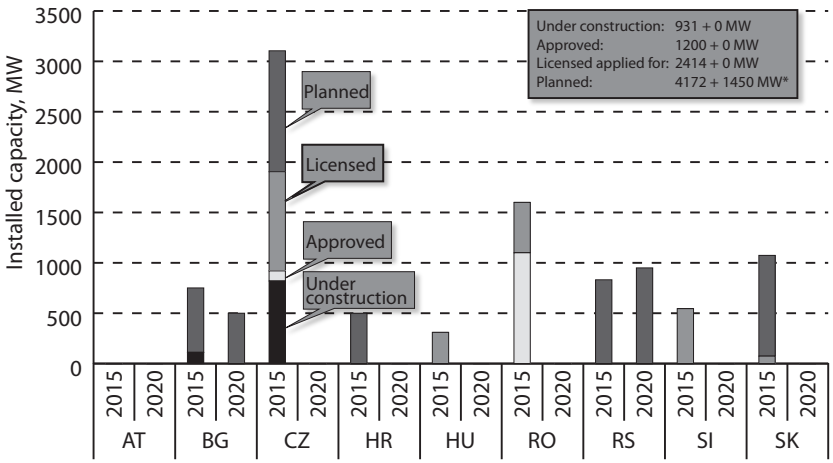
Our best available information source for expected investments was the regular regional generation investment review by Platts Energy in East Europe. In this publication new power plant projects are categorized according to fuel source/technology and their development status. Development status can be (in decreasing phases of readiness):

- in operation
- under construction
- construction approved
- license applied for
- project in planning phase.

Coal-fired power plant investments in the region

Figure 5.7 shows the expected new coal-based power capacities in the region. Most known investments should be commissioned before 2015 and only 1450 MW are in the planning phase and likely to be commissioned between 2016 and 2020.

Figure 5.7. Expected new coal-fired (and lignite) power plant capacities in CSEE countries between 2010-2015 and 2016-2020



Source: Platts (2010)
**The first figure refers to 2010-2015, the second to 2016-2020*

Less than 1000 MW new coal-based power plant investments are under construction which will operate mainly in the Czech Republic. Another 1200 MW capacity is under the approved phase in the region. The total projected capacity commissioned in the first half of the decade is 8717 MW while total projected capacity commissioned in the second half of the decade is only 1450 MW.

Table 5.3. Planned coal-fired (and lignite) power plants in the region

Country	Unit name	Installed capacity [MW]	(Expected) year of commissioning
BG	Maritza East 3	640	2015
BG	Lom TPP (Lomski Ligniti)	500	2016
CZ	Ledvice	660	2013
CZ	Most	1200	2013
RO	Turceni 3 and 6	660	2012
RO	Isalnita III	500	2013
RO	Braila IV.	800	2014
RS	Nikola Tesla B3	700	2016
HR	Plomin III.	500	2015
SI	Sostanj	545.5	2014

Source: Platts

Maritza Iztok III (BG)[12]

The Maritsa Iztok 3 power plant is the third largest lignite-fired generating asset in Bulgaria, supplied with the nearby lignite fields. Situated in the southern part of the country, the plant is connected to the Turkish grid as well. A 73% share of the company was privatized in 1998, acquired by the US company Entergy Corporation in order to propagate refurbishment. Italian Enel joined the refurbishment project in 2003 and purchased Entergy's assets. The refurbishment and modernization of the 840 MW plant was finished by the joint venture of NEK (27%) and Enel (73%) in February 2009.

Further expanding its capacities in Bulgaria, in 2006 Enel proposed the commissioning of a 640 MW lignite-fired power plant consisting of two 320 MW units. In 2007, Enel and NEK published a feasibility study that suggested the building of a single unit with a 750 MW nameplate capacity. The project is due to be completed by 2015 at a cost of 950 million €. However, in March 2010 Enel announced its intent to sell its 73% share in the plant, making the status of the project fragile.[13] EVN and AES both announced that they were interested in Enel's stake.

Lom (BG)

Bulgarian engineering company Enemona envisaged building of a lignite-fuelled power station already in 2007. The company gained the permit of coal extraction in the Lomski region in October 2007 by the Ministry of Energy and Economy. Furthermore, the Bulgarian state granted the project a First-Class Investment Certificate, which means smoother administration procedures, state financial aid

[12] The description of the new power plants (both coal and nuclear power plants) are mainly based on the publication of Platts: Energy in East Europe.

[13] http://www.thebulgariannews.com/view_news.php?id=120888, http://www.enel.bg/?page_id=382

and preferential land acquisition.[14] Enemona is currently looking for a concession partner to begin the coal extraction in the region.
The Lom TPP is planned to have a capacity of 400-600 MW and due to be finished by 2016. According to Enemona, the coal deposits provide ample resources to fuel the proposed power plant for 60 years.[15]

Ledvice (CZ)
Construction has been already started of the 660 MW lignite-fired power plant of Ledvice that is scheduled to be completed in 2013. CEZ has concluded a long-term supply contract with the coal producer Severoceske Doly to ensure the future supply of the power plant. CEZ already operates a 220 MW power station on the site.

Most (CZ)
Czech Coal, in a joint venture of Germany's E.On plans to construct a 1200 MW lignite-fuelled power station containing 2 identical 600 MW units. The €2 billion project is expected to be finished in 2013. The mines which are to supply the plant are believed to contain economically exploitable reserves until 2055.

Turceni 3&6 (RO)
Two units of Romania's largest coal-fuelled power plant, consisting of 7 identical 330 MW units, are to be refurbished and modernized until 2012. The power station, formerly owned by Termoelectrica, is operated by the state-owned company Energy Complex Turceni. The €425 million project is partly financed by the €170 million EBRD loan.[16] The investment will reduce the emissions of the plants, as well as enhance its availability and efficiency. The Turceni complex accounted for 11% of power generation in Romania in 2009.[17] Turceni has finished the modernization of units 4 and 5 in 2006.

Isalnita III (RO)
The state-owned Isalnita power station is the third largest lignite-powered plant in Romania. Plans of building a new 500 MW unit were envisaged in 2009, tendering began in January 2010. CEZ, Edison and AES were to join a joint venture, however in March 2010, CEZ abandoned the project.

Braila IV (RO)
Termoelectrica in a joint venture with Enel and E.On announced the construction of a 800 MW coal CHP. Financing will be carried out by Enel and E.On, while

[14] www.investbg.government.bg
[15] http://enemona.bg/english/index.php?133
[16] http://www.ebrd.com/russian/pages/news/press/2009/090721a.shtml
[17] http://translate.google.com/translate?hl=hu&sl=ro&tl=en&u=http%3A%2F%2Fwww.eturceni.ro%2F%23

Termoelectrica provides the site for construction. The plant is expected to enter into commercial operation in 2014.

Nikola Tesla B3 (RS)
EPS has not yet found a strategic partner for its 700 MW lignite-powered power plant. The deadline for tendering has been extended for the second time to February 2011. Potential investors claimed that the uncertainty of the Serbian Government regarding coal mining concessions makes the €900 million too risky. In August 2010, possible rise in project costs was announced. Moreover, rumors spread about CEZ pulling out of the bidding. The institutional framework and the resulting high uncertainty make the project improbable.

Plomin III (HR)
The Plomin TPP operates 2 units with the total capacity of 330 MW. The station covers around 10% of the Croatian consumption. The constructing of a third, lignite-fired 500 MW unit is still in the planning phase, due to be finished in 2015. However, the decommissioning of the 1969-constructed 120 MW Plomin I unit and the role of the station in Croatian generation ensures the future of project.

Sostanj (SI)
State-owned energy company, HSE plans to expand the lignite-fired Sostanj TPP with a single, 545.5 MW unit. The license of unit 6 has already been approved, and the financing seems solid: €120 million has been already invested in the project by HSE to the €800 million project and EBRD agreed to provide a loan of €200 million in July. The remaining funds will be covered by bank loans. The plant will utilize CCS technology to reduce the carbon output of the power station. Construction is expected to begin in 2010. The 1960-1970's built Sostanj units 3, 4 and 5 are due to be shut down gradually in the following years, while unit 6 will replace the capacities in 2014.

Nuclear power plant investments in the region

Table 5.4 lists the planned nuclear power plants in 6 countries in the analyzed region. The total installed capacity of these units is 11682 MW.

Table 5.4. Planned nuclear power plants in the region

Country	Unit name	Installed capacity [MW]	(Expected) year of commissioning
BG	Belene	2000	2017
BG	NPP Kozloduy	1000	2017
CZ	Temelin	1000	2024
CZ	Dukovany, 1	1000	2023
HU	Paks II A	1000	2020
HU	Paks II B	1000	2025

Country	Unit name	Installed capacity [MW]	(Expected) year of commissioning
RO	Cernavoda 3 and 4	1440	2015
SK	Mochovce,3	471	2012
SK	Mochovce,4	471	2013
SK	Bohunice V3	1300	2020
SI	Krsko	1000	2017

Source: PLATTS

Belene (BG)

Located in Northern Bulgaria by the Danube, Bulgaria's second nuclear power plant is planned to enter commercial operation in 2015, consisting of 2 pressurized water reactors with a total capacity of 2000 MW. On site preparations already began in 1981, the original plans included 4 pressurized water reactors with 440 MW capacity each. By 1990, the plant was at 40% completion phase. However, the project got suspended in 1990. From 2005 on, the project is lead by the National Electricity Company (NEK), the construction itself carried out by Russia's Atomstroyexport with Germany's Siemens and France's Areva on board as subcontractors. In 2008, RWE and Electrabel both wanted to enter a joint venture with NEK for a share of 49% in the future power plant. NEK selected RWE in September 2008. RWE was expected to invest €1.5 bn by the end of 2009 which is around one-fourth of the total building cost. In October 2009, RWE abandoned its stake due to missing project deadlines. Currently NEK is looking for a partner to raise funds to continue the construction. The most promising candidate would be Serbia, aiming to replace its fossil capacities with nuclear power.[18]

Kozloduy (BG)

Kozloduy NPP and Iberdrola formed a joint venture company to put into operation a 1000 MW capacity new unit at the Kozloduy site. At present, the Kozloduy plant operates units 5 and 6 with a nameplate capacity of 1920 MW. Units 1 and 2 were shut down in 2003, while 3 and 4 in 2006 as a prerequisite of the accession of Bulgaria to the EU. In July 2010, EU provided €300 million for the decommissioning of units 1-4.

Although Unit 7 is still in the planning phase, the recent events regarding the Belene project make the project more promising.[19] The government expects foreign investment. So far Toshiba/Westinghouse and Atomstroyexport seems to be interested in the venture.

[18] http://www.sofiaecho.com/2010/11/09/990158_serbia-croatia-to-decide-by-november-13-on-participation-in-belene-nuke-project Nov 13-15 körül kiderül a döntés

[19] http://www.novinite.com/view_news.php?id=118769

Temelin (CZ)
In August 2009, CEZ opened a tender for two pressurized water units to be commissioned in 2024. The license for the power plant has been approved.[20] According to CEZ, the Temelín plant in the 1980's has been engineered to house 4 units but in the early 1990's the capacity was downgraded to 2 reactors, therefore the infrastructure is already in place for the new units. The issue of constructing units 3 and 4 was raised already in 2005 but was approved only in 2009 due to strong political and civil opposition. Areva, Westinghouse and the joint venture of Skoda and Atomstroyexport were qualified to bid for the construction. Because of the company's increasing debt and uncertainty over the future of the electricity market the construction might be delayed by several years.[21]

Dukovany (CZ)
CEZ plans to install another 1000 MW to the existing 1,850 MW nameplate capacity of its Dukovany NPP. The Dukovany plant, commissioned in 1985-1987 being the first nuclear power plant in the Czech Republic, has undergone several capacity upgrades and lifetime extensions. Skoda Praha is currently repowering the turbines and turbogenerators of the 4 units at the site, resulting in a capacity raise from 440 to 498 MW and a lifetime extension to 2045.

Paks IIa (HU)
Hungary's only nuclear power plant extension is only in the planning phase but the political support and the role of Paks in Hungarian generation ensures the continuation of the investment. The 1974-1979 commissioned Paks operates with four 440 MW units, providing 40% of Hungarian consumption. The lifetime of the existing blocs would expire in 2012-2017 but the legislators have extended it further 20 years. The present capacity of 2000 MW will be boosted with another 1000-1600 MW in a single unit, tendering will begin in 2011. The four possible reactor types considered are a 1100 MW ATMEA unit by French AREVA and Japanese Mitsubishi, a 1000 or 1200 MW AES-2006 by Russian Atomstroyexport, a 1000 MW by US Westinghouse and a 1600 MW French-German EPR.

Cernavoda 3&4 (RO)
The project is carried out by the 2009-formed venture company Energonuclear, consisting of CEZ, Enel, RWE, Iberdrola, GDF-Suez and the steel producer ArcelorMittal.[22] Four utility companies would hold 9,15% share each, Iberdrola and ArcelorMittal 6.2% while the Romanian State through Nuclearelectrica would possess 51% in the to-be-completed plant. The cost totals €4 billion, 30% of which would be paid from equity. In September 2010 CEZ abandoned its 9.15% stake, claiming the investment risky. Still, the remaining investors claimed to continue

[20] http://www.world-nuclear.org/info/inf90.html
[21] http://www.radio.cz/en/section/curraffrs/construction-of-new-blocks-at-temelin-nuclear-power-plant-might-face-delays
[22] http://www.nuclearcounterfeit.com/?p=1459

the venture and raise their stakes. Furthermore, the Romanian state announced to cut its share in Cernavoda due to financing difficulties. Even if the financing of the NPP seems to be relatively uncertain, the remaining parties provide sufficient support for the completion of the project.

Mochovce, 3 (SK)
Slovenské Elektrárne has started the construction works of Mohovce 3 and 4 units. The new pressurized water reactors possess a capacity of 471 MW each. Unit 3 will enter commercial operation in 2012, unit 4 in 2013. The estimated investment cost of €2.8 billion will be paid by the 66% Enel-owned Slovenské Elektrárne almost fully. The investments are supported by strong government commitment.[23] The 1998-commisioned Mohovce plant houses two 470 MW VVER units which are expected to shut down in 2028-2030.

Bohunice V3 (SK)
The third reactor unit at Bohunice NPP is still in the planning phase. Jadrova Energeticka Spolocnost Slovenska, a 100% state-owned company operating of the Bohunice V1 unit started a joint venture with CEZ. The new capacity would be rated 1000 to 1600 MW, costing around €3.32 billion. The new Slovakian government announced in August to cut the financing and any state guarantees but keeps its 51% stake in the venture. JAVYS hopes that the opinion of the government changes in the following weeks. CEZ has abandoned several huge projects recently and the sudden change in government policy may jeopardize the Bohunice project as well.

Krsko (SI)
Slovenia plans to install a 1000 MW unit to the nuclear power plant Krsko, jointly owned by Slovenia and Croatia. The 1983-commissioned plant went into joint operation in 2002 since serious disputes broke out in 1998 when the Slovenian government nationalized the power plant and stopped the supply of electricity to Croatia. The company, owned and managed by 50% Croatian HEP and 50% Slovenian GEN Energia, operates a single 696 MW unit. The energy strategy of Slovenia forecasted highly rising demand which could be met by the new Krsko capacities. State-owned NEK intends to finance the €2 billion investment from the future electricity sales.

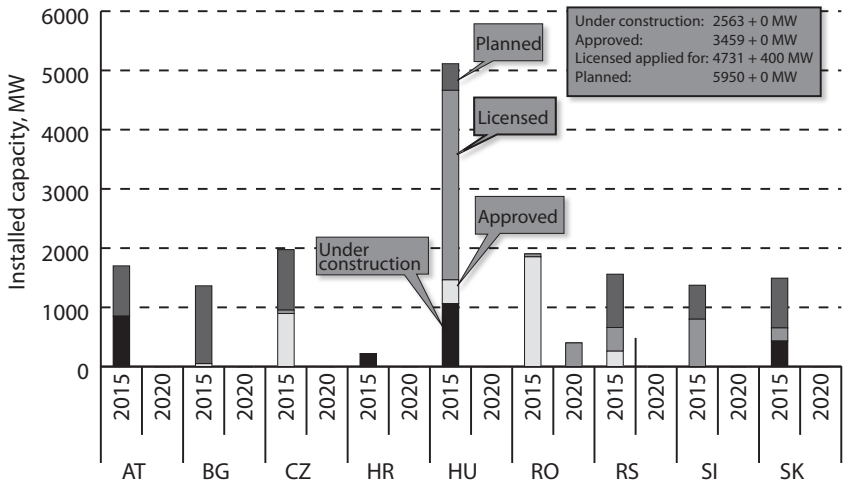
Gas-fired power plant investments in the region

Figure 5.8 shows the expected new gas-fired power plant investments in the region. The majority of investments are planned in Hungary. Almost of known investments should be finished by 2015, only 400 MW new capacities are planned to be commissioned in the second half of the decade. More than 2500 MW new capacities are under construction which is quite large compared to coal-based power generation (931 MW). More than

[23] http://www.world-nuclear.org/info/inf91.html

16,000 MW new gas-fired capacities are at least in planning phase which is extremely high.

Figure 5.8. Expected new gas-fired power plant capacities in the analyzed countries between 2010-2015 and 2016-2020



Source: Platts (2010)
**The first figure refers to 2010-2015, the second to 2016-2020*

Although we gave an overview of the most important coal-based and nuclear investments, we skip this for gas-fired investments for two reasons. First, these generators are not base load plants and have lower impact on electricity prices. Second, gas-fired power plants can be built within 3-4 years (including the planning phase), while this period is much longer for other technologies.

5.11. Expected utilization and profitability of the power plants in the region

As we have demonstrated in the previous chapter there are a lot of planned power capacities in the Central and East European region. Most of these investments are only in the planning phase. Even though RES power capacities alone can cover consumption growth in the next decade, probably some investments will be carried out and probably operate in a profitable way.

To calculate the profitability of new power plants we use a regional electricity market simulation model. First, we provide a detailed description of the model structure and operation. Afterwards, the modeling results and the profits of the new power plant projects are presented. Finally we conduct a sensitivity analyses for the most important input data.

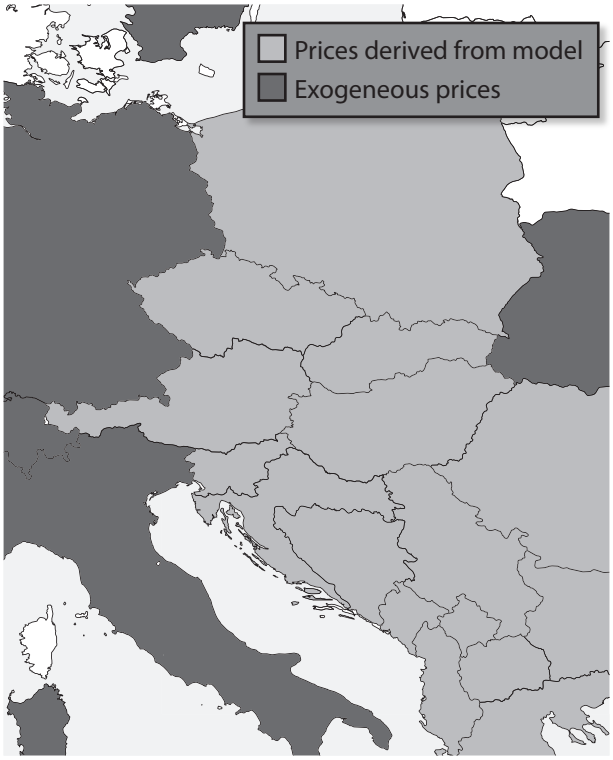
5.11.1. Model description

The Central and South-East European electricity market model simulates the operation of a regional electricity wholesale market in a stylized manner. This section describes the background assumptions and economic principles that govern the simulation.

Analyzed countries

Figure 5.9 below shows the countries included in the model divided into two groups: in countries with light grey background prices are derived from the demand-supply balance. In countries with dark grey background we assume exogenous prices.

Figure 5.9. Analyzed countries



Source: REKK

Market participants

There are three types of market participants in the model: producers, consumers and traders. All of them behave in a price-taking manner: they take the prevailing market price as given and assume that whatever action they decide upon has a negligible effect on this price.

Producers are the owners and operators of power plants. Each plant has a specific marginal cost of production which is constant at the unit level. In addition, generation is capacity constrained at the level of available capacity.

The model only takes into account short term variable costs including the following three components: fuel costs, variable OPEX and CO_2 costs (where applicable). As a result, the approach is best viewed as a simulation of short term (e.g. day-ahead) market competition.

Price-taking producer behavior implies that whenever the market price is above the marginal generation cost of a unit, the unit is operated at full available capacity. If the

price is below the marginal cost, there is no production at all. If the marginal cost and the market price coincide then the level of production is determined by the market clearing condition (supply must equal demand).

Consumers are represented in the model in an aggregated way by price-sensitive demand curves. In each demand period, there is an inverse relationship between the market price and the quantity consumed: the higher the price, the lower the consumption. This relationship is approximated by a downward sloping linear function.

Finally, traders connect the production and consumption sides of a market, export electricity to more expensive countries and import it from cheaper ones. Cross-border trade takes place on capacity constrained interconnectors between neighboring countries. Electricity exchanges always occur from a less expensive country to a more expensive one, until one of two things happen: either (1) prices, net of direct transmission costs or export tariffs, equalize across the two markets, or (2) the transmission capacity of the interconnector is reached. In the second case, a considerable price difference may remain between the two markets.

Trading with countries outside the modeled region

The model only simulates the supply-demand characteristics of the Central and South-East European region, and not the UCTE system as a whole. However, trade still takes place at the region's borders, e.g. with Germany or Italy. Our assumptions regarding the cross-border trade with countries outside the modeled region is that prices in these countries are exogenously given and not influenced by the amount, or direction, of the cross-border transactions.

Equilibrium

The model calculates the simultaneous equilibrium allocation in all markets with the following properties:

- Producers maximize their short term profits given the prevailing market prices.
- Total domestic consumption is given by the aggregate electricity demand function in each country.
- Electricity transactions (export and import) occur between neighboring countries until market prices are equalized or transmission capacity is exhausted.
- Energy produced and imported in each country is in balance with energy consumed and exported.

Given our assumptions about demand and supply, regional market equilibrium always exists and is unique in the model.

Electricity product prices

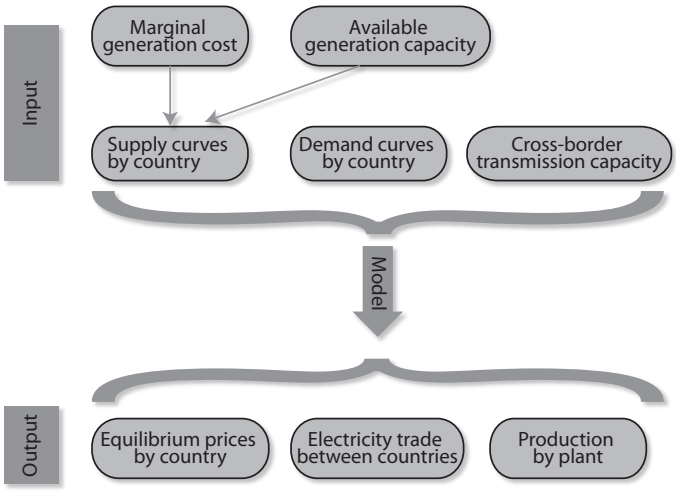
The calculated market equilibrium is a static one: it only describes situations with the same demand, supply, and transmission characteristics. However, these market features are constantly in motion. As a result, short run equilibrium prices are changing as well.

To simulate the price development of more complex electricity products, such as those for base load or a peak load delivery, we perform several model runs with typical market parameters and take the weighted average of the resulting short term prices.

Overview of data requirement

Figure 5.10 shows an overview of input and output data constituting the Central and South-East European electricity market model.

Figure 5.10. Input and output data in the market simulation model



Source: REKK

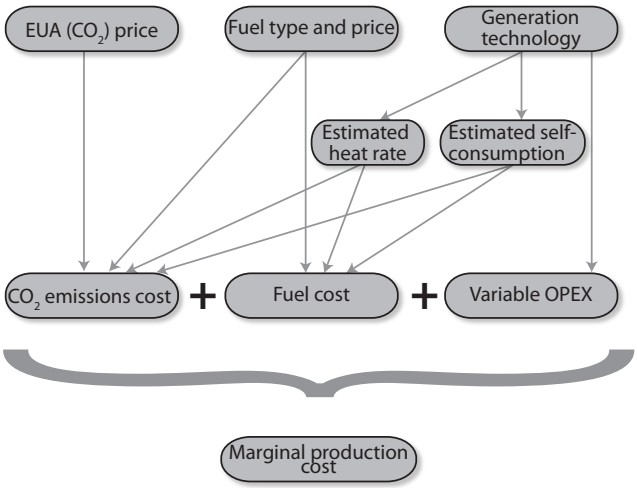
There are three main input data categories: supply, demand and cross-border transmission. In this section, we will introduce each of them in turn. In the following we briefly provide a short summary of the model, in the Appendix A you can find detailed description of the input data.

Supply data

As Figure 5.10 shows, supply input data consist of production costs and capacities. These will be detailed in the current subsection. Since we are modeling short term competition, the only relevant costs to calculate with are variable costs, i.e. those that quickly respond to changes in the level of output.

As we mentioned before, the optimal short run production decision of a power plant depends on how its marginal (or incremental) production costs compare to the prevailing market price. The marginal production cost of a given unit is composed of three main components: CO_2 emissions cost, fuel cost and variable OPEX, as shown in Figure 5.11.

Figure 5.11. Marginal cost estimation methodology in the market simulation



Source: REKK

Demand data

Within each year, we model the market equilibrium in 24 separate demand periods. We sum up the total consumption in the analyzed 15 countries for every hour in 2007 and group the hours into 24 separate demand periods. The first group represent the lowest load hours, while the 24th represents the highest load hours.

After classifying the hours into separate demand groups, we take the individual country observations for each hour and calculate their average in a given period. Finally, we determine the average load for all of the analyzed countries in 2007 and we also calculate the ratio of the given load of the demand period to the average load, which ratio is different country-by-country.

5.11.2. Modeling results

Using the demonstrated model, we can calculate the production (and also the trade flows between neighboring countries) of all of the power plants in the region in every different (24 annual) load situations in a year, and also the price for a country for a given load situation. Based on these data we can calculate the yearly profit for a given power plant. Comparing this profit to the yearly fixed cost of the power plant we can get the final profit in a given year.

First, we demonstrate the expected utilization of the old power plants, which operate in 2010 as well, and also the newly commissioned power plants. Furthermore, we determine the yearly profit of all of the power plants, which we compare to the fixed cost, and from that the net profits are derived. In the last part of this session we carry out sensitivity analyses as well.

Electricity price forecast

One of the main outputs of the modeling is the wholesale price in the analyzed countries. We demonstrate both the base load prices and the peak load prices. The latter are crucial for the gas-fired power plants because their marginal costs of electricity production are relatively high compared to the base load power plants, implying that they can produce electricity only in peak hours.

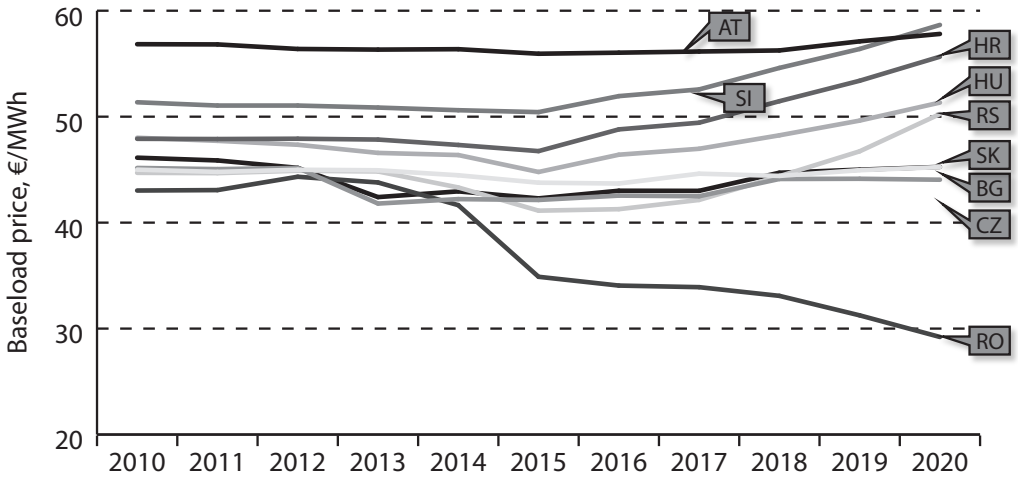
In the base scenario, we assume that natural gas prices are connected to crude oil price which is assumed to be stable at the price level of 70 $/barrel in real terms in the next decade. Another assumption is that EU Member States will meet their non-binding RES electricity generation targets. We expect that the CO_2 price will remain at 15 €/t (in real terms) through the next decade. The last main assumption is that only those investments will be finished where the investment is under construction or the construction has already been approved.

In 2010 base load prices vary between 42 and 56 €/MWh in the region. The highest price is in Austria, the lowest in Romania. In Austria the price is nearly the same as in Germany due to the strong interconnections. In Romania there is a sharp price decrease in 2014 and in 2015 due to the connection of two new large power plants to the grid: a 600 MW coal unit (Braila IV.) in 2014 and 1440 MW nuclear power capacity (Cernavoda 3 and 4) in 2015.

According the results, base load prices will be quite stable until 2015 and after that - except in Romania – they will increase. Most of known investments will be executed until 2015, while in the second half of the decade the consumption will be still growing, but no new capacities will be executed. The lack of new investments and electricity

consumption growth in the second part of the decade bring about a higher price level in most of the analyzed countries.

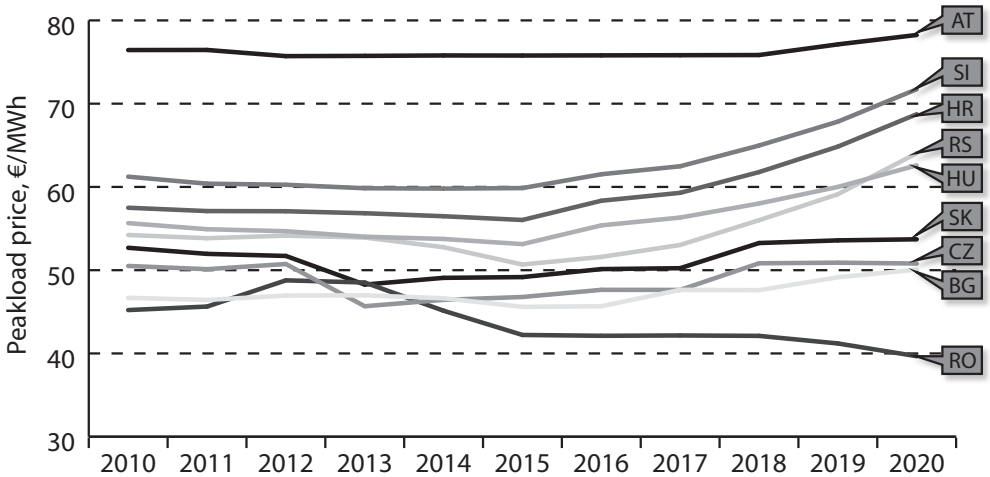
Figure 5.12. Base load prices in the analyzed countries between 2010 and 2020



Source: REKK market simulations

Peak load prices show similar trends, except that they are distributed in a wider range: in 2010 between 45 and 76 €/MWh, while in 2020 40-78 €/MWh.

Figure 5.13. Peak load prices in the analyzed countries between 2010 and 2020



Source: REKK market simulations

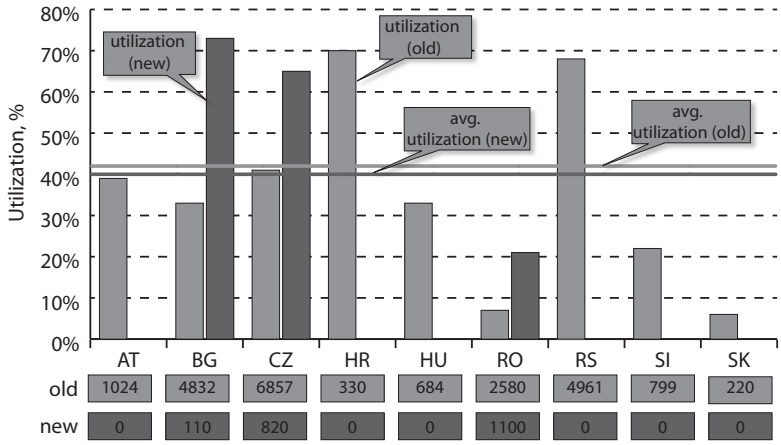
Utilization of the coal and gas-fired power plants

In order to determine the total profit of a given power plant, first we have to calculate its utilization. In the following we determine the average utilization of old power plants

(already in operation in 2010) and also of new projects where the investment is under construction or the construction has already been approved.

According to the modeling result, the average utilization of coal-fired (and lignite) power plants are 40.2% in the case of old power plants and quite the similar (41.7%) for new ones. The highest utilization rate of old power plants is in the non-EU countries, while the lowest is in Romania and Slovakia. New power plants produce more electricity due to their lower marginal cost. In Bulgaria and in the Czech Republic new power plants operate with a 65-72% utilization rate.

Figure 5.14. Utilization of coal-fired power plants in the analyzed countries in 2015, and the total installed coal-fired capacity in a given country



Source: REKK market simulations

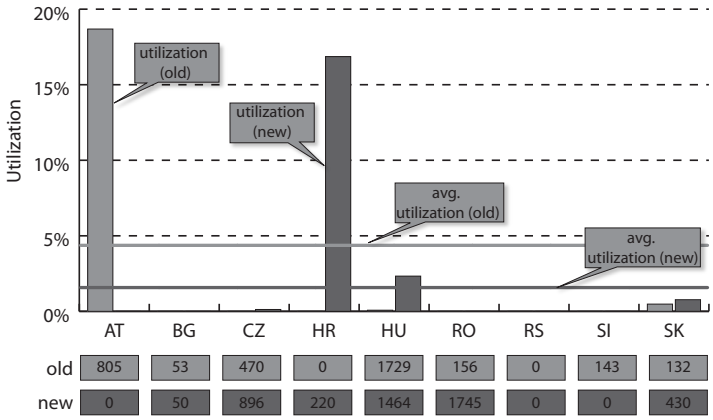
We see a totally different picture in the case of gas-fired power plants. The utilization rate exceeds 15% only in Austria, while in Slovakia, Hungary and in the Czech Republic it is far below 5%. In all the other countries gas-fired power plants cannot produce due to their high marginal cost.

We have to note that electricity productions from cogeneration plants are not included in these figures because their utilization rate is fixed (see Appendix A) and independent of the market situation. Another exemption in Hungary is that secondary reserves provided by gas-fired power plants are not taken into account in these figures.

In the base scenario nearly 5000 MW new gas-fired capacities are built, but they can produce electricity profitably only in Croatia, Hungary and Slovakia. This suggest that in

this situation, when gas-price is high, CO_2 cost is low and the penetration of RES capacities are fast, no new gas-capacities would be realized.

Figure 5.15. Utilization of gas-fired power plants in the analyzed countries in 2015, and the total installed gas-fired capacity in a given country



Source: REKK market simulations

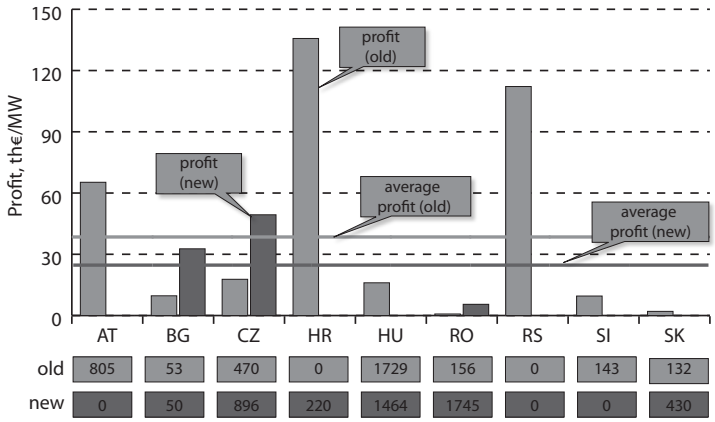
Yearly profit of the coal and gas-fired power plants

After examining the utilization rate of different types of power plants, we present the yearly profit for coal and gas-fired power plants. We determine the profit per MW, and not per MWh because the yearly fixed costs are related to capacity and not to generation.

The average profit of old coal-fired power plants is 40 th€/MW, while for new ones it is below 25 th€/MW. It is striking that in Croatia and Serbia profits are much higher than in other countries. The reason is very simple: in these countries there is no CO_2 regulation which means zero CO_2 cost that lowers their marginal cost. Calculating with an average 1 tCO_2/MWh emission, 15 €/tCO_2 carbon price and with 50 % utilization rate we get an amount of 65.7 th€/MW. This number shows the relative competitive advantage of non-EU countries.

In the Czech Republic the new capacities can produce nearly twice as much profit as old power plants and this profit per MW is the highest within the analyzed EU countries.

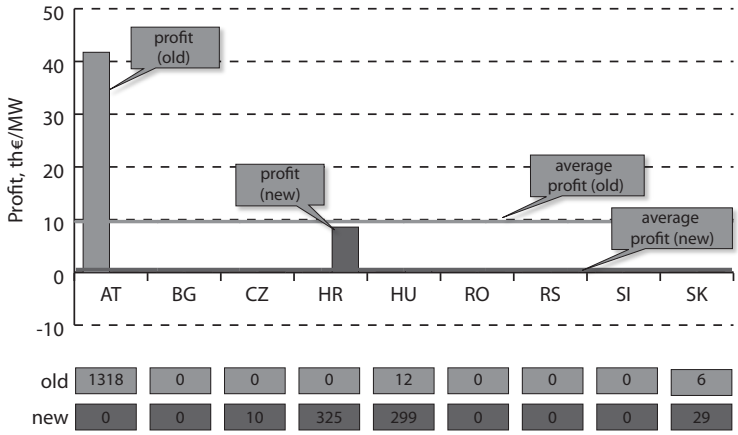
Figure 5.16. Yearly profit of coal-fired power plants in the analyzed countries in 2015, and the total net generation of gas-fired capacity in a given country



Source: REKK market simulations

As we expect, the profit of gas-fired power plants are small. Only in Austria (old power plant) and in Croatia (new power plant) could profits be significant. The profit level is 42 th€/MW in the previous country, and 8 th€/MW in Croatia.

Figure 5.17. Yearly profit of gas-fired power plants in the analyzed countries in 2015, and the total net generation of gas-fired capacity in a given country



Source: REKK market simulations

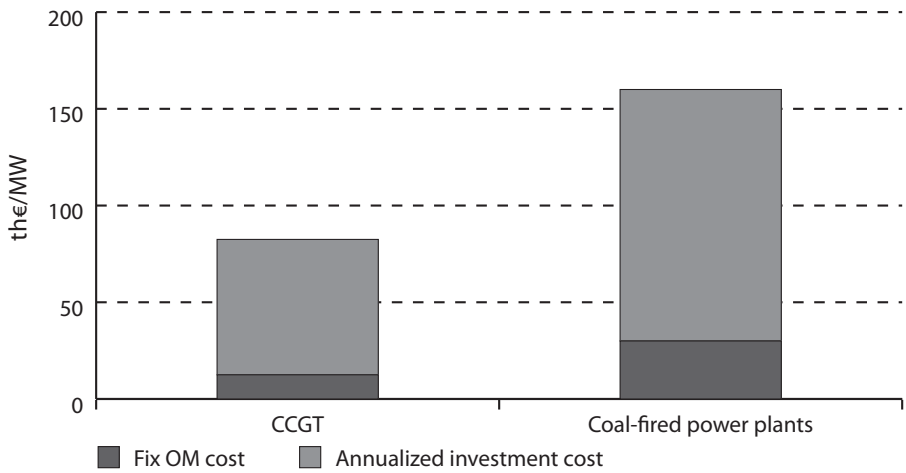
The existence of profit itself does not mean that it is worth to produce electricity in a

given power plant, for that decision we should consider the yearly fixed costs as well. Fixed cost consists of two main parts: operational and maintenance cost (O&M) and capital expenditure (CAPEX).

The total O&M cost is 25 th€/MW in CGGT, and 60 th€/MW in the case of coal-fired power plants, according to an EU Commission Staff working document (SEC, 2008). O&M cost can be split into two further categories: variable and fixed parts. The previous one has been taken into account in the marginal cost as well. We assume that the fixed O&M cost is half of the total O&M cost.

Total investment cost is around 635 th€/MW in the case of CCGT and 1265 th€/MW for coal-fired power plants (SEC, 2008). The lifetime of these power plants are quite different: CCGT can operate 30 years, while coal-fired power plants lifetime is 40 years. If we calculate with a 10% real discount rate and annualized the investment costs, we can derive the following CAPEX figures.

Figure 5.18. Fix O&M cost and CAPEX, th€/MW



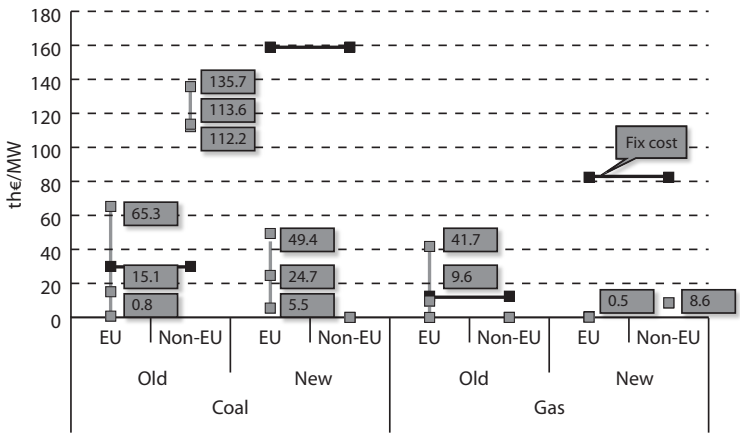
Source: SEC (2008)

Both the fix O&M cost and the CAPEX is lower in CCGT compared to a coal-fired power plant. We assume that CAPEX is only taken into account in new power plants, while in old power plants this value is zero because investment capital has already been depreciated.

It is important to compare the annual profit with the annual fixed cost. In the following we demonstrate the minimum, the maximum and the weighted average yearly profit excluding fixed cost, and the fixed costs themselves for different technologies. We split

the analyzed countries into two groups: EU countries (AT, BG, CZ, HU, RO, SK and SI) and non-EU countries (RS, HR).

Figure 5.19. Average/minimum/maximum yearly profit excluding FC for different technologies and regions and FC in 2015, th€/MW



Source: REKK market simulations

As we can see, the profit of old coal-fired power plants in non-EU countries (114-136 th€/MW) is higher than their fixed costs (30 th€/MW) meaning that these power plants can operate in the long-term as well. In EU countries the picture is not so clear. Although, in Austria the yearly profit is enough to cover the annual fixed cost (65.3 th€/MW profit vs. 30 th€/MW fixed cost) but the annual profits of other countries in the group are below the level of fixed costs. If this situation is the same in the whole decade then some of these power plants might better be decommissioned.

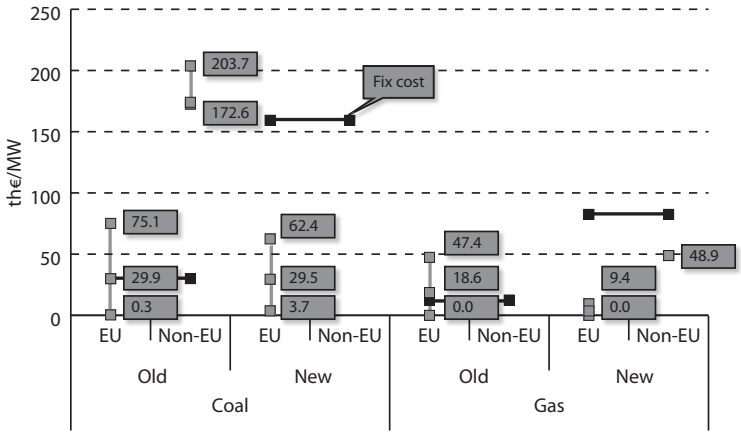
But there is another factor influencing the profitability of the power plants operating in the EU countries: plants in the EU get CO_2 quota for free which decrease their yearly fixed cost. As we have already demonstrated this could exceed 60 th€/MW in the case of a coal power plant. Free allocation will remain until 2012, and in some countries it might be continued until 2020. Due to the freely distributed quotas, old-power plants could keep operating in a profitable way.

In the case of new investment the situation does not look so prosperous. Although the yearly profit is a bit higher compared to old generators but their fixed cost is much higher (because of CAPEX) and their yearly profit is not enough to cover fixed costs. In non-EU countries there is no new coal-based investment until 2015.

As we have pointed out before, gas-fired power plants can operate only for a few hours in a year (except Austria) and being the marginal producers they do not generate much profit even in those hours. It means that it is more problematic to operate them in a profitable way compared to coal-fired plants. New gas-fired power plants are in the worst

situation because they can not produce profit, so probably these investments will be not executed.

Figure 5.20. Average/minimum/maximum yearly profit excluding FC for different technologies and regions, and FC in 2020, th€/MW



Source: REKK market simulations

The situation in 2020 is better than in 2015 but neither new coal, nor new gas-fired power plants can cover the fixed costs, meaning that it is not worth to invest in fossil-based power plants for the time being. Old coal-fired power plants can operate profitably in non-EU countries, and their total profit is higher than in 2015. In EU countries in 2020, not only plants in Austria but also the average old coal-based generator of the region can produce electricity in a profitable way. Similar profitability can be seen in the case of old gas-fired power plants in EU countries.

Sensitivity analyses

In the following sections, we show the results of various sensitivity analyses in comparison to the base case forecast discussed above. We analyze the sensitivity of our results to changes in the following input data:

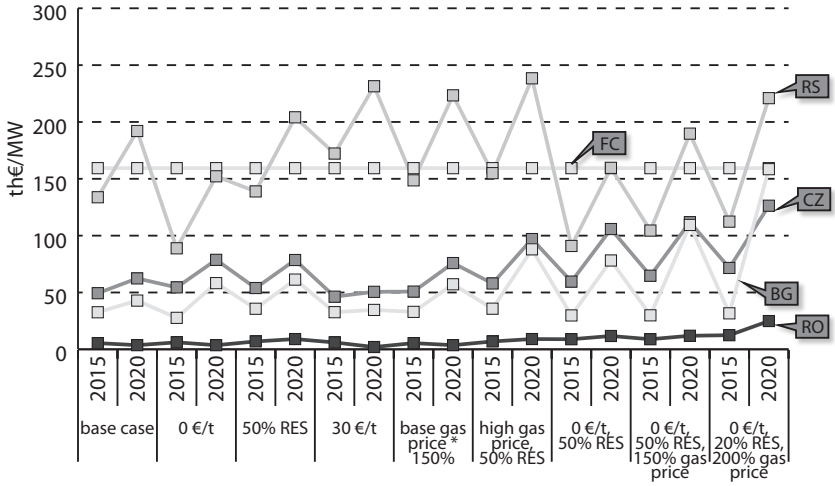
- CO_2 price: from 15 €/t to 0 and 30 €/t.
- Natural gas price: In Central and South-East Europe, natural gas is more expensive than in Western European countries due to the lack of gas-to-gas competition (natural gas is imported dominantly from one direction). So in our sensitivity analyses we calculate with a 30% discount in the gas price. The other extreme, but probably not totally unrealistic case when the gas price is 1.5 times higher than in the base case assuming high oil price and a non-competitive gas market.
- RES targets: As we have seen before in some countries the non-binding RES-E target is quite ambitious (e.g. in Romania). Hence we examine the effect of halving new capacities to be built until 2020.

First, we execute the sensitivity analyses for the new coal-fired power plants and after that for the gas-fired power plants. We do not demonstrate all the variation in input data, only those that increase profitability.

It is conspicuous that in only one country (Serbia) is it profitable to build coal-fired power plants. We have to note that this power plant is only a virtual one with a capacity of 1 MW, for the lack of actual investment plans in the near future. This virtual power plant can cover its fixed cost in most cases, as you can see in Figure 5.21.

In all the other countries coal-based investments are not profitable except in the extreme situation when the cost of carbon is zero, two times higher gas price and only 20% of the new RES put into operation.

Figure 5.21. The specific profit for new coal-fired power plants in different countries and in different scenarios, 2015, th€/MW

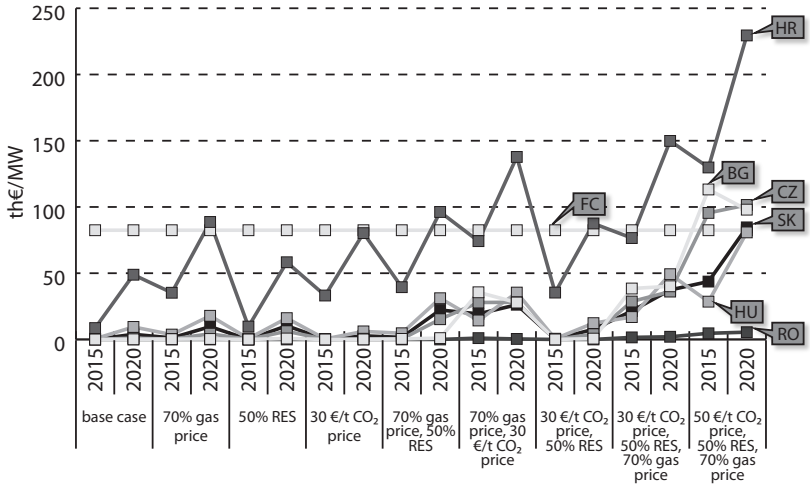


Source: REKK market simulations

We gained very similar results for gas-fired power plants. Only Croatia seems to be a country to build new gas-fired power plant but only if the gas price is relatively low or CO_2 cost is high and only half of the new RES is out in operation. The profitability increases considerably for the region in general only if the CO_2 cost is quite high (50

€/t), only half of the new RES generation is executed and these countries enjoy Western European gas price level.

Figure 5.22. The specific profit for new gas-fired power plants in different countries and in different scenarios, 2015, th€/MW



Source: REKK market simulations

5.12. Conclusion

In this study, we set out to explore whether liberalized wholesale electricity markets in the Central and South-East European region provide enough incentives for investments into new generation capacity, thus preserving long term supply security in the sector.

In fact, we have found that new investments are abundant, and – using a competitive regional electricity market simulation model – have even pointed out that many of them might not earn an adequate return on investment until 2020. The main explanations lie with the drop in power consumption during the economic crisis, the heavily subsidized growth of renewable electricity sources, and the slow decommissioning of older units.

We also pointed out a likely effect of CO_2 emissions pricing, which is that building and operating new fossil-fuel plants will be considerably more profitable in non-EU member countries in the Balkans, such as Serbia and Croatia. On a regional level, this development should not affect the supply security situation negatively, as long as cross-border transmission capacities are allocated transparently and non-discriminatively.

Overall, our assessment suggests that long term supply security in electricity has not been endangered by market deregulation, although the continuing presence of governments in the sector must also be acknowledged.

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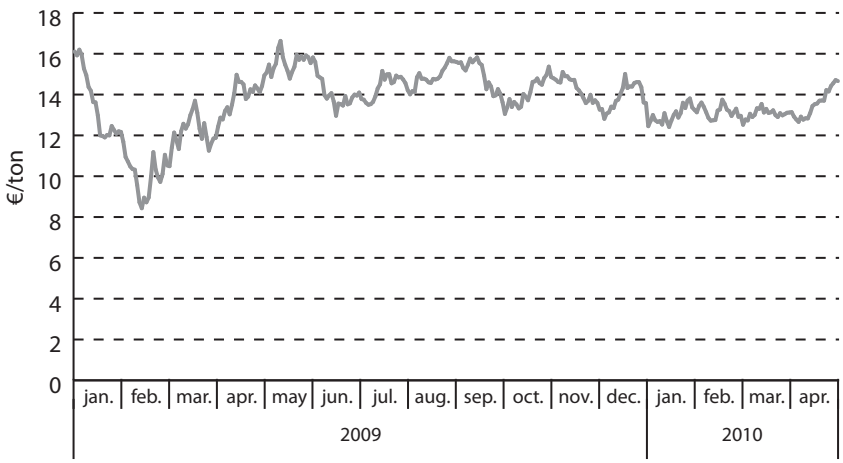
5.14. Appendix

In the following we summarize the main assumptions related to the supply side of the electricity market, most of them is needed to calculate the marginal cost of the production of a given power plant.

5.14.1. CO_2 emissions cost

CO_2 emissions costs arise in the case of fossil fueled units (coal-, gas- or oil-fired) in countries that participate in the EU's Emission Trading Scheme (ETS). Burning fossil fuels produces CO_2 emissions for which power plants must possess a corresponding number of EU Allowance Units (EUA's). EUA's are traded in exchanges and have a transparent price that has lately fluctuated around 14-15 €/ton (for December 2010 delivery, see Figure 5.23). For forecasting purposes, we include an EUA price of 15 €/ton in the base scenario.

Figure 5.23. Recent EUA prices in Europe



Source: ECX

The number of EUA's needed to produce 1 MWh of electricity depends on the type of fuel used and the efficiency of fuel energy conversion into electricity (unit heat rate and self-consumption). Table 5.5 shows the CO_2 emissions of various fossil fuels. According to the data, a gas-fired unit produces about half as much CO_2 as a lignite plant with the same efficiency.

Table 5.5. CO_2 emissions by fuel type

Fuel type	CO_2 emissions [kg/GJ]
Hard coal	93.7
Lignite	112.1

Fuel type	CO_2 emissions [kg/GJ]
Natural gas	55.8
Heavy fuel oil	77.0
Light fuel oil	73.7

Source: UNFCC

A quick calculation shows that the marginal CO_2 cost of a CCGT unit with a 50 percent overall efficiency is around 6 €/MWh, whereas the CO_2 emissions of a lignite-fired unit with a 30 percent efficiency costs about 20 €/MWh.

5.14.2. *Fuel cost estimation method*

The fuel cost in each generation unit depends on the type and price of fuel, and the overall efficiency of electricity generation, which is the product of two factors: the amount of electricity generated from 1 MWh of primary fuel burnt (fuel efficiency), and the amount of electricity fed into the network from 1 MWh of electricity generated. The latter factor differs from unity by the proportional self-consumption of a generation unit. We also add an energy tax element to the fossil fuel price for EU member countries.

Availability and fuel efficiency

Table 5.6 and Table 5.7 list the assumed efficiency and availability parameters (based on the literature and empirical observation) for various power plant types and commissioning dates.

Table 5.6. Gross fuel conversion efficiency factors

Year of commissioning	Fuel conversion efficiency		
	Gas/Oil ST	Coal ST/Biomass	CCGT
1960	37%	35%	-
1970	39%	37%	-
1980	41%	39%	-
1990	43%	41%	50%
2000	45%	43%	55%
2010	47%	45%	58%
2020 (assumed)	49%	47%	60%

Source: KEMA (2005)

Table 5.7. Self-consumption and expected availability of power plants

Plant type	Self-consumption	Availability
Gas/oil-fired steam turbine	5%	90%

Plant type	Self-consumption	Availability
Coal/biomass-fired steam turbine	13%	85%
CCGT	5%	90%
Nuclear	6%	95%
Wind	-	20%

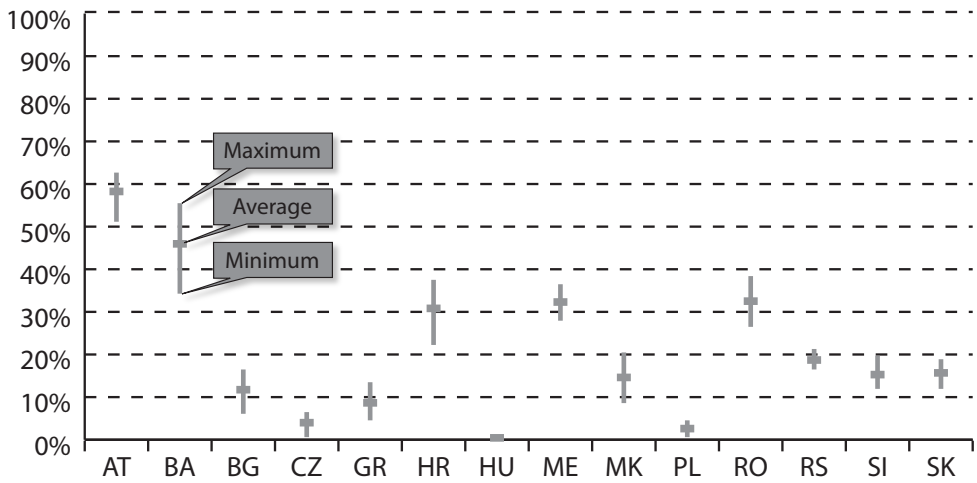
Source: REKK calculations

Table 5.7 also shows the assumed average availability of a unit, i.e. the percentage of days when it is not under maintenance. For wind turbines, the availability parameter equals the average utilization rate, since wind generation is a weather-dependent technology.

Since nuclear units are always in base load operation and they are hardly ever the price setting producers, modeling their fuel costs with a bottom-up approach starting with fuel efficiency is an unnecessary complication. Instead, we use a fuel cycle cost estimate of 10 €/MWh as the upper limit of figures cited in the literature. Regarding wind and hydro producers, their short run marginal costs are assumed to be 0 €/MWh.

The availability of hydro units is a more delicate question. In general, it is a function of the average water discharge of the river they are built upon, but that itself is an often changing function of annual precipitation in the given area. Based on previous observations, Figure 5.24 shows the minimum, maximum, and average annual production levels of hydro power plants in the modeled countries as a percentage of annual domestic consumption.

Figure 5.24. Annual production levels of hydro plants by country as a share of total domestic consumption



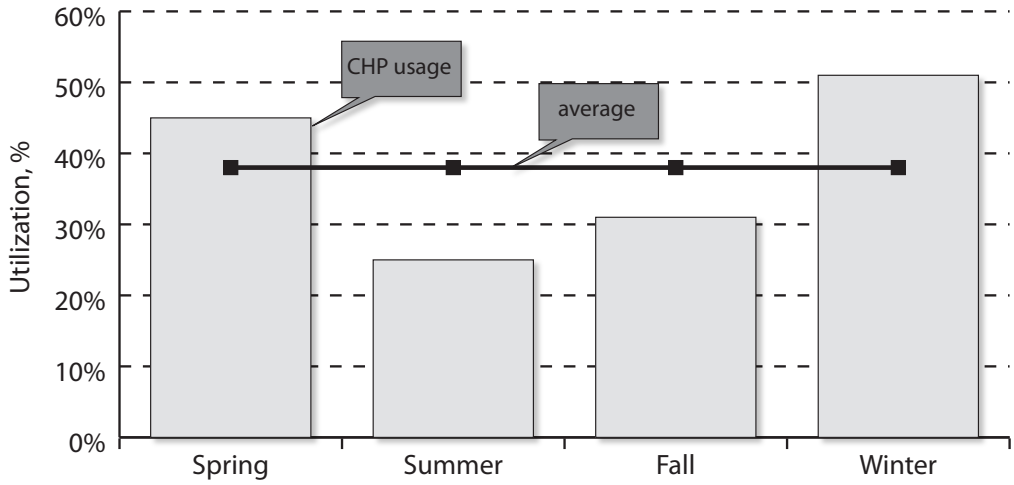
Source: ENTSO-E, REKK calculations

The availability factor of hydro units is set equal to their observed average utilization rate, in the baseline scenario.

Combined heat and power plant (CHP)

In the market simulation we assume that the production of CHP units are heat driven, which mean they have to produce electricity as well when they produce heat. Furthermore we assume that between 2010 and 2020 they will produce the same amount of electricity as they did in 2008 with the following utilization in a given season.

Figure 5.25. Utilization of CHP units



Source: MAVIR

Secondary reserve

In the case of Hungary we take into consideration reserves as well, but only secondary reserves. Primary reserves can be provided by most of the participants and the quantity of primary reserve is quite small, only 10-20 MW per year, while in the case of tertiary reserves power plants have enough time to react and not only gas-fired power plants can provide this type of reserve.

We assume that secondary reserves are fully provided by spinning, gas-fired power plants: it is necessary to be able to decrease the production, which is only possible if the power plants are spinning, while only gas-fired power plants have as fast reaction time as is required by the TSO. In the following we determine the amount of necessary secondary reserve.

However, to provide a given amount of reserves to the system, power plants must run at an excess capacity because of minimum utilization requirements. As a result, we preferred to estimate the minimum presence of gas-fired capacity in the system, which turned out to be 500 MW in the summer of 2009. We take this value to be the necessary spinning reserve requirement.

Fuel prices

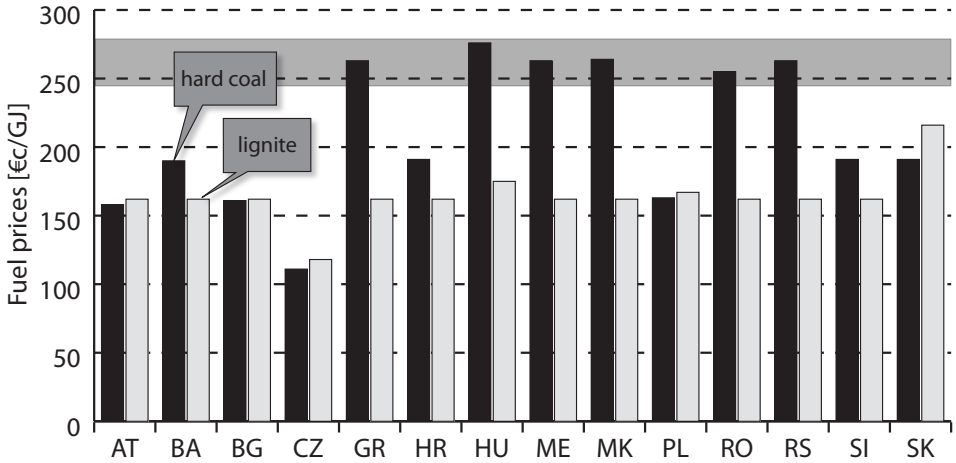
There are 3 types of fossil fuels to calculate with:

- **Solid**: hard coal, lignite, biomass
- **Liquid**: light and heavy fuel oil
- **Gaseous**: natural gas

For **solid fuel** types, we maintain the assumption that prices of these are largely independent of the crude oil price and remain constant in real terms throughout the modeled period. Biomass prices are fixed at 4 €/GJ.

Figure 5.26 shows hard coal and lignite price assumptions for the modeled region. The current range of international coal prices in Western and Northern European ports are shown by the grey rectangle (around 247-278 €c/GJ). Several countries have prices below this level, which is mostly attributable to cheaper local sourcing (and prevalent subsidies on mining).

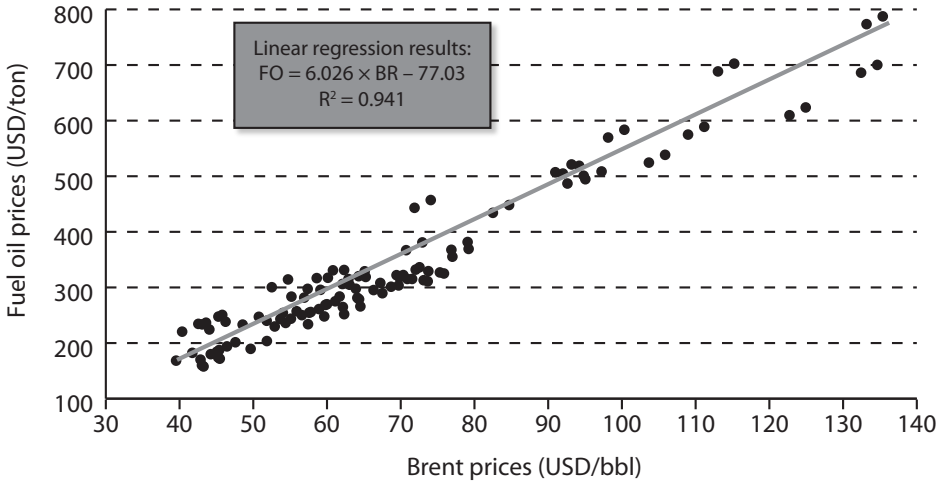
Figure 5.26. Assumed hard coal and lignite prices in the model



Source: KEMA, PLATTS, REKK calculations

Liquid fuels are refined oil products. Since the refining process operates with fixed proportions of output to input, it is reasonable to expect close co-movement between crude oil and fuel oil prices.

Figure 5.27. Average monthly Brent and light fuel oil prices in European ports (August 2004 – March 2009)



Source: OECD, REKK calculations

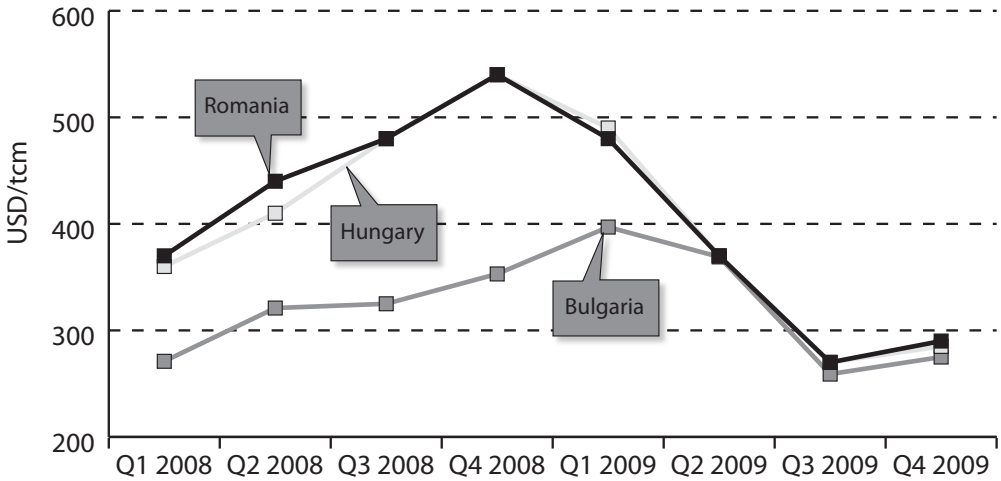
Indeed, as it is shown, these prices track each other closely. Based on average monthly price data between August 2004 and March 2009, crude price changes explain 94 percent of the variation in LFO prices. This estimated linear relationship will be used in the prediction of the future LFO price based on crude oil price forecasts. We take heavy fuel oil (HFO) to be 5 percent cheaper than light fuel oil.

Natural gas prices are also linked to the crude oil price via long-term Russian import contracts that make up an overwhelming share of domestic gas consumption in Central and South-East European countries. In a common contracting formula, the gas price is indexed to an equally weighted average of light fuel oil and gas oil prices. Since access to (currently cheaper) alternative gas sources in Western Europe is blocked by the inadequacy of the infrastructure, we use the known import gas pricing formula for predicting future prices (based on expected crude price developments), also adding a 5 percent markup to cover the cost of domestic transportation and storage.

Figure 5.28 provides evidence that using a single import pricing formula is an adequate approximation to gas prices across the region. The graph shows the gas import prices in Bulgaria, Hungary and Romania as reported by the respective regulatory authorities for

2008-2009. Although Bulgarian import conditions used to be more favorable, they were completely adjusted to the other countries' pricing level about one year ago.

Figure 5.28. Natural gas import prices through long-term contracts with Russia



Source: ANRE, HEO, SEWRC, REKK calculations

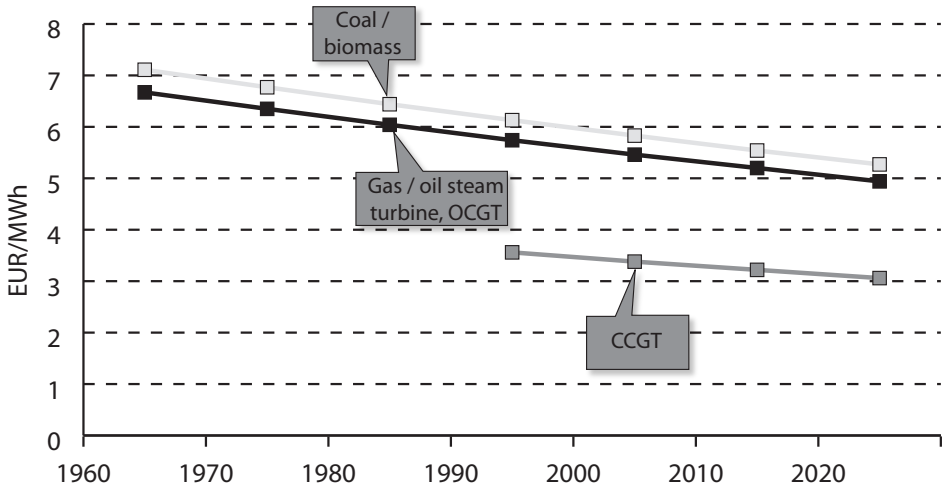
5.14.3. Crude oil prices

In the base case of the modeling we use the similar, 70 $/barrel crude oil price between 2010 and 2020 (in real terms).

5.14.4. Operating expenditures (OPEX)

The final element of marginal cost estimation is the inclusion of the variable part of operating expenditures. An approximation of these for the potentially price-setting (marginal) technologies is shown in Figure 5.29.

Figure 5.29. Estimated variable operating expenditures by technology and year of build



Source: data collection by MOL Hungary

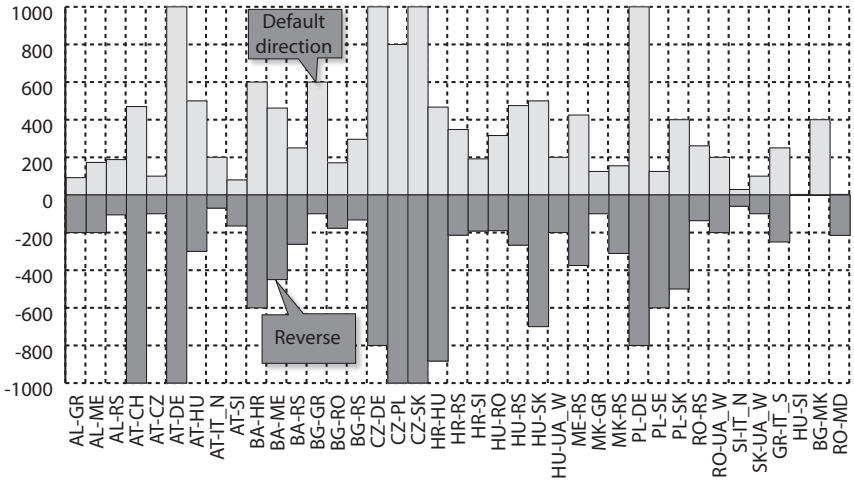
5.14.5. Decommissioning

Decommissioning of power plants was more problematic, because it is dependent on not only age of the power generator, but also hang on the market environment. Sometimes it is worth to refurbish a power generator, even it is very old. In general, we do not really information about the expected date of decommissioning in a specific power plant, only in some cases. Where we have no clear information on the date of decommissioning, we assume that a power plant will be closed after their lifetime, but at least it will operate till 2012. In coal (or lignite)-fired power plants we assume a lifetime of 50 years, in the case of OCGT 40 years, while we expect a 30 years long lifetime for CCGT.

5.14.6. *Cross-border interconnections*

The capacities available for cross-border trade in the model are shown in Figure 5.30. In addition, Table 5.8 details the new interconnection capacities likely to come online from 2010 to 2020.

Figure 5.30. Existing capacities for cross-border trade (below 1000 MW)



Source: ENTSO-E

Table 5.8. Expected cross-border capacity expansions

Country 1	Country 2	Year of commissioning	Capacity [MW]
HU	HR	2011	400
HU	SI	2015	300
RO	RS	2015	350
RS	MK	2010	350
ME	AL	2010	350
BG	GR	2017	350
HU	SK	2018	350

Source: ENTSO-E

5.14.7. *Neighboring market prices*

Market prices for large Western European markets, such as Germany or Italy are linked to the crude oil and CO_2 prices, as well as demand period. Smaller outside markets, such as Moldova or Ukraine, are taken into account as low price import sources for the region.

Lessons from the 2009 January gas crisis for Central and South East Europe

6.1. Introduction

The purpose of this paper is to draw the lessons from the EU's January 2009 gas crisis for national governments and regulators of the most affected countries. The results of the study are based on the review of the crisis related experiences of Austria, Bosnia and Herzegovina, Bulgaria, Croatia, the Czech Republic, Hungary, Romania, Serbia, Slovakia and Slovenia (in the followings: SOS countries). Most importantly, we try to explain the difference in the performance of the countries under study in mitigating the effects of the crisis that had emerged from a dispute between Russia and Ukraine on terms and conditions about future gas shipments to Ukraine and the transit shipments through Ukraine to the European Union. The understanding of success factors in crisis management can help shaping the appropriate policy response to the risk of similar future events. Finally, we point out the need to reform some present regulatory practices regarding gas crisis management at the national level.

6.2. Gas industry background

The natural gas industry of the EU is characterized by important regional asymmetries. Among them the asymmetries in network topology and in gas supply sourcing between Central and Eastern European (CEE) new member states and Energy Community members on the Balkans versus the continental 'old' member states are important to understand for the study of the 2009 gas crisis (Kaderják et al, 2007, Noel, 2007, Kaderják et al, 2008).

The gas transmission networks of old members are relatively well interconnected. Pipeline connections to all the three major supplying regions (Russia, Norway, North Africa) as well as a fast developing LNG infrastructure are available for them. This topology supports gas sector cooperation across member states and allows for a substantial diversification in supply sourcing. On the contrary, the gas transmission network topology in the Visegrad 4 continental new member states (Poland, Czech Republic, Slovakia and Hungary) reflect the East-West gas transmission routes connecting major Russian gas fields to markets in Central and South Europe (Germany, Italy) and points of delivery further to the West. North-South connections and consequent cooperation across these member states are missing. With regard to South East Europe, interconnections among the three different routes[1] that provide Russian gas supplies to these countries are still missing. The first exception to this case is the 4.5 mcm/day interconnector between Hungary and Romania that was commissioned in October 2010, however, it still does not provide reverse flow. The current physical gas infrastructure of the CSEE countries does not allow for much diversity in gas supply sourcing.[2]

A high level of unilateral gas import dependence on Russia is the other important characteristics of the CSEE gas sectors. While in 2006 the share of Russian gas in the primary gas supply of EU15 was an average of 20%, the same share for nine out of the ten[3] Eastern European member states was above 50%, and for six above 80%. There is, however, a wide variation among these countries regarding the importance that natural gas plays in serving overall energy needs and in fueling electricity generation and economic growth.[4] We compare the natural gas dependence of selected SOS countries[5] to the EU average by the employment of a combined measure and depict the results by Figure 6.1. As we can see, Slovakia, Bulgaria and Hungary are the most exposed economies in this regard – they produce the same amount of GDP by using 5-6 times more gas than the

[1] 1) Russia-Ukraine-Romania-Moldova-Bulgaria-FYR of Macedonia; 2) Russia-Ukraine-Hungary-Serbia-Bosnia and Herzegovina; 3) Russia-Ukraine-Slovakia-Austria-Slovenia-Croatia.

[2] Note also that for these countries there is a fundamental difference between how the operations of their electricity as opposed to the gas systems changed as a result of the EU accession process between 1990 and the mid 2000s and the connected reorientation process from Russia to the EU. While, as a consequence of UCTE harmonization, the cooperation of the electricity system of new members halted with Russia back in the middle of the 1990s, and has been technically integrated into the European electricity grid, in the case of gas the political changes had in fact no effect on how the gas transmission system has been operated since then.

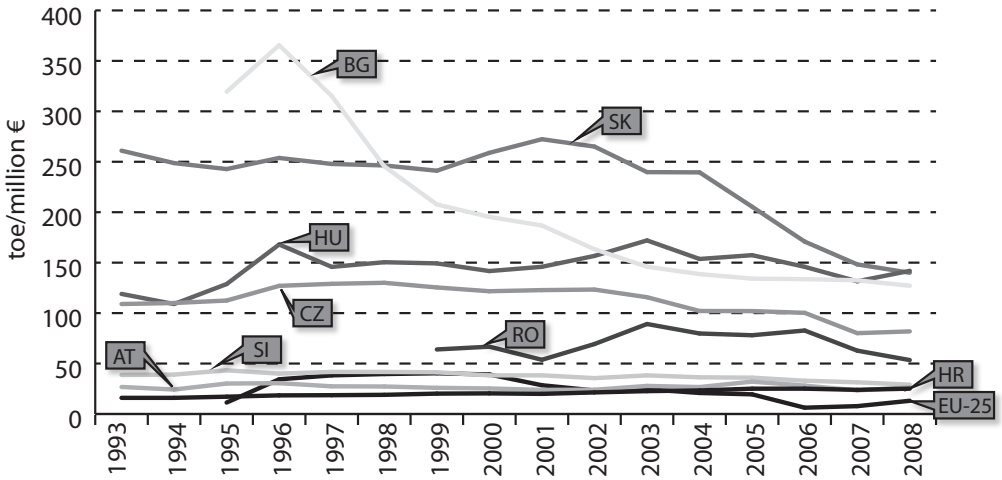
[3] The exception is Romania, due to its significant domestic gas production.

[4] See also the analysis of Noel (2007) in this regard.

[5] Comparable data for Serbia and BiH were not available.

EU average. In the case of Romania and the Czech Republic the according multipliers are 2 and 3.

Figure 6.1. Natural gas dependency of the economies of CSEE countries* toe/Million



Euro (on year 2000 GDP basis)

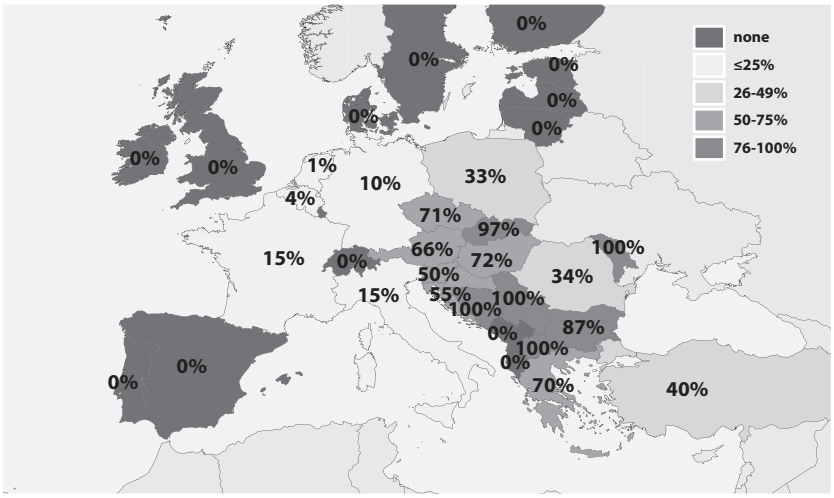
*This index is a combined one, and it can be expressed as follows:

(net gas import/GDP) = (net gas imports/total gas used) * (total gas used/total energy consumption) * (total energy consumption/GDP).

Therefore, it is a combination of import dependency, gas dependency and energy intensity

Due mostly to the asymmetries in network topology and gas supply sourcing, the 2009 gas crisis had also a highly asymmetric impact on the EU gas economies as illustrated by Figure 6.2.

Figure 6.2. Reduction in gas supply (imports + domestic production) on January 7, 2009



Source: Boltz (2009b)

Table 6.1 provides an overview of basic gas market data on the annual balance of consumption and supply sources for those countries analysed in this paper. Note that the aggregate size of the gas markets under study equals only about 70% of the German gas market. As we can see, natural gas based electricity generation accounts for more than 30% of gas consumption in Hungary and Austria, while gas consumption for industrial purposes plays a dominant role in Slovenia (57%) and Serbia (54%) and its share is over 30% in Austria, Bulgaria and the Czech Republic. Short-term fuel substitution in electricity generation or load shedding in the case of the rest of industrial activities is relatively easy and can be mandated by the gas TSOs or energy regulators. To apply demand side measures is more complicated in case of direct household gas use. Household consumption is dominant in the Czech Republic (42%) and Slovakia (44%) but its share is close to 30% in Hungary, Croatia, Serbia and Romania.[6]

[6] We divided the gas consumption of combined heat and power production 50-50% between electricity and the household sector. For updated data on the structure of gas consumption in these countries visit http://www.iea.org/gtf/.

Table 6.1. Annual gas supply and demand data for the countries under study, 2007

	Share of natural gas in primary energy use (%)	Domestic production bcm/year	Import bcm/year Per source			Mobile storage capacity	Annual gas consumption			
			Russian	Other	Total		Households	Electricity and heat	Industry	Total
Austria	23	1.8	4.2	2.4	6.6	4.2	2.2	2.6	2.7	8.4
Bulgaria	14	0.4	3	0	3	0.6	0.8	0.44	1.11	3.4
Bosnia and Herzegovina	6	0	0.32	0	0.32	0	0.1	0	0.2	0.32
Czech Republic	16	0.09	6.75	2.25	9	2.90	3.8	0.45	3	9
Croatia	26	2.9	1.05 (export 0.75)	0	1.05 (export 0.75)	0.62 (10% is rented by Slovenia)	1.08	0.4	0.72	3.3
Hungary	43	2.5	7.9							
(East)	2.6 (West)	10.5	3.8	4	4.3	1.5	13			
Romania	36	11.3	5.7	0	5.7	2.8?	4.7	3	4.3	17
Serbia	13	0.25	2.14	0	2.14	0	0.65	~0.45	1.3	2.4
Slovakia	31	0	9	0	9	2.8	4	0.4	1.8	9
Slovenia	14	0	0.66	0.54	1.12	0.11 (rented)	0.17	0.11	0.68	1.2

In order to better understand the short-term flexibility features of the gas systems under study to react to supply shocks, we collected the data presented in Table 6.3. By combining information from the previous tables we can immediately identify the most obvious supply side options that were available for the SOS countries to replace imported Russian gas during the crisis. The three most important supply side options are alternative (non Russia contracted) imports, domestic production and increased withdrawal from gas storage (see Table 6.2).

Table 6.2. Availability of supply side options for SOS countries to replace Russia contracted gas imports

	IMPORT DIVERSIFICATION (Non-Russia contracted import/total import, annual)	DOMESTIC PRODUCTION (production/ winter peak load)	STORAGE (withdrawal capacity/ winter peak load)
Austria	36%	16%	104%
Bosnia and Herzegovina	0%	0%	0%
Bulgaria	0%	8%	35%
Czech Republic	25%	0%	96%
Croatia	0%	38%	45%
Hungary	25%	13%	69%
Romania	0%	54%	43%
Serbia	0%	6%	0%
Slovakia	0%	0%	73%
Slovenia	48%	0%	n.a.

As it seems apparent, underground storage withdrawal is the most robust option for the rest of the countries, most prominently Austria, the Czech Republic, Slovakia and Hungary. Domestic production is the most significant for Romania and Croatia. 'In-house' resources, that is withdrawal capacity and domestic production together is enough to serve peak load of Austria for some time and enough to serve 97% of peak load in Romania, 96% in the Czech Republic, 83% in Croatia, 82% in Hungary and 73% in Slovakia given that those facilities operate at their peak capacity. On the difficult side are Bulgaria, Bosnia and Herzegovina, Serbia and Slovenia. Four out of the 10 countries had managed to reach a certain level of contractual diversification away from Russia in their gas sourcing. Alternative partners for them come from Norway (Austria, Czech Republic), Germany (Austria, Hungary), France (Hungary) and Algeria (Slovenia).

Table 6.3. Short-term flexibility features of the gas systems under study (2007 data)

	Winter daily peak consumption, mcm/day	Peak capacity of domestic roduction, mcm/day	Daily import transmission capacity, mcm/day/relation			Storage withdrawal peak capacity, mcm/day
			Russian	Other	Total	
Austria	45	7	145	20	165	47
Bulgaria	13	1	80	0	80	4,5
Bosnia and Herzegovina	1.8	0	2	0	2	0
Czech Republic	57	0.25	145	n.a.	-	55
Croatia	12.7	4.8	5	0	5	5,7
Hungary	75	10	30 (+ 13 transit)	12	42	52
Romania	65	35	100	11	111	28
Serbia	11	0.7	13	0	13	0
Slovakia	30	0	300	65	300	29
Slovenia	4	0	~7			0 (renting in Austria)

6.3. A brief history of the crisis and the related literature

Between January 7th and 19th of 2009 the transit of Russian gas to Europe through the Ukraine was halted. This was the most serious European gas crisis to have happened since the start of Russian gas transmission to Europe decades earlier. According to Simpson (2009), a daily average of 380 Mcm or a total of 5 Bcm of Russian gas delivery through Ukraine to the EU and South East Europe was lost during these days. While the below average temperatures during the rest of the crisis days had an upward pressure on the daily gas load, this effect was mitigated by a significant drop in the non-household gas demand implied by the economic recession. Also, the weather in December 2008 was milder than the average and resulted in an oversupply of storage capacities on the European market during the crisis. Less favourable demand and storage supply conditions or a longer crisis could have had a much more detrimental impact on consumers than what they experienced in January 2009.

The chronology of the unfolding commercial and political dispute between Russia and Ukraine, the involvement and role of EU institutions and companies in resolving the problem as well as the details of the new long term agreement between Russia and Ukraine has been documented by Pirani et al (2009) already in February. The paper provides only preliminary comments on the impact of the crisis on European gas consumers (p. 53-56) and these comments are based mostly on the early reports from the Gas Coordination Group. In its conclusion this report already emphasizes the need to react from Europe's side in terms of new gas infrastructure developments, concentrating in the short-term on CSEE providing '...additional interconnection with neighbouring countries, North-West Europe and Southern European countries with the capacity to import additional LNG supplies from existing terminals, plus additional storage close to these markets' (p. 58). Soon after the crisis the International Energy Agency completed an assessment of the facts and figures on the gas industry impacts of the gas cut and of the measures by which the industry attempted to mitigate those negative impacts (Simpson, 2009). At the continental scale, the most important developments were the followings. Already at around January 7, the flow of the UK-Holland interconnector was reversed. In order to replace missing EU supplies through Ukraine, Russia increased gas shipments through the Yamal and Blue Stream pipelines. Three days later Germany increased gas shipments to Croatia and additional spot LNG cargoes became available for Greece and Turkey. At around January 16, Hungary increased gas shipments for Serbia and Bosnia and Herzegovina. Finally, just before the restoration of gas shipments through Ukraine, reverse flow was made possible to bring additional gas from the Czech Republic to Slovakia and from Greece to Bulgaria. In his assessment Boltz (2010, p. 14) concluded that Europe did not have a shortage in gas when the crisis hit but instead had a difficult time to get the gas from where it was to places where it was needed.

It was the Oxford Institute for Energy Studies that commissioned the first study that aimed at a deeper understanding of gas supply security preconditions in the region that was most seriously hit by the crisis. In his study Kovacevic (2009) covers countries from South East Europe having natural gas industries (Bosnia and Herzegovina, Bulgaria, FYR of Macedonia, Montenegro, Romania and Serbia). He notes the basic problem of

missing interconnection among the three different routes that provide Russian gas supplies to the investigated countries. A major message of the paper is related to the insufficient investments that the gas, electricity and district heating sectors had received in recent years, especially in light of the fast increasing (winter) peak demand for these services. The increased seasonality of demand together with still existing price subsidies for locally produced gas in Croatia and Romania prevents necessary investments to take place. An important observation of the study is that the supply of alternative fuels to replace gas was abundant during the crisis period (fuel oil for electricity generation; electricity and firewood for space heating). We can agree with Jonathan Stern stating in the preface to the Kovacevic paper that '…in South Eastern Europe the crisis therefore defined an energy efficiency and energy interconnection agenda for European utility stakeholders and policymakers.' Nevertheless, the Kovacevic paper covered only a limited number of affected countries from CSEE and it did not provide a systematic analysis of crisis management and its lessons. The first effort to accomplish the latter was made by Kaderjak (2009).

The staff of the European Commission completed an assessment of the crisis by mid summer of 2009 (COM, 2009) with a focus on the lessons from the crisis for European policy and served as a basis for promulgating the recent security of gas supply Regulation.[7] It puts the emphasis on identifying means by which emergency preparedness and crisis response mechanisms could be improved at the Community level. The paper recognises the asymmetric impact of the crisis on Central and Eastern European member states and some Energy Community members. It identifies the most important elements of a reinforced future gas supply security policy as the follows: the strengthening of the internal gas market mechanism; improved market transparency; a reinforced European gas infrastructure with special reference to constraints, missing interconnections and the need for reverse flows; national action to enhance demand response measures; contractual diversification; improved cross border cooperation in times of crisis situations; and a reinforced role for the Commission to coordinate action to prevent and respond to gas crises.

[7] Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC

6.4. Institutional arrangements of crisis management

In Table 6.4 we present available data on how the different countries offset the amount of missing Russian shipments by supply and demand side adjustments during the crisis. It is important to ask first about the institutional arrangements that played a role in coordinating the actions of supply and demand side market participants to mitigate the supply shock of the gas cut and ensured the balance between load and supply during crisis days.

We find that transparent market transactions, in-house transactions of multinational gas companies, extraordinary nominations of TSOs for which the right was provided by crisis action plans and other government measures like the implementation of end customer restriction regulations made up the mix of institutional reactions to the crisis.

There is a significant range in the state of gas market development and maturity in the region. Austria is the obvious example where its well functioning gas balancing market did the rest of the crisis management job. Its mechanism allowed 100% replacing of the missing Russian imports very quickly. The daily traded volume on the market during the crisis reached the average monthly volumes of 2008. A notable balancing gas price increase sent the appropriate signal for suppliers (i.e. storage operators, importers and producers) to increase their market participation. In addition, cheap fuel oil prices relative to gas product prices prompted gas fired power plants to voluntarily switch from gas to fuel oil during crisis days. (Boltz 2009a, pp 20-2.).

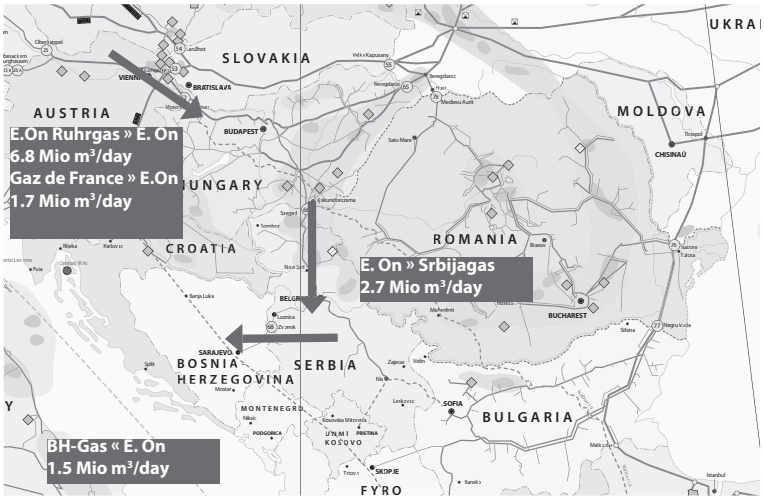
Table 6.4. Adjustments to missing Russian shipments by supply and demand side measures during the crisis

	Missing Russian import mcm/day	Additional supply (physical replacement)			Customer restriction			Official damage estimate (million Euro)
		Local production	Storage	Alternative import	Fuel switch	Industrial customers	Household / Protected customers	
Austria	10	0	10 (D)		√	Ø	Ø	-
Bulgaria	7-9	0.2	1	2 (GR) *	Yes, 6-7 mcm/day			225
Bosnia and Herzegovina	1,8	0	0	1.5-1.9** (AT -HU)	Yes, until January 12			n.a.
Czech Republic	15	0,25	5-10	10 (D)	Ø	Ø	Ø	-
Croatia	4	5,7			√	√	Ø	270
Hungary	24	3	21	transit	√ - 7	√ - 2	Ø	80
Romania	8-10	1	29	not possible	√	reduced demand due to recession	Ø	-
Serbia	10	0,7	0	4,7 (AT -HU)	√	√	√	50
Slovakia	17-20	not possible	14-16	3 – 4	√	√	Ø	1000***
Slovenia	0.9-1.2	not possible	1 (AT)	0.5-1	?	Ø	Ø	-

* from January 19
** from January 9
*** possibly overestimated

Market and price mechanisms played a substantially less prominent role in other countries of the region to manage the crisis. This is mostly due to either the complete lack (e.g. Serbia, Bosnia and Herzegovina and Croatia) or the poor functioning of gas markets. However, intra-company transactions proved to be partially successful substitutes for liquid markets in some cases. The prominent example was provided by EON. This company has gas industry assets in a number of the affected SOS countries (Czech Republic, Slovakia, Hungary) and could manage, in cooperation with the Austrian and Hungarian TSOs, to contract and ship additional gas for Hungary and the most exposed markets of Serbia and Bosnia and Herzegovina (see Figure 6.3) after January 9.[8] EON reports that the price of these additional shipments was the same as for its 'normal' commercial transactions with these countries and thus the whole arrangement can be considered as a case for solidarity (EON 2009).

Figure 6.3. Additional supplies arranged by EON to the region from January 9, 2009.



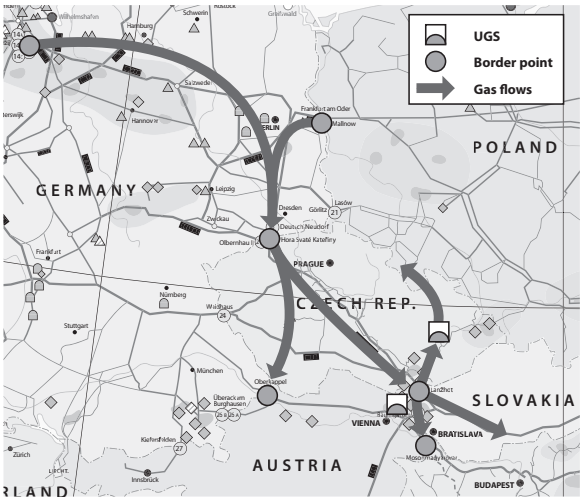
Source: GTE, Keuchel (2009)

Another example is that of RWE (see Figure 6.4). This German giant is having gas industry assets around the region including the gas transmission company of the Czech Republic (RWE Transgas Net). RWE Transgas managed to ship additional 10 mcm/day of gas from its European portfolio compared to pre-crisis levels for the Czech (7 mcm) and the Slovak (3 mcm) markets from the peak of the crisis (January 12). On January 19 they could even manage to reverse the flow on the Slovak-Czech interconnector and ship 4 mcm into the Slovak market (Kleefuss 2009). These companies claim with good reason

[8] Preparations for a possible crisis with a significant impact on the CSEE markets were already started in the Essen center of EON in December 2008 (EON 2009).

that strong energy companies (instead of liquid local markets) secured gas deliveries to the region during the crisis.

Figure 6.4. Additional supplies arranged by EON to the region from January 9, 2009



Source: GTE, Kleefuss (2009)

Finally, when markets and intra-company transactions are not present and/or not enough to manage a supply shock, extraordinary rights for the TSO can be provided by a crisis management action plan to balance demand and supply by the application of non-market based nominations. It is also the TSO who is best positioned to manage customer restriction regulations. However, serious concerns were raised with regard to the application of this measure in some cases in January 2009. For example, during the entire crisis period the Hungarian government refrained from officially announcing a crisis situation and thus providing the extra nomination rights for the TSO. The reason was a fear from the potential of litigations that might have emerged from TSO decisions that overruled commercial contracts. This example highlights the importance of establishing ex ante rules for liabilities and commercial settlements with regard to TSO decisions during crisis situations.

There have also been reports from Hungary, Croatia and Slovakia about the partial malfunctioning of customer restriction regulations during the crisis. TSOs had limited access to the actual consumption data of restricted customers and thus had some problems with enforcing demand side measures. Austria, on the other hand, had developed a detailed crisis management plan after the 2006 gas crisis and did manage it properly during January 2009. (Boltz 2009a)

6.5. Seriousness of supply and final impact of the crisis

Now we turn to look at what happened to the different SOS countries during the crisis with the purpose of learning about their successes and failures in crisis management. Success in this regard means to avoid customer restrictions and the associated economic value of lost load (VOLL).[9] In this paper we apply a simple consideration for comparing the countries: the less impact the crisis had on final customers the more successful we consider crisis management to be in a given country.

First we compare the impact of the gas cut on gas supply across the countries. We apply two measures: the share of Russian gas in the annual gas supply of the country (domestic production plus net imports) and the share of missing Russian gas in winter peak demand. In the first respect, Bosnia and Herzegovina, Slovakia, Serbia and Bulgaria have an almost 100% exposure to Russian supply. Due to domestic production, Croatia and Romania rely only up to one third of their supply on Russia. The exposure to Russian deliveries during winter peak periods is moderated by underground storage operations in almost all the cases. Bosnia and Herzegovina and Serbia remains in a very vulnerable position with 100% and 91% respectively. On the other hand, 6 out of the ten investigated countries have a value below 35%.

In order to balance missing gas and keep supply and load in balance during the crisis days, various demand side measures with various durations for different customer groups were put in place in the region. Fuel switching (from gas to oil) in electricity generation and gas based district heating was a commonly applied measure, in some cases on a voluntary basis (Austria) while in some others as part of the implementation of consumer restriction regulation (Hungary). Interruptible contracts of industrial customers also helped to reduce gas demand in Slovakia, Romania and Slovenia. Obligatory customer restriction was limited to industrial users in Croatia, Hungary and Slovakia while in Bulgaria, Bosnia and Herzegovina and Serbia household customers and public institutions were also restricted in their gas use for some time.

Table 6.5 compares the seriousness of the supply effects of the gas cut to the seriousness of customer restrictions during the crisis.

Table 6.5. Seriousness of the supply and customer impacts of the gas cut

	SUPPLY IMPACT 1 (Russian import / (domestic production + total import), yearly total	SUPPLY IMPACT 2 (Missing Russian import / winter daily peak load)	CONSUMER IMPACT (seriousness of restrictions on end consumers)
Austria	50%**	22%*	*
Bulgaria	88%***	62%**	***
Bosnia and Herzegovina	100%***	100%***	***
Czech Republic	74%**	26%*	*
Croatia	33%*	25%*	**

[9] Szolnoki (2010) provides a review of the methodologies to estimate gas supply related VOLL and also the first estimates on the amount of VOLL in relation to the 2009 gas crisis.

	SUPPLY IMPACT 1 (Russian import / (domestic production + total import), yearly total	SUPPLY IMPACT 2 (Missing Russian import / winter daily peak load)	CONSUMER IMPACT (seriousness of restrictions on end consumers)
Hungary	61%**	33%*	**
Romania	34%*	14%*	*
Serbia	90%***	91%***	***
Slovakia	100%***	62%**	**
Slovenia	59%**	25%*	*

Legend:

	SUPPLY IMPACT	CONSUMER IMPACT
Value is below 50%	Low*	No obligatory restriction on end customers
Value is between 50 and 75%	Medium**	Obligatory restrictions for customers other than household/ protected consumers
Value exceeds 75%	High***	Obligatory restrictions in each customer category

As the table illustrates, certain countries were successful in fully mitigating the shutoff for their consumers (Austria, Czech Republic, Romania and Slovenia), while Croatia's consumers suffered a significant effect that was more severe than the actual supply interruption. The effects of the cut-off of deliveries were the most severe in the case of Bulgaria, Serbia and Bosnia and Herzegovina.

Crises management had no impact on consumers in some countries. We could identify the following reasons for successfully weathering the supply disruption in the case of Austria, the Czech Republic, Slovenia and Romania:

Import diversification. The share of gas imported from non-Russian sources is 48% in Slovenia, 36% in Austria and 25% in the Czech Republic. Although a majority of these are traditionally regarded as (only) 'contractual' diversification (in other words, contracts concluded with a party other than Russia are generally also fulfilled with gas from a Russian source), the crisis revealed that the contracting parties were able to fulfil and in several cases temporarily even increase their deliveries. The three countries have appropriate interconnections in the German-Austrian direction.

Successful reorientation of the typical flow directions and the establishment of technical conditions for West/East flows. The performance of the Austrian, German, Czech, Slovak and Hungarian TSOs in establishing West/East gas deliveries proved to be a crucial component to successfully replacing missing Russian supply. The management in these companies proved to be outstanding. The increased imports from the West played

an important mitigating role in the January crisis because of this reorientation of gas supplies.

Efficient market mechanisms. There was a sufficient amount of bids during the crisis on the Austrian balancing market to replace the shortage of gas supply. This prevented any regulatory interventions and helped to manage the situations in Slovenia and Austria. In addition, significant industrial consumers in Austria voluntarily switched fuels.

Sufficient domestic storage capacity and production. The ratio of domestic production to winter peak consumption, from amongst the studied countries, is the highest in Romania. This production and the availability of significant storage capacity prevented Romania from implementing restrictions on consumers. Storage capacity played a key role also in managing the crisis in Austria and the Czech Republic.

Countries managing the crisis with a medium impact on consumers. This category includes Croatia, Hungary and Slovakia. These countries needed to impose restrictions on consumers during the crisis, but restrictions were not extended to residential and other protected consumers (hospitals, schools). Lacking a liquid gas market, the multinational companies of the region (E.ON, GdF, RWE) provided for the replacement of considerable portions of the missing gas through intra-corporate transactions. The enforcement of restrictions on consumers encountered difficulties in all three countries.

Countries managing the crisis with a high impact on consumers. The gas industry of the countries suffering the highest consumer impact and damages (Bulgaria, Serbia, Bosnia and Herzegovina) can be characterised by opposite conditions as experienced by those who managed the crisis successfully. Most importantly, countries most effected are far from the relatively liquid German/Austrian markets, lack domestic gas production and if they have any at all, their gas storage capacity is limited, they import exclusively Russian gas and the total consumption is supplied through a one-directional transit pipeline. These countries were prepared for a crisis only at a minimum level and they had problems to mobilize alternative fuel stocks when they had any. Affected consumers often replaced the missing gas used for heating or district heating with electric heating.

6.6. Regulatory problems encountered during the crisis

The gas crisis resulted in fierce political reactions in the affected countries of the region and prompted intensive debate on the short and long term strategies for improving gas supply security. Much of the debate has been around various physical development projects to enhance supply side options. Table 6.6 provides an overview of recent infrastructure development related proposals, part of which have been concluded in the course of 2010.

Table 6.6. Options enhancing security of gas supply, which are currently under discussions

Country	Proposals	Concluded since the crisis
Bulgaria	Reinforcement of the interconnections and development of bidirectional interconnections with Romania, Greece and Turkey; establishing projects for LNG import.	
Czech Republic	Extension of storage capacity; extension of the Western interconnection pipeline.	
Croatia	Acceleration of the KrK LNG project; establishment of a second storage facility; establishment of the Croatian-Hungarian gas pipeline connection.	Croatia – Hungary interconnection to be concluded by early 2011
Hungary	New interconnections with Slovakia and Slovenia; upgrading of the HAG connection with Austria.	Underground mobile gas storage capacity upgraded by 2.7 bcm (from which 1.2 bcm is strategic storage). Hungary-Romania interconnector concluded in October 2010.Hungary Croatia interconnector to be concluded early 2011
Serbia	Development of natural gas storage capacity jointly with Gazprom; Bulgaria-Serbia interconnector.	
Slovakia	Establishing a wholesale and storage undertaking partly owned by the state; regional storage cooperation; nuclear power production; option of a strategic storage.	
Slovenia	Establishing a domestic gas storage facility; demand for further coal-based and nuclear power production.	

Source: own research based on Platts reports; Hungarian Energy Office

Regulatory fine-tuning and a better utilization of demand side measures to offset gas supply shocks might be much cheaper supply security measures than infrastructure development. The crisis highlighted that the affected countries differ in their preparedness

for such an event to a large extent. We could identify at least the following areas for further action.

Fuel switching provided the most immediate demand side option during the crisis. The exceptional situation that fuel oil prices were below natural gas prices during the crisis period resulted in massive voluntary fuel switching in Austria. It also helped the easy enforcement of fuel switch regulation[10] for electricity generation in Hungary. However, in Bosnia and Herzegovina, Serbia and Bulgaria alternative fuel was available for 3 weeks but logistic problems permitted fast switching (Kovacevic 2009, p.14).

Interruptible contracts were not reported to play a significant role in crisis management. This might partly due to the lack of efficiently functioning gas markets where a shortage in supply would be reflected in sufficiently high market prices to encourage customers to sell their ability to be interrupted for suppliers. Other regulatory types of incentives are mostly lacking around the region.

There were serious shortcomings reported about the enforceability of industrial customer curtailment regulations in Croatia, Hungary and Slovakia. While the TSOs were responsible to enforce curtailments, they had no direct access to consumption data but only the DSOs. The TSOs did not have sufficient powers to punish non-compliance of customers. Another piece of the problem was that the restriction decision had no relation to the cost the curtailment imposed on the customer. A consequence was that large industrial customers started to lobby immediately at the responsible ministries to get exemptions from the curtailment and many were indeed provided by it. A market oriented approach when customers had a certain degree of freedom ex ante in trading off the expected cost of being curtailed to the expected benefit of avoiding restriction could reduce the social cost of a customer restriction regulation and improve the enforceability of it. A revision of the regulation on the availability and sharing of information is also necessary in many instances.

Financial liabilities from emergency situation TSO nominations hurting private contracts were not well defined. The litigation risks emerging from this uncertainty unnecessarily limited the pace of action of the TSO.

As an example, the Hungarian government revised the country's gas market emergency regulation as a response to the 2009 January crisis. The revisions' key elements were the followings: elaboration of an incentive scheme of facilitating the rapid fuel switch of consumers; obligatory provisions on the booking of commercial storage by market players; clarification of the rules on financial arrangements of transactions in a crisis; clarification of the nomination right of the system operator on the strategic stockpile and the revision of the consumer restriction categories and its scheme.

[10] In Hungary gas based electricity generation companies are obliged to hold 8 days of fuel oil reserves on their sites and another 8 days close to their sites.

6.7. Concluding remarks

The 2009 January crisis can be viewed as an unprecedented short run supply security experiment that helped to detect the strengths and weaknesses of the gas industries of the CSEE region. Most prominently, the discovery of the reverse flow capabilities of the European gas transmission grid opened up formerly unproved capacities and according diversification perspectives for the region. It is apparent now that a better utilisation of the present infrastructure can itself mitigate short run supply disruptions. In addition, the relative success of some countries in managing the crisis provides us with further guidance for future action. We can briefly sum up the lessons as follows.

First, import diversification, both physical and contractual, improves supply security. Despite former scepticism (at the end, all molecules in the region come from Russia), contractual diversification delivered during the crisis. Contracting partners managed to supply formerly agreed and even additional amounts of gas for the investigated countries.[11] Relatively easy and cheap solutions for infrastructure upgrade have been identified and some already realized.[12]

Second, well functioning gas markets were fast and efficient in mitigating a major supply shock, as the Austrian case illustrated. Compared to market transactions, the intra company arrangements that provided the additional supply for the rest of the region were essential but slow and complicated to manage. Moreover, those countries with sufficient physical connections to the relatively liquid gas markets of Austria and Germany (Czech Republic and Slovenia) or to the LNG receiving terminal of Greece (Bulgaria) enjoyed the additional advantage of receiving reverse flows from these directions. Market development, integration with the liquid continental gas market and the improvement of supply security goes hand in hand for the region.

Third, a regional gas storage market should soon be developed to replace the present, segmented situation. Cross border physical availability and the related regulatory harmonization was missing around the region in regard of storage access during the crisis. The positive exception to this rule was the cooperation of Serbia and Bosnia and Herzegovina with the Hungarian storage operator, but it was based on ad-hoc arrangements. The conflict that resulted from the deliveries from Slovak storage facilities to Czech suppliers clearly calls for commonly agreed rules for cross border access to underground storage services.

Finally, the crisis also tested the functionality of crisis preparedness and the related regulation of the region's countries. Regulatory improvements to encourage low cost fuel switching and to promote interruptible contracts could best improve the demand side responsiveness to supply shocks. The improvement in customer restriction regulation should focus on data transparency and availability and appreciate the huge differences in the costs that a curtailment might impose on customers. And the financial liabilities from the emergency related decisions of the TSOs should be clearly defined.

[11] The exception is Romania, due to the lack of infrastructure at the time of the crisis. Note that in October 2010 the Hungarian-Romanian interconnection was completed, thus Western shipments could enter now the Romanian gas market.

[12] For example, a West-East flow capability from Baumgarten (Austria) to Slovakia on a 9.6 bcm/y pipeline was accomplished in October 2010 with a cost of only 4 million Euros (Report of *Platts Energy in East Europe*, November 5, 2010).

A great benefit from the 2009 January gas crisis comes from the strong, coordinated and exceptionally fast reaction to it from the European Union. Recent EU measures[13] and initiatives[14] seem to recognize the supply security concerns of CSEE and put forward meaningful obligations and proposals to accomplish the gas grid and market integration of the countries of this region.

[13] Regulation 994/2010/EU.

[14] Energy infrastructure priorities for 2020 and beyond – a Blueprint for an integrated European energy network. European Commission, November 2010.

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Regulatory Preconditions to Encourage Multi-Country New Gas Infrastructures in CSEE

7.1. Introduction

The regional integration of national energy markets would increase security of supply by creating a larger market for generation and infrastructure investment and could contribute to better diversification of primary resources. Adequate network infrastructure with high interoperability and liquid markets is a key prerequisite for market integration. Investment into new infrastructure is indispensable to achieve better diversification of gas sources and to increase commercial relations between the countries.

The aim of the present study is to examine the regulatory framework that must inplace to carry out the necessary investment into new gas transmission pipelines and storage facilities in Central and South East Europe. Our research is not limited to study investment incentives, but try to give an overview of all the regulatory tools and practices recommended by European organisations during their work to advance regional integration of national gas markets.

When designing the optimal regulatory framework one must take into consideration the latest development of the European legislation (including draft regulations and framework guidelines), the practical experiences (with different measures implemented by regulators and market participants to further market integration) accumulated within the framework of regional gas initiatives under the auspices of European Regulators' Group for Electricity and Gas (ERGEG), and the wide range of studies commissioned by the Energy Community during its work on studying investment regulation.

In the first part we summarize the most important elements of the European legislation and the relevant ERGEG Framework Guidelines. The second part of the study will present the development in the frame of the ERGEG Gas Regional Initiatives through the initiatives, programs and arrangements to encourage investment and interoperability. In the third part we present the possible methods of infrastructure investment regulation with a special focus on proposals made by ECRB when studying the possibilities of establishing a regional gas grid.

7.2. EU legislation: directives, draft regulations and framework guidelines

A cornerstone of the regulation on a single European natural gas market, which also gives a framework to rules concerning security of supply is the EU Gas Directive (Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC). A second level of the regulation is the Regulation 715/2009/EC including the key detail rules and guidelines. The third level includes Framework Guidelines worked out by the ERGEG, which are to guide Member States how to interpret and carry out provisions specified in the Directive and in the Regulation. Although they are not legally binding yet, Guidelines are expected to have a binding force gradually in the future. In the following, we introduce the key elements in relation with security of supply and infrastructure investments (construction of pipelines) specified in the Directive, the Regulation and the given Guidelines.

7.2.1. Monitoring and reporting on security of supply and the ten year network development plan

The Directive provides that Member States have to monitor security of supply and requires regular (annual) reporting. The monitoring activity will cover the balance of demand and supply on the national market, the level of expected future demand and available supplies, and the envisaged measures reinforcing security of supply. Currently, the report is a subsection to the National Report prepared annually by Member States, however, expected to be developed to be a separate report on security of supply in a structure that is uniform at regional/EU level. The current regulation requires several similar forecasts that are expected to become uniform in the future both in structure and in content. A compulsory component of the 10-year network development plans to be prepared by TSOs, which are going to be hammered out by the ENTSO-G as a EU-level network development plan, is the forecast on the future balance of demand and supply. The proposal for a Council Regulation concerning the notification to the Commission of the investment projects in energy infrastructure within the European Community and repealing Regulation (EC) No 736/96 on the one hand obliges Member States to regularly publish and supply data, while on the other hand obliges the Commission to regularly report in a cross-sector analysis among other facts the balance of demand and supply.

The Directive requires TSOs to prepare 10-year network development plans. The planned network developments will be adjusted to the future balance of demand and supply and contain efficient measures in order to guarantee the security of supply. The network development plan will be prepared, elaborated and accepted based on a regular, open and transparent consultation with system users. When calculating demand forecast being a basic assumption to the network development plan or the market needs of system users serving as base for given investments, market players' expectations and the needs identified by them as system users have to be taken into account. The regulator

may approve a network development plan if it is documented to have taken into account the investment needs identified during the consultation process. In the course of the approval, the regulator also examines whether the network development plan is consistent with the non-binding Community-wide ten-year network development plan, prepared by the ENTSO. If any doubt arises as to the consistency with the Community-wide network development plan, the regulator, following a consultation with ACER, may require the relevant TSO to amend its network development plan.

The most important provision of the Regulation governing the detailed rules of the operation of natural gas markets and the terms of access is the establishment of the European Network of Transmission System Operators for Gas (ENTSO-G). The ENTSO-G is one of the three EU institutes that are regarded by the Commission as the key drivers to the single European energy markets. The third package requires Member States to set up the association of electricity TSOs (ENTSO-E) in addition to the association of natural gas TSOs (ENTSO-G), and provides for the establishment of the association of regulatory authorities (ACER). The European legislators expect the ENTSOs to operate and develop the transmission network at a Community level, while expect the ACER to monitor the execution of the tasks performed by the ENTSOs.

The lack of provisions on the ENTSO-G's organisational structure, on the shareholder role of the founding TSOs, on the decision making process and the Commission's right to make the final decision overwriting the decisions of ENTSO indicates that the organisation will primarily be charged with the professional background and preparatory works while the decision making right in all important issues will stay with the Commission. Due to the lack of regulation on organisational issues and the long approving procedure, ENTSO-G may start operation in 2012 at earliest. (The single network code may be completed in 2013, while the approving process of the non-binding ten-year network development plan does not consist any procedural deadlines.)

The key task for the ENTSO-G is the elaboration of the network code and the ten-year network development plan. The network code among others includes rules on capacity allocation, congestion management, balancing, transparency, interoperability, connection and data exchange. Generally, the network code elaborated by the ENTSO-G will govern all the cross-border issues of natural gas transmission, while the rules of other issues not affected by cross-border transmission will be elaborated by the national TSOs in their own network code.

Although the ten-year network development plan and the supply adequacy outlook to be prepared every two years may seem to be a soft and mock measure because of the lack of a binding force, both are very important tools from the viewpoint of infrastructure investments and security of supply. The supply adequacy outlook is important because it includes the forecast that estimates the demand level to be satisfied (and thus the requirements towards the network), which serves as a base for the network development plan. The supply adequacy outlook may have an effect on the realisation of given potential projects, although supposedly, given project sponsors rather base their decisions on the prospects of the targeted national or regional markets, and on the other hand, when examining the viability of a project, project sponsors will not trust by all means the demand forecast of the ENTSO-G.

However, the European network development plan in itself is an indispensible factor for project sponsors because it signals effective investment intention (to construct pipelines). Although the European plan is not binding (i.e. the execution of investments included in the plan cannot be forced), the reliability of the plan is high due to the obligatory harmonisation with the regional and the national network development plans (and the ones relating to the given TSOs).

The extensive consultation process accompanying the preparation, elaboration and finalisation of the network development plan provides a platform to the potential system users, shippers and market players involved in the consultation process to deliver an opinion on the given interconnection projects. Although they have this possibility even in the course of the preparation of national network development plans (worked out by the given TSOs), network development needs at European level are more likely to include those pipelines crossing several countries that would not necessarily be compiled from pipeline sections included in the national plans (the construction of a purely transit pipeline constituting a part of a longer network may not be even included in the network development plan of the given TSO).

Theoretically, the consultation process before network development can function similarly to the initial, market surveying phase of the open season procedure. The TSOs disclosing the plans receive feedbacks from the system users participating in the consultation about the extent of the market interest in a given section (e.g. an interconnection capacity). The consultation process also allows capacity bookings even though to a limited extent. The market players interested in the construction of the given section may submit upon the request of the TSO a financial guarantee that ensures that they will in fact use it once the pipeline is constructed (by significantly reducing the given TSO's risk). The key difference between the two procedures is that capacities constructed in the framework of open season are exempted from regulated access and the project is based on the financial support of a limited circle of system users/shippers, while in the course of network development consultation, projects are based on future bookings/demand of a wide circle of system users, financed by all system users and not exempted from regulated access.

7.2.2. Draft regulations concerning security of supply

In addition to the ten-year network development plan, the European Commission worked out several measures to guarantee security of supply. One of these measures is the draft Regulation facilitating the European level monitoring of infrastructure projects, which will repeal the Council Regulation 736/96 on the data supply related with energy projects. In accordance with the draft, Member States submit information every two years in a uniform structure and content on the energy projects planned to be developed in their region. Based on the data and information received, the Commission makes a report every two years on the future development of the energy networks of the European Union. The report identifies the potential future gaps of energy demand and supply, obstacles to the investments required (for achieving the objectives set by EU on the security of supply and the sustainable development) and promotes best practices to address them.

The proposal supporting the Commission's monitoring activity complements the existing forecasting and reporting obligations on security of supply imposed on TSOs and regulators. The natural gas Directive imposes an annual forecasting and reporting obligation on regulators with regard to the future balance of demand and supply, while requires TSOs to make a similar forecast with regard to the preparation for the network development plan. The network development plans of TSOs will be harmonised at regional than at Community level in the framework of the ten-year network development plan to be prepared by the ENTSO-G. (In parallel, the demand-supply forecasts calculated by the given TSOs for the territory of their own network will constitute a regional then a Community-level forecast in the ENTSO-G supply adequacy outlook.) However, there has not been any institutional solution to aggregate the security of supply reports prepared by the Member States. Similarly, the activities of the Member States (or regulators, respectively) to guarantee security of supply labelled as long term investment planning (capacity planning?) and the relevant measures could not have been harmonised either. The Commission's monitoring of security of supply, however, will allow that national measures on security of supply constitute a uniform and coherent set of measures serving the interests of the whole Community.

Another set of measures has been formulated in a draft Regulation repealing the existing Directive 2004/67/EC concerning measures to safeguard security of natural gas. The objective of the new draft Regulation on security of supply is to harmonise the measures taken by the given Member States in the event of supply disruptions and crisis and to avoid individual measures that jeopardize the operation of single energy markets. In addition to crisis management, the proposal highlights the role of prevention and gives a significant impetus to the implementation of interconnection investment projects serving security of supply by determining the infrastructure requirements needed for prevention.

The proposal requires the Member States to elaborate a Preventive Action Plan and an Emergency Plan. The Preventive Action Plan has to identify the risks that may jeopardise the security of supply of a given Member State (disruption of supply through or from a major piece of infrastructure, transmission disturbances in a third country etc.), and to determine the measures that may mitigate these supply risks. In addition, the action plan has to include those measures that are required to comply with the infrastructure and supply standards specified in the draft Regulation.

With regard to infrastructure standard, the draft Regulation includes two requirements, the N-1 standard and the requirement of reverse flow capacity. On the one hand, the network has to be able to handle the transmission problem deriving from the disruption of any of its pieces of infrastructure. In the event of a disruption of the largest gas supply infrastructure, the remaining infrastructure (N-1) has to have the capacity to deliver the necessary volume of gas to satisfy total gas demand of the given area during a period of 60 days of exceptionally high gas demand. In accordance with the requirement of reverse flows, Member States (TSOs) have to enable permanent physical capacity to transport gas in both directions on all interconnections (within two years of the entry into force of the Regulation).

The supply standard specifies the consumption level, of which a Member State has to be prepared for. The proposal adjusts this level to the needs of protected customers. The

Member State has to ensure the gas supply to the protected customers for at least 60 days in exceptionally high demand periods or in the event of emergency as defined in the draft Regulation (and in the case of extremely cold temperatures during a seven days peak period statistically occurring once every twenty years). In the proposal, protected customers are all household customers already connected to a gas distribution network, and if a Member State so decides, can also include small and medium-sized enterprises, schools and hospitals (provided that they are already connected to a gas distribution network).

The Emergency Plan prepares Member States for supply emergencies. The Proposal identifies three crisis levels. In the first level (Early Warning) there are signs that refer to the occurring of a crisis. The second level (Alert) is when a supply disruption occurs but the market is still able to resolve the situation. In the third level (Emergency) there is a credible risk that the supply standard to the protected customers can no longer be met with market based instruments e.g. due to disruption of the supply from the largest infrastructure. The Emergency Plan defines the role of market players (shippers, distributors, traders/suppliers and industrial customers) and the regulator; establishes detailed procedures to be followed for each crisis level; identifies market based measures to be implemented for the Alert level, and non-market based measures to be implemented for the Emergency level; and designates a crisis manager or team.

The Emergency declared by the Member States will be validated by the Commission. The Commission will declare a Community Emergency if more than one Member State has declared Emergency or when the Community loses more than 10% of its daily gas import from third countries. In a Community Emergency, the Commission will coordinate the actions of the competent authorities of the affected Member States, which in given events, may also include the change or withdrawal of the action taken by a Member State.

The Commission will establish a Gas Coordination Group, which is to facilitate the coordination of measures concerning security of supply. The Group will be composed of representatives of the regulators, ACER, ENTSO-G and representative bodies of the industry. The Group will be responsible for elaborating assessment methodologies to assess the level of security of supply, testing the levels of preparedness of Member States, compiling best practices and guidelines, monitoring the implementation of the Preventive Action Plans and Emergency Plans and coordinating measures to deal with emergency within the Community.

7.2.3. Guidelines for better use of existing infrastructure

ERGEG as a predecessor of ACER, (Agency for the Cooperation of Energy Regulators), have committed to work diligently during the interim period between the adoption of the 3rd Package and the date when ACER is able to fully exercise its powers by March 2011. The aim was to provide assistance to ACER in view of framework guideline development when the 3rd Package enters into force.

The European Commission officially requested ERGEG to prepare a (i) framework guideline on capacity allocation mechanism (CAM) (ii) on congestion management practices (CMP) of transmission networks (iii) on balancing rules and (iv) on storage CAM and CMP all address the issue to encourage better use of the existing infrastructure and to put in place a regulatory system that gives the right infrastructure investment signals.

(i) Capacity Allocation on European Gas Transmission Networks

The challenge of building the EU gas market consists of moving from several interconnected national markets to a single market made of several interconnected balancing zones. In this perspective, facilitating gas flows across interconnections is considered as a priority objective of the future network codes. The focus is given to developing compatible rules on the two sides of interconnection points, which includes the same products and the same allocation procedures. The objective is to create bundled products at all the interconnections which would constitute bridges between adjacent markets. In the end, a small number of capacity products should be applied all over Europe with coordinated and converging allocation mechanisms; auctions are the preferred model while pro-rata would be allowed as interim step.

TSOs shall amend all relevant clauses in capacity contracts and/or relevant clauses in general terms and conditions relating to the allocation of capacity at relevant interconnection points, by six months after entry into force of the network code. This requirement shall apply to regardless of whether the relevant contracts or general terms and conditions provide for such an amendment. The old contracts can not be subject to tacit extension so they will roll out. In the coming European gas era standardized contracts will rule, the TSOs defining the general terms and conditions for capacity allocation and capacity services.

In the long run capacity services will be harmonized at all interconnections, and the same bundled products will be allocated at the same time through on-line auctions all over Europe.

TSOs will have to jointly offer firm and interruptible capacities for a defined amount of the available capacity at all interconnections.

The new model wants to ensure the possibility of reaction to market signals so TSOs have to set aside at least 10% of their available capacity for firm short term capacity services.

The deadline for bundling all available capacity (corresponding entry and exit capacity at all interconnection points) in 5 years after entering into force of the legally binding network codes. As an interim solution, to accelerate bundling of capacity TSOs insure that capacity becoming available on one side of an interconnection point exceeding the

available capacity on the other side of the interconnection point shall be allocated for a duration not exceeding the expiration date of the corresponding capacity on the other side of the border.

For simplicity reasons where two or more points connect two adjacent entry-exit systems these have to be integrated into one single capacity service representing one virtual interconnection point.

Capacity allocation for the same capacity service will take place at every interconnection in Europe in a timely coordinated way.

For day-ahead capacity services only auction can be the allocation method. For other services pro rata allocation may be applied as an interim mechanism, when conditions are not met for efficient and fair auction. This has to be decided by the relevant national regulatory authorities. Pro rata mechanism means that every shipper is allocated the proportion of its capacity demand related to the total capacity demanded by shippers during the allocation procedure.

Although at the present time most TSOs offer their capacity on a first come first served basis (FCFS), this principle can not be used in the future unless provided differently in the regulation. Only unsold capacity after an allocation window can be allocated directly to shippers in the meantime between two allocation windows, hence only for short term capacity services. The conditions for FCFS are made explicit; no congestion will occur between the two time windows; there are at least yearly and monthly capacity allocation windows under the form of either auctions or pro-rata allocations; FCFS capacity is published and made available for all market participants.

(ii) Congestion management procedures

The capacity allocation methods prescribed above go hand in hand with the parallel developed congestion management procedures.

The aim of the work was maximising the capacity offered by means of proper capacity calculation and regular up-dates, in order to reduce physical as well as contractual congestions. Addressing contractual congestion mainly for short-term capacity, but also for long-term capacity, via various mechanisms including: capacity oversubscription and buy-back, capacity surrender, short term and long term Use-It-Or-Lose-It (UIOLI). We describe these mechanism in more detail to have a deeper understanding how they will be implemented.

Capacity calculation is a core issue of the guidelines. Today, there is still no industry standard for calculating capacity. Historical data show that on most congested interconnection points a contractual congestion exists, and the actual physical flow is far from the physical capacity of the system. Many studies show that on annual average, capacity utilisation of major cross-border points is around 50% and full capacity utilisation is a rare occurrence or never happens. One such example is the interconnector from Hungary to Austria, as seen in the chart below. Technical capacity (blue) is always fully booked (purple), but use (yellow) is far behind.

According to the new guideline, the technical capacity has to be calculated through transparent methodologies using best available and cost-efficient procedures. TSOs has to identify the capacity that can be physically used in order to maximise the offer of

capacity to the market. When forecasting system use TSOs may also consider market trends, historical flow data and data on results of allocation processes.

A new approach of the guidelines is that the TSOs shall implement on oversubscription and buy back mechanism in order to offer additional capacity exceeding the currently published technical capacity on a firm basis. This is based on the fact that the TSO can anticipate that not all of the booked capacity will be used and the regularly used capacity is below the contracted capacity. Based on statistic scenarios the TSO can estimate the use of the booked capacity and the probability and amount of unused capacity and should offer the unused capacity on a long term basis. This brings a slight risk of TSOs not being able to offer all firm capacity they committed. In case of actual or potential physical congestion, when the fulfilment of the nominations made is not possible TSOs shall have the option of buying back capacities. In doing so, it is not only the holders of the additional capacity who will be requested to sell back their capacity utilisation rights, but all shippers who have booked capacity at the point in question. TSOs have to tender for buying back capacity.

The new guideline is committed to take this risk; given that capacity has typically been calculated on a very conservative basis in the past and that large safety margins have been built in to deal with technically problematic network conditions, a slight shift in the risks is considered appropriate by ERGEG. At this point we must state that the full responsibility for the network operations still lies with the TSO. This contradiction needs financial incentives for the TSO to take the above mentioned risk that this mechanism may result in TSOs losing or keeping some revenue.

To increase the amount of capacity offered on a firm basis the new guideline encourages that shippers can surrender unused booked capacity to the TSO. This could be done on a well functioning secondary market as well. However historic evidence and public consultation results underline the fact that many of the drawbacks of secondary markets result from the fact that it is not the TSO who acts as counter part of the shippers. Neither offering shippers nor buying shippers like to give insight into their specific activities. To overcome this problem, shippers can decide to surrender booked capacity to the TSO who integrates this capacity into the process of primary offer and allocation.

The central element of short term congestion management is the restriction of firm re-nomination rights. The present nomination system in most Member States is designed for the present long term capacity holders. The existence of unlimited re-nomination rights (that shippers can change up-and-down their nominations without any limits up to two hours before the gas day) is particularly harmful for the emergence of competition. Especially where technical capacity is fully booked and long term capacity rights are in a few shippers hand they can influence how their competitors' interruptible nominations are fulfilled

The introduction of a use it or loose it (UIOLI) mechanism would bring back unused capacity on the firm day-ahead market and extend the room for short term competition. This is the only way non-nominated capacity can be allocated to other shippers on a firm basis.

The guideline gives hints for national regulators to introduce long term UIOLI for capacities, when there is a clear need for capacity and new entrants can not secure their need on the primary and secondary markets. The withdrawal would mean that the ca-

pacity holder would lose his capacity rights, partially or completely, for a given period or for the remaining term.

(iii) Gas Balancing Rules on European Gas Transmission Networks Draft Pilot Framework Guideline

In a complex, large and interconnected gas network users should balance their own portfolios the best they can. The aim is to provide, as much as possible, for network users to collectively balance their portfolios so as to minimise the need for TSOs balancing actions. As a prerequisite to this goal network users must have the necessary information. Transparency will be ensured through the increased level of obligation on TSOs to provide the necessary information to achieve this goal. TSOs shall provide to each network user the available information regarding its inputs on to the system and off takes from the system at appropriate intervals during the balancing period. TSOs shall publish, per balancing zone, the amount of gas in the transmission system at the start of each gas day and the forecast of the amount of gas in the transmission system at the end of each gas day. The forecast amount of gas for the end of the gas day shall be updated on an hourly basis throughout the gas day. Where hourly balancing regimes are in place, the above information shall be hourly.

After the balancing period network users will be billed for any imbalance charges and the imbalance of their portfolios shall be set to zero. The target model suggests that the balancing period determined for a transmission system shall be a daily interval, at the end of which network users are cashed out for any deviations, as accumulated over the course of the preceding 24 hours, between their inputs and off-takes from the system. Imbalance charges are billed separate and must reflect the costs incurred by the TSO in buying gas and balancing services. It shall be levied on the network users that contributed to the imbalances.

TSOs shall procure the gas they need through buying and selling gas in the wholesale gas market on an equal footing with network users. Where there is no liquid wholesale market, they shall by balancing gas on anonymous balancing platforms, on a non-discriminatory basis through a system of bids and offers on the balancing platform.

(iv) Assessment of Capacity Allocation Mechanisms and Congestion Management Procedures for effective Access to Storage

The measures presented here are at the present stage only proposed amendments to the GGPSSO, hence even if they will be accepted; these will be first non-binding rules. After entering into force of the 3rd Package they can be turned into binding regulation. The main line of the proposals is similar to the above presented regulatory measures: more transparency and increased organisation regarding timing is required from Storage System Operators, when allocating storage capacity.

To ensure compatibility with transmission capacity allocation mechanism(s) of the connected TSO(s) a basic set of storage products must align to transport products with regards to duration and lead time for regular allocation. Just as transport products, storage products should be standardised, so in the future they can be commercialised on (electronic) trading platforms. Combined storage and transport products can emerge this way for further improving services to storage customers.

Storage regulation has also a strong influence on balancing, because storage as the most important flexibility tool has a crucial effect on the balancing possibilities of network users. For this reason there must be standard storage products offered that are compatible with the balancing regime both in terms of product definition and timing.

The allocation process shall start with an open subscription period. Timing of open subscription period shall be fixed, meaning that for yearly allocations always from October to mid December of the previous year and for daily auctions in the morning the day ahead. After the open subscription period Storage System Operators have an overview of the demand and can decide on the allocation procedure. When no congestion occurs, they might allocate capacity straightforward. In case of congestion an auction should be implemented. Similar to the transport capacity allocation, the intention is that FCFS method should be disallowed after a transition period.

Congestion management tools and principles like UIOLI mechanisms are problematic to apply in case of firm storage products, because it limits storage as a flexibility tool. Most Storage System Operators hence offer in case of congestion interruptible capacity products but their usefulness of the storage users is doubtful. The only source of storage capacity in congested markets might come from secondary markets. These are now hardly working and mostly illiquid. Regulation will incentivise Storage System Operators to maximise their offer of non nominated capacity at least on an interruptible basis and at least day ahead. Information on unused capacity will be published real time. It serves double purposes: supply situation on secondary markets and probability of interruption can be accessed.

7.2.4. A major driver to infrastructure investments: Exemption of new infrastructures from regulated third party access

One of the most important and also the most controversial drivers to infrastructure investments is the exemption from regulated third party access. Article 36 of the Gas Directive allows major infrastructure investment projects to restrict access to the affected infrastructure (transmission pipeline, natural gas storage, LNG terminal) for third parties, and determine the terms and conditions of the access without the ex-ante or ex-post approval of the regulatory authority. The institute of exemption has been established to promote the projects that contribute to increasing security of supply and enhancing competition on the natural gas market, but would not be realised under regulated access terms.

The construction of interconnection capacities and transmission pipelines crossing several countries is basically the responsibility of TSOs, who finance the required investments from system use tariffs. Each system user can have access to these pipelines at tariffs determined by the regulator. The extension of infrastructure conducted by TSOs, however, are limited by the network development plans approved by regulators (these plans try to find balance between the system users' willingness to pay and the effects of development enhancing competition and security of supply). There are investments that can not be realised under conditions of standard infrastructure developments but only if they are exempted from the rules of regulated access. When granting exemption, the regulator has to find the balance between the favourable effects of the project (enhancing

competition and reinforcing security of supply) and the potential unfavourable effects of the restriction of regulated access (hindering competition).

The request of the project sponsor to obtain exemption is first judged by the relevant regulatory authority; however, its decision is often subject to the approval of a supervisory body in the Member State (e.g. Ministry). Cross-border infrastructure projects (e.g. interconnection pipelines) require the affected regulators to agree on the terms and conditions of the exemption. Lacking an agreement or upon the request of the affected regulators, ACER makes a proposal on the approval or the rejection of exemption. The exemption decisions of a Member State (and the ACER's proposal, respectively) are examined by the Commission and if justified, the Commission may oblige the Member State(s) to change its decision.

The majority of exemption decisions, however, is not limited to the approval or the rejection of a request, but includes the detailed conditions to exemption. Exemption decisions are always case-by-case, namely they are determined by the specific features of the given investments and its effects on the relevant markets. Therefore exemptions have several variations. An exemption may be full or partial exemption. The full exemption exempts the project from all obligations of the regulated access, while the partial exemption grants exemption only from given rules (e.g. access has to be provided to all market players under equal conditions, but the rules of tariff calculation does not have to be approved by the regulator). The exemption may cover the whole infrastructure, but can be limited to a certain share of the overall capacity of the infrastructure investment (e.g. 80% of the capacities is exempted from the rules of regulated third party access, i.e. the project sponsor may keep it for his exclusive use, while the remaining 20% has to be made accessible to other market players at tariffs approved by the regulator).

In accordance with the Directive, the exemption is subject to the simultaneous fulfilment of several criteria. These are the following: (a) the new infrastructure enhances competition and security of supply; (b) the level of risk of the investment is such that the investment would not take place unless an exception is granted; (c) the project sponsor is separate at least in its legal form from the TSO; (d) charges for the use of the infrastructure are levied on users of that infrastructure; (e) exemption is not detrimental to competition. When determining the criteria to exemption, the regulator has to make a decision so that the former criteria are met to the largest possible extent. In the following, we examine under what conditions the given criteria (in particular the ones on competition and security of supply) are expected to be met.

Infrastructure investments almost always have a positive effect on security of supply. A new interconnection pipeline enhances security of supply merely by facilitating transport of gas from an existing source of supply by the diversification of transport routes. The effect on security of supply is more favourable if the new pipeline facilitates transport of gas from a new source of supply. The contribution of LNG terminals to security of supply is greater than the contribution of gas pipelines as the former allow for imports from much wider choice of locations.

The positive effect of infrastructure investments on competition is not as unambiguous as in the case of security of supply. Increased capacity in itself enhances competition, even though the restriction of access (by exemption) counteracts this effect to some extent or fully in given cases. Infrastructure investments are most likely to have

a positive effect on competition if the new capacities help non-dominant undertakings with small market share to enter the market. If a dominant undertaking is the direct beneficiary of an exemption or become an indirect beneficiary by booking significant amount of capacity, the investment – irrespective of the new capacities – may increase market concentration and hinder competition. Therefore, the exemption of projects initiated by dominant market players as shareholders is not recommended in the majority of cases. However, even the projects of dominant market players can be exempted under strict conditions. If the share in the project or voting right of the dominant undertaking is limited or a determined part of the natural gas transported on the capacities booked by the dominant market player is publicly released, a significant part of the unfavourable effects can be avoided (it is another question, however, whether the project sponsor still thinks the project is worth being continued under such strict conditions).

However, the new capacities may be purchased by dominant market players even if the projects were promoted by independent market players. (It is typical for certain power plant projects e.g. large wind farms that the project developer sells to a dominant market player.) Most simple way of excluding the effects that harm competition is to limit the volume of capacity that can be purchased/booked by dominant undertakings.

In general, a major share of the capacities of the new infrastructure is offered in the form of long-term contracts to the shareholders and a smaller part to other market players – generally in the form of open season. (Long-term contracts are concluded because these generally guarantee future revenues and so provide for project financing.) The rigidity of long-term contracts may be mitigated and the positive effects of the investment may be strengthened if the project sponsor is required to offer a part of the capacities (10-20%) for short-term contracts. Reservation of capacities for short-term contracts does not have a positive impact on the project financing structure by reducing the predictability of long-term revenues, even though would considerably facilitate the evolvement of spot markets, and small market players' entering the market (e.g. small customers lacking appropriate financial background or existing customer base are not able to conclude long-term contracts). A similar effect can be achieved if the project sponsor is obliged to establish the possibility for secondary capacity trading.

The volume of capacity to be built in the course of the project is of utmost importance both from the viewpoint of security of supply and competition. Given that an infrastructure investment in majority of cases supersedes the alternative projects to be established on the affected route or site, it is very important that the established capacities should be proportional to market demand. The positive effect of a project that is implemented on the basis of sub-optimal capacity investment may lag far behind the possibilities. Scarce capacity significantly increases the market power of those market players who are booking the new capacity and provide continuous rents to the project sponsors (in general, this is the most common reason for sub-optimal capacity investment).

With a view to avoid the negative effects hindering competition that derive from the sub-optimal capacity investment, the regulator generally obliges the project sponsor requesting exemption to test market demand. An often used tool for testing market demand is the open season procedure, which includes two phases. The first, non-binding phase aims to survey market demand, while the second, binding phase is to allocate

capacities on a market base in an open and non-discriminatory way. The project sponsor has to take into account the declared market needs in calculating capacity investments.

In addition to sub-optimal capacity investment, another threat coming from superseding alternative projects is that the establishment of capacities is adjourned, since the project sponsor requesting exemption does not always have the aim to establish the respective infrastructure but may wish merely to hinder the establishment of capacities by blocking locations or routed for competing project. (Beside a project that obtained exemption and license, the realisation of a competing project that is designed to meet the same market demand is likely to fail.) This risk (which is called exemption hoarding in the regulatory terminology) may be reduced by the regulator by limiting the validity of the exemption decision by making it conditional on the project starting operation period within a certain time period. If the project fails to start (or be completed) within the determined time period, exemption will automatically lapse.

In addition to enhancing security of supply and market competition, a criterion for granting the exemption is that the project is definitely separated from the TSOs' projects of regulated third party access and financed by system use charges (this can be ensured by the requirement to establish a legal person different from the TSO and the charge to be paid for the infrastructure), and that the risk level of the project does make necessary the exemption from regulated third party access (i.e. the absence of exemption jeopardizes the realisation of the project).

The risk of investment into pipeline has two main sources; (i) uncertainty of availability of upstream gas sources, and (ii) uncertainty of selling the purchased gas on the downstream market. These factors contribute to the uncertainty of capacity bookings and transport of gas, and finally to the risk of return on the investment. Upstream risk can be efficiently reduced by long term take-or-pay contracts. These contracts can however only be concluded when market players are secure about selling the gas on the downstream market. The risk of selling gas on a liberalised downstream market is smaller when the vertical integration of the target market is low and liquidity of the wholesale market is relatively high. Under these circumstances the selling of gas has no major obstacles. Where there is no such market structure the best way to eliminate downstream risk is to have relative high share of the retail market.

Another criterion for granting exemption is that risks are high but can be managed. Practically, the project sponsor should implement appropriate risk management tools (e.g. long-term natural gas purchase contracts), however, should not have significant market power on the retail market, because the level of risks would not justify exemption (furthermore, the impact of exemption on the retail market competition would be extremely negative).

7.3. ERGEG Gas Regional Initiatives

The Gas Regional Initiatives were launched by ERGEG in 2006 in order to foster progress towards a single European energy market on regional level based on the voluntary cooperation of stakeholders (regulators, TSOs, traders and professional organisations). At regional level, the problems deriving from the diversity of the regulation and operation of the different national markets are easier to identify and solve, while the active participation of stakeholders facilitates to find solutions to concrete problems. The cornerstones of regional initiatives are the voluntary basis, bottom-up strategy, graduality and practicality.

Regions	Member States
Northwest (NW)	Belgium, France, Denmark, Germany, the United Kingdom, the Netherlands, Northern Ireland, Poland, Ireland and Sweden
South (S)	Spain, Portugal and France
South-Southeast (SSE)	Austria, Bulgaria, the Czech Republic, Greece, Hungary, Italy, Poland, Romania, Slovakia, Slovenia

Regional initiatives on the one hand, are strongly based on the proposals of the draft Regulations of the ERGEG, while on the other hand, have a positive feedback on the finalisation and acceptance of the Regulations through their successful projects (successful individual solutions may be included in the proposals and spectacular success stories may help proposals to be accepted).

Five dominant topics are highlighted in the framework of Regional Initiatives namely investment, capacity allocation and congestion management, transparency, facilitating the interoperability of transmission systems and enhancing security of supply. The ERGEG publish annual reports on the development of the regional initiatives. In the following, we give a brief overview of the most relevant solutions provided by the given regions.

7.3.1. Supporting investment: coordinated open season procedures

With regard to investment in new cross-border pipelines, several regions elaborated and launched Open Season (OS) processes. In the course of an OS, market players may make bids in a determined time interval to book the capacities of the interconnection point under development. In the first phase of an OS, bids are not binding since the aim of this phase is to identify market demand and to test the viability of the project. Given that in the first phase market players are duly interested in the project, and the project sponsor decides to build the pipeline, the capacities of the new cross-border pipeline can be allocated to the bidders in the second – binding- phase.

In the North-West region, the French and Belgian TSOs (GRTgas and Fluxys) launched an OS in April 2007 to assess the level of interest in booking additional long-term capacity from Belgium to France. The project included the development of north-south capacity on the Belgian transmission system, enabling gas to be transported from the Dutch-Belgian border and German-Belgian border across Belgium to France. In the course of

the preparation of the OS, the affected TSOs signed a Memorandum of Understanding on the required technical and commercial arrangements. The TSOs coordinated each phase of the process leading up to the completion of the necessary investment on both sides of the border. (The TSOs also committed to exchange information regarding any decision that could have an impact on the project on each side of the border.) In addition, the process was coordinated with the open season organised by the Dutch TSO (GTS - Gas Transport Services). GTS offered shippers the possibility to adjust their bids on the GTS network on the basis of the French-Belgian open season results by postponing the binding phase deadline.

Because of complexity of coordination proved to be a crucial factor in the North-West region a virtual test case is being undertaken to test market interest in building a hypothetical pipeline between Germany, the Netherlands, Belgium and France. The project aimed to find out how to improve coordination of OS involving several TSOs. Furthermore, a manual explaining the regulatory framework for investment across all countries in the region was published as well.

In the S region, the French TSO (TIGF) and the Spanish TSO (Enagás) launched Open Subscription Period (OSP) to allocate cross-border capacities that either exist or are under development in a transparent and non-discriminatory way (a procedure that is implemented purely to allocate existing cross-border capacities is called open subscription rather than open season). A considerable result of the OSP in 2008 is that the relevant Spanish national legislation has been amended because it did not provide any possibility to implement coordinated open season procedures and open subscription periods. Allocation of capacities was carried out according to priorities given to multiannual and multi-seasonal capacity request; capacity requests with the same level of priority were satisfied on a pro-rata basis. Bidders could book 80% of the capacities for a long run (for a period longer than a year) while 20% for a short run (in annual cycles) (this rate is typical in other open seasons as well).

Following the successful allocation of existing capacities through open subscription, the TSOs decided to develop Open Season procedures to test market interest in two new projects. The first project is to reinforce the Western axis through new investments in the existing interconnections (Larrau/Biritou) in 2013 and to extend capacities inside France, while the other one involves creating a new interconnection point on the Eastern axis from 2015 (MidCat project). The OS to expand the Western axis was launched in July 2009. Results signalled clear market interest in the western interconnection project, thus provided a sufficient basis to make an investment decision (and for regulators to approve the projects). Requests from shipper to flow gas from Spain into France were 200%, while requests to flow gas from France into Spain were 58.5% of the capacity offered. (For the proposed extension to capacities within France between the various TSOs, shippers asked for 160% and 33% of the capacity offered.) On the other hand, the market demand was low to trigger the development of the MidCat project.

Although assessing demand in the framework of OS procedures is acknowledged and accepted, demand for capacity booking estimated in the framework of OS may be misleading from the viewpoint of future viability of the projects. Theoretically, interconnection capacity development is determined by market demand. However, such demand for capacity booking is expressed often only if markets are relatively liquid and matured,

i.e. the value chain includes a sufficient number of market players. These conditions, however, are not present lacking a certain level of integration of national markets, (eg. sufficient level of interconnection capacities) therefore present market demand does not necessarily reflect future potential market demand, which partly depends on the implementation of the project. The chicken or the egg dilemma, and fostering projects that failed due to an unsuccessful OS procedure, can be solved only by a prudent market analysis and forecast as well as by appropriate regulatory incentives.

7.3.2. Improving capacity allocation and capacity use: open subscriptions and capacity markets

Developing open seasons and building new infrastructure can increase market integration in the long run, but to make situation better in the short run, capacity use on existing interconnection points should be improved. Current underutilization of capacities and interconnection congestions are often caused by contractual congestions. That is why improving capacity use through the establishment of day-ahead capacity markets, congestion management and improving the efficiency of allocation through the elaboration of coordinated allocation mechanism were among the most important tasks of Regional Initiatives.

Day-ahead capacity markets - primary markets for non-firm capacity and secondary markets for firm capacity - are significant because they can considerably improve the liquidity of the natural gas markets in the region. In 2008, the Belgian TSO (Fluxys) tried to improve capacity use and strengthen primary capacity market by selling non-firm capacities.

On a proposal from the EFET, the affected TSOs launched a pilot project to establish day-ahead secondary market for firm capacity at a German-Dutch interconnection point (Bunde/Oude Statenzijl) and at a German-Danish interconnection point (Ellund). The technical platform of the online capacity trading,developed by the Anglo-Dutch energy exchange APX and the German secondary trading platform trac-x, was designed to allow shippers to trade capacity on day-ahead basis. If a TSO curtails the firm capacity purchased by a given shipper on the day of shipping, the shipper has to be compensated.

A good example of coordinated capacity allocation is the already mentioned Open Subscription Period implemented at the Spanish-French intersection (Larrau). In the framework of open subscription period, capacity is primarily allocated on a long term basis (for periods longer than a year) and on a 'moderately' short term basis (within a year) opposite to secondary capacity trading platforms.

In 2007, the SSE region examined the possibilities to establish a one-stop-shop capacity booking scheme and a Regional Gas Grid Manager. The one-stop-shop provider should be responsible for providing information to potential shippers on the available transportation capacity for the whole transportation route and the cumulative transportation tariff for the requested route, and forward the necessary contract documents to the applicant. This service -coordination function fulfilled by the one-stop-shop provider- enables shippers to book capacity for the whole transportation route between certain interconnection points via a single entity. The one-stop-shop provider should run a common trading platform (bulletin board) facilitating secondary capacity trade. (If

the voluntary cooperation of TSOs is insufficient to provide one-stop-shop services, the function of the one-stop-shop provider could be achieved by regional gas grid manager.) The ambitious initiative has finally turned into the elaboration of a Standardised Bulletin Board, an intermediate step towards a single trading platform. In the framework of Standardised Bulletin Board, the region's TSOs disclose such pieces of information with the help of a template that help shippers to find each other, by announcing their supply of and demand for transportation capacities on the bulletin board.

7.3.3. Improving interoperability: harmonising operational procedures

The improvement of interoperability of the natural gas networks of Member States enable market players to compete at regional level through facilitating cross-border trade and liquid hub based trading. Operational procedures -including technical and commercial issues, as well as operational and business practices of TSOs - must be harmonised to facilitate interoperability.

Instruments of harmonisation are Interconnection Point Agreements and Operational Balancing Agreements. In the South South East region, the affected TSOs concluded Interconnection Point Agreements and Operational Balancing Agreements for the Baumgarten interconnection point, which significantly facilitate for shippers active in the region to trade natural gas at the Baumgarten hub (Central European Gas Hub – CEGH). The Interconnection Point Agreements and the Operational Balancing Agreements generally should cover technical and commercial issues, including: matching, rules for flow control, measurement principles of gas quantities and gas quality, gas quality specifications, allocation rules, procedures for balancing shipper flows and dealing with imbalances, coordination of operation and information exchange between adjacent TSOs.

In 2008 regulators of the South region elaborated an action plan for the integration and development of the Iberian gas market (MIBGAS). The Spanish and the Portuguese regulators started to establish a common trading licensing procedure and to work on a proposal to modify existing regulations. In an effort to increase interoperability with neighbouring natural gas systems, the Spanish regulator decided to implement the EASEE-Gas (European Association for Streamlining Energy Exchange-Gas) Common Business Practices in the national legislation and amended the network code to achieve full compliance with Common Business Practices (the Spanish measurement procedures and the rules of nomination and matching processes have to be modified among others).

The work on improving the interoperability of systems was linked with the increase of liquidity of hubs in the region. Several studies were made in the regions on how to increase the liquidity and the turnover of hubs. ERGEG also made observations on the insufficient liquidity of hubs. In its report, ERGEG found that it is caused among others by the lack of independence of TSOs, SSOs (Storage System Operators) and market operators from market players. The largest progress was made by the North West region, where a test action plan was worked out, identifying barriers to trade and elaborating actions to overcome them, and conducted at the Danish GTF. The project was considered as a success, after which stakeholders proposed to implement similar liquidity increasing

programmes at other hubs in the region as well. In the SSE region, liquidity programmes include the publication of day-ahead gas price index at the CEGH and the establishment of an independent market operator of the Italian gas hub (PSV) in addition to the already mentioned measures conducted at the Baumgarten hub (establishment of Standardized Bulletin Board facilitating secondary capacity trading, and the conclusion of Interconnection Point Agreements and Operational Balancing Agreements to increase interoperability).

7.3.4. Increasing transparency: data release projects

A driver to the initiatives on developing transparency is the 2007 ERGEG report monitoring the compliance with the transparency requirements specified in the EU legislation (Directive 2003/55/EC and Regulation 1775/2005). The ERGEG report found that the implementation of transparency provisions was very heterogeneous in the different Member States, with a very low level of the general compliance and an insufficient level of transparency. The report proposes to extend the obligations on data publication to a wider range of market players (including storage and LNG operators), to apply a more uniform interpretation (and not a restrictive one as revealed in the monitoring exercises) and to harmonise the way of information disclosure.

A major transparency project related to the use and availability of transmission capacities was launched in the North West region. The stakeholders (regulators, TSOs, system users) agreed on a wish list for information items to be delivered. The stakeholders agreed to focus the project primarily on the release of data on regional gas flows and the availability of interconnection capacities. (Data releases were made on a voluntary basis by TSOs and network users.) All TSOs in the region were expected to publish the information requested by network users by the end of 2009. Since the end of 2007, also storage operators have to comply with transparency requirements, who have to disclose daily information on storage inflows, storage outflows, and storage level (by Spring 2010, similarly to transmission pipeline operators, near all the storage operators met the obligations on data supply).

Regulators in the South region commissioned an in-depth study on the level of transparency on transmission, which showed high levels of compliance with the relevant obligations of the EU Gas Regulation and those recommended by the LNG Guideline of ERGEG. Good results encouraged regulators to oblige TSOs to publish every six month the building status of new interconnection capacities. The South-Southeast region is lagging behind the two other regions in terms of progress. Several TSOs of the region were reluctant to participate in the transparency platform of the GTE+, a common surface to disclose information on Europe's natural gas transmission system, and neither the relevant regulators had the sufficient power or legal authority to enforce it. The South-southeast region tries to compensate the lack of commitment of stakeholders by setting up a Strategic Advisory Panel ,following the example of the North-West region. The Panel consists of the acknowledged and senior representatives of the gas industry and has the task to improve communication and cooperation between stakeholders.

The regional diversity of progress in the field of transparency shows that the approach that is based on the voluntary cooperation and the initiatives of stakeholders is not fully

successful in this regard. The interpretation of the transparency requirements, as well as the content and structure of data publication should be uniform and the requirements should be binding so that all the regions could achieve similar progress in this respect.

7.3.5. Reinforcing security of supply: recommendations

Initiatives on security of supply are in strong relation with the projects to increase interconnection capacities, to improve the use of existing capacities, to increase the liquidity of regional hubs and to enhance interoperability of transmission networks. These projects may reinforce security of supply on a long term by increasing the quantity of transportable natural gas and by diversifying the routes of supply, and on a short term by improving the flexibility of networks. (The increase of interconnection capacity between France and Spain was strongly supported by the relevant regulators since it reinforces the security of supply both in the South and the North-West region by allowing Algerian gas to flow to North European countries and piped gas from the North European fields to flow to the Iberian Peninsula.)

The January 2009 gas crisis significantly determined the orientation and content of the initiatives that related to the reinforcement of security of supply. The South-Southeast region being the most affected by the crisis made a report on the lessons to be learnt from the crisis in 2009 with the following proposals on how to enhance security of supply in the region.

(i) Majority of the region's natural gas pipelines allows flows only from East to West. Upgrading transmission pipelines for reverse flows may give significant contribution to congestion management in the event of sudden disruption of a supply route at a relatively low cost. (As experience proves, a few simple technical modifications to Kittsee-Petrzalka pipeline temporarily allowed gas flows from West to East.) If the southbound transit through Romania, Bulgaria, Greece and Turkey were upgraded for northward flows, the Mediterranean LNG would significantly mitigate supply difficulties of the North Balkan region in the case of a crisis.

(ii) Storage capacities in the region are not adequate for managing a sudden crisis. New storage facilities, especially peak storages may considerably increase the flexibility of the systems and would bring diversification on a short term.

(iii) The North-South corridor could enhance long term security of supply by securing access to alternative gas sources (LNG projects in Italy and Greece as well as along the Baltic coast) and by providing an alternative transmission route. Construction of the transmission pipeline through Denmark, Poland, Slovakia, Hungary and Croatia would allow the region to have an access to alternative natural gas sources, which would improve long term security of supply (in addition, it could solve temporary transit problems by connecting the North-South corridor with Yamal and Brotherhood pipelines)

(iv) When designing LNG projects in Italy and Greece, the capacity of LNG terminals should exceed the demand of the national markets so that these LNG

facilities can also support natural gas transport into the North-Balkans region (e.g. Revithoussa extension to 5.2 bcm exceeding currently the needs of the Greek market is considered a similar – regional – project).

7.4. Regulatory requirements and incentives of regional pipeline projects: A case study on the Energy Community Gas Ring

Incentives to natural gas infrastructure investment projects (essentially the construction of cross-border pipelines) are of utmost importance for the countries of South East Europe. The natural gas infrastructure of the countries in the region (particularly in the successor states of ex-Yugoslavia) is very underdeveloped and requires significant investments, while the small size and the different regulation of the given countries set back to a large extent the realisation of major projects.

The Energy Community consisting of the countries in the South East European region set the aim of integrating the small and separated markets and establishing a single regulatory space. The Treaty establishing the Energy Community was signed on 25 October 2005 by the countries of the region, Albania, Bulgaria, Bosnia and Herzegovina, Croatia, Kosovo, FYR of Macedonia, Montenegro, Romania and Serbia. The contracting parties resolved to implement the European legislation in the field of energy in order to ensure a stabile, predictable and uniform regulatory environment for infrastructure investments. (Measures required for the implementation are specified in Road Maps and Action Plans, which are prepared to the given Member States and allow to track the progress.)

In recent years, the ECRB (Energy Community Regulatory Board), which is the main body of the European Community for preparing decisions cooperated in the preparation of several studies examining the regulatory environment (regulatory measures) required to promote regional projects. Majority of the proposals urges to implement as soon as possible the already introduced and detailed regulation on energy and the relevant guidelines detailing and specifying the legislation. In the following, we introduce the issues that may play an important role in the realisation of the infrastructure investments in the region in addition to the already detailed regulatory instruments.

In majority of the countries in the South East European region, natural gas markets are small, less developed due to the availability of cheap competing fuels (lignite and water) and low population density with a sluggish infrastructure. The natural gas market does not exist in several countries (Albania, Montenegro, Kosovo), or there is only an insignificant level of natural gas consumption (Macedonia, Bosnia and Herzegovina). The volume of installed interconnection capacities is low and the cross-border transactions are limited to transit flows dominated by long-term contracts with a very small number of national incumbent undertakings. Destination clauses prohibit selling the purchased natural gas to other than the original destination of the contract. There is no obligation to release the contracted but not used interconnection capacities, which implies a very limited access to interconnection capacities. The region, however, is of strategic importance from the viewpoint of security of supply of the Central and South Eastern Europe region, since the route of several bulk import transportation projects is designed to cross the countries of the region (South Stream, Nabucco, Trans Adriatic Pipeline). Creating a regulatory environment that is conductive to investments is therefore an important

objective from the viewpoint of the security of natural gas supply not only of the South East Europe region but also of the EU.

Currently, the investment and network development plans of the countries in the South East Europe region are based on different approaches in the various jurisdictions, there is a diversity in various institutions in charge for investment planning and different time frames are used for planning. The single forum to reconcile investment plans is the Ministerial Council, which is the decision making body of the Energy Community, which determines the investments plans that are of outstanding importance from the viewpoint of the establishment of a uniform regional natural gas market. The Ministerial Council approved in December 2008 the updated list of Priority Infrastructure Projects.

A significant part of the priority projects fits the concept of the so-called Gas Ring supported by the Energy Community. The purpose of the Gas Ring concept is to connect all countries in the region via a ring of transmission pipelines. The concept was first introduced in details in a study financed by the World Bank and published in 2008. When elaborating the concept (and defining the route of the ring), the routes of the exiting transmission pipelines (or the ones being in an advanced phase of preparation), the planned route of cross-border transmission pipeline projects (Nabucco, South Stream, TAP) and the location of the planned LNG terminals have been taken into account. The ring would integrate the natural markets of the given countries so that it involves unsupplied territories into natural gas supply and makes several alternative natural gas sources available to the region.

The Gas Ring is, even at an international level, a major investment. It would mean the establishment of approximately 1264 km pipeline at a cost of 952 million USD (this amount excludes both the construction of the connection with the bulk import transportation pipelines (Nabucco, South Stream, TAP) and the necessary investments in distribution networks). Considering the conditions of the region, the project would be implemented not in the framework of a large centrally controlled project, but gradually by separately constructing the pipeline sections included in the network development plans of the given TSOs. There are several conditions to be fulfilled so that the given investments carried out by TSOs can be integrated into a uniform regional natural gas network.

7.4.1. Regulatory incentives and measures to facilitate new infrastructure investment

The most frequently mentioned conditions to the realisation (and bankability) of major infrastructure investments are the adequate project plan (that ensures that the investment is economic), predictable, coherent and uniform regulatory environment, comprehensive contractual scheme, implementation of risk management tools and dispute settlement mechanisms. In the following, we examine these conditions in depth, particularly the expectations towards the regulatory environment.

A fundamental condition to an economic investment is that the planned infrastructure is built on the basis of market demand, which implies a sufficient extent of use of the infrastructure and thus generates continuous revenues for the investor. The market

interest revealed in the first phase of the Open Season procedure clearly indicates this market demand (while capacity bookings in the second phase will provide a guarantee for the investor). Financing is doubtful if the given infrastructure is planned to build on the basis of future needs like in the case of the Gas Ring. One solution is to bring forward a sufficiently large quantity of demand (anchor loads) to launch the investment. As regards the Gas Ring, this anchor load can be ensured by natural gas fired power plants. In the calculation of the authors, the Economic Consulting Associates, a CCGT capacity of 2100 MW should be in place for the Gas Ring to provide a minimum of 2 to 2.5 Bcm of anchor demand annually from the first year of operation of the new gas transmission infrastructure. Financially this means that the 1.25 billion USD construction cost of CCGT power plants providing for the anchor demand is added to 952 million USD investment cost required for the establishment of the Gas Ring.

An adequate regulatory environment is of utmost importance with regard to the establishment of the Gas Ring. This partly contributes to the harmonisation of the regulatory practices of the given countries (in line with the regulation of the Community as presented in former chapters), and partly to the implementation of adequate incentives. The harmonisation of the various regulations essentially means the uniform implementation of the European legislation, guidelines and practices that have been discussed detailed in the former chapters. Accordingly, in the following, we primarily focus on those regulatory incentives that can directly facilitate the realisation of major cross-border infrastructure projects.

One of the most frequently implemented incentives is the exemption from regulated third party access. This is an accepted way of promoting huge-sized and high-risk investments in the regions having well-developed network infrastructure and significant volume of interconnection capacities, since it generally has a positive effect on the competition and the security of supply (due to the regulator's active participation/contribution in setting the terms and conditions). In the less developed South East European region having a less developed natural gas network, however, the majority of regulators would be reluctant to support the exemption to be granted to the investments in the lacking network infrastructure since by this decision a significant part of the future natural gas network constituting the backbone of a uniform regional market would be exempted from regulated TPA for a long term. Consequently, other incentives should be found in the case of the projects of the Gas Ring (that often aim to develop the internal transmission network of the country concerned).

Regulators can provide positive and negative incentives to facilitate investments falling under regulated TPA and carried out by the TSOs in the framework of the network development plan. According to the general principle of tariff calculation, the regulator takes into account when setting the national network tariffs the actual cost incurred including the appropriate return on investment. To positively incentivise new infrastructure investment through tariff methodologies, the regulator acknowledges a higher rate of return in the case of new investments, and commits itself to a given tariff calculation methodology for a long term. When applying a negative incentive, the regulator obliges the TSO to spend congestion (e.g. auction) revenues for sorting out congestions (namely for increasing the capacity of the affected piece of infrastructure e.g. interconnection

point) or to reduce tariffs by congestion costs not used for sorting out long term congestion.

Regional projects (or the construction of transmission pipelines crossing several countries), however, raise a problem that cannot be solved purely by positive and negative incentives. When planning pipelines to be built in the framework of the Gas Ring concept, not only the national demand of the country that intends to build the given pipeline section but also the demands of neighbouring and further linked markets should be considered. Accordingly, the installed capacity of the regional pipelines should be higher than the aggregate capacity of the network based on the pipeline sections of the given TSOs calibrated on the basis of the demand of their own markets. Although suboptimal capacity planning can be avoided by the cooperation between the affected TSOs and regional planning (harmonisation of the network development plans of given TSOs), the financing of the required investment raises another problem.

Following the approval of the network development plan, the regulator includes the cost components of the projects included in the network development plan of given TSOs' in the network tariffs. However, the inclusion of the excess costs of a section to be built in a given country that incurs due to non-domestic investments may face difficulties. The regulator of the country where the given section is located may typically not accept the inclusion of interconnection costs which are of benefit only for customers of neighbouring markets in national tariffs. In general, neither the regulator of the neighbouring country that requires the excess capacity can include the costs created outside its territorial authority in the national regional asset base. (The issue of the allocation of non-domestic investments is a typical case for a 'regulatory gap'.)

The first step to solve the problems with regard to regional project planning and cost sharing is to harmonise the network development plans of TSOs and the regulators' approval procedures. In the European Union, a Community-level ten-year network development plan is compiled by the ENTSO-G and national ten-year network development plans are approved by the ACER in order to harmonise national network development plans and approval procedures. The Energy Community should establish an association for TSOs based on the ENTSO-G sample, which would be responsible for compiling a regional network development plan, while the ECRB should be empowered to harmonise the given TSO's network development plans and to approve the regional network development plan.

The second step is to harmonise tariff calculation methodologies with the regional network development plan. This includes the introduction of appropriate (positive and negative) incentives on the one hand, and the inclusion of extraterritorial network development costs that are for the benefit of domestic customers in the national tariffs/regulated asset base on the other hand. One possible way of cost sharing of regional investments (and the inclusion of extraterritorial investments) is the inclusion of the costs of upstream capacity bookings of the TSO in the network tariff of the TSO. A TSO can make an upstream capacity booking if it wants to ensure that the capacity increasing investments that are required for the security of supply of its own operation territory are carried out on the neighbouring country's network. If capacity increasing is of utmost importance for several countries, the respective TSOs may initiate a collective capacity booking. It is the long term capacity booking that ensures for the TSO carrying out the

investment that the project is economic, while the customers of the neighbouring countries that benefit from the increased capacity will finance the project by paying the cost component included in the network tariffs.

The above incentives may induce increase in network tariffs, which, however, may be compensated on the long term by an increasing competition and improving security of supply enhanced by the new non-domestic investments. Exemption from regulated third party access should be limited to the projects that would not be realised under the above incentives scheme.

7.4.2. Risk mitigation

In addition to an appropriate (harmonised, predictable and promoting) regulatory environment, the realisation of a cross-border network development project requires the implementation of adequate risk management mechanisms and tools. The first step of risk management is to establish a contractual scheme that aims to provide for future revenues and to limit costs (namely to prevent risks). Project sponsors conclude a part of the contracts for the purpose of protecting their investment (and of mitigating political risks, respectively) whiles the other part in order to mitigate financial risks.

Agreements concluded for the purpose of investment protection are generally made with the cooperation of the states concerned. In the Host Government Agreements, parties agree on specific rights granted by the state (this one specifies the legal framework of the operation of the investment), benefits, privileges (e.g. tax discounts), exemptions (e.g. free movement of goods and services) and the (tax, rent or employment) obligations imposed on project sponsors. As regards cross-border investments, the respective states may generally conclude agreements with each other (Inter-Governmental Agreements), in which they declare their mutual interest in the project, mutually confirm their support for the project and pledge to honor their respective Host Government Agreements.

Commercial risks are mitigated by agreements providing for the long term availability of sources, the wholesale of natural gas, capacity bookings and the operation of infrastructure. Capacity booking and operation contracts are to ensure that the infrastructure investment is economic. Natural gas purchase and wholesale contracts are to ensure that the players who book capacity (shippers) are supplied by sources and able to pay i.e. these contracts indirectly mitigate the commercial risks of the project sponsor. The availability of sources can be ensured by Production Sharing Agreements concluded between the undertakings producing natural gas (and selling natural gas to shippers) and by the respective state on the sharing of the revenues from the sales of the produced natural gas and by, while the wholesale of natural gas is ensured by long-term take-or-pay contracts.

The second step of risk management is the implementation of Risk Mitigation Instruments, which protect the project's shareholders and sponsors from political and commercial risks. Risk Mitigation Instruments among others include protection against damages caused by expropriation, rioting, civil wars, exceeding planned costs in the preparatory and construction phases of the project, insolvency as well as fluctuations of exchange and interest rates. Risk Mitigation Instruments are provided by multilateral and bilateral development institutions (World Bank Group, KfW Entwicklungsbank), or insurance companies and financial institutions (AIG, Lloyds, Zurich).

7.5. Conclusion

The recent amendments of the EU legislation on natural gas made significant contribution to security of supply. The monitoring end reporting activities of member states (on supply adequacy) have been strengthened, which improved their ability to identify and manage any approaching supply risks. The detailed consultation rules concerning the preparation, elaboration and finalisation of ten year network development plan as well as drafting of regional network development plan make a much better environment for identifying investment needs and promoting their realisation. The draft regulation on security of supply with detailed infrastructure and supply standards fastens member states more resistant to supply disruptions and more prepared to manage emergencies and supply crises.

As long term dependency on external gas sources can hardly been avoided, the main focus of ERGEG's work on framework guidelines is the better use of the present transmission and storage infrastructure. The main tools are standardization of products, increased transparency requirements on TSOs regarding necessary (on-line) data, compatibility regarding timing and introduction of UIOLI procedures wherever possible, to bring back capacity to the primary and secondary markets at least for short time products and on an interruptible basis.

To eliminate barriers to trade a European wide capacity allocation mechanism will be put in place that will be based on coordinated auction of transmission capacities. The focus is given to developing compatible rules on the two sides of interconnection points, which includes the same products and the same allocation procedures. The objective is to create bundled products at all the interconnection points which would constitute bridges between adjacent markets. In the end, a small number of capacity products should be applied all over Europe with coordinated and converging allocation mechanisms. A basic set of storage products has to be developed compatible with the transport capacity products to make them exchangeable and interchangeable. Enabling to commercialize these products will increase liquidity on virtual hubs and trading platforms.

The gas regional initiatives strongly relied on the proposals of the draft regulations of the commission and the framework guidelines elaborated by ERGEG, and made significant contribution to the finalisation and acceptance of the proposals. The achievments of regional initiatives in this respect are fare-reaching. Coordinated open season procedures have been elaborated and implemented to assess market demand and support well funded investment decisions. TSOs and regulators implemented open subscriptions periods and established more liquid capacity markets to improve efficiency of capacity allocation and improve capacity use. Signing Operational Interconnection Point Agreements and Operational Balancing Agreements and implementation of EASEE-Gas Common Business Practices contributed to the harmonisation of operational procedures and improved the interoperability of the natural gas networks of Member States. In the framework of transparency projects TSOs and storage system operators disclosed data on regional gas flows, the availability of interconnection capacities, storage level, inflows and outflows. The South South East region examined the possibility to establish a one-stop-shop capacity booking scheme and a Regional Gas Grid Manager,

set up standardised bulletin board and made several recommendations to make member states more resistant to sudden disruption of natural gas transport.

After describing the broad regulatory framework that must be in place and the practical experience of regional initiatives we overviewed the regulatory incentives and measures to facilitate new infrastructure investment. We found that the harmonisation and coordination of the network development plans of neighbouring TSOs and the regulators' approval procedures, as well as elaboration of regional network development plan is of the utmost importance. Close cooperation of TSOs and regulators through the relevant organisations (in the EU the ENTSO-G and the ACER, respectively) is indispensable element of this process.

Tariff calculation methodologies should be harmonised with the regional network development plan. This may include the introduction of appropriate (positive and negative) incentives and the inclusion of extraterritorial network development costs that are for the benefit of domestic customers in the national tariffs. One possible way of cost sharing of regional investments is the inclusion of the costs of upstream capacity bookings of the TSO in the network tariff of the TSO. Exemption from regulated third party access in regions with underdeveloped gas infrastructure should be limited to the projects that would not be realised under the above incentives scheme.

However, the conditions to the realisation of major infrastructure investments are not limited to the implementation of predictable, coherent and uniform regulatory environment. Sound project plan – including implementation of market test to assess future demand – , comprehensive contractual scheme – including concusion of commercial and intergovernmental agreements – , risk management tools and dispute settlement mechanisms must be in place, too.

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Mid-Term Gas Supply Security Scenarios For The CSEE Region

8.1. Introduction[1]

The energy infrastructure of Central and South East Europe (CSEE) had been developed while Europe was divided by the Iron Curtain. Since independence the region's electricity grid expanded into an integrated European system (UCTE). Meantime the gas transmission network remained almost intact and sufficient steps were not made to decrease the region's almost unilateral dependence on Russian supplies or increase gas liquidity throughout the region. The two gas crises of the past five years (2006 and 2009) that had a significant impact on EU supplies revealed the asymmetric exposure of the CSEE region to the supply security, price and political risks related to Russian gas deliveries. The key question today for the future of gas supply security and also for gas market development in CSEE countries is how fast and deep their physical and commercial integration into the European gas market will be. Recent EU measures[2] and initiatives[3] seem to recognize these concerns and put forward meaningful obligations and proposals to accomplish the gas grid and market integration of eastern member states. However, the success of these efforts will depend on the interplay of a relatively large number of factors related to technology, geopolitics and finance that surround gas industry developments in CSEE.

The aim of this paper is exactly to reflect on this complexity and generate interdisciplinary debate about long-term risks and opportunities by presenting three middle run (20 years) scenarios for potential gas industry development in and around the CSEE region. Such a scenario development might create the basis for identifying relevant, 'best response' local (regional) policy alternatives to the different scenarios.

Our aim is not providing the most likely infrastructure and market development scenarios, but to gain an understanding of the likely barriers towards accomplishing a gas network across the region to provide more secure, liquid and diversified gas supply by 2030. The cascade of events in the scenarios is composed of the most likely strategic moves of geopolitical actors and alternative developments of scenario drivers. It highlights the trigger factors and their scope of impact in different contexts. The outlined barriers can be avoided with smart policy or aligned strategy and thus making the rest of the scenario irrelevant. Furthermore, the provided scenarios are permeable, policies or other actions can switch the outlines from one scenario to the other, thus requiring a constant analysis of achieved milestones, at the same time keeping the long term vision in sight and not overwritten by possible desert spurious moves or trends of other drivers.

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[1] This paper would not been written without the valuable contribution of Mihály Bayer, András Gy. Deák, András Rozmer, Anita Orbán, István Salgó, Natália Soczó, Balázs Váradi, László Varró, István Zsoldos. They have dedicated their precious time and expert analysis during three workshops of this project. Certainly, full responsibility for the mistakes of the paper remains with the authors.

[2] Regulation 994/2010/EU.

[3] Energy infrastructure priorities for 2020 and beyond – a Blueprint for an integrated European energy network. European Commission, November 2010.

8.2. Methodology

A substantial literature on energy supply security indicators has been developed in recent decades, reflecting the multi-dimension nature of the topic. Most of the work in developing those indicators has been carried out with an eye on long-term security (see Kruyt et al., 2009 for a recent survey). In their paper Kiss et al (2010) report on an effort to apply traditional supply security indicators in the CSEE context and to understand gas supply security by their help. However, their work could not capture some wider aspects of gas supply security such as upstream market developments, the pace of technological change in e.g. the gas and the renewable energy industries or the foreign policy strategies followed by the EU and its major gas supplier partners or regions. These latter aspects make long-term gas supply security risk assessment very challenging. Data analysis and quantitative modelling alone may not be sufficient because of their limited ability to address market shocks, sudden technological and political changes or unexpected events in the market. This shortcoming of traditional analysis creates the basis for a more interactive, interdisciplinary and heuristic approach to the problem.[4]

The scenarios presented in this paper have been developed by the help of three subsequent structured consultations with leading Hungarian energy, energy security and financial market experts in the first half of 2010. The expert group agreed that it was useful to create three key categories out of those factors that are shaping future regional gas market and supply security developments: technology, geopolitics and finance. These dimensions are also largely external to local energy policy decision makers, although some of them can be affected by targeted policy action.

Next the different elements of the above dimensions were classified according to the level of perceived uncertainty by the experts around their future impact on the regional gas market. Low uncertainty and high impact elements are named drivers, high uncertainty high impact elements are called scenario shapers. The work to identify drivers, scenario shapers and other relevant variables involved discussions that helped a consensus to emerge on to what extent these factors are external to action at the local or regional level.

Based on the results of the consultations, we have been developing a large number of potential scenarios composed of combinations in technological developments, financial preconditions and the likely moves of relevant geopolitical players. Then we reduced ourselves to 1+3 scenarios. In the baseline we assume a liquid market, diversified import supplies and no physical and regulatory bottleneck to free gas flows across the region by 2030. Therefore in this case the region's resilience to sudden price shocks or physical interruptions is substantially above the 2010 levels. The three other scenarios were selected so that they could help the most in understanding the likely barriers towards accomplishing the baseline.

We continue now with summarizing our findings on technology, finance and geopolitical variables.

[4] Examples for the art of complex future energy scenario development can be found in Shell 2050 and the National Intelligence Council (2008).

8.3. Technology

Technological development and the spread of innovations may result in significant demand and supply side shifts on gas markets. The principal impact of technological development is the one on the cost and competitiveness of gas relative to its competitors (coal, renewable, nuclear) in serving customer needs in heating, electricity generation and industrial applications. Such an impact might change the relative cost of gas to its competitors directly (e.g. the reduced cost of non conventional gas drilling) or indirectly through technological change in the consuming sectors (e.g. improved energy efficiency of CCGT power plants or of the building sector). The other potential impact of technological change might be the emergence of new consumer segments (e.g. gas-fuelled cars) and the consequent change in demand. Technological change will also affect the supply side of the market in terms of the cost and availability of supply sources and gas transportation.

Technology trends affecting the future of the region's gas market or its security can mostly be considered as external to the region. Technological innovations are not likely to come from CSEE. Innovations are going to spread into the region with a delay, depending on gas market maturity and the robustness of demand Local policy support for innovation might be strictly limited by fiscal constraints.

Table 8.1 summarizes our assumptions about the most important technology variables including LNG, electricity generation, carbon capture and storage (CCS) and the availability of non-conventional gas for CSEE.

We expect a further penetration of LNG on the global as well as on the European gas market. The LNG technology became available almost 40 years ago. Since then it has gone through significant cost reduction, but as for today it has reached its technological limits. No significant further cost reduction is expected in the upcoming two decades. As for the CSEE region, supplies through pipelines will remain dominant up to 2030.

Electricity generation is becoming the most significant gas consuming sector in Europe in the upcoming decades. Here gas based technologies have to compete with other fossil (coal, lignite, oil), nuclear and renewable based technologies, some of which enjoying significant state subsidies and preferential treatment. Since, according to our assumption, the CCS technology is not developing fast enough, it is not playing a role in the upcoming two decades and cannot successfully support the deployment of other traditional fuel sources like coal. Therefore new electricity generation options are going to be narrowed down to three solutions: nuclear, renewable and gas-fuelled. European hydro potential does not have plausible capacity for further growth. The most advanced intermittent renewables (wind and photovoltaic) need generation reserves to be balanced. Since large scale electricity storage is not economically available – and it is not expected to be available in the upcoming decade – the spread of renewables make the application of additional flexible CCGT capacity necessary. New nuclear development plans are on the table across the CSEE region. We can account on their availability only in the second phase of the examined period. Any delay or cancellation of these nuclear developments can trigger a second wave of CCGT capacity building. Therefore gas turbines play an increasingly important role in the overall electricity production of the EU.

However, due to thermodynamic reasons the authors of this paper do not assume major further efficiency increase in CCGT technology.

Table 8.1. Technology scenario drivers

Scenario drivers	Description
Liquefied Natural Gas (LNG)	Because of the technology's thermodynamic attributes (cooling, keeping pressure, etc) and material technology needs to remain capital intensive.
CCGT Efficiency	This is a mature technology; no significant efficiency increase is expected, because of building-material constrains. Further efficiency increase would require higher temperatures and there is no material at present that could meet such a need.
Wind	It is a mature and competitive technology. Further penetration is expected.
Nuclear	New nuclear technology is feasible but penetration is limited by high capital investment needs and long construction time. Regionally, mostly life extension and the expansion of existing sites are probable.
No CCS	Carbon Capture and Storage technology (CCS) do not develop fast enough to play a significant role during the time scale examined in this paper.
Electricity Efficiency	No significant alternatives are available to increase the efficiency of electricity usage. The implication is that future demand for electricity is going to be closely related to changes in economic activity (GDP).

Unexpected or highly unlikely additional resource availability or policy success can reshape gas demand patterns in the region. One of these uncertain game changers is non-conventional gas. The data currently available suggests that Europe is not likely to get a clear understanding of its non-conventional gas reserves before 2015. The current drilling cost estimates are double the costs in the US. These assumptions can change mid-term. A significant but heavily policy dependent issue is the likely change in the efficiency of building heating. The success of improved building energy efficiency heavily relies on policy implementation.

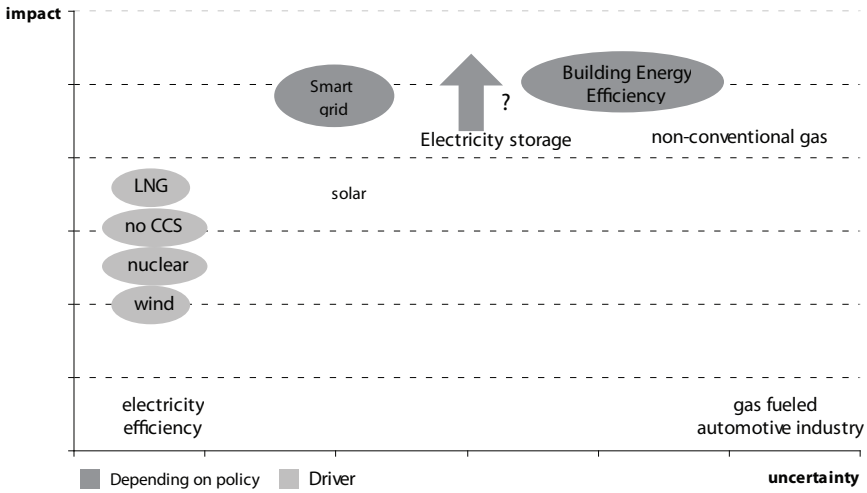
Table 8.2. Technology scenario shapers

Scenario shapers	Description
Non-conventional gas	Non-conventional gas resources are huge and can be exploited with currently available technology. However, safety concerns relating to the drilling technology still exist. The U.S. success story might not be repeated in Europe. The fields in Europe are smaller and located deeper. However, Central and Southern Europe is considered to be rich in non-conventional gas resources (Poland, Czech Republic, Slovakia, Austria, Romania, Ukraine). Population density and environmental regulations also mean a more significant barrier for extensive drilling in Europe. However, this resource may have a significant impact in China if it is recovered on a mass scale inside the country.
Building energy efficiency	About 40% of energy is used to heat and cool buildings in Europe. Thus a significant improvement in building energy efficiency might have a significant impact on the gas market. However, market mechanisms alone do not trigger significant changes in increasing building energy efficiency. No external factors were identified that could initiate such a massive investment at the consumer side. Therefore, this variable is primarily dependent on policy-making. Related costs might be significant; adequate institutional regime is needed and bears the risk of rent-seeking and other politico-economic distortions.
Smart grid	The current regulatory paradigm has to be re-examined and rethought in the near future. System-operation at the transmission and distribution levels is put under pressure by adding new, relatively small sized renewable electricity production facilities. This is further exploited by the future spread of electric vehicles in the network. Smart grids can address the capacity limits of the electricity networks and provide additional surplus capacities.
Electricity storage	Nanotechnology is contributing to significant and rapid innovations. Electricity storage costs are expected to fall by almost 75% in the next 10-20 years.
Solar energy	The impact of this technology depends on policy frameworks. It can significantly contribute to electricity supply, once the network bottleneck and imbalance issues are properly addressed and once the European electricity grid development achieves a more mature state.

The above drivers and scenario shapers were applied to the specifics of the CSEE region. Figure 8.1 below depicts the impact and uncertainty of each component. The vertical axis stands for the significance of the impact. Farther the component is located from

zero along this axis, the higher its impact on gas market future development is. Therefore it shapes the security of supply needs of the segment, while the horizontal axis stands for the level of uncertainty. The farther the component is located from zero along this axis, the higher uncertainty it couples with.

Figure 8.1. Technology Matrix



Source: REKK note

Drivers are marked with light grey. The matrix clearly shows that these have various impacts with low uncertainty level. Those marked with dark grey are scenario shapers. Their impact and uncertainty depends on governmental or EU policies. They have the potential for large impact, but due to their dependency on policy implementation their uncertainty remains relatively high, and impact level ambiguous.

Other components depicted remain important variables affecting the future of global gas markets, but their relevance in CSEE is limited. Despite the fact that non-conventional gas technology is widely used in USA and the technology is available, its effect in CSEE remains very uncertain, while it unquestionably has a major impact if this resource becomes available on large scale before 2030.

The baseline scenario for the technology drivers can be summed up in the following: throughout this study the authors assume that electricity demand development is linked to GDP. Building energy efficiency improvements are not bringing as significant results as expected. Although nuclear power stations are built across the region by the second phase of the period, these are not playing a game changer role, and have marginal effect on gas consumption patterns. It can be further assumed that renewable energy is going to remain popular and politics continues to actively encourage the use of these resources. Electric vehicles reach around a 20% share of the total vehicle park by 2025. The 20% share marks the start of the spread of these cars. At the same time the spread of gas fueled cars is not anticipated.

8.4. Finances

Future gas supply security in CSEE critically depends on infrastructure investments. This, in turn, is highly determined by the access of the region's private players and governments to the global financial market. The region's financial capabilities are largely determined by external and global trends. Interference is possible through macroeconomic discourses. On the mid-term we assume a stabilizing macroeconomic environment throughout the region that is accompanied by rising energy prices.

After 2008 the financial markets have been going through a significant change. It has been made clear that cheap, easy, long-term credits became part of history and there is no return to the old practices. Nevertheless, there is no clear vision of what the future brings. It is expected that for the next decade short-run, smaller scale projects might receive relatively easy financing, while large-scale investments face enormous global competition for extremely tight finances. The crises triggered demand for tighter financial regulation. Adversary, it increases regulatory risk and strongly limits any new innovation on the financial markets.

The current crises suggests that the 'too big to fail' doctrine is supported by market participants. This led to the fact that nowadays the possibility of state bankruptcy in the Western hemisphere is underestimated. To our understanding the capability of the region's governments to participate in large-scale infrastructure development projects is strictly limited by their fiscal instability.

While we assume a stagnating aggregate gas demand at the regional level up to 2030, we could identify a differentiated attitude of investors for the different infrastructure elements of the gas sector. The most preferred investments seem to be into storage and cross-border capacity-building or development. These kinds of projects offer a clear investment cycle and a sufficient return under stable regulatory conditions. Although cross border capacity projects bear sizable regulatory risks, this type of risk is less relevant in case of natural gas storage.

Production prospects for conventional drilling across the CSEE region are limited. There are perspective projects in Romania and Croatia, and a very small-scale project in Hungary. There is no clear understanding of the region's non-conventional resources and it is not likely to play a role in the upcoming decade in the CSEE.

Notions about prospective LNG terminals are unsettled. Despite the fact that setting up a re-gasification terminal is cheaper than a gasification plant, it remains a capital-intensive project that has more exposure to demand risks and price volatility.

We could detect the highest reservation among financial market players against long distance transit pipeline projects. These types of projects require complex risk-mitigation procedures. Cross continental pipelines laid in different soil in different countries rise various risks of regulation and cross cultural communication among different regulators, workforce and planners. Long-term supply contracts could limit these reservations. However, current gas market trends, namely the split of natural gas prices from oil prices and the introduction of spot prices in price formulas evoke counter-tendencies. It is getting less clear as to how sustainable long-term price formula contracts are in an ever-growing market liquidity environment. Thus, losing the basis of stable long-term

contracts would have an adverse effect on investment decisions that would negatively influence financial markets decision-making on large-scale investment projects.

Table 8.3. Investor willingness to finance gas industry projects

Project	Investors reservation
Storage and cross-border capacity development	Low
Production	Medium
LNG	High
Long distance transmission pipeline	Very-high

Source: REKK note

Also the nature of project financing is changing. Firstly, it is no longer supported by investment bankers that the borders between the balance sheets of the companies of the same holding vanish. As a consequence, a wave of return from project financing to equity financing can be forecasted. The share of own to external capital will have to increase up to at least 30-40%. Some projects become absolutely equity financed and this will increase the capital cost of investment.

8.5. Geopolitics

Similarly to the technology category, global energy market shapers were identified firstly with a specific focus on Europe. Later the identified drivers were applied to the CSEE region.

The main geopolitical shapers of world energy markets and its natural gas segment until 2030 are undoubtedly the BRIC countries, Europe and the United States. The developments of these countries and their policies in the next two decade depend on complex, and partly interdependent factors, therefore key elements were identified to narrow down the scope of the study.

Table 8.4. Identified geopolitical drivers

Drivers	Description
Climate Change Policy	The post-Kyoto climate change policy framework may have a crucial impact on global natural gas consumption patterns. A strict and global policy framework pushes China, India and other emerging countries to greener energy consumption, therefore triggering cleaner natural gas consumption. However, in absence of such a policy, these countries remain coal-driven as it is a relatively cheap source for them. In a nutshell, a comprehensive climate change policy fosters competition for natural gas resources.
Globalization	Globalization is defined as the international production's further integration. In the past few decades, this was clearly one of the main drivers behind global energy consumption growth. Does this trend have an obvious continuation or are interruptions and reverse effects to be expected? The halting of globalization would increase contractual and transportation insecurity, due to weak interdependencies that cannot counterbalance international conflicts. Interruption in globalization increases access difficulties to natural gas resources and changes the competition for these resources that are no longer driven by prices but rather by political interests and favors.
Trading policy	The next twenty years bring a change in trading patterns. Its change and scale can hardly be estimated. The common wisdom for a freer trade with fewer barriers is to be revised, and a new era of custom barriers and protectionism can start to unravel. It is a fact that the European Union's energy import dependency increases with the depletion of internal energy resources. Thus, in the event of a trade war outbreak, the EU is strongly motivated to keep its energy import flow as secure as possible.
Gas cartel	The forming of a working gas cartel is on its way. However, the level of cooperation among major suppliers remains dubious. The patterns of natural gas consumption (seasonal differences, physical qualities, geography, transportation and drilling technologies, demand elasticity) put limits on such an organization. Its impact on secure supply worldwide is weak, as the lessons from previous "gas wars"* suggest. The gas cartel would mean a political network among its members that can serve to influence infrastructure developments, but not to signify direct risk for supplies.
Gas pricing	It appears that a stronger de-linking of oil and natural gas markets is influencing the way natural gas is priced. The dominance of long-term contracts on the European market shrinks. Instead of more than 20-year long contracts, shorter term agreements are to be signed with more flexible clauses. Spot markets have major role to determine gas prices, which worries investors in the short term.

Drivers	Description
Exporter dependency	It is expected that gas exporters – especially those with pipelines – are relaying heavily on their importers' markets. The main risks lie in climate change policy and economic growth and their effect on demand. What kind of strategy producers are going to follow to react to demand side challenges that are embodied in climate policy? The low expected level of growth in the traditional markets can force producers to turn to more prosperous market directions.
Security threats	It cannot be ruled out that inter-state conflict occurs in the producer or transit countries in the coming two decades. Is it possible to identify with a high certainty a potential aggressor? What kind of transit route or producer country is at the stake and what is its contribution level in supply security?** While measuring interstate relation-risks attention should be given to the so-called non-state actors. For many decades international politics downplayed the importance of non-state actors. Meanwhile the highest risks in the new world order seem to come from some of these actors (transnational criminal gangs, international terrorist groups, underground political movements). The recent Kyrgyz or the Iranian (1979) government overthrow were both unexpected with major consequences and tangible effects on domestic mining production. Although the population discontent was known, the timing, the scale and the consequences were not anticipated. Can such a threat be identified among the significant players of the natural gas supply chain? If so, what would be its impact level?

**There were several attempts in history from producers in Central Asia and South America to bargain higher prices with turning off the pipeline taps. However, the overwhelming majority of these attempts were not successful. On the other hand, consumers used the tactics of shutting down the pipelines more successful and could revise the prices in a favourable manner in most cases. (For further details and examples see: Victor D.G. (ed.) [2006]: Natural Gas and Geopolitics From 1970 to 2040. Cambridge University Press, Cambridge)*

*** During the Russian-Georgian conflict supplies in Baku-Tbilisi-Ceyhan (TBC) were stopped. However, no damage was made to it during the campaign*

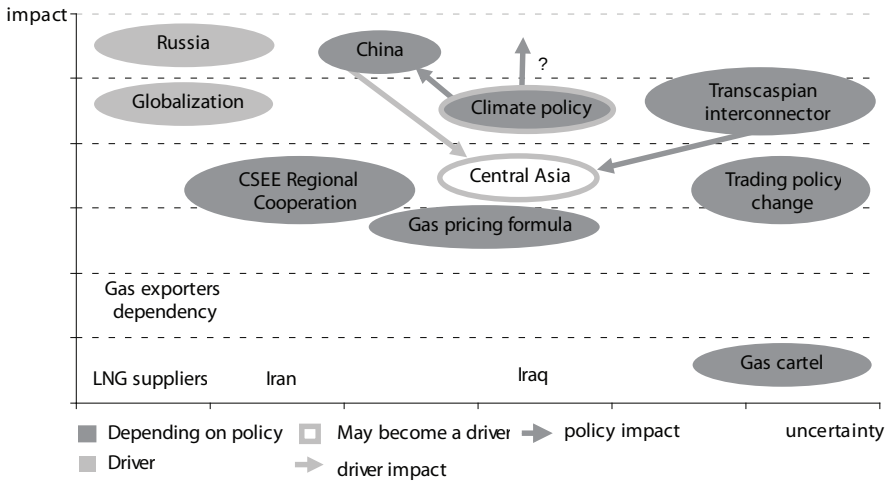
Figure 8.2 below depicts the impact and uncertainty of the geopolitical drivers we considered to be relevant for gas market development in CSEE. It is clear that whatever Russia does in the upcoming two decades will impact the region's gas industry in a major way. We assume that the primary objective of Russia in relation to the CSEE gas market is to keep its dominant position in order to extract the maximum rent from this position as long as possible. The level of success in regional cooperation and in implementing present day EU internal and external policies will affect the success of Russia to meet this objective.

Globalization will also play a significant role with high certainty. This paper assumes that the region's production and economic integration is further deepening. Those indicators that are not marked with colours are sub-drivers, and largely depend on other drivers. The impact of Turkey on our region's gas industry will depend on whether it will host Nabucco or other southern corridor projects that supply CSEE or not. Similarly, developments in potentially significant supplier countries like Iran and Iraq might only have a moderate and indirect impact on CSEE.

As Figure 8.2 depicts that most of the geopolitical drivers remain policy dependent. For example, the CSEE Regional Cooperation might have either a positive or a negative effect on regional gas prices depending on the success of its implementation (e.g. there

is close cooperation, vague cooperation, or no cooperation at all). Another example is climate change policy, where the success of policy implementation will have a large impact on gas demand and prices globally and in CSEE too. However, in some other cases – such as a potential cartel of natural gas producers - we assume its impact on the region to be moderate whether it is formed or not.

Figure 8.2. Geopolitics Matrix



The geopolitics matrix was used to develop further geopolitical scenarios with a particular focus on the CSEE. Some larger world energy market shapers are considered to have only a marginal role on the CSEE energy market development. The United States shapes the future of natural gas market through its reduced share in international gas trading due to the utilization of its recently discovered vast non-conventional gas resources. As a result, significant LNG upstream sources became available for the European and Asian markets. Two BRIC countries (Brazil and India) do not directly affect gas supplies towards the CSEE region due to their geographical location. In contrast with this, China and Russia directly impact CSEE supply security. China competes with Russia and the EU for the gas resources of Central Asia. A key component of the Russian strategy to secure its dominant market position in Eastern Europe is to block direct supplies from Central Asia to the EU. The objective of the European Union in regard of gas supply security in CSEE is to complete its physical and commercial integration into the internal gas market.

All in all twelve models were developed in order to assess the possible outcomes of the behaviour of the three decisive geopolitical actors (EU, Russia, China) depending on whether they behave in business as usual, cooperative or non cooperative manner. The interplay of their behaviour with other sub-drivers (such as climate change policy, trading, gas pricing, infrastructure development, gas exporters' cartel) was discussed and analyzed. These models were used for carrying out a back-cast analysis of supply security of the CSEE region from 2030. Back-cast analysis can help to understand which

trends have to be changed or reversed in order to achieve higher security of supply. This approach helped identifying key cross-border capacity and alternative import infrastructure needs and their implementation timeline and possible barriers. From these background studies we selected the three most valuable scenarios to present in the rest of the paper.

8.6. Scenarios

First we briefly summarize our baseline assumptions about the development of key drivers and then develop three scenarios called Small Steps, Keep Tricking and Final Solution.

Technology. In the first decade no new game changer technology penetrates the region. Renewable technology spreads and related CCGT development remains moderate. However, policy preparations are launched to adapt smart technologies. First and foremost electricity generation and consumption pattern is affected by new technologies that moderate gas market demand. Smart grids and electricity storage technologies brought tangible results across the region are not significant until the last third of the examined period. The spread of electric cars and the related electricity demand growth at the beginning can be offset by off-peak electricity generation surplus capacity or by the new nuclear power plants across the region. The increased electricity demand that arises from mobility come forward around 2030, that is beyond this study focus. Electricity sector related gas demand growth is offset by decreasing gas demand due to energy efficiency improvement in the housing sector.

Finances. Investors' sensitivity increases against risks that come along with the tight financial environment. Although new financial products are created, the scope of long term financing shrinks to ten to fifteen years. Only the most promising projects can secure finances with relatively high capital costs. It is not expected that under such conditions significant surplus capacities would be built without governmental involvement or guarantees. The number of new entrants in infrastructure development remains limited.

Climate Change Policy. A globalizing climate strategy increases the demand for cleaner energy resources. LNG and traditional pipeline supply faces tight competition. Europe particularly competes with the Far East and prices are closely linked in both continents and driven upwards. The high costs related to climate policies do not slow down the economic growth in Europe. However, fossil fuel consumption slowly de-links from GDP growth and partly replaced by renewables and nuclear.

Geopolitics. The BRIC, United States, and the European Union are certainly shaping energy markets in the next twenty years. However, for the CSEE region the most important and influential actors are Russia, the EU, China and the transit countries that are sub-determined for the latter three.

Even if the CSEE national governments' diplomacy means remain limited, they are holding the responsibility to turn the balance and implement security of supply projects that are badly needed in the region. To put it other way: national governments have to poise on the Russia – USA axis and along their geostrategic games in Central Asia, sometimes by adding new axis in form of China and EU. As an outcome, the CSEE diversification or security of supply plans may be endangered if alternative sources are blocked or if the required finances are not granted. One of the greatest threats is a constant incapability of proper and fruitful cooperation among national governments. Such a cooperation is weakened by those private and public parties having a vested interest in preventing the development of gas-to-gas competition in the region and thus conserving above market gas prices.

The following baseline scenario describes the most favourable development path for the countries of the region that delivers supply security and gas market liquidity by 2030. It is used to identify actors or other possible drivers that could distort such a currently widely favoured outcome.

8.6.1. Baseline scenario

It is assumed that climatic conditions remain stable up to 2030. Macroeconomic conditions also remain stable despite current turbulences, and there are no significant swings in the exchange rate in the long-term. Demographic trends do not affect gas consumption patterns significantly enough in the examined period. All EU and national policies are taken into account that had been announced until the end of June 2010 with the expected outcomes. Oil and gas prices do not rise to levels that would encourage a massive abandoning of natural gas usage.

After the successful open-season of Nabucco, the pipeline building is launched in 2012. First gas flows arrive as expected in 2015, while the second branch's construction terminates before 2020. Parallel to the second pipeline construction additional outtake points are built in the direction to Serbia, both from the Bulgarian and Romanian section. Although market liquidity significantly increases the regions integration with Western European gas markets remain weak. Smart grids are not entirely adapted across the region, however policy preparation is launched. The share of CCGT plants in the overall generation mix does not increase significantly. Nevertheless, the neighbouring Western Balkan consumption growth increases transit volumes through the CSEE, highlighting possible new bottlenecks in the system.

During this period Russia intends to save its market position in the CSEE, but the stronger cooperation and coordination of national governments' policies in the region and strict EU legal requirements on national gas market regulation ward off Russia from up keeping its dominant market position that it had before 2015. The Russian supplier sticks with its high gas pricing policy as the newly built LNG capacities cannot entirely replace the volumes imported from the east earlier.

The region secures an alternative gas supply source (Caucasus, Middle East) by 2020 that is achieved by strong diplomatic support of the EU and national governments with a cooperative Russia. Therefore, the next decade infrastructure development plans are characterized by enhancing a tighter integration with Western European natural gas markets and the accession of the new EU members and candidates in the West Balkan. The nuclear power plants across the region are built according to the schedule as of 2011. Therefore, the spread of new large CCGT plants is limited while the region is properly supplied with electricity. Small gas fuelled generators are used to improve networks that are overstretched with the added renewable capacities and to serve system balancing needs. However, the successful implementation of smart grids further reduces the need for additional new gas fired generation capacities. The new energy efficiency targets after 2020 cause a stagnating gas demand. Nevertheless, plans are drawn to further increase the Northwest-Southeast capacity flow along with the Nabucco pipeline. In this manner market liquidity is significantly increased, and at the same time the region's storage capacities and gas-to-gas competition fostered.

This scenario is reference only, as this outcome would not require additional policy adjustments of the currently set policies.

All the next three scenarios assume that all the currently proposed and EU-backed cross-border interconnectors are built by 2015.[5] Note also that neither of the following scenarios counts with large-scale non-conventional gas production to take place in Eastern Europe during the investigated period. The possibility that Russia "liberalizes" its gas exports is also disregarded. However, any of the above two developments could become a game changer for the region once it happened.

8.6.2. Scenario I: Small Steps

The most significant security of supply project plans, such as long distance import pipelines and LNG plants in the region were drafted a number of years ago. The complexity of such projects reasonably requires several years of preparation. However, the global financial turmoil has slowed down implementation of these investments. The tightening of financial markets and narrowed conditions for long-term investment financing were one of the reasons. Other cause unfolds directly and indirectly from the European Union driven policies that further increased the risks, market necessity, and financially viable utilization of these infrastructure projects. The EU's Climate Strategy casts a shadow over the clear understanding of Europe's future energy consumption levels and politically backed production technologies. Firstly, the power sector's decarbonization and energy efficiency initiatives throughout the European Community's economy seriously limit the potential increase of gas consumption volumes. Gas consumption patterns shifts in favour of power generators larger utilization and couples with shrinking or stagnating demand from residential and industrial sector. Although the total EU natural gas consumption is expected to grow until 2025, the scale of growth in the CSEE region is limited to such a degree that not all of the proposed alternative supply projects would be utilized.

Secondly, the EU's general support for southern corridor projects turned out to have a limited effect and only carries a reserved political support. Endorsement from involved national governments remained crucial in the development of these projects that may support all the parallel proposals. Or some governments select one project to patronage it strongly along their strategic vision. However, the overall pessimistic shape of the

[5] Hungary-Slovakia: approximately 100 km, 6 bcm/a capacity to be built by FGSZ and Slovakia's transmission system operator EuStream, with feasibility study underway. The first delivery is proposed in 2014.
Hungary-Slovenia: to be built by FGSZ and Slovenia's Geoplin, with feasibility study in preparation.
Romania-Bulgaria: interconnector is planned to run under the Danube River from Giurgiu (Romania) to Ruse (Bulgaria), with a capacity of 1.5 bcm/a. The interconnector is built by Transgaz and Bulgargaz under an existing agreement, with completion intended by the end of 2011.
Greece-Bulgaria (Komoteini – Dimitrovgrad – Stara Zagora) flow from Greece to Bulgaria with a 1 bcm/a capacity.
Bulgaria-Turkey reverse flow.
Bulgaria-Serbia: (Dupnitsa-Nish) planned flow from Serbia to Bulgaria, with a capacity of 2 bcm/a, completion intended by the end of 2013.
Austria further increases its storage capacity by 5 bcm/a.

economies of these CSEE countries has not allowed adequate provisions to increase the development pace of these projects.

As a result, in 2011 long distance pipeline projects (Nabucco and South Stream) realization perspectives fall back to levels of their early stages. The competition between LNG and different pipeline projects, and the contradictive interests of project owners have postponed the originally planned handover dates. It is clear that no new import supply capacity – including LNG and pipeline – comes online before 2015.

The cooperation for large-scale projects, such as Nabucco, remains limited despite efforts made during the EU presidencies of Hungary and Poland. Political debates about security of supply remain a lip service as companies continue to hesitate regarding their investment. The poor results of Nabucco's open season trigger the abandoning of the project. National governments' interests increase in projects, where related costs, implementation procedures are easier and the number of participants and transit countries are limited.

By 2015, it becomes evident that the likelihood of pipeline project realization gradually decreases despite the fact that they are kept on the table. During the period of 2011-2015 the uncertainty of pipeline projects have negatively affected LNG investments as well. In particularly, there are no meaningful achievements in any new import capacity building that encourage some regional actors to stronger cooperate with the Russian supplier by further extending supply contracts.

Poland as a single actor, based on its own capabilities builds its LNG terminal, thus successfully diversifies its import sources by 2015. However, this has no significant effect on the countries supply security examined in this research scenario[6] and the realization of a North-South interconnection provides only a limited capacity.

The revival of supply security investments is accompanied with the accession of Croatia to the European Union. This event brings down the last barriers to the Krk LNG facility. The settlement of regulatory environment that conforms to EU standards and the access to EU finances finally mean a start for the building of the terminal that comes online not earlier than 2018. Parallel to the Krk LNG terminal development, Eastern Balkan countries (Romania, Bulgaria) are looking for their own alternative supply means that fits their needs. These countries successfully secure finances that are partly secured through state guarantees for the public companies involved. The countries involved develop at least 6 bcm reverse capacity from Turkey[7] to Romania. Thus, Bucharest and Sofia secure the access to the relatively liquid Turkish natural gas market. However, these countries could not secure enough capital to develop a pipeline from East to West through Turkey. It heavily depends in Turkey itself or the Trans-Adriatic Pipeline owners.

These developments do not come without open confrontation with Russia, whose interest is heavily violated by developing a South-North corridor in the Eastern Balkan and leads to occasional supply disruption on Blue Stream. This way Russia emphasizes the importance of the Balkan pipeline's North-South flow.

[6] Slovakia's supply security is increased by two interconnectors to Poland. However, these new capacities have very limited effect towards other countries' security in CSEE.

[7] Once Turkey realizes that the CSEE gas supplies are not going trough its territory, it makes every effort in its power to depict itself as a reliable and favorable transport hub, in order to secure TAP (ITGI) at least. At the same time, it secures diversified import sources from Russia, Azerbaijan, Iran and the Middle East.

In this sense, an unobtrusive cooperation characterizes the region by 2020. There is no place for large-scale cooperation that is required by mega-projects. Countries individually or in small groups (2-3 participants) secure their own supply security. Those left out turn to the least expensive solution: building new cross-border capacities or increasing the existing ones. Serbia turns to Romania and Bulgaria that have secured small amounts of alternative supply. Meanwhile, Belgrade face financial constrains to further increase its capacity from Bulgaria and to develop the interconnector to Romania. Political support to these projects vanishes because of the vast resources that were spent on the Banatski Dvor storage.

Slovenia's relatively small natural gas market requires only minor updates that are easily met by domestic resources during the examined period.

As a result, the integration of the region's gas infrastructure still remains weak by 2025. Although further plans are drawn to substitute the missing northwest-southeast connection capacity limits across the region, such infrastructure's capacity is not satisfactory enough in 2030. Natural gas from Germany still could not flow freely and in solid amounts to Bulgaria or Greece due to a lack of adequate infrastructure capacities.

The new LNG plant serves the neighbouring countries well and no supply falls are expected. However, a coincidence of supply fall with extreme weather can still cause minor supply disruptions in some poorly connected areas.

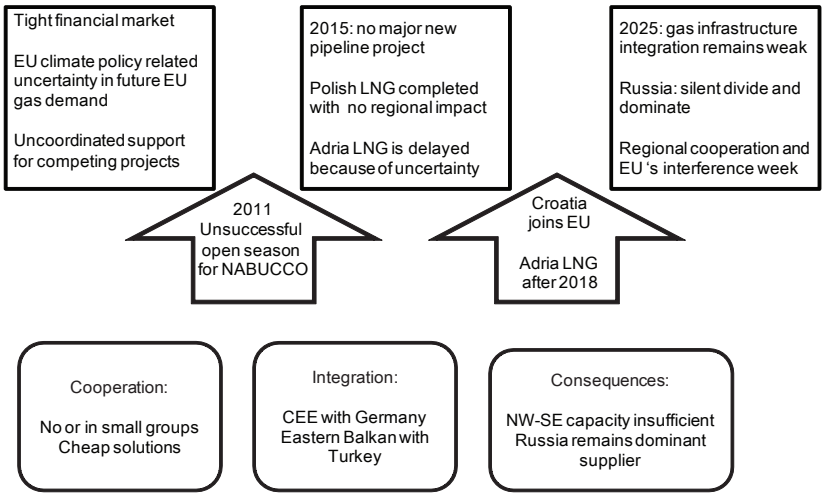
During this period, Russia continues its silent "divide and rule" strategy driven by economic interests. However, its success is limited, as the main barrier of cooperation lies among the EU member states and not third party actors.

As the scenario shows, regional cooperation and the EU's interference remain weak. In the scenario, Turkey would not play a significant role and Central Asian resources would not be crucial before 2030. Azerbaijan becomes the main alternative supplier for the Eastern Balkan region, secured through bilateral contracts between downstream and upstream gas companies with diplomatic backing. Baku's position is challenged only in the Western Balkan, where world LNG suppliers have access. However the Eastern Balkan depends on their own production due to bottlenecks in the infrastructure, Russian, Azeri and Turkish re-exports, while Western European, and Croatian supplies have limited access to these parts of the CSEE region.

It has to be pointed out that despite country-by-country improvements in supply security, Russia would remain the dominant import supplier in the region. The new LNG facilities and cross-border capacities mean reduced share in these markets for a Russian

supplier, but do not provide sufficient volumes in many countries to end Russian dominance.[8] A summary of Small Steps is depicted on Figure 8.3.

Figure 8.3. Small Steps



8.6.3. Scenario II: Keep tricking

By 2011 it becomes clear that none of the proposed CSEE import supply capacity projects[9] can hang on to their original deadlines. Private investors hesitate to implement their proposals that make national governments impatient. As the number of proposed projects increases, the competition for finances and for the same upstream sources among different projects turns more sever. The upcoming years are characterized by strategic communication and symbolic events. Investors are keen to track the competing project developments and are ready to abandon their own projects once a competitor gets in an advanced phase of its own project realization. Governments easily offer political support for various projects as their interest is increasing their supply security with the minimum amount of taxpayer's money. This seemingly bold governmental position increases investors' doubts. This vicious circle has a positive side effect. Turkey becomes more cooperative with the EU on southern corridor project implementation as it fears losing its natural gas hub position.

The overall outcome is a general delay in projects. The successful open season for Nabucco in 2011 and the beginning of its construction in 2012 endangers other LNG projects on the Adriatic and Black Seas.

By 2015 the cross-border capacities are fully constructed and negotiations among the regional countries are on their way to increase the northwest-southeast capacity flows parallel to Nabucco by 2020.

However, stagnating demand forces Nabucco investors to abandon the building of the second parallel line of the originally proposed plan. Therefore, the region is served only

[8] Bulgaria, Serbia, Slovakia

[9] Krk LNG, South Stream, Nabucco, AGRI

by one 15.5 bcm/a capacity trunk in 2020. From a geopolitical perspective this is a significant ease, as no Central Asian resources are required, and the demand can be served from Azeri and North-Iraqi fields. However, this capacity is too moderate to challenge the dominance of Russia-originated supplies. Russia moderately does all in its power to put obstacles against increasing gas-to-gas competition in CSEE. It successfully allies with interest groups across the region that turns to be enough to prolong its dominance and favorable returns on gas sales, occasionally, by giving discounted gas on limited scale. The divide and rule tactic threatens cross-border capacities but it is not the dominant reason for alternative supply project delays or cancellations.

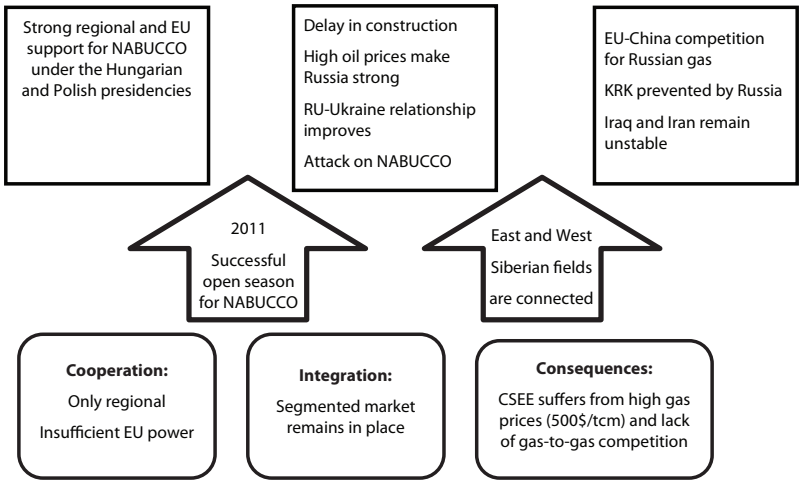
Despite the fact that several cross-border capacities and new import capacity are built at this time, the regions security of supply shows wide differences among the countries. Most of them have significant increase in security where some regions still lack adequate infrastructure. This urges governments to take further action. Old plans are brought to the discussion table again. Russia still intents to secure its dominant supply position in CSEE by promising a watered down project of the original South stream pipeline, while the region's governments are looking for a solution that offers more diversified supplies. Although, by this time LNG prices lost their significant competitiveness with pipeline prices observed earlier in the decade, a sparkling debate takes place among parties about the competing Krk and Black Sea LNG terminals. At the end the Croatian project secures priority and finance for project implementation. Building the LNG terminal triggers a new cross-border capacity investment phase to connect the Croatian LNG plant with Baumgarten storage and neighboring Slovenia, and Bosnia-Herzegovina and further develop the existing branch along Slovenia-Italy.

As a result of these infrastructure developments Serbia becomes the least integrated to the regional gas infrastructure. Serbia's accession to the EU after 2025 enables new support schemes that enhance new investments in the whole energy sector. It enables the termination of long planned interconnectors with Nabucco's Romanian (Timisiora) and Bulgarian sections (along Craiova-Vidin).

Serbian laws correspondence with EU legislation and favorable geographical location enables a generous investment flow that allows the building of the final corner stone of the region's supply infrastructure, a Northwest-Southeast interconnector that can deliver natural gas in case of necessity from the North and Baltic Sea to the Black Sea coast at the same time offering parallel capacity to the realized small Nabucco. The project is

realized by 2030, marking an era of high natural gas liquidity in the region. A summary of Keep Tricking is depicted on Figure 8.4.

Figure 8.4. Keep Tricking



8.6.4. Scenario III: Final Solution

Governments' and investors' tactical moves end by 2011. The Central European EU presidencies (Hungary and Poland) echo a very strong support for Nabucco, thus brake up shrouds of clouds over investment projects. It underlines the fact that other running southern corridor projects are tactical tools and not feasible proposals. The EU political and financial backing is supported with better-than-expected open season results of Nabucco in the summer 2011. However, construction works face delays as unexpected difficulties arise with permits. The time plays in hands for Russia. After the presidential elections in May 2012 and rising oil prices above 100 USD/barrel the political and economic strength and space of manoeuvre opportunities return to Moscow. As the completion of Nabucco pipeline becomes as real as never before Russia turns to more serious measures to safeguard its position in the CSEE region. The renewed flow of oil wealth enables the Kremlin to offer high enough prices for Azeri gas that loses its competitive advantage in CSEE market. Some of the Nabucco project owners as an answer push for North Iraqi sources. At the same time the Iranian political situation did not normalize on a scale that would enable direct supplies from the Persian state. In this regards only Turkish re-export can be expected with additional rent on it. Meanwhile access to Turkmen resources are not available, as Baku is taken out by Russia, Azerbaijan hesitates to allow any Turkmen transit towards Europe. 2015 arrives without any tangible results. As the Caucasian gas slip away the AGRI project loses its bases. Russia pays high prices for the Azeri gas but it is able to slightly compensate its losses by saving its positions in the CSEE region. The Azeri gas capture allows Russian supplier(s) to present more credibly its South Stream plan, as supply sources are granted. However, no real action is taken in this manner. As the Russian-Ukrainian relations improve in a rocketing manner, Mos-

cow no longer sees the use of this stick and carrot. Upgrade of the Ukrainian infrastructure starts with Russian participation before 2020.

The region – although no supply interruption is foreseen – suffers from high gas prices that negatively affect its competitiveness inside and outside of the EU. Russia understands well the delicate position of natural gas in the energy sector. It does not raise the prices to unjustifiable levels, but keeps a maximum where no other substitutes would enter (500 $/tcm midterm).

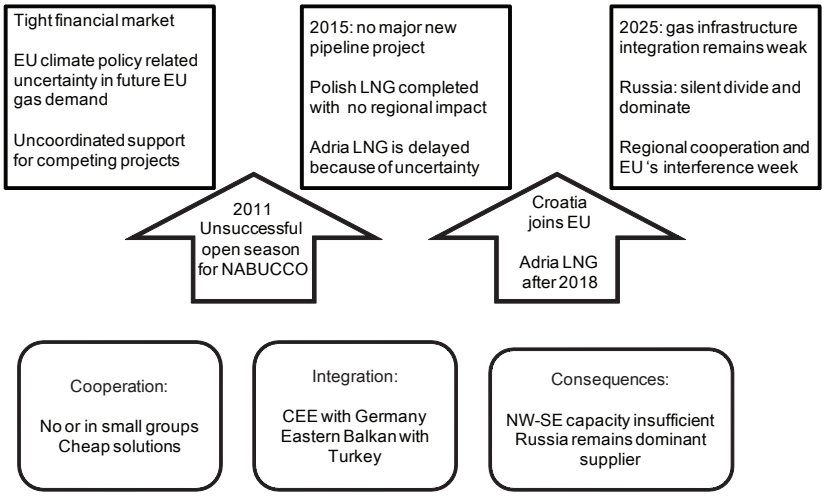
After this unsuccessful decade debates start over in the region about renewed diversification plans. Some would still like to secure the Krk LNG investment, but Russia is strong enough again to block it. Moscow uses its new cash wealth to implement the grandiose plan of resource unification, thus connecting the Eastern Siberian fields with the Western Siberian ones by 2030. It connects the Chinese and European markets after Central Asia did so, but was not able to manoeuvre around Russia. Russian upstream investments move to East, closer to China. Price competition starts between Europe and China for Russian gas, making a negative impact on the Russia-dependant European countries.

Nevertheless, the idea of Nabucco pipeline is not entirely dead. The region makes successful measures to develop a small capacity access to the liquid Turkish market. Although the construction of Eastern Balkan reverse flow capacity develops at a snail's pace, that is accompanied by harsh Russian actions (Occasional interruption on the Blue stream). These cross border capacities (Turkey-Bulgaria-Romania-Serbia-Hungary) finally come online after 2025. Ankara attempts to fill these capacities with re-exported gas. However, Brussels looks suspiciously at these opaque stocks that mark these resources unfavourable and associated with high transfer- and political risks. The scale of flow is not significant enough to challenge the Russia-originated supply dominance. Rather, it serves to buy up interest groups in the former socialist states with a silent approval from Moscow.

The upheaval of cross-border capacity building in the early 2010's is not followed later on in the decade. It increased the security, but their capacity volume remained too low to support gas-to-gas competition or proper North-South – East-West flows across the region. The fiasco over Nabucco disappears only slowly. High gas prices and the fear from Russia forces governments to return searching for alternative solutions around 2025.

However, no real action is taken in this regard until 2030. A summary of Keep Tricking is depicted on Figure 8.5.

Figure 8.5. Final Solution



8.7. Policy Lessons

The creation and analysis of complex mid-term gas industry development scenarios allows us to formulate a few conclusions and policy recommendations.

During the exercise it became apparent that the different supply security scenarios boil down to versions of gas infrastructure reinforcement plans representing, in turn, specific gas supply entry point and capacity combinations for the region. The different infrastructure patterns create options for the improvement of gas market liquidity and gas-to-gas competition. Because of the significance of the price risk of a concentrated gas market structure for economic development and welfare, it is worth to jointly investigate supply security and market integration characteristics when justifying gas infrastructure enforcement options in CSEE.

One of the critical components that easily led to the collapse of the favourable Baseline Scenario was the uncertainty created by the uncoordinated and non credible support of the different governments for the different critical infrastructure projects. One might argue that this setting is just to foster a healthy competition among alternative development plans which, at the end, will select the most rewarding project. We think rather the opposite. A non-cooperative behaviour from the region's governments would increase the already high financial and regulatory risks around the projects and destroy the needed coalitions to complete multi country projects. For this reason we conclude that a clear and strong commitment to one of the critical gas supply infrastructure projects by ensuring financial and regulatory support would be favourable. Confidence among regional partners should not be discouraged by Russian moves in the spirit of divide and dominate across the region. A regional body like the V4 or V4+10 should manage the necessary cooperation. The harmonization of regional transmission planning for the post 2015 period could be an important outcome of such a cooperation.

The harmonization of access and capacity allocation rules as well as of access tariffs would be essential to ensure increased gas-to-gas competition and also to make a regional market in underground storage to develop.

The completion of a Northwest-Southeast pipeline system with reverse flow capability could provide the opportunity to properly connect the region to the Western European markets. This would require the expansion of current cross-border capacities in such a way that takes regional instead of national needs into account. (e.g.: HAG capacity should not be extended only with a view on the Hungarian market developments, but for the reason to able to carry adequate gas amounts to Bulgaria if needed).

[10] V4 countires are Poland, the Czech Republic, Slovakia and Hungayr. V4+ includes additional countries of the Balkan with developed gas infrastructure: Croatia, Slovenia, Serbia, Romania, Bulgaria, Macedonia, BiH, Moldova.

8.8. Appendix I. Other interconnector pipelines under consideration

Romania
Timisoara – Serbia border (Nabucco branch) 34 inch (700 mcm/h, 6.1 bcm/y)
GUEU: Nikolayev-Tiraspol-Onesti-Negru Voda 20-42 inch (6.76 bcm/y)

Serbia-Bulgaria-Romania
Craiova-Vidin-Nis 12-34 inch (700 mcm/h, 6.1 bcm/y)

Croatia
Karkivac-Split (Plinacro Development Plan) – a regional branch from Italy-Greece Interconnector) 24-30 inch (6 bcm/y)

Table 8.5. Russian Gas Scenario

Branch	Volume (bcm/y)	Peak flow (mcm/h)
Skopje-Tetovo-Elbasan-Tirana	2	352
Belgrade-Sarajevo-Split-Pdgorica	2.85	500
Rogatec-Zagreb-Karlovac-Rijeka	0.56	99
Filasi-Turnu-Severin	0.13	23
Azenovgrad-Smolyan	0.04	7

Source: The World Bank [2010]

Table 8.6. Nabucco Scenario

Branch	Volume (bcm/y)	Peak flow (mcm/h)
Skopje-Tetovo-Elbasan-Tirana	2	352
Belgrade-Sarajevo-Split-Pdgorica	4.03	707
Székesfehérvár-Zagreb-Karlovac-Rijeka	0.56	99
Filasi-Turnu-Severin	0.13	23
Azenovgrad-Smolyan	0.04	7

Source: The World Bank [2010]

8.9. Appendix II. Key Infrastructure and Demand Indicators

Table 8.7. Daily peak capacity of national gas systems in 2009

	Austria*	Bulgaria	Croatia	Czech Republic	Hungary	Romania	Serbia	Slovakia	Slovenia
Underground storage	55 mcm	4.3 mcm(a)	4.8 mcm	51.5 mcm (+?)*	80.1 mcm	30.7 mcm	5 mcm****	34.35 mcm**	0 mcm***
Domestic production	4.5 mcm	0.34 mcm	5.6 mcm	0.5 mcm	10.2 mcm	29.86 mcm	0.5 mcm	0.5 mcm	0 mcm
Import	270.45 mcm	76.91 mcm	5.08 mcm	159.71 mcm	72.1 mcm	118.16 mcm	11.3 mcm	312.34 mcm	11.54 mcm
Transit	66.14 mcm	57.1 mcm	0 mcm	110.54 mcm	11.3 mcm	76.91 mcm	n.a. mcm	273.42 mcm	5.08 mcm
TOTAL	263.82 mcm	88.3 mcm	15.48	211.21 mcm	163.3 mcm	178.72 mcm	16.08 mcm	347.19 mcm	11.54 mcm
Total excluding export	197.682 mcm	23.11 mcm	-	101.17 mcm	151.1 mcm	101.81 mcm	n.a.	73.77 mcm	6.46 mcm
Highest daily peak measured since 2000	57.94 mcm	15.6 mcm	12.9 mcm	67.49 mcm	89.13 mcm	83 mcm	5 mcm	n.a.	n.a.

Source: National TSOs, Regulators and Ministries in charge of Energy Sector data in 2008

*In country infrastructure problems. Innsbruck depends on one supply point (Keifersfelden)
** Cross reference, the Czech Dolni Bajanovice storage capacity (9 mcm) is used by Slovakia
*** leased storage capacities in Austria, Croatia and Italy
**** not operating yet

Table 8.8. Annual capacity of national gas systems in 2010 (including proposed and under construction developments)

	Austria*	Bulgaria	Croatia	Czech Republic	Hungary	Romania	Serbia	Slovakia	Slovenia
Underground storage	9.8 bcm	0.350 bcm	3.03 bcm	3.75 bcm*	6.13 bcm	4.84. bcm	0.45 bcm	2.75 bcm*	0 bcm**
Domestic production	1.6 bcm	3.14 bcm	2.03 bcm	0.19 bcm	2.8 bcm	10.9 bcm	0.2 bcm	0.2 bcm	0 bcm
Import	98.71 bcm	28.07 bcm	8.35 bcm	58.29 bcm	26.4 bcm	43.128 bcm	4.1 bcm	114.00 bcm	4.21 bcm
Transit	24.14 bcm	20.84 bcm	0 bcm	40.35 bcm	4.1 bcm	28.07 bcm	n.a. bcm	99.88 bcm	1.85 bcm
TOTAL	110.11 bcm	31.56 bcm	13.41 bcm	62.23 bcm	35.33 bcm	58.868 bcm	4.75 bcm	116.95 bcm	4.21 bcm
Total excluding export	85.97 bcm	10.72 bcm	n.a.	21.58 bcm	31.23 bcm	30.798	n.a.	17.07 bcm	2.36 bcm
Forecasted consumption in 2030	13.6 bcm	8.1 bcm	7 bcm	11.2 bcm	13.4 bcm	24.1 bcm	4. bcm	10.6 bcm	2 bcm

Source: National TSOs, Regulators and Ministries in charge of Energy Sector data in 2008

* In country infrastructure problems. Innsbruck depends on one supply point (Keifersfelden)

8.10. References

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SECURITY OF SUPPLY AT THE REGIONAL LEVEL IS LARGELY DEFINED BY THE LIMITED ACCESS TO GAS TRANSPORT INFRASTRUCTURE AND HENCE GAS RESOURCES. AS GAS DEMAND HAS GROWN IN THE LAST DECADE IN THE REGION MAINLY DUE TO THE NUMBER OF GAS FUELED POWER PLANTS PUT INTO OPERATION, THE ACCESSIBILITY OF GAS RESOURCES BECAME ONE OF THE MAIN POLITICAL AND ECONOMIC CHALLENGES FOR THESE STATES. A FURTHER PROBLEM IS THAT THE REGION IS CURRENTLY SUPPLIED BY ONLY A FEW PLAYERS AND THE ENTRANCE OF NEW SUPPLIERS INTO THE GAS MARKET IS LIMITED BY SEVERAL MARKET AND LEGAL CONDITIONS.

THE SECURITY AND SUSTAINABILITY OF ELECTRICITY SUPPLY IS MOSTLY DEFINED BY THE AVAILABILITY AND CONTINUOUS SUPPLY OF PRIMARY ENERGY RESOURCES. DUE TO THE SPREAD OF GAS FUELLED POWER PLANTS THE PROBLEMS OF GAS SUPPLY INCREASINGLY INFLUENCE THE SECURITY OF ELECTRICITY GENERATION. THE CONTINUITY OF ELECTRICITY SUPPLY I.E. THE RELIABILITY OF IT HOWEVER REQUIRES FURTHER CONDITIONS. IT IS NOT ENOUGH TO HAVE CONTINUOUS FUEL SUPPLY IF THERE IS LIMITED GENERATION CAPACITY. A FURTHER CRUCIAL FACTOR OF GAS AND ELECTRICITY SUPPLY SECURITY IS THE ADEQUACY OF NETWORK INFRASTRUCTURE, ESPECIALLY ITS CAPACITY AND THE MANAGEMENT OF CONGESTIONS. INSUFFICIENT NETWORK INFRASTRUCTURE THUS IN ITSELF CAN ENDANGER THE SECURITY OF SUPPLY OF A COUNTRY OR A REGION.

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