REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q4 2014

REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

The aim of the Regional Centre for Energy Policy Research (REKK) is to provide professional analysis and advice on networked energy markets that are both commercially and environmentally sustainable. We have performed comprehensive research, consulting and teaching activities on the fields of electricity, gas and carbon-dioxide markets since 2004. Our analyses range from the impact assessments of regulatory measures to the preparation of individual companies' investment decisions.

Training programs

- Energy market economist post-graduate training
- ERRA summer schools
- Regulatory trainings
- Price regulation
- Electricity market trainings
- Market monitoring
- Gas market trainings
- Tailored trainings upon request

Research

Geographically, our key research area is the Central Eastern European and South East European region:

- Regional electricity and natural gas modelling
- CO_2-allowance allocation and trade
- Renewable energy support schemes and markets
- Security of supply
- Market entry and trade barriers
- Supplier switching

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- Pride forecasts and country studies to support investment decisions
- Consultancy service for large customers on shaping their energy strategy on the liberalised market
- Consultancy service for regulatory authorities and energy supply companies on price regulation
- Consultancy service for system operators on how to manage the new challanges
- Preparing economic assessment for strategic documents

Nowadays, due to market opening, energy markets cannot be analysed without taking into account regional environment. We monitor the market situation and developments of the countries of the Central Eastern and South East European region. We have built a regional electricity market model including all countries of the EU to forecast regional electricity prices. In 2012, we have developed a regional gas market model for the Danube Region countries, which was expanded to a model covering Europe.

The experts of REKK with their energy regulatory experience and academic background can supply scientific solutions taking also into account the specialities of the given markets.

Dear Reader,

The first report of this year starts with a double article: we investigate the flexibility of the European natural gas system triggered by the Ukrainian crisis unfolding in the second half of 2014. The ongoing conflict between Ukraine and Russia raises the question again whether the European natural gas system is able to survive the temporary or long-running cut of Russian import without any significant sacrifice. The system can reply to the cut by enhancing storage withdrawal, increasing LNG import, boosting domestic production, fuel switch of natural gas-fired power plants (swich to oil), and replacing the production of gas-fired power plants by coal-fired ones. The article examines the potential of the above flexibility tools, as well as conditions and barriers of application. We analyse the potentials and flexibilities included in natural gas infrastructure, particularly the role of reverse flows and the factors hindering the application of specific flexibility tools.

Our second article gives an overview of the experience with the implementation of the Energy Efficiency Directive passed in October 2012. We pay special attention to the well known provision of the Directive, i.e. the implementation of Article 7 on the establishment of Energy Efficiency Obligation Schemes. We also analyse methodological failures in Member States' setting of energy savings targets and the measures recommended by Member States, which, together with the loopholes included in the Directive, might lead to the risk of non-delivery of the target expected earlier by the European Commission.

The third article examines challanges faced when we try to increase the share of renewable energy sources in domestic district heat production. The first part of the article gives a short summary on experiences of Hungarian project development and financial challanges as well as interesting international regulatory examples presented on the workshop coorganised by REKK and the British Embassy in November 2014. The second half of the article introduces recommendations on the improvement of regulatory environment of renewable-based district heat production, which were articulated by the participants of the workshop, particularly of the roundtable discussion represented by district heat producers, district heat suppliers, project developers, banks and regulators.

Péter Kaderják, director

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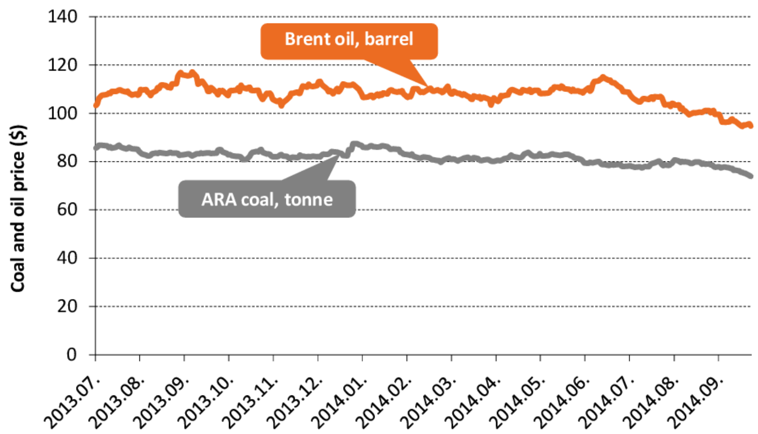
Energy market developments

The third quarter of 2014 witnessed a significant fall in prices of crude oil and natural gas prices on European markets, with a narrowing gap between the two. While Japanese and the American natural gas prices remained unchanged during the quarter, TTF spot prices of natural gas characterising European markets continued to decline in July, and there was a moderate cut also in long-term contract prices. However, European natural gas prices rebounded to 20 €/MWh by the end of the quarter. At the same time, both base load and peak prices on the German power exchange remained unchanged just like the purchase price of emission allowances (EUA), which stagnated at 6 €/t. Thank to declining gas prices, the German clean spark spread, which was massively negative at the beginning of the year, converged to 0 €/MWh in July, however, it failed to live long. Natural gas based production became unprofitable again by the end of the quarter.

The Hungarian quarterly electricity consumption was equal to that of the comparable period of 2013 accounting for 9,65 TWh. The share of import stopped growing on average at 32% of consumption. The reason behind the long-lasting high share of import is unambigously the relative expensiveness of the Hungarian market in the region: it is indicated by the fact that Slovakian and Austrian import prices lifted to 10-15 €/MWh on the monthly interconnection auctions. Day-ahead base load prices exceeded the prices of the same products of the neighbouring exchanges by 7 €/MWh on average, while the price gap was 8.5 €/MWh in the case of futures. The quarter saw a radical divergence of the Hungarian and the Slovakian markets: hourly prices were equaling only in one third of the total time period under review.

The consumption of the third quarter was 2% less in 2014 than in previous year. There was not any perceptible deviation in the domestic production in 2014 compared to the period under review of 2013, while Hungarian net natural gas import exceeded the previous quarter's amount by 13%. Gas import was stored in storages, the saturation of which increased to 46% by the end of the quarter. 53% of the import totalling 2.8 billion cubic meters came from the direction of Ukraine, while 47% from the direction of Austria.

Figure 1 **The 2015 EEX-traded ARA coal futures prices and Brent crude oil spot prices between July 2013 and September 2014**



Source: EEX, IEA

International price trends

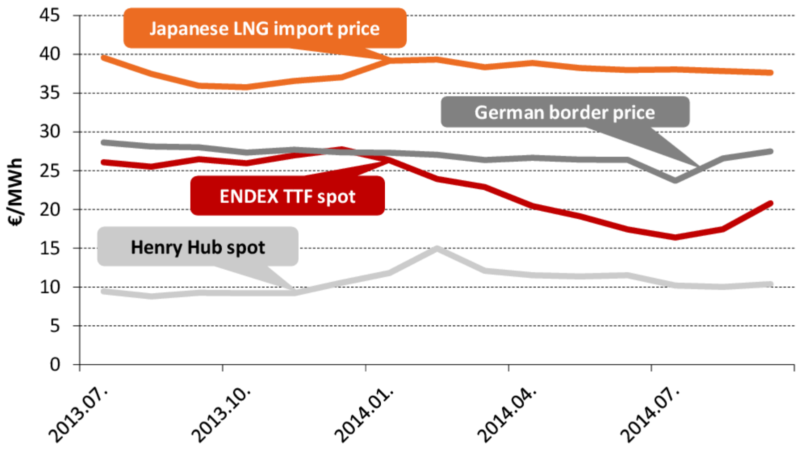
In the third quarter of 2014, price indices indicating world market prices of crude oil and coal determining energy markets plummeted significatly. After the previous quarter's stagnation, Brent price fell from 110 $ a barrel to 95 $ a barrel by the end of September hitting two years' bottom: the last time when oil was traded at such a low price was in June 2012. Even though to smaller extent, the price of year-ahead ARA coal futures traded at EEX followed Brent prices: ARA prices per tonne declined from 79 $ at the beginning of July to 74 $ (*Figure 1*).

From among international gas prices, *Figure 2* depicts Japanese LNG import prices characterising Asian markets, Henry Hub spot prices determining North American markets and German border prices converging to Russian import prices as well as TTF gas prices traded at liquid exchange. In the world market, the upper limit of natural gas prices is LNG prices imported to Japan, while the lower limit is natural gas prices traded at Henry Hub in the US. The quarter did not witnessed any considerable changes – exceeding 50 Eurocent/MWh – either in Japanese or in American natural gas prices. Japanese prices varied between 37.5 and 38 €/MWh, while Henry Hub natural gas prices ranged between 10 and 10.4 €/MWh. TTF spot prices continued to sink until July, then grew again from August. Spot prices of natural gas dived to as deep as 15 €/MWh in July reaching its three years' low (TTF gas was traded at 15 €/MWh last time in September 2011). Natural gas prices declined by 40% between March and July 2014 due to the fairly mild winter and LNG transports tending to shift to Europe during the last half year. This tendency made a turn in the second half of July and in August, when the production of the Norwegian Nordic Sea fields lagged behind previous year's production. TTF gas price went back to beyond 20 €/MWh by the end of the quarter. German border prices used as the benchmark of oil-linked long-term contracts fell to 23 €/MWh only in July, otherwise stayed at 27 €/MWh.

German year-ahead base load prices showed purely moderate shifts: prices grew by 1 €/MWh from July to August, then sank to 34.5 €/MWh in September. Peak power prices followed base load price movements and were ranging from 43 to 44 €/MWh. EUA futures with December 2114 delivery prices stagnated at 6 €/t in the quarter (*Figure 3*).

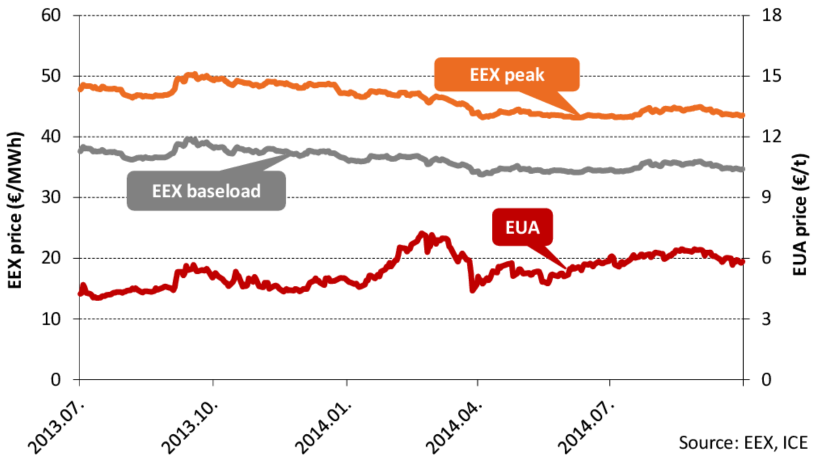
The profitability of gas- and coal-fired power plants can be measured by two kinds of price differences: with the clean spark spread in case of gas-fired plants, and with the clean dark spread in case of coal-fired generation. Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, where generation costs are represented by the cost of gas (spark spread) or coal (dark spread) needed for generating 1 MWh of electricity, and the additional cost of CO_2 emission allowances. *Figure 4* shows the monthly averages of these two indicators, which are calculated using spot baseload power prices on the German EEX exchange and on the basis of the Dutch TTF spot prices as well as ARA coal prices. The clean dark spread, indicating the profitability of coal-fired power generation never left negative range in the previous years. However, the fall in gas prices from Spring to Fall triggered a spectacular upswing in the clean dark spread: its monthly average in July approximated to 0 €/MWh. Nonetheless, the spread sank again to below -5 €/MWh due to growing gas prices in August and September. The clean dark spread varied between 8 and 13 €/MWh in the quarter – although the profitability of coal-fired power plants was significantly worsening from Fall 2013 (from 15-20 €/MWh to 10 €/MWh).

Figure 2 **Internationally significant natural gas prices from July 2013 to September 2014**



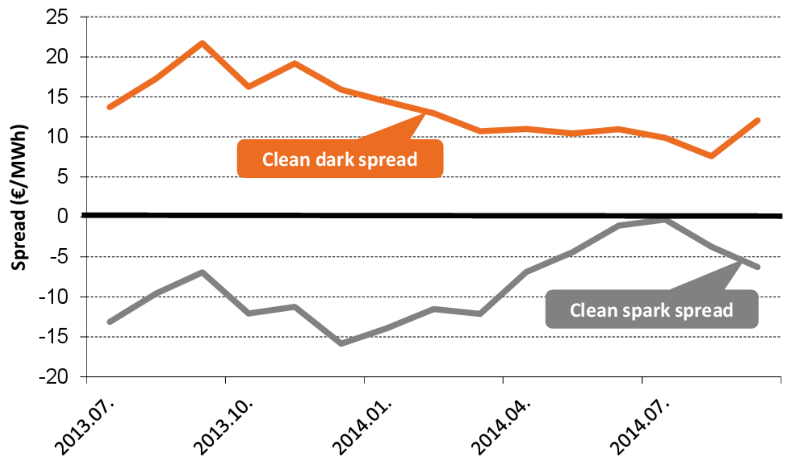
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 **Changes in the annual futures price of the EEX electricity and the futures price of CO_2 quota with a December deadline between July 2013 and September 2014**



Source: EEX, ICE

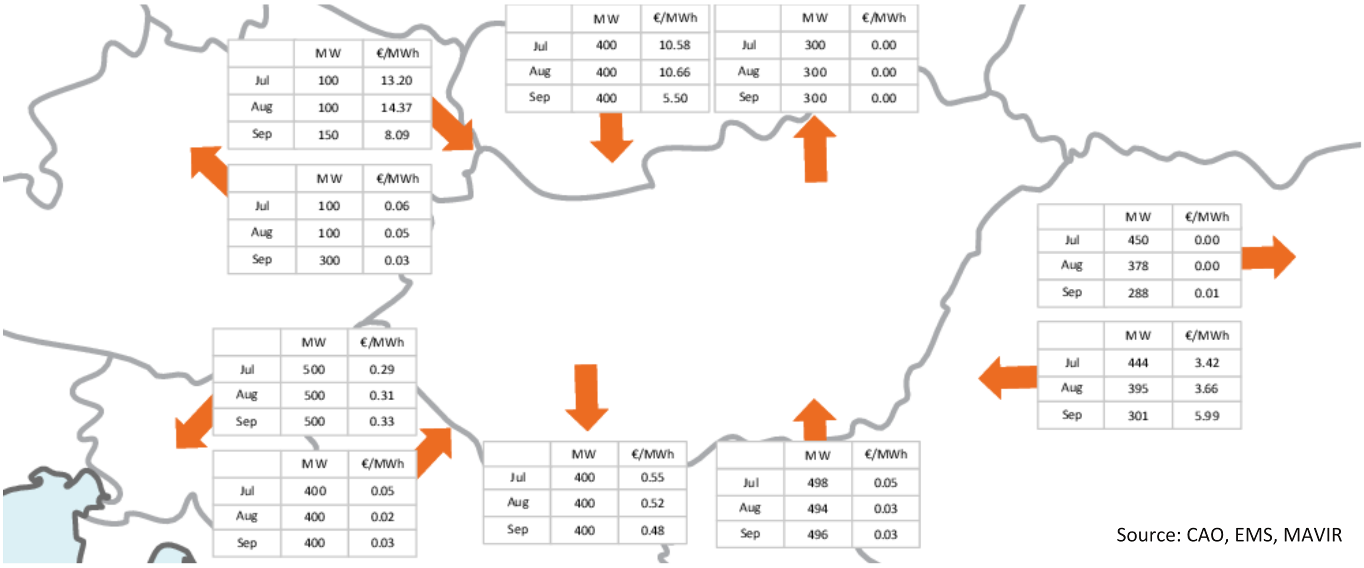
Figure 4 **Clean spark spread (gas-fired power plants) and clean dark spread (coal-fired power plants) on the German market between July 2013 and September 2014**



Source: REKK calculations based on EEX, ICE and Gaspool data

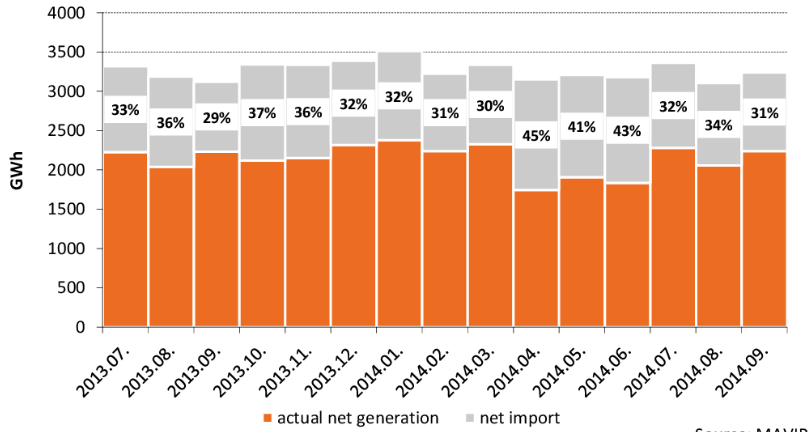
Note: In our calculations, we assumed a 50% efficiency for gas power plants and a 38% efficiency for coal power plants.

Figure 5 **The results of monthly cross-border capacity auctions in Hungary, Q3 2014**



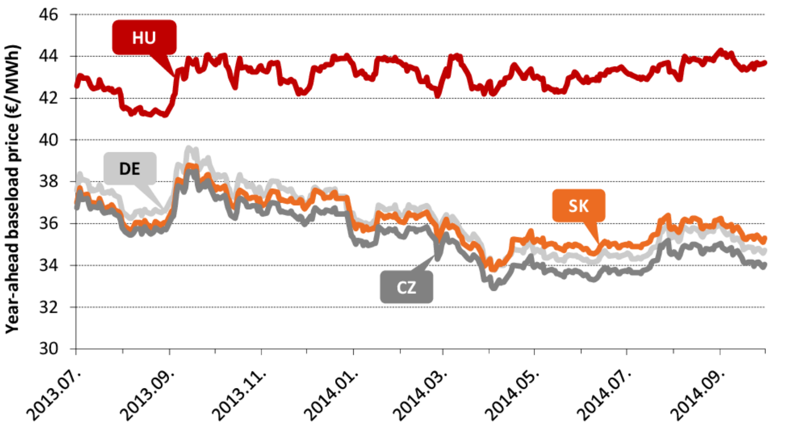
Source: CAO, EMS, MAVIR

Figure 6 **The monthly net electricity production of the domestic power plants and the monthly net electricity import between July 2013 and September 2014**



Source: MAVIR

Figure 7 **Year-ahead baseload future prices in the individual countries of the region between July 2013 and September 2014**



Source: EEX, HUPX, OTE

Overview of the domestic electricity market

The monthly cross-border auctions reflect well the relationship of the Hungarian power market with the neighbouring markets. On the key Slovakian and Austrian intersections, the in-capacities to Hungary cost more than 10 €/MWh in July and August, while on given Austrian intersections, the price exceeded 14 €/MWh. Hungarian market prices were 3.5 to 6 €/MWh higher than in Romania. In Croatia and Serbia, market prices were similar to the Hungarian ones. Croatian prices were higher purely by 0.3 €/MWh, while Serbian prices by 0.5 €/MWh compared to Hungarian prices (*Figure* 5).

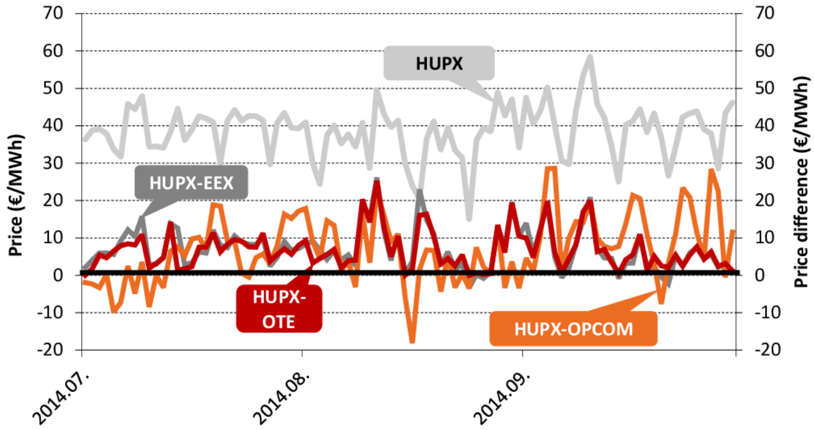
Hungary's electricity consumption was 9.65 TWh in the third quarter of 2014, which is in fact equal to the comparable quarter of 2013. There were not any structural changes in the distribution of net import and domestic power plant production: on quarterly average, 32% of the consumed electricity was imported, similarly to the third quarter of 2013. The high share of import shown in *Figure* 6 is clearly resulted from the gap between import prices and selling prices of domestic power plants.

On futures markets of regional exchanges, year-ahead base load futures were up by 1 €/MWh by August, which was followed by a 0.5€/MWh drop in September. Interestingly, the gap between the prices of Czech and Slovakian base load futures that had diverged in the second quarter remained also in the third quarter: Slovakian futures exceeded Czech futures on average by 1.2 €/MWh. Hungarian futures continued to vary between 42 and 44 €/MWh also in the third quarter: 2015 base load futures cost on average 43.5 €/MWh, which exceeded Slovakian futures prices by 8.5 €/MWh (*Figure 7*).

Figure 8 depicts day-ahead HUPX baseload prices and the various price differences of regional power exchanges (EEX, OTE, OPCOM) compared to the Hungarian power price. Day-ahead baseload traded on HUPX accounted for average 38 €/MWh in the third quarter. The price for one unit of electricity on the Hungarian exchange is 7 Euro higher than on the German or Czech markets. Romanian prices are independent from the German and Czech markets, still, even these spot prices were on average 4-5 €/MWh lower than HUPX. The price difference was the same as in the previous quarter.

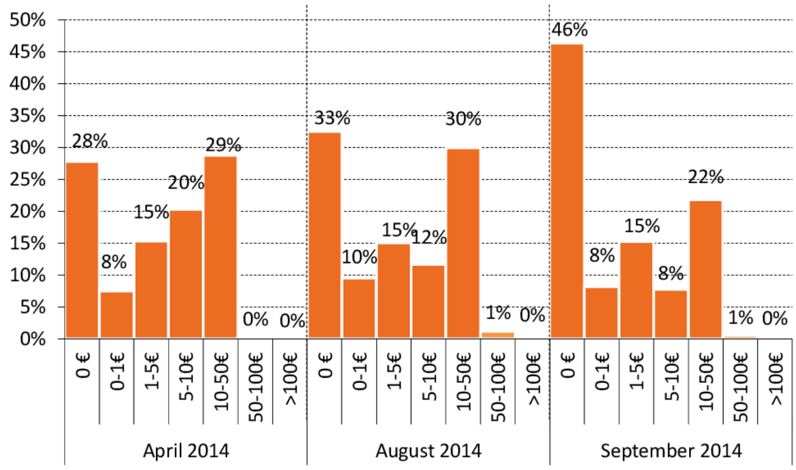
The effect of market coupling can be assessed based on hourly price differences between the Hungarian and Slovakian power exchanges. *Figure 9* shows the frequency – i.e. the percentage of hours – in which prices were equal or different to a certain degree during the July-September period. The 'goodness' of market coupling can be indicated by a histogram, where the majority of observations are in the range 0-1 €/MWh. Hungarian prices were equal to Slovakian ones in one third of the period, in other words, the Slovakian and the Hungarian markets were actually splitting in two thirds of the period from July to the end of August. In July and August, the gap between the prices of the two exchanges was beyond 10 €/MWh in 30% of the hours. In September, markets splitted fewer times, even though prices were levelling out in purely 46% of the hours.

Figure 8 **Comparing the prices of EEX, OPCOM, and HUPX day-ahead baseload power between July and September 2014**



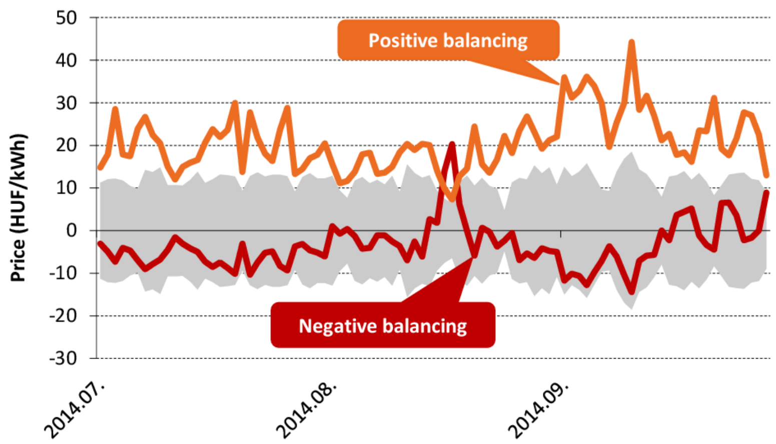
Source: EEX, OPCOM, OTE, HUPX

Figure 9 **The frequency of various levels of price differences between the Hungarian and Slovakian power exchanges between April and September 2014**



Source: REKK calculation based on OTE data

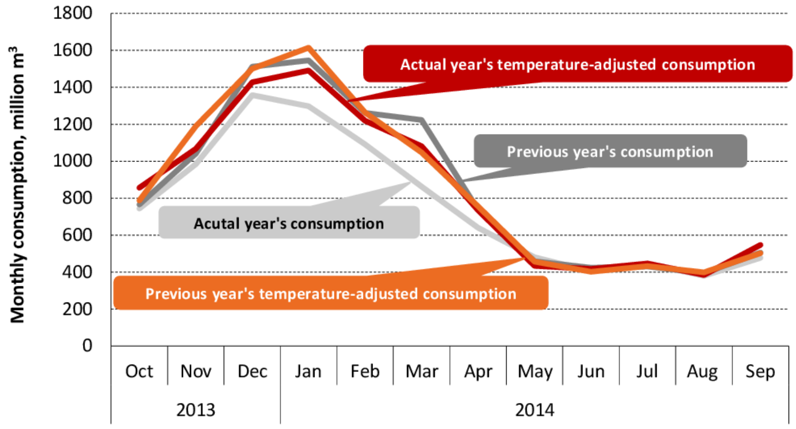
Figure 10 **The daily averages of the balancing energy and HUPX spot price in Q3 of 2014**



Source: MAVIR, HUPX

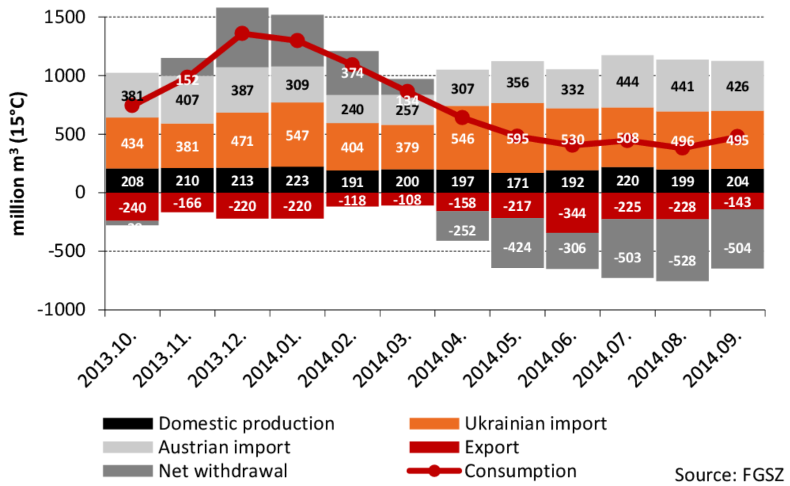
Note: In this figure, the top border of the grey area is determined by the HUPX day-ahead price, and the bottom border is determined by minus one times the HUPX price. In accordance with the MAVIR Trading Rules, the HUPX day-ahead price determines the lowest positive balancing energy price, while minus one times the HUPX day-ahead price determines the lowest negative balancing energy price.

Figure 11 **The unadjusted and temperature-adjusted monthly natural gas consumption between October 2013 and September 2014, compared to the corresponding monthly consumption figures of the previous year**



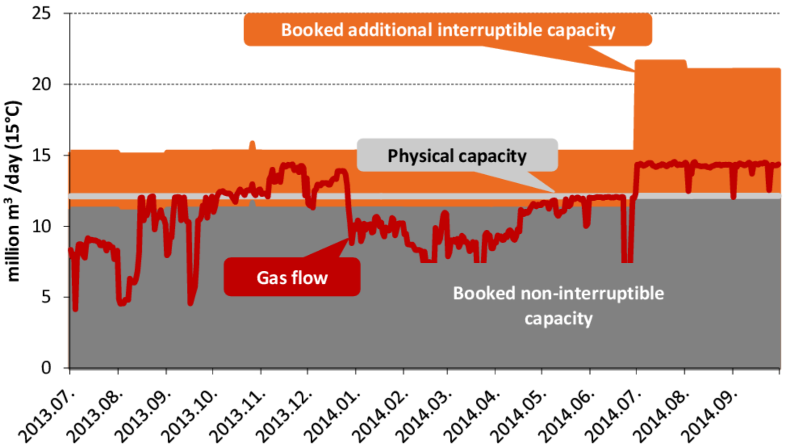
Source: FGSZ, European Climate Assessment & Dataset and REKK calculation

Figure 12 **Monthly changes in the source structure of the domestic gas market between Ocotber 2013 and June 2014**



Source: FGSZ

Figure 13 **The volume at the Mosonmagyaróvár (Austrian) feed-in point from July 2013 to September 2014, alongside the contracted firm and interruptible capacities**



Source: FGSZ

Note: the illustrated physical capacity is the value provided by the FGSZ.

The wholesale price is impacted by the costs arising from the deviation from schedule and balancing energy prices. The system operator determines the accounted unit price of upward and downward regulation based on the energy tariffs of the capacities used for balancing. The order of using these capacities is established based on the energy tariffs offered on the day-ahead regulatory market. The system for charging balancing energy has been developed by MAVIR so that it provides incentives to market participants to try to manage foreseeable deficits and surpluses through exchange based – in other words, covering the expected deficit and surplus through the balancing energy market should not be attractive for them. For this purpose, the price of upward balancing energy cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing energy than the price at the exchange. In the third quarter, the average price of positive balancing energy price was 20.1 HUF/kWh, which was somewhat lower than the 22.7 HUF/kWh value of the previous quarter, while the price of negative balancing energy amounted to –3.4 HUF/kWh, exceeding the previous quarter's price of -5.2 HUF/kWh (*Figure 10*).

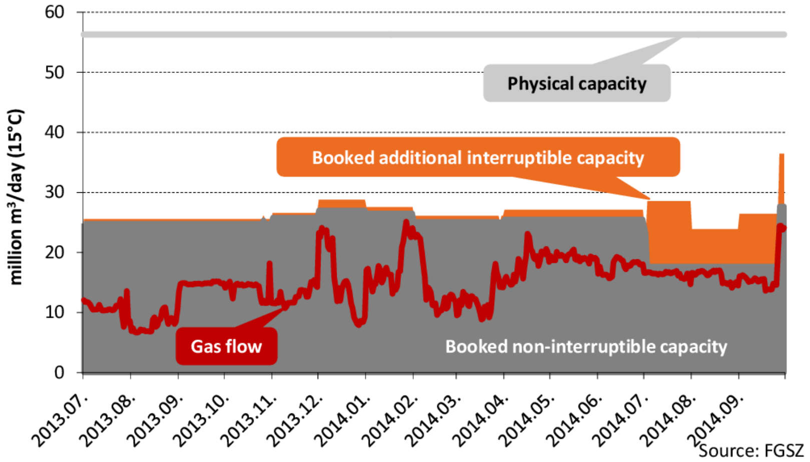
Overview of the domestic natural gas market

Rationally, gas consumption in summer months does not depend on temperature, consequently, it purely indicates the industry's gas comsumption. Compared to the third quarter of the previous year, gas consumption during the period from July to September 2014 was lower merely by 2% than that of 2013 (*Figure 11*).

In the third quarter, Hungarian gas production accounted for 624 million m^3, which fits in with average quarterly production trends. The Hungarian import amounted to 2.8 billion m^3, while the export was 600 million m^3 in the quarter. Consequently, the total net import accounts for 2.2 billion m^3, which exceeds previous quarter's net import by 13%. 53% of import arrived in Hungary via the Beregdaróc entry point, while 47% via the Mosonmagyaróvár entry point. The quarter saw the appreciating role of storages in Europe due to the Russian-Ukrainian conflicts, which had an impact also on the Hungarian storages: in this quarter, 1.5 billion m^3 natural gas was injected in Hungarian storages, which accounted for 636 million m^3 in the third quarter of 2013 and 980 million m^3 in the second quarter of 2014. Although the 46% saturation of commercial storages still falls short of that of European storages, it is up by close to 10 percentage point than previous year's saturation level (*Figure 12*).

In the third quarter, 1.3 billion m^3 natural gas arrived in Hungary via the Mosonmagyaróvár entry point, which is 30% higher than the previous quarter's import and exceeds the third quarter of 2013 by 60%. Based on data disclosed by transmission system operator, FGSZ, 117% of the available physical capacities of the entry point and 67% of all booked capacities were utilised. On July and August capacity auctions, system users submitted bids for two or three times more capacities than those that were available. From 1 July, the capacity fee of Mosonmagyaróvár entry point decreased from 33.81 HUF/MJ/day to 24.37 HUF/MJ/day, which has a crucial role in auction price calculation. The overbooking of capacities and the significant growth in import were triggered partly by decline in prices and partly the uncertainty in winter supply (*Figure 13*).

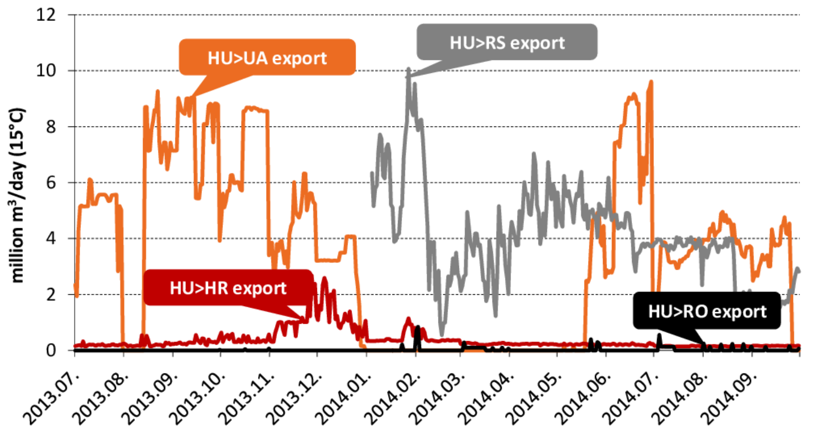
Figure 14 **Natural gas volume at the Beregdaróc (Ukrainian) feed-in point from July 2013 to September 2014, alongside contracted firm capacity and interruptible capacity**



Source: FGSZ

Note: The illustrated physical capacity is the figure provided by the FGSZ. The data also contains the transit gas flow arriving from Ukraine, directed to Serbia and Bosnia from January 2014 onwards.

Figure 15 **The volume of gas exported to Ukraine, Croatia, Romania, and Serbia from July 2013 and September 2014**



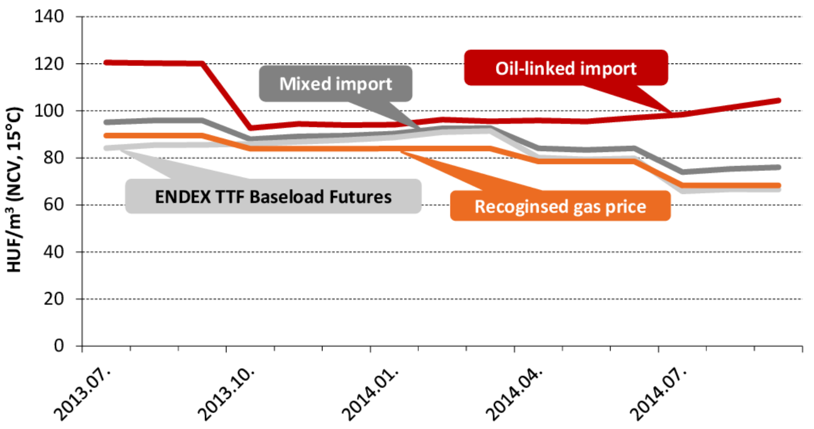
Source: FGSZ

Note: From January 2014, the FGSZ publishes the transit gas flows that exit on the HU>RS (Kiskundorozsma) point and are directed to Serbia and Bosnia.

At the Ukrainian entry point a total of 1.5 billion m^3 natural gas was imported, which accounts for 10% less transport compared to the previous quarter, but 46% higher than the comparable period of 2013. Simultaneously with Hungary's halting flow of interruptible gas to Ukraine on 27 September, the amount of gas transported from Russia via Beregdaróc grew by a daily 10 million m^3 at the end of the month. Despite, only 29% of physical capacities and 61% of booked capacities were utilized in the quarter (*Figure 14*).

Figure 15 shows Hungarian gas export to neighbouring countries (excluding transit). In the quarter under review, 53% of export went to Ukraine, 44% to Serbia and the remaining part was shared by Croatia and Romania. In the major part of the quarter, the export to Ukraine exceeded the previous quarter's transport by 20%, however the total of this export was transported through interruptible capacities. At the end of September – a few days after Alexei Miller' s visit to Hungary – FGSZ, citing technical reasons, suspended transports, which have not been relaunched.

Figure 16 **The accepted natural gas price for universal service providers and the individual elements of gas formula between July 2013 and September 2014**

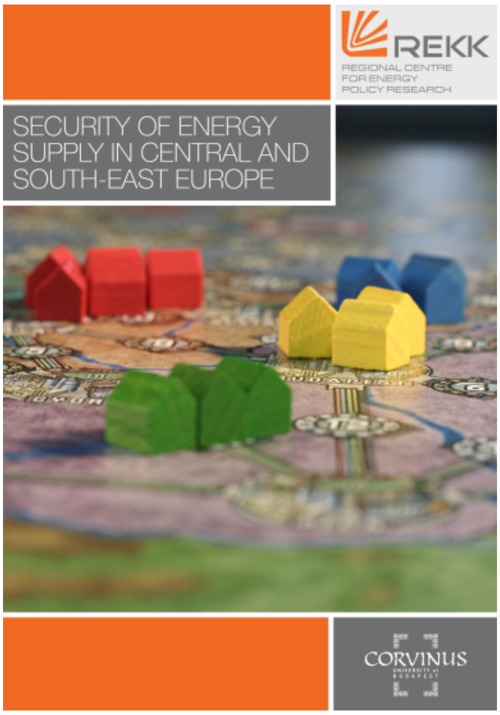


Source: REKK calculations based on EIA and ENDEX data

Note: The 'recognized natural gas price' is the REKK estimation of the quarterly MEKH figure of the accepted weighted natural gas price, which relates to the universal service provision, and is based on the decreed gas price formula and the decreed EUR and USD foreign exchange rates, using publicly available information. The estimation does not take into account the effect of the storage gas featured in the gas price formula. The 'mixed import' was calculated with a similar estimation, but in this case foreign exchange market rates were used instead of the rates set by decree.

Figure 16 shows Hungarian gas prices. Oil-linked prices shifted above 100 HUF/m^3. The reason behind, however, is not energy market events, but the weakening HUF to the USD. The TTF downturn lasting until the middle of the quarter and the exchange rates recognised in decree led to the increasing divergence of market prices from oil-linked prices: Compared to the previous quarter's 78.51 HUF/m^3, the gas price recognised for universal service providers and calculated as the weighted average of 75% market and 25% oil-linked price dropped to 68 HUF/m^3. When calculating this recognised gas price, we had to calculate with the exchange rates recognised by decree; if calculations are based on actual exchange rates, the price is higher by close to 7 HUF.

Security of Energy Supply in Central and South-East Europe



REKK has published the volume containing the studies of the SOS project started in 2009. The papers of this book were motivated by the wish to get a better understanding of the threats and challenges to gas and electricity supply security in a number of countries in Central and South Eastern Europe (CSEE). We very much hope that the reports of this volume, which have been prepared in an exceptional collaborative effort by the colleagues of the Regional Centre for Energy Policy Research, will be helpful for the executives of those companies interested in investing into the energy sector of the region and can also provide food for thought for European and local policy makers and regulators concerned about energy supply security in CSEE.

The entire publication can be downladed free of charge from the Books section of the rekk.eu website.

Short-term flexibility of the European gas infrastructure

The 2014 Ukrainian crisis heavily threatened the European gas supply security. The 2009 gas crisis prompted a number of infrastructure investments and policy tools to tackle a future gas supply interruption by the Member States. Although the European Commission prepared a stress-test about the issue, we still find it useful to share our analyses of the topic. The Commission's stress test (COM(2014) 654 final) concluded that new Member States (Central-Eastern Europe and the Baltic States) will be hit hardest by a supply interruption from Russia. The Commission noted in their analysis that the measures in case of an emergency are on the national level and lack the regional cooperative aspect. The stress test prepared by the Commission highlighted that regional cooperation may greatly alleviate the effects of a supply shock on European level.

The above results cannot be taken by surprise. The January 2009 gas crisis provided an important lesson to Europe. While gas supply sources were sufficient to serve overall demand, the infrastructure failed to transport gas from where it was available to where it was needed. It was not only infrastructure bottlenecks that prevented the efficient distribution of the gas, but misaligned incentives led to the suboptimal use of existing gas infrastructure.

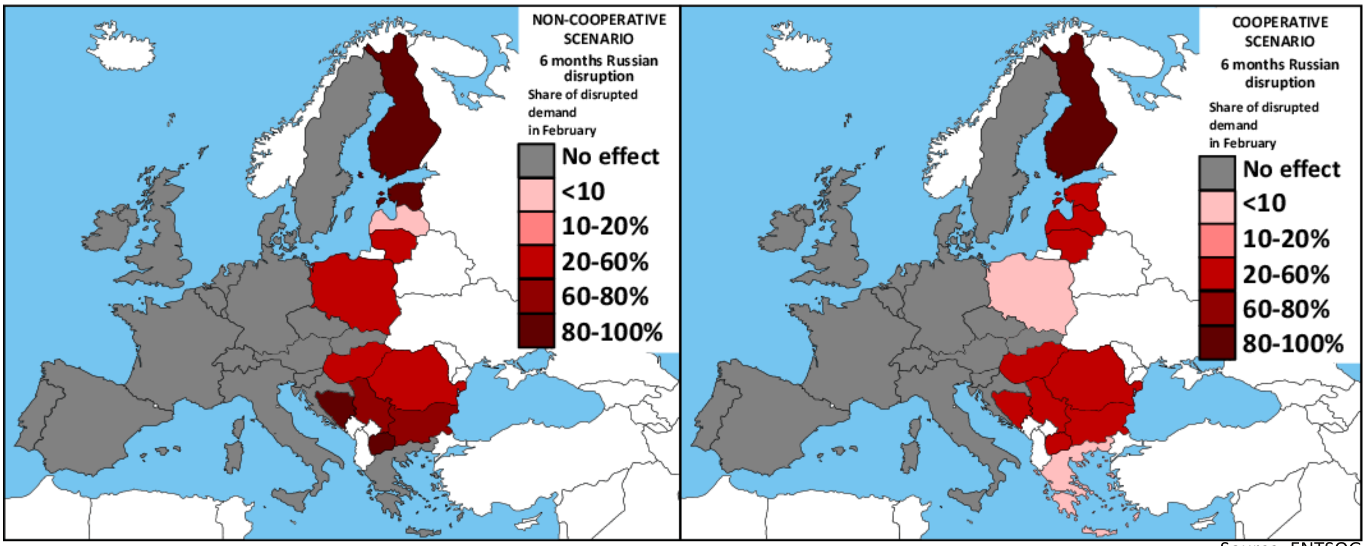
In our short piece, we evaluate the potential flexibility of the European gas infrastructure. First, we will first give a bird's eye view on the total available flexibility measures. This simple review gives us the possibility to narrow down the scope of our inquiry and focus only on the most important sectors. Second, we refine the flexibility options by taking network constraints into account and show the effect of reverse flow possibilities on crisis management as well. Third, we present a more thorough analysis of fuel switching in the power generation sector. Our analyses will be based on REKK's European Gas Market Model (EGMM) and European Electricity Market Model (EEMM).

THERORETICAL DAILY FLEXIBILITY OF THE EUROPEAN GAS INFRASTRUCTURE

We present a simple framework to pinpoint the most significant sectors affecting gas flexibility, namely a stocktaking of existing infrastructure and comparing capacity to historical utilisation, thus allowing for the estimation of theoretical flexibility. Bear in mind though that most of these flexibility figures are representing a theoretical maximum, since due to physical infrastructural bottlenecks and regulatory constraints not all flexibility can be realised.

Natural gas imports from external markets account for 60% of gas consumed in Europe. 80% of the gas imports is supplied by four non-EU countries (Algeria, Norway, Qatar and Russia), and Russia gives 25% of these volumes. Russian import equals 1226 TWh (~126 bcm) per annum, meaning a 3559 GWh (~335 mcm) daily consumption. In case of a sudden loss of Russian flows to Europe, this figure must be met with alternative sources of supply. The following supply or demand side measures may be utilised to balance out the missing supply:

Figure 17 **Possible supply interruptions in February at the end of 6-month Russian supply disruption scenario, average winter conditions**



Source: ENTSOG

Supply side measures

1. Raise domestic natural gas production
2. Ramp up the utilisation of LNG regasification plants
3. Increase the withdrawal from gas storages
4. Increase import shipments from pipeline suppliers other than Russia

Demand side measures

5. In the power sector and district heating gas fired units, that are capable should switch to alternative fuel source (typically oil) or other, non- gas fired units can come online
6. The rest of the heating sector - dominantly individual households and services - can save some gas by heating the homes to lower temperatures, and/or those that are capable by switching to other fuels (electricity, biomass, coal, oil)

In our simple analysis, we present two estimates: an average flexibility, which means that we subtract average winter use from technical capacity, and a low flexibility, in which case a high daily utilisation is assumed.

Supply-side addjustment

Flexibility of production

In some European countries, indigenous consumption is present. Although the European gas fields are generally on the depletion, production may allow for some daily flexibility. To quantify this figure, we assumed the maximum historical daily production as the technical maximum and then compared this figure to the average 2012 daily production. Total European flexibility adds up to 2016 GWh (~213 mcm/day). About three quarter of this flexibility, 1530 GWh is covered by the Groningen gas field. It must be noted that the Dutch government will limit extraction from the Groningen field – due to seismic risks. Without the Groningen gas field, daily flexibility of indigenous production drops down to 485 GWh (~51 mcm/day).

Flexibility of LNG regasification terminals

LNG regasification plants were greatly under-utilised in 2013: average daily utilisation was 20% of their total technical capacity. If, in theory, all terminals were to run at their full capacity, an additional 4016 GWh/day (238 mcm/day) capacity increase would be possible. Greatest potential can be found in British, Spanish and French terminals.

Storage facilities

Existing underground storage facilities possess vast withdrawal capacities, which have been under-utilized lately. In 2013, average utilisation of the withdrawal capacities was merely 29%. Even in the coldest day, this figure was only 55%. The average flexibility scenario allows for 9820 GWh/day (nearly 1 bcm/day) withdrawal capacities, while the low flexibility option gives 6200 GWh/day (650 mcm/day).

Non-EU pipeline suppliers other than Russia

Algerian and Norwegian pipeline suppliers offer an alternative to Russian-imported gas. Comparing 2012 average utilisation to the maximum of 2008-2012 volumes we get an estimate of alternative pipeline flexibility of 608 GWh (~65 mcm).

Demind-side adjustment

Reducing indoor heating

To determine the effect of indoor temperature on gas consumption, we estimate the relationship between outdoor temperature and daily natural gas usage in some selected European cities. This relationship differs greatly between European countries and cities, depending on climate, heating sector characteristics and consumer behaviour. We assumed that a 1 degree colder temperature indoors is equivalent with a 1 degree warmer temperature outdoors. Based on four European cities (Warsaw, Milan, Paris and Budapest), this estimation gives a 2-9% saving on consumption. Expert estimates provide a 6% saving for 1 degree colder indoor temperature, corroborating our results. As a rule of thumb, a 6% saving on gas consumption will be used as an EU-wide saving potential. Since EU gas consumption totalled 5000 TWh (~462 bcm), a curtailment of indoor heating by 1 degree would reduce gas usage with 820 GWh (86 mcm) on a daily level.

Fuel switching of the power sector

Gas-fired power generating capacities are commonly used in Europe to meet the daily peak demand and provide balancing services. Due to low electricity wholesale prices, stagnating gas prices and low CO_2 quota costs, coal generation turned out to be more favourable in Europe. Nevertheless, there are still gas-fired units operating in Europe, even at lower utilisation. Switching of these units to oil is technically feasible, some Member States even require gas-fired units to keep oil reserves on the site of the power plant to allow for quick switching. Gas-to-oil short term switching gives a saving of 3425 GWh/day (360 mcm/day).

Total flexibility of the European gas system

We give two estimates: in case of average flexibility option, LNG regasification terminals are used at their average capacity and we assume the total flexibility of the Groningen fields. As for the low flexibility scenario, we assume the highest daily utilisation for LNG terminals and storages, thus allowing for a limited flexibility option and no flexibility at the Groningen fields. In total, average flexibility option allows for a daily adjustment of more than 20 000 GWh (~2.2 bcm), while even in the low flexibility option the system has 13 700 GWh (~1.4 bcm). Greatest assets are the storage, fuel switching in the power sector and increased LNG flows. As compared to the 3400 GWh/day (~355 mcm/day) lost flexibility, Europe has 4-6 times higher daily flexibility option (*Figure 18*).

Barriers to the full utilisation of the existing flexibility measures

However, this simple framework does not take into account the infrastructural and regulation-related constraints intrinsic to the natural gas system, thus this figure only serves as a theoretical maximum.

First and foremost, natural gas markets in Europe lack transparent and ubiquitous price signal. Even though gas is traded on exchanges, most of the natural gas flows based on long-term contracts and regulated prices. The signal offered by the price itself in case of a supply shock on a liquid market would allow for the quick adjustment on the market. However, a number of government (e.g. price caps, mismanaged strategic storage) and dominant player influences (long term contracts) constrain the delicate workings of the gas market.

Second, full utilisation of the technical withdrawal capacities may not be possible. Withdrawal rates are highly dependent on the geological conditions (eg. whether storage site is a depleted gas field or a salt cavern) and the relative volumes of working gas stored. Storage data published by operators tells that withdrawal rate may drop to 20-50% of the technical withdrawal capacity at working gas levels below 50% of total working gas capacity. Lacking interconnections between member states inhibit the storage usage in neighbouring countries. Moreover, storage facility located in a neighbouring country may not be fully utilised in case of an emergency situation, when the security of supply for a region is jeopardized.

Third, LNG capacities may not be used up to their full capacity due to the lack of LNG importing vessels, or constraints in long term LNG contracts.

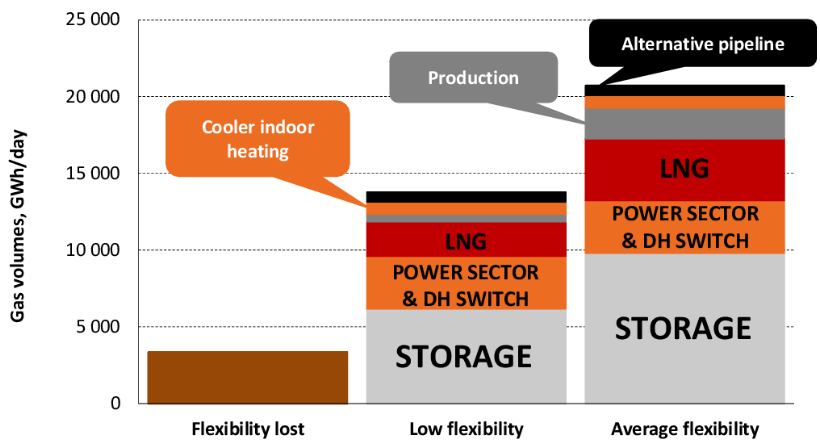
Fourth, flexibility of indigenous conventional natural gas production is dwindling and unreliable: natural gas fields are on the depletion in Europe, ramping up production may only be feasible on the short term. For instance, extraction will be capped for the coming years in the Groningen natural gas field, the greatest production asset in Europe. Non-conventional production has not commenced yet in Europe and thus may not serve as a short-term flexibility option.

Fifth, the demand side adjustment of indoor heating is impossible to enforce in most buildings, thus policies aiming to reduce gas demand via heating adjustment may yield meagre savings only.

Finally, the estimation before assumed supply and demand appear at the same point. This is clearly not the case, even if we find huge unused flexibility in Western Europe, gas may not be transported to Eastern Europe due to transmission bottlenecks or regulatory constraints.

Therefore the above estimation may only serve as an indicative example, but falls short of grasping the intrinsic workings of the natural gas networks of Europe. To include network and regulatory constraints to the scope of our analysis, we apply REKK's EGMM and EEMM.

Figure 18 **Theoretical maximum daily adjustment of the natural gas infrastructure**



Source: REKK estimation based on Eurogas, Eurostat, ENTSO-G

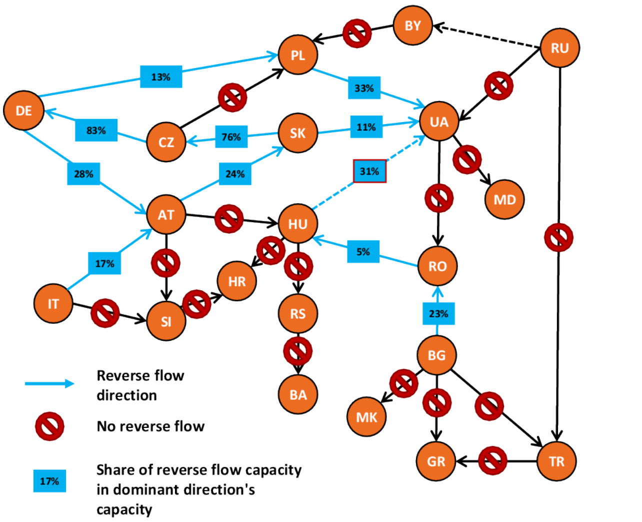
Effect of physical reverse flow on CEE markets

REKK's EGMM incorporates European gas pipelines, LNG terminals and storages, as well as indigenous production, long term contracts and country-level demand. Consumption is modelled on a monthly basis, and so intertemporal arbitrage by storage is an option. The model allows for trading between countries, as long as long interconnector constraints and long-term contracts allow it. Model outputs are monthly consumption figures and monthly country prices.

Our analysis with EGMM showed that network investments since 2009 have greatly contributed to the resilience of the European gas system. Furthermore, it became apparent that allowing reverse flow in non-crisis situations does little in term of prices. The real value of these capacities comes into use only when a major interruption occurs. Reverse flow turned out to be more beneficial in the EU-12[1] than in the EU-28, and the long-term effects were more substantial than the long-term ones.

Infrastructure investment realised in the region may be regarded as a means to enhance the flexibility of the European gas system. Recently, a new LNG terminal has been commissioned in Lithuania, a new regasification plant is about to start operation in Poland and an interconnector between Hungary and Slovakia is about to start shipping gas. Besides costly investments, capacity expansion on the border is still possible by cheap and simple technical modifications of existing infrastructure allowing reverse flows on the existing pipelines.

Figure 19 **Reverse flow directions, in % of dominant direction**



Source: ENTSO-G, 2014 June, TSOs

[1] Czech Republic, Slovakia, Poland, Romania, Hungary, Estonia, Latvia, Lithuania, Bulgaria, Slovenia, Croatia, Finnland

Historically, the gas transmission system was set up to allow for the transport of natural gas to Europe from suppliers outside Europe. Long-term contracts facilitating the transport of gas coming from costly upstream investments constrained the possibility of reverse flows by means of three mechanisms:

- Destination clauses prohibited re-selling of gas to another country, jeopardizing trade of gas between European countries. This way European countries were not interested in investing in new network infrastructure or allowing reverse flows on any existing pipelines.
- Delivery clauses required the gas shipped at certain network points, usually at the border of the country. This further constrained striking alternative deals with other suppliers or trading gas between European countries.
- TOP obligations defined an annual contracted quantity of gas to be shipped to the importing country, allowing for ±10% flexibility of the ACQ to manage demand variations due to temperature swings. However, this flexibility is not sufficient to trade significant amounts of gas to neighbouring countries.

Due to these three factors, the gas transmission system in Europe exhibited a predominantly east-west network topology, not allowing for reverse flow on the major pipelines.

To help the creation of an internal European gas market, the Third Energy Package abolished the destination clauses. Still, delivery clauses and TOP obligations remained in force. Virtual reverse flows started to emerge on existing pipelines, helping the more efficient workings of the gas market in non-crisis situations. However, in case of major disruptions, the gas network should be able to ship gas on major pipelines to the other direction. This requires network investment, which has not been realised in all cases. Compared to new pipeline investment, upgrading an existing pipeline with reverse flow capabilities is a more cost-effective option. During the 2009 gas crisis, a number of pipelines were found to be able to host reverse flows: gas from Germany through the Czech Republic was shipped to Slovakia, and Greece supplied Bulgaria by the end of the crisis. Learning these lessons after the crisis, new EC regulation required all TSOs to make their interconnectors capable of reverse flows. However, the regulation provided the possibility for National Regulatory Authorities to grant exemption from reverse flows, based on cost-benefit analysis.

In order to encourage infrastructural investment able to increase security of supply and boost integration of national energy markets the EU has created a special financial scheme in 2009, the European Energy Programme for Recovery (EEPR). The scheme supported 1360 million Euros to gas infrastructure investments, of which 1285 million EUR was allocated to new interconnection development, and 78 million to reverse flow projects. Since 2009, ten reverse flow projects received support, costing at most 30 million EUR. Figure 19 summarizes the existing reverse flow capabilities of the European gas system, 5 years after the Ukrainian crisis and establishing the EEPR (*Figure 19*).

It is apparent that reverse flow is possible on all major transit pipelines (TAG, WAG, Brotherhood). However, many interconnectors are still unable provide reverse flow services or have reverse flow capacities significantly smaller than the dominant direction. Reverse flows capability are not in place major transport pipeline crossing the Balcans and South Eastern Europe.

Enabling reverse flow in our region (in CEE contries) proved to be a hard task too. The HAG exemption request was disputed in the case of the HU>AT direction by the Hungarian regulator, claiming that on the Hungarian side the pipeline was originally built for bi-directional flows, so from their perspective they do not see the logic for an exemption. The dispute is not yet resolved.

On the Hungarian-Romanian border the Romanian TSO was reluctant to invest in reverse flow from Romania to Hungary. Hungary was again against the exemption, claiming that in a supply disruption Hungary could use Romanian sources (storage or domestic production). The Commission was involved in the negotiations and a minor reverse flow capacity (5% of the total capacity) was inaugurated in 2013.

The Commission had to be involved into negotiations on the Greek-Bulgarian and Romanian-Bulgarian physical reverse flow projects in order to bring the parties to an agreement. However these projects proceeded very slowly.

To sum up, reverse flow allows for cost-effective mitigation of short and long term gas crises, serving common European interest. However, current short-sighted regulatory practice in Europe limit reverse flow capabilities, allowing for exemptions on crucial network infrastructure elements. It is worthwhile to reconsider the modification of framework regulation allowing for these exemptions and try to expand reverse flow capabilities to all pipelines.

FUEL SWITCHING OF THE POWER SECTOR

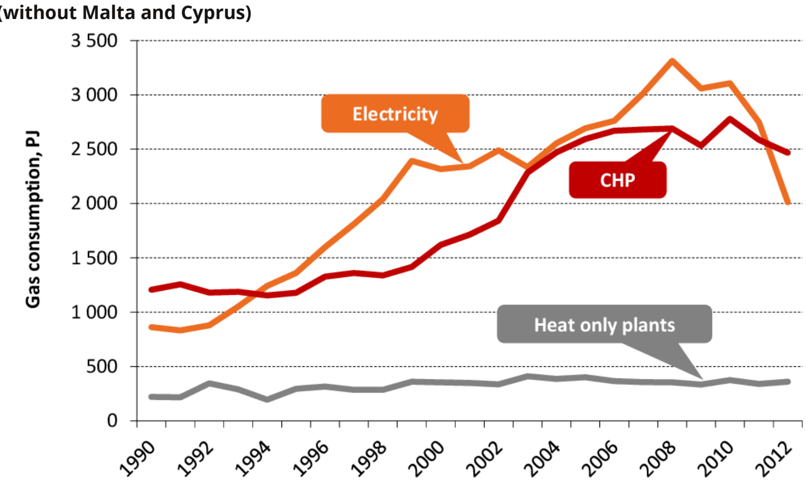
The energy transformation sector is a large consumer of natural gas: in 2012, 30% of total EU natural gas consumption was covered by electricity and heat generation. Natural gas consumption of power plants showed a steadily increasing trend up to 2008. From 2008, electricity-only production plummeted due to falling power prices and heavily decreasing negative spark spread, which resulted in a 1000 PJ drop in consumption from 2008 to 2012. Gas consumption in CHP plants did not decrease, most probably due to the heat sales of generation.

The energy sector may allow for two types of fuel switching: on the short term, natural gas-fired units may be replaced with oil firing, medium term adjustment allows for higher utilisation of coal fired units (*Figure 20*).

To assess the fuel switching ability of the Member States, we listed the coal-fired fleet and the gas-fired capacities in Europe. Capacity data were obtained from REKK's EEMM model (which uses Platts's Power Plants tracker figures and REKK's data collection). Production figures were obtained from Eurostat's databases, by estimating electricity production based on fuel consumption of the units.

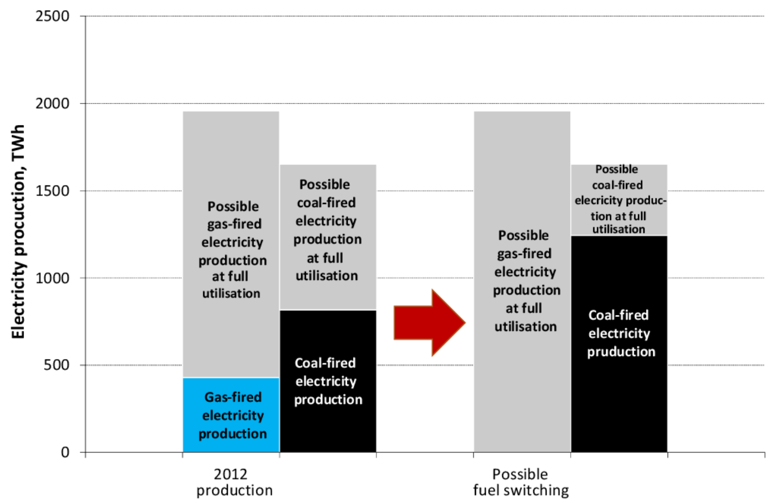
On EU-26 average, it is apparent that utilisation rate of gas-fired units has been steadily dropping since 2004. Several factors contributed to this decrease: strong interest to invest in CCGT power plants, increasing renewable production, stagnating electricity demand after 2008, and falling spark spread after 2010. In 2012, utilisation of gas-fired power plants

Figure 20 **Natural gas consumption of electricity, CHP and heat only plants in the EU-26 (without Malta and Cyprus)**



Source: Eurostat

Figure 21 **Gas-fired and coal-fired production compared to theoretical electricity generation**



Source: REKK calculation

was 22% on average in the EU-26. In parallel, coal utilisation has been raising up to 50% in 2012 and replaced the more expensive gas-fired units.

Based on historical price developments, we can't expect natural gas to regain its place. Our calculations indicate that only a twofold increase in coal prices would allow for natural gas-based energy production to be competitive.

Installed capacity-wise the European power system has ample capacities to switch total natural gas production to currently unused coal generation. In theory, installed coal capacities in the EU-26 (not including Malta and Cyprus) allowed for the production of 1650 TWh electricity, while gas-fired capacities would produce 1956 TWh if they were running at every hour. It has to be noted that these figures are only theoretical value, providing us with a rough estimate of the flexibility coming from fuel.switch. If the coal is cheaper how could it be possible that the average utilization rate of coal is "only" 50%, and similarly why is the natural gas utilization rate not driven to zero? There are three reasons behind this phenomenon:

- In a low demand period renewable and nuclear production crowded out coal-based generation.
- Cogeneration production driven by heat demand is based on natural gas; coal fired power plant cannot take over their role.
- Cross-border capacity quantity is insufficient to let the underutilized coal fired capavities export their production (*Figure 21*).

For example, in Germany in off-peak hours average utilisation of coal-based units is only 40%, since renewables, nuclear and CHP generation is still a cheaper option than coal-based power generation. In peak hours, average utilisation of coal-based units may raise up to 80%.

Another reason for lower coal-based utilisation is the lack of sufficient cross-border capacities. Although the European grid is a more meshed system than the natural gas networks, bottlenecks still exist. To show the effect of network constraints on the generation, we modelled a reference scenario in the EEMM and compared this to the case when a 5000 MW interconnector was added to connect Italy with Germany via Switzerland (*Table 1*).

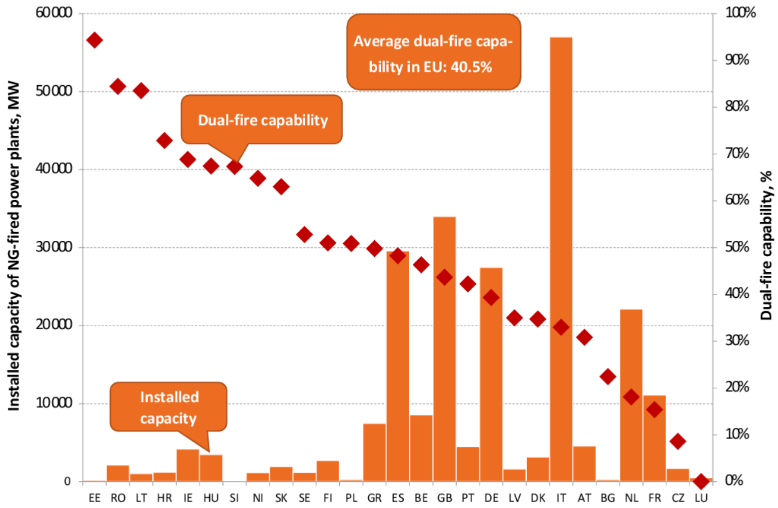
The modelling shows that German coal-based units now are able to replace Italian natural-gas based generation, due to the increased cross-border possibilities. On European level, this means a 1.4% increase in total coal-based utilisation and a 1.2% decrease in natural gas-based utilisation. To sum up, although coal utilization was only 50% in 2012, it cannot increase in the short run due to the current of structure of load patterns and insufficient cross-border capacity in the power system. The expansion of interconnections in critical borders may allow for lower gas consumption and higher utilisation of coal-fired units

Table 1 **The effect of a new 5000 MW DE-CH-IT cross-border line on electricity price, coal and gas fired power plants' utilization rates**

		Without new cross-border line	With new cross-border line	Difference
Electricity wholesale price €/MWh	Europe	44.1	44.9	0.8
	Italy	62.1	56.0	-6.1
	Germany	39.4	43.1	3.7
Coal utilisation, %	Europe	52.3	53.7	1.4
	Italy	70.1	68.1	-2.0
	Germany	55.1	58.6	3.6
Natural gas utilisation, %	Europe	15.4	14.2	-1.2
	Italy	19.8	13.9	-5.9
	Germany	17.2	17.2	0.0

Another source of flexibility coming from the power sector is gas-to-oil switch: this is technically possible both in the short and in the long run. However, not all gas-fired units are able to simply switch their fuel. 90% of gas-fired power plants commissioned before the 1970's are capable of switching to oil without further adjustment, whereas less than 30% of gas-fired units commissioned after 2000 is able to do the same. Steam turbines switch easier than gas turbines, 75% of steam turbines have dualfuel capabilities but only 35% of gas turbines are capable of switching to oil. Some countries oblige their power plants to keep reserve oil for crisis situations (Finland, Greece, Hungary, Ireland and Lithuania). 80-90% of heat-only plants is capable to replace gas with oil. To sum up, 300 PJ of natural gas-based units is able to switch to oil. Average switching potential of natural gas based power plants to oil in Europe is 40% (*Figure 22*).

Figure 22 **Dual-firing capability of European power plants**



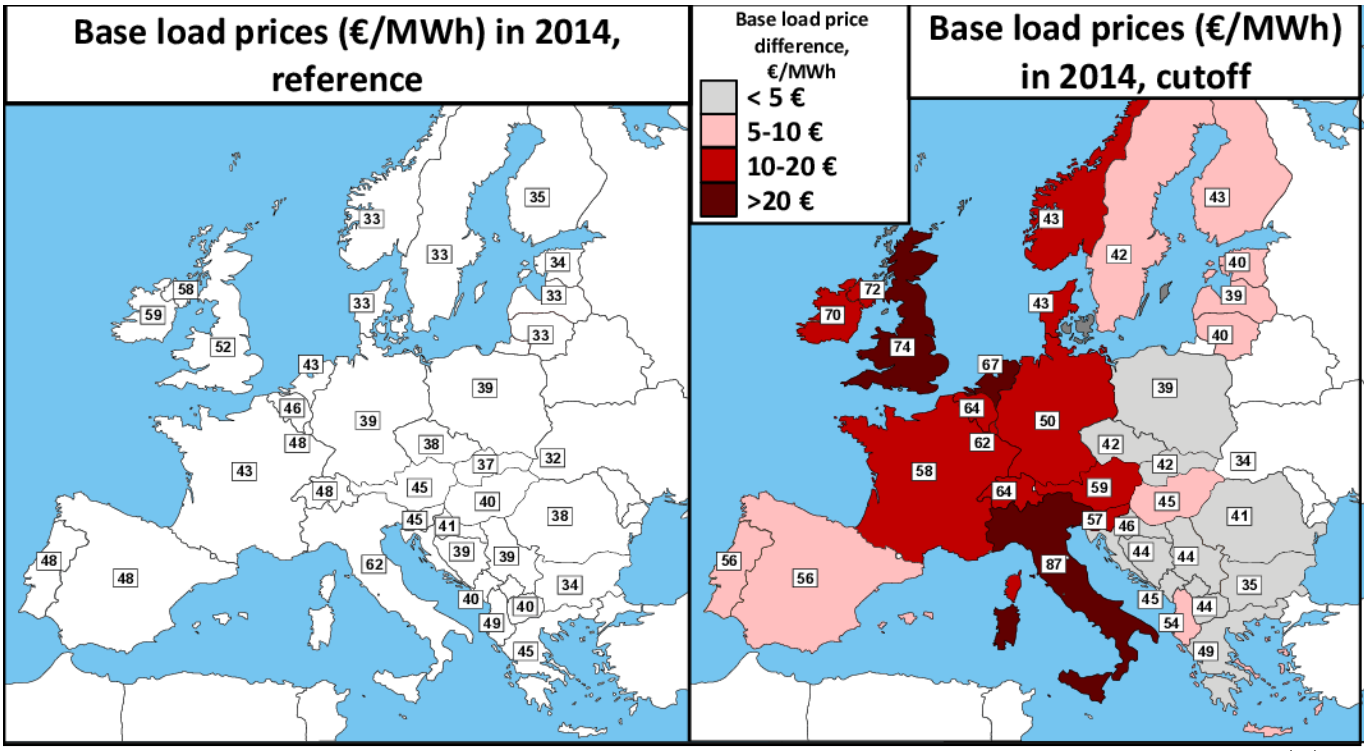
Source: Eurostat and REKK estimation

Oil-based electricity and heat generation has its downsides compared to natural-gas based production. To generate a unit of energy from oil is more expensive and not as clean GHG emission-wise. Burning oil instead of natural gas can cause local emission problems, especially in large cities. In the 90-110 USD/barrel crude oil price range, natural gas-based electricity production is cheaper. However, the 70 USD/barrel crude price of late 2014 makes the oil-based generation more favourable than gas-based, without prejudice to the non-GHG emission-related costs of oil-firing.

Finally, we quantified the price effect of a major disruption in gas supply to Europe. In this case, gas-based power generation ceases completely. Our two infrastructure scenarios represent the 2014 situation and the 2020 infrastructure. The 2020 infrastructure includes all renewable capacities set by member states in their NREAPs, and all additional network investment set in the TYNDP of ENTSO-e.

Surprisingly, electricity prices are affected less severely in the EU-12 region than gas prices. The region suffers less price increase than Europe on average. None of the countries need to institute load curtailment. The answer to this puzzling difference compared to the EGMM results may be the fact that in the EU-12 power plants were greatly underutilised in the reference case and in the same time possessed sound fuel switching abilities, whereas in Western Europe, utilisation was higher in the reference case and switching capabilities more constrained. On average, prices increased by 13 €/MWh (*Figure 23*).

Figure 23 **Effect of a natural gas disruption on the wholesale electricity prices in 2014**



Source: REKK calculation

The 2020 scenario shows similar results, but the price effects are less harsh: new renewable capacities and low demand growth mitigate the price effects. On average, prices increased by 11 €/MWh, Italy and UK are affected the most.

SUMMARY

Our three short analyses showed that the European countries would be hit heavily by a sudden cut of Russian supplies through Ukraine, both in the gas and electricity sectors. However, the European gas network and electricity grid is capable of tackling this crisis on the short term even with the current infrastructure. Congestion on the interconnectors inhibits the full utilisation of the potential of the network and the grid. Some of this congestion may be handled by removing regulatory constraints and introducing reverse flows on all interconnectors. On the electricity markets, gas to coal switch is also limited by network bottlenecks, while the main barrier of gas to oil switch is the market price and the unfavourable emission characteristics of the oil firing.

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The implementation of Art 7 of the Energy Efficiency Directive

The Energy Efficiency Directive (EED) (2012/27/EC) addresses one of the key goals identified in the Europe 2020 Strategy, namely a 20% reduction in projected primary energy consumption by 2020. The EED puts forward a comprehensive policy package targeting various sectors with untapped energy savings potential with the intention of placing the community back on track to achieve the 20% target.

First of all, the EED requires Member States to set their indicative national energy savings target by 2020 (Art 3). Apart from setting national target (translated into absolute level of energy consumption in 2020), the EED introduces a number of provisions such as the preparation of national building energy efficiency strategies (Article 4), a requirement to renovate 3% of public sector buildings each year (Articles 5 and 6), the need to establish energy efficiency obligation schemes or alternative measures (Article 7) and provisions for auditing and metering (Articles 8 to 12).

On the basis of national notifications related to the implementation of the EED, the Commission has estimated that the EU will miss its 20% energy savings target for 2020 by 1-2%. In order to close this gap the Commission concluded that proposing new legislation in this regard would not have a significant effect by 2020 and that the best approach for achieving the 2020 target would be to strengthen the implementation of existing legislation.[1] In its Communication, the Commission therefore stated that it does not intend to propose new measures, at the same time it called on the Member States to intensify their current efforts to ensure joint delivery of the 2020 target.[2]

Energy efficiency obligations schemes (EEOSs) (Art7) are expected to contribute substantially to the achievement of the energy savings ambitions of the EU. Article 7 requires MSs to introduce energy efficiency obligation schemes with a target that is at least equivalent to achieving new savings each year (from 2014 to 2020) of 1.5% of the annual energy sales by volume. The obligated parties can be energy suppliers and/or distributors. The inclusion of this policy tool to the EED is based on the generally positive experience with such schemes in a number of European countries such as the UK, Italy, France, Denmark, the Flanders region.

Art 7 offers a high degree of flexibility both in terms of defining the actual savings target and the modes of achieving it:

- MSs can deduct the energy use in the transport sector from the baseline (2010-2012 average of final energy consumption).
- MSs can further reduce the savings target set agains the adjusted baseline up to 25%[3] by the followings:
    - Gradual phase-in of savings rate: 1% in 2014 and 2015; 1.25% in 2016 and 2017; 1.5% in 2018-2020.
    - Allowing the energy use of industrial installation covered by the EU ETS to be counted towards the target.
    - Allowing energy savings from transformation (heat and electricity generation), transmission and distribution to be counted towards the target.
    - Allowing savings from early action to be counted towards the target (implemented after 2008 and having effect at least until 2020).
- MSs have the option of implementing alternative policy measures instead of, or in combination with, EEOS if it results in the same level of energy savings. These alternative policy measures include:
    - energy or CO_2 taxes;
    - finance and fiscal incentives schemes;
    - regulations or voluntary agreements;
    - minimum standards for products (including buildings) and services;
    - energy labelling schemes; and
    - trainings, education and advisory schemes encouraging more efficient energy use.

[1] SWD(2014) 255 final
[2] COM(2014) 520 final
[3] The MSs can use these 4 reduction options fully or partially and in any combination but the overall reduction should not exceed 25% of the savings target.

MSs were required to notify the European Commission how they intend to implement Art 7 including the use of the above mentioned flexibilities by 5 Dec 2013. In addition, they could provide further information in this regard in their National Energy Efficiency Action Plan (NEEAP) due in April 2014. In the following sections we provide a brief overview of how the 28 countries plan to implement Art 7 of the EED and discuss some general problems in their implementation approach.

The use of EEOS

Energy efficiency obligation scheme is the default policy option of the EED, intended (by the Commission) to bear a lion's share of the targeted energy saving. Even though the details of the schemes are not fully developed by some MSs, altogether 17 countries have decided to use obligation schemes to meet its savings target under Art 7, either as the only measure or in combination with alternative policy measures. Two MSs have them already in operation (Denmark and Poland) and two others are planning to implement them (Bulgaria, Luxembourg) as the only policy instrument for Article 7 (*Figure 24*). Other MSs will use only alternative measures. On the basis of MS submissions 38% of the proposed savings at the community level will be generated by obligation schemes making it the most important policy measure in terms of proposed savings but failing to be a truly default instrument. Apart from EEOSs, taxes, standards and fiscal incentives are important policy instruments as well showing that MSs are keen to keep using more traditional policy tools (*Figure 25*). The majority of savings is expected from the building sector (*Figure 26*).

Cross-cutting energy and CO_2 taxes were included by 10 MS and tax rebates for energy savings technologies or measures were notified by 6 MS. Truck and road tolls are also included in this category on the basis that they increase the cost of energy consumption (hence reduce consumption) even though are not specifically labelled as energy taxes. It is important to note that MS can only claim savings for energy and CO_2 taxes that are additional to EU minimum levels of taxation. Financial incentives usually mean non-refundable grants or other forms of financial incentives (financed from national and EU funds) dominantly for building refurbishment. Similarly, energy efficiency regulation usually cover national buildings energy efficiency regulations that go beyond the EU legislation. Some countries reported voluntary agreements with industry for the reduction of energy use (e.g. UK, Belgium, Finland).

Figure 24 **The current uptake of EEOS in Europe**

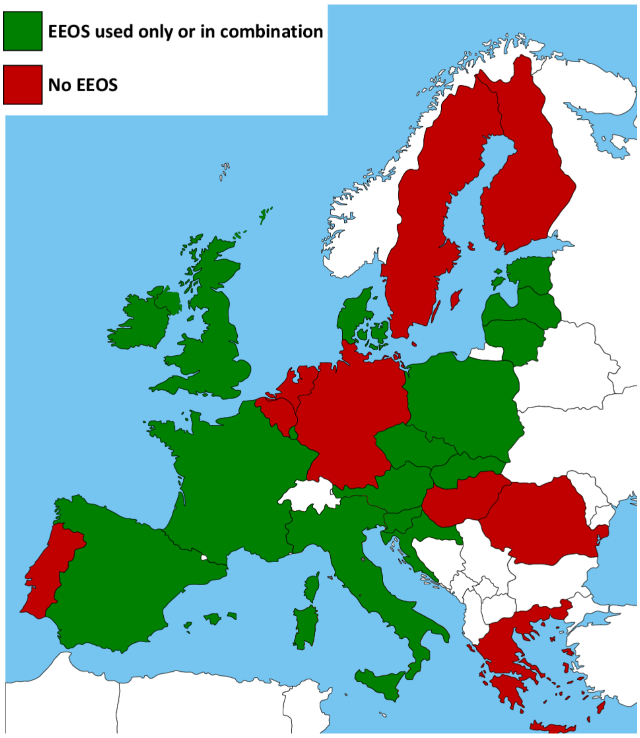
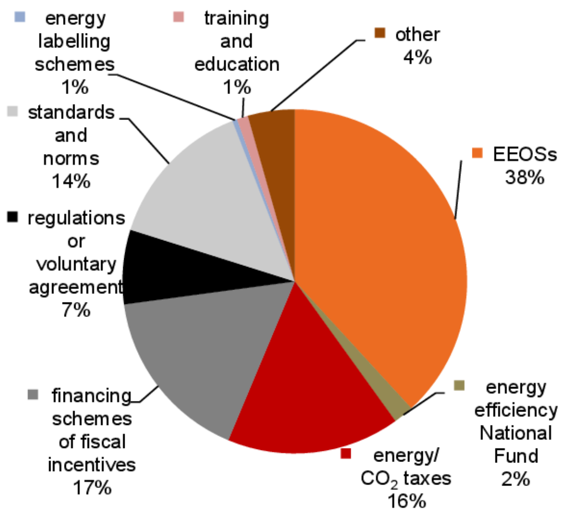


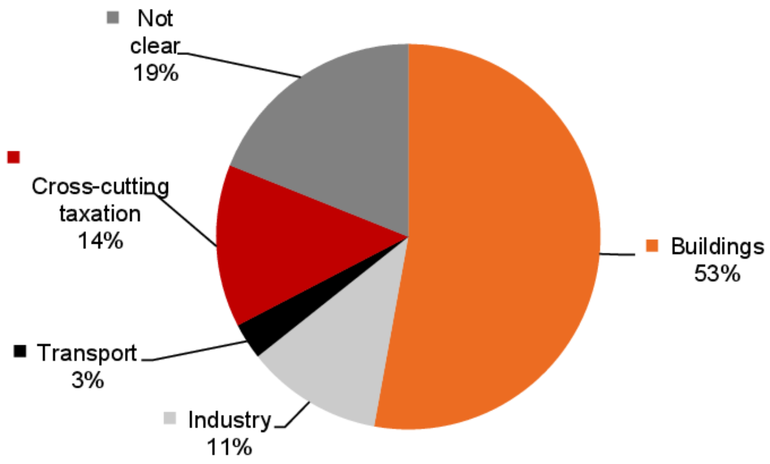
Figure 25 **The share of the various policy measures in the total proposed savings, EU28**



Three main issues stand out in the implementation of Article 7 by Member States. Firstly, the decision of almost all MSs to propose lower energy savings targets results in insufficient quantity of savings. Secondly, due to the inclusion of various alternative measures (apart from EEOSs) the risk of policy overlap is substantial that might mean the overestimation of expected savings. Finally, the risk of non-delivery is considerable as well due to methodological weaknesses.

Almost all MS used the option of excluding the energy use of the transport sector from the baseline (with the exception of Sweden). As a consequence,

Figure 26 **The shares of target sectors, EU28**



◆ Proposing actions that are not additional,

◆ proposing actions that are not aimed at energy savings and

◆ proposing projects that are not aimed at end-users.

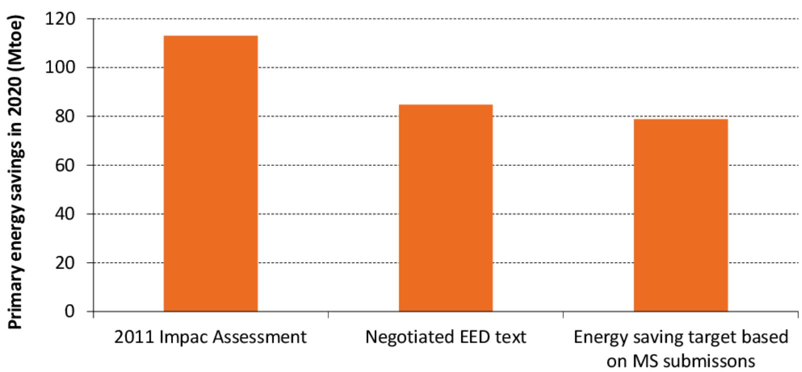
Additionality is a key issue: only those savings can be counted towards the Art 7 target that go beyond the minimum level required/prescribed in the EU legislation.[7] This requirement influences heavily the savings from energy efficiency improvement in the building sector and from energy taxes as these policy measures take up a significant share of proposed energy savings. This means that only savings deriving from building refurbishment above the minimum level defined by the EPBD is eligible under Art 7.[8] The recast EPBD requires MS to establish a cost optimal methodology for new buildings and for refurbishments of existing buildings. Similarly, only the effect of the differential between the EU minimum and the actual higher tax level can be accounted against the Art.7 target.[9]

the baseline got 32% lower (adjusted baseline).[4] In addition, most MS (with the exception of Denmark, Portugal and Sweden) use the available exceptions to full extent. This reduces the EU28 cummulative savings target for the 2014-2020 period (calculated from the adjusted baseline) from 42 to 33% that is only marginally higher than the minimum provided by the 25% reduction option.[5]

The 2011 Impact Assessment assumed that Art 7 will result in an annual primary energy savings by 2020 of 108-118 Mtoe.[6] The Commission recalculated the expected saving on the basis of the final EED text and considering the 25% exemptions and provided an estimate for annual savings in 2020 of 84.8 Mtoe. MS proposed 77.8 Mtoe primary energy savings target for 2020 in their notifications (*Figure 27*). A comparison with the initial 2011 Impact Assessment shows that the targets proposed by MS are 30% lower than the expected savings.

Apart from the low ambition of MSs manifested in the use of target reduction options, some typical methodological weaknesses identified in relation to the measures proposed in the national implementation plans carry further risk of non-delivery:

Figure 27 **Comparison of expected energy savings in 2020, Mtoe**



[4] *According to Eurostat data for 2010-2012, the percentage of final energy used for transport is 32% of total final energy consumption.*
[5] *If the 25% exemptions are fully used, the cumulative energy savings between 2014 and 2020 drops from 42% to 31.5% of the baseline.*
[6] *SEC(2011) 780 final*
[7] *Annex V of EED*
[8] *2010/31/EU*
[9] *2003/96/EC Energy Performance of Buildings Directive (EPBD)*

Another methodological issue is the inclusion of policy measure that are not aimed at energy savings per se (mainly renewable energy projects) or not aimed at energy savings at end-users. The eligibility of renewable energy production is an ambiguous issue as increased renewable energy production saves fossil-based energy use but the Commission interpretation is that only measures targeting exclusively energy savings are eligible. Several MSs has proposed measures aimed at energy savings at generation and/or transport of energy (transmission and distribution) such as CHP promotion and network loss reduction that cannot be counted towards the target as Art 7 of EED requires the savings to be achieved at end-use. These savings can only be accounted for under the 25% flexibility cap.

The implementation of Art 7 in Hungary

The Art 7 notification submitted by Hungary is virtually void of content. It reflects the indecisiveness of the government on the issue: neither the actual savings target (inclusion of the energy use of the transport sector in the baseline or the use of the 25% flexibility options) nor the policy measures planned to be used in implementation (the introduction of EEOS) has been decided. In addition, Hungary so far failed to submit its NEEAP as well.

We safely believe that Hungary will not introduce an energy efficiency obligation scheme but would rather rely instead on alternative measures, most importantly EU funding available for the 2013-2020 financial period to support energy efficiency investments at buildings. Other CEE countries are likely to use these funds actively even though only the Czech Republic and Latvia mentioned them explicitly in their implementation plan. These funds – however – cannot be directly disbursed to natural persons (flat/house owners) due to EU regulation and hence some forms of financial intermediaries are required to tap the energy savings potential of the residential sector.

Hungary has missed the deadline for transposing EED in its national legislation and as a consequence the Commission initiated an infringement procedure (similarly to other 23 MSs). Apart from issuing a "Letter of Formal Notice" Hungary (and Bulgaria) was formally requested to show evidence of progress in transposition ("Reasoned Opinion"). Hungary has to supply the Commission with this evidence by the end of January 2015 otherwise it will be referred to the Court of Justice and risks financial penalty. The Commission is in the process of preparation infringement procedures regarding the implementation of Art 7 specifically.

Future legislative and policy process

Energy efficiency has been recognised to continue to play a significant role in delivering the EU's climate and energy objectives for 2030. Within a Communication laying down the modalities for the policy framework for climate and energy in the period from 2020 to 2030, the Commission proposed a new reduction target for GHG emissions of 40% compared to 1990[10]. 25% energy savings have been assumed for the cost-effective delivery of the 40% GHG reduction by 2030.[11] Taking into account the important role of energy savings to improve the EU's security of supply as highlighted in the recent European Energy Security Strategy[12], the Commission has found it appropriate to maintain the "existing momentum" of energy savings and propose an ambitious energy efficiency target of 30% for 2030.[13] Even though the ambition of the Commission for the 2030 energy efficiency target has been reduced by the Council from 30% to 27%, the Commission has the opportunity to strengthen this goal back to 30% in the forthcoming years.[14] Therefore the role of Art 7 is likely to remain fundamental in the post 2020 era. In the light of the energy efficiency target for 2020 and the forward looking target of 2030, it is necessary to assess the effectiveness of Article 7 in delivering expected savings and, if appropriate, take steps in order to ensure that its implementation would realize the potential of EED and lead to the required level of savings by the end of 2020 and contribute to the 2030 target.

The EED explicitly requires the Commission to assess and submit a report to the Parliament and the Council by 30 June 2016 on the implementation of Article 7.[15] In conjunction, the Commission can put forward a legislative proposal focusing – but not limited – to the following aspect of Art 7:

- to change the final date ("sunset clause") of Art 7 that is currently ending at 2020: this would mean the extension of the lifetime of articles, including new target setting for the 2020-2030 period;

[10] *COM(2014) 15 final*
[11] *COM(2014) 15 final*
[12] *The recent European Energy Security Strategy views energy savings as „one of the most effective tools to reduce the EU's external energy dependency and exposure to price hikes". COM(2014)330*
[13] *COM(2014) 520 final*
[14] *COM(2014) 520 final*
[15] *Article 24(9)*

- to change the definition of savings target including
  - its ambition level (currently 1.5% per annum of energy sales to final consumers),
  - focus (only end-use energy savings are eligible: no renewable use and generation/distribution efficiency improvement are eligible/accountable),
  - adjustment of the baseline with transport sector energy use (abolishment or limitation of this reduction option),
  - flexibility options (modification of the current 4 options) and overall cap (changing the 25%).[16]

The early review of Art 7 of the EED shows that the Commission considers Art 7 as a key tool to deliver the targeted savings by 2020 and would like to secure that the expected savings will be delivered. In addition, it also reflects the fact that the Commission is aware of the novelty of EEOS for the majority of MSs and the complexity and methodological challenges of its implementation.

[16] *Article 7(1), (2) and (3)*

Recommendations for the implementation of a successful renewable district heat generating program in Hungary

Report on the 13 November 2014 workshop of REKK

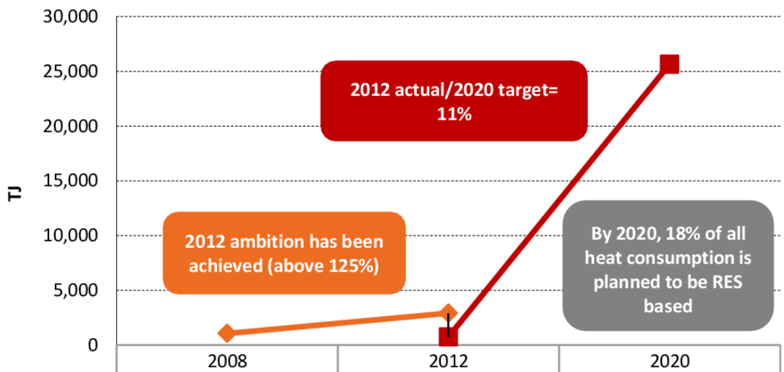
The British Embassy hosted our autumn professional day titled „Regulatory prerequisites of a successful renewable district heating program in Hungary". During the event heat producers, service providers, project developers, and professional organisations, all with successful renewable based district heating projects, and representatives of domestic and foreign regulators shared their experience and discussed the regulatory and institutional conditions of continued progress.

Indicating the importance of the topic, the event was opened by Jonathan Knott, the ambassador of the United Kingdom in Budapest, and *Dr. András Aradszki*, minister of state for energy affairs within the Ministry of National Development. The National Renewable Energy Action Plan - in line with the environmental targets of the EU - anticipates over 25 PJ of renewable based district heat generation by 2020, ten times the present volume.

Domestic project experiences - impressive developments

For the last few years a number of district heating systems have made considerable progress transforming their energy mix. Representatives of these projects - *László Nyíri*, the managing director of MI-HŐ, *János Ádók*, member of the board at Hódmezővásárhelyi Vagyonkezelő és Szolgáltató Zrt. and *Attila Péterffy*, CEO of Pannon Hőerőmű Zrt. - shared their experience with the audience during the first section of the workshop.

Figure 28 **Targets of renewable energy based district heat generation within the National Renewable Energy Action Plan**



	2008	2012	2020
Actual	1067.0	2920.0	
Target		754.0	25665.0

Source: REKK - Towards 2020

In Miskolc during the 2013-14 heating season the share of renewables was already 47% within the fuel mix of the district heating system that supplies 30,000 apartments. The development of renewable heat capacities was carried out with the direction of private investors, but in close cooperation with the municipal district heat supplier, using government grants. A small biogas engine that has also been awarded a prize of innovation provides heat for 319 apartments, the biomass boiler supplies 1119 apartments, while the geothermal system - unique in Hungary with its heat capacity of 2*30 MWth, capable of generating 800 TJ heat in a year - produced about 500 TJ heat during 2013/14. The full utilisation of geothermal capacities is limited by the long term contract with the natural gas fired heat producer. Annually 172,400 tons of GHG emissions can be avoided with the three systems together.

In Hódmezővásárhely 8 extracting and 2 reinjecting wells provide a total of 14 MW geothermal based heat to the town, supplying 20% of households and most public institutions. The success of the last few years is underpinned by the continued acquisition of new users for the district heating system, including, for example, hotels and supermarkets. As a result of the extensive geothermal system the gas consumption of the heat centres of the district heating system fell from 4.6 million m3 in 1993 to 300 thousand m3 by 2013.

Pécs today is the proud holder of the greenest Hungarian city title as 99% of the energy supplied by the district heating company to both households and industrial consumers is renewable. In addition to a small wood fired Finnish boiler, the backbone of the district heating system of Pécs is the straw fired power plant with a capacity in excess of 70 MW, built with a HUF 24 billion financing of the parent company. A critical precondition to executing the investment has been the close cooperation among the power plant, the district heating company and the municipality. A number of difficulties arose during the investment, e.g. the Danish company supplying the technology went bankrupt. In order to ensure the uninterrupted supply of fuel, the market for straw had to be created, nearby farmers had to be educated on the storage and sale of straw. Dalkia also took part in training the farmers and financing their machinery, and in order reduce risk, it engaged in contracts with them covering 5+5 years. As a result of the successful development, annually 80 million cubic meters of gas consumption is precluded with the new system.

On top of geothermal and biomass fired production, these systems also retain gas boilers as peak/reserve capacity.

Where could funds for further development originate from?

In his opening speech, Dr. András Aradszki, minister of state for energy affairs, articulated that *the Government is committed to nurturing and further developing the district heating systems, as well as using renewable energy*. In order to reach the pledged renewable ratios, Hungary will promote all those solutions that can reduce the gas dependency of district heating to the planned degree.

In addition to biomass and geothermal based energy use, energy generation from waste combustion is also to be advanced (here a shift of emphasis can be observed). In Hungary annually 15 million tons of waste is generated of which only 5% is utilised, while raw materials worth HUF 120-150 billion are wasted as a result of large scale landfilling. In order to expedite this transition, the Government aims to develop waste management, and the corresponding strategic plans are under preparation.

The goal of the government in support of the promotion of geothermal district heating projects is restraining the administrative and financial measures that inhibit or complicate their implementation.

Financing the investments is a difficult question, but the minister of state explained that they wish to create opportunities for the modernisation of cogeneration, heating plants, and heat transmission systems, the replacement of pipelines and the reduction of their diameter, the replacement of heat centres, the insulation of above ground pipelines and the construction of underground pipelines. Connecting heat districts and improving the energy efficiency of buildings will also be important. The ten operational programs of EU financed assistance provides about HUF 8700 billion of sources, of which more than 1500 billion is available for the environment and energy efficiency operational program. Within that from the perspective of renewable district heating priority 5 is the most important: HUF 290 billion will be available for energy efficiency improvement and the application of renewable energy sources. The renovation of district heating systems will be a separate measure with over HUF 40 billion of funds.

In addition to state support in many cases *private capital may also provide funding for these investments*. Financing these projects can be attractive for private financial institutions because a heat supply service with predictable volumes without major price swings generates dependable cash flows. *Balázs Jávor*, head of the Financing Department at UniCredit Bank described the „non-recourse project finance" technique employed for the financing of renewable energy investments. The essence of this structure - different from general corporate loans - is that the loan is taken out by a separate project enterprise, an SPV (special purpose vehicle) the only activity of which is energy sales, and the generated revenue covers the repayment of the loan.

In case of suitable partners and a predictable (regulated) heat price renewable energy based district heating projects can be nicely financed. Financial institutions, however, often impose stringent conditions which, if not fulfilled, reduce the chance of the positive approval of the loan application. Of these, the following requirements should be highlighted:

- i) revenue forecasts require a regulation that is stable and predictable in the long run,
- ii) if there is a regulatory change, however, it should not impact already operating projects financed through loans,
- iii) in case this still happens, the already operating project should be able to adapt to the altered rules.

Another vital issue is the extent to which the price setting methodology is transparent and accessible, that is, which cost types are eligible in accordance with Decree 50/2011[1] (e.g. can interests on the loan be used towards the regulated price).

Another factor that can advance investments is that in some regions a given renewable energy based district heating system offers a lower, more attractive consumer tariff than the cost of individual gas boiler systems.

[1] *Decree 50/2011. (IX. 30.) of the Ministry of National Development*

Within the European Union the use of renewable energy based district heating has grown by 85% for the last five years, with biomass in a leading position

During the British opening presentation of the event and the second section of the workshop the relevant foreign experience was shared by the presenters. *Jonathan Knott, the UK ambassador to Hungary* described that while district heating penetration in his country is relatively low at the moment, there are ambitious targets for renewable energy use.

The strategic document on the future of heat generation published in 2013 („Future of Heating") seeks to achieve a 14% ratio for district heating systems[2] within British heat consumption by 2030, and a 40% share by 2050. Last year the Government of the United Kingdom created the Heat Network Delivery Unit, the task of which is to support municipalities in establishing community heat networks. In October 2014 the UK Investment Bank designated a GBP 10 million[3] sum for this financing goal, accessible to municipalities through applications.

RES district heating projects receive additional funds from the Renewable Heat Incentive, a long term financial operational support program managed by Ofgem. The RHI pays 2 pennies after each kWh of heat produced from renewable energy and its goal is to transform the heating systems of large, multistorey buildings to renewable energy sources.

European renewable based district heat generation is dominated by biomass, providing close to 80% of renewable energy based heat. Except for a few member states, a support regime or regulatory environment promoting less mature RES technologies has not evolved. *Gerald Bourland, the CEO of the Central and Eastern European region of Dalkia* reported on this trend. In Poland Dalkia succeeded in enlarging its network (+3% annually) and already use biomass fired boilers for some of their heat generation.

The system of the Estonian ex ante district heating regulation was described by *Märt Ots, the president of the Estonian Competition Authority*. The most typical form of heat generation is district heat production (with a share of about 70%), there are more than 200 district heating companies in the country. There are substantial biomass resources, making up more than 50% of the fuel mix, while the formerly prevailing use of gas and heating oil declined.

Regulation of the district heating sector belongs to the competition authority, which sets preliminary prices for both producers and suppliers[4]. The regulatory amendment of 2004 allows municipalities to define obligatory district heating areas, and most of them made use of this option.

According to the regulation the tariff setting methodology is cost based, the regulated price is the sum of the opex, capex and allowed return (RAB x WACC). The value of WACC is also set by the competition authority, in line with market interest rates, its current value is 7%. In addition to the monopolistic service areas established through the municipal definition of districts, preliminary price setting is also justified by the fact that most district heating companies (95% of them) are privately owned.

Because of the large work load of individual price setting, based on the new, 2014 regulation a national reference price is introduced. The calculation, based on the bottom-up LRIAC model and assuming a modern and efficient district heat producer and supplier is expected to result in a reference retail price of 5 €/MWh. District heating companies selling their service below the reference price are free to set their tariffs, independent of the regulation. For companies that would continue to sell their heat above the reference price, the individual price regulation will stay in place. District heating networks not in compliance with expectations on technological efficiency are obliged to make a development plan on how they wish to reduce network loss below 15% (by 2017).

In Estonia a 2010 amendment of the regulation introduced open access to the supply network for district heat generating companies. According to the amended regulation if a new participant wishes to supply heat to the district heating network, the supplier is obliged to issue a tender and to select the heat producer with the lowest cost, following an open competitive procedure. Numerous district heating suppliers have completed new contract procedures and successfully achieved lower heat prices.

Criteria for success in the regulation

In the third section of the workshop the conditions of the regulatory framework were discussed with the participation of prominent representatives of the sector: *Róbert Kubitsch*, head of department at the District Heating Price Regulation Main Department of MEKH, the regulator, *Attila Chikán*, CEO of ALTEO, *Csaba Fekete*, president of the Professional Association of Hungarian District Heat Suppliers, *Balázs Boko-*

[2] *heat networks*
[3] *equivalent to about HUF 4.2 billion*
[4] *Based on the new district heating regulation of 1998.*

rovics, president of the Board of Directors at PannErgy and *György Kasza*, head of department at the Climate Protection Projects Main Department of the Ministry of National Development. The discussion started with the keynote presentation of *Péter Kaderják*, director of the Regional Centre for Energy Policy Research.

I. One of the most important lessons of the round table discussion is that since competitive heat supply depends on cheap heat, the sector would be better off if district heating companies could allow the least cost district heat producer to enter the market. The waste heat of industrial facilities, geothermal and biomass fired heat producers, or even waste incineration could generate heat at 40-85% of the cost of gas boilers. Periodic tendering could become a good practice in this direction. At present, however, long term contracts limit the decision sphere of district heat suppliers (In Miskolc, for example, in case geothermal heat is used, the capacity fee falling on the unutilised heat generation of the gas boiler also has to be paid based on the present contract, amounting to 600-900 HUF/GJ.) According to the comments production makes up 70% of the costs of district heating, while distribution is responsible for 30% of expenditures, thus selecting a cost-efficient heat producer is essential.

   Investors, project organisers and financiers all expect long term predictability, contracts that last for 15-20 years, and it is imperative that all participants (regulator, producer, municipality, consumers) can commit themselves to the system.

II. The development of the *regulation on producer and consumer prices* plays a key role. Affordability for consumers and return guarantees preferred by investors could both be ensured by the introduction of a price cap type system of price regulation that would warrant predictability for a given renewable energy based district heating project. This regulatory framework is easy to plan and it can be combined with cost expectations based on technological benchmarks. The performance of producers that supply at a price below the regulated level (for instance those with higher capex, using more adventurous drilling technologies) could be exempted from regulatory control.

   If this is not feasible, a business model can also be based on annual price calculations as long as the basic principles are known. Within the sector the framework of the central price regulation introduced in 2011 was difficult to form and a lot of criticism has been voiced, but important steps have been taken to increase transparency. The MEKH contributed to the producer price calculation of several projects, sometimes in the form of preparing a preliminary price calculation.

III. In order to promote developments *it would be important for investors to be able to realise a WACC premium above currently allowed returns*, thereby stimulating the accomplishment of riskier renewable projects that require large investment costs, and the entry of the generated heat into gas based district heating networks that are occasionally still more competitive.

   The 4.5% gross return on assets allowed under the current system results in close to 7% of IRR5 on a 25 year time horizon, in principle only slightly below the level expected by sector investors. It seems worthwhile to continue discussions with respect to refining the limits on allowed returns, and several related proposals have been put forward:

   a) During the initial period following the completion of the investment prices should not be set annually, instead, there should be a 5-7 year period of frozen prices and any efficiency gains achieved by the producer during this time could be retained as profit.

   b) The 4.5% limit should apply to the total project cost including awarded support (such as KEHOP - the Environmental and Energy Efficiency Operative Programme).

   c) Increasing the transparency of the system, thus instead of setting prices for the long term, it becomes important to clarify the cost items that can be used toward annual price calculations, ensuring that producer prices would react to the larger fluctuations of the price of biomass within a five year period.

[5] *IRR: internal rate of return*

IV. The participants of the round table discussion were hopeful with regard to the use of our 2014-2020 EU development funds. *Compared to the previous period the funds available for district heating development will likely double to approximately HUF 43 billion.* Another HUF 20 billion of additional facilities will also be available for district heating investments in the form of non-refundable support and guarantees.

a) The previous practice that developers compile the projects based on the published criteria when the tenders are announced, needs to be changed. The soundness of the projects would be guaranteed for district heating companies, strategic investors as well as project contractors by a reverse order: designing and discussing a viable project that satisfies real consumer needs before the appropriate financing mix is assembled. Therefore the availability of tender facilities needs to be more predictable and reliable during the upcoming funding cycle. One of the difficulties in this field is that Hungary does not have an approved District Heating Action Plan, leaving room for uncertainty with respect to long term development plans.

b) Based on recent average subsidies (e.g. 0.8 PJ/HUF 2 billion geothermal district heat) it is clear that in addition to the HUF 43 billion available from EU funds additional financing sources will be required to meet renewable district heating targets.

V. On the regulatory side additional challenges are posed by the *unfavourable perception of district heat supply* (usually among those that do not use district heating) and the *continuously declining demand for heat*. Presently operating systems are not prepared for the impact of energy efficiency investments (building renovation can generate savings of up to 60%) and this will create severe problems. The need to expand the district heating consumer base is thus an unescapable piece of the future strategy.

VI. The participants of the roundtable emphasised that *providing the own contribution* is an important problem with respect to the investments. While funding sources are available and district heating companies wish to keep pace with modern technologies, the companies - often under municipal ownership and facing broad financing uncertainties - struggle to add their own contribution to foster the development.

VII. In addition to investment grants, support through a feed-in tariff that is proportional to the generated volume of heat could provide predictability and the stabilisation of cash flow for RES district heating projects. The current structure of operating subsidies - the almost HUF 10 billion paid from the Central Budget by MAVIR to compensate for the losses of district heat suppliers - is not a clever solution in the long run, but a premium like the British RHI support scheme would boost heat production based on solar, geothermal or biomass resources.

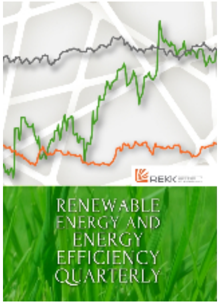
Modernisation of the sector, application of economic and environmentally friendly technologies would be important. This could be achieved through establishing the recommended regulatory framework conditions.

The presentations of the workshop are available at the webpage of REKK: www.rekk.eu

Further research results: REKK (2014): Renewable Based District Heating in Europe – a policy assessment of selected Member States (draft version)

Renewable Energy and Energy Efficiency Quarterly

REKK launches a Renewable Energy and Energy Efficiency Quarterly electronic newsletter to provide timely and concise information on the development of renewable energy markets and energy efficiency policy developments in Hungary and in Europe.



From the contents of the 1st issue:

Focus

- Implementation Of The EED

Development Of Technology And Fuel Prices

- PV Panel Prices In Hungary
- Biomass Price Developments

Hungarian Regulatory Panorama

- Changes In Legislation
- Changes In Renewable Capacities Based On MEKH Resolutions
- More Renewable Quotas For Mátra, 15 MWe PV Capacities
- No Considerable Withdrawals
- Hamburger Hungária To Commission A 42 MW RES Co-Firing Unit
- Negligible New Waste And Biogas To The Grid
- Geothermal Consessions

EU Regulation

- 2030 Climate and Energy Policy Framework - Final Decision Expected In October
- Communication On Energy Efficiency And Its Contribution To Energy Security And The 2030 Framework For Climate And Energy Policy
- Results Of The Second Call Of NER300

Monitoring Of Investment Support Options

- EU Funding For Renewable Energy And Energy Efficiency In The 2014-2020 Period
- Investment Support: EEA And Norway Grants For Geothermal District Heating

From the contents of the 2nd issue:

Focus

- The Hungarian Strategy On The Energy Use Of Building

Development Of Technology Prices

- Estimated Levelized Cost Of Electricity

Hungarian RES-E Regulatory And Market Panorama

- Yearly Development Of RES-E Generation In Hungary
- Monthly Development Of RES-E Generation In Hungary
- Changes In Legislation
- Changes In Renewable Capacities Based On MEKH Resolutions
- Prospective Wind Producers Sue the State
- Few Renewable Power Plants Are To Connect to The Grid
- Geothermal Concessions

EU Regulation

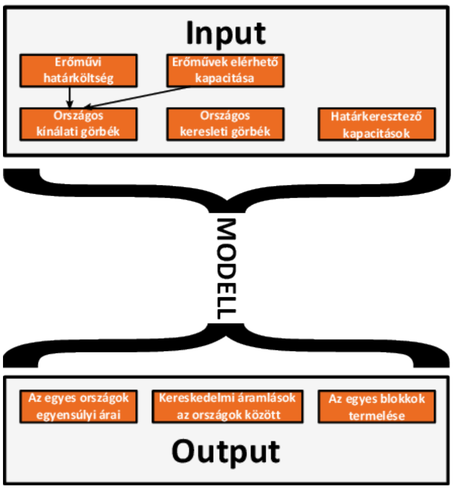
- Delayed Energy Efficiency Directive
- Long-awaited Deal On The EU's 2030 Energy And Climate Goals

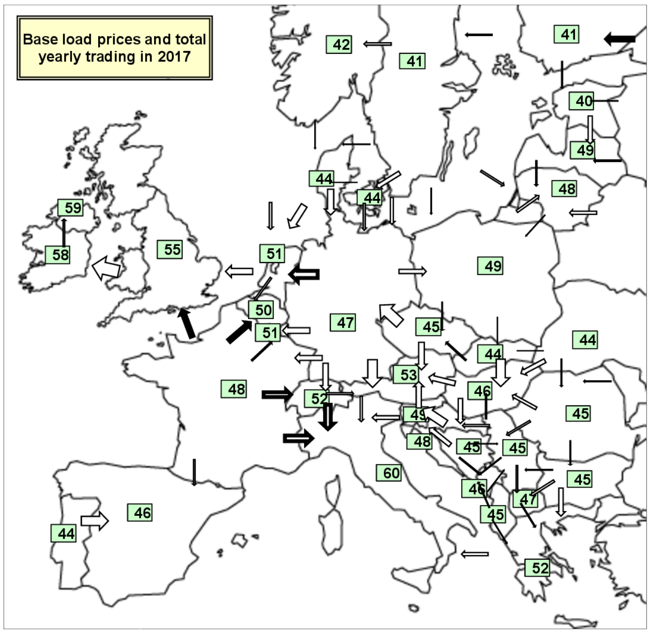
Monitoring of Investment Support Options

- RES and EE Grants In The Hungarian Operative Programmes 2014-2020
- Support For The Residential Sector

EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

EEMM is the electricity market model of REKK developed since 2006 modelling 35 countries





ASSUMPTIONS

- Perfect competitive market
- The model calculates the marginal cost of nearly 5000 power plant units and the unique merit order for each country
- 12 unique technologies
- Includes future power plant developments
- Takes 85 interconnectors into account
- Models 90 reference hours for each year. By appropriate weighting of the reference hours, the model calculates the price of standard products (base and peak)

USAGE

- Provides competitive price signal for the modelled region
- Facilitates the better understanding of the connection between prices and fundaments. We can analyse the effect of fuels prices, interconnector shortages, etc. on price
- Gives price forecast up to 2030: utilizing a database of planned decommissionings and commissionings
- Allows analysing the effects of public policy interventions
- Trade constraints
- Assessment of interconnector capacity building

RESULTS

- Base and peakload power prices in the modelled countries
- Fuels mix
- Power plant generation on unit level
- Import and export flows
- Cross-border capacity prices

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Evaluating the TYNDP of ENTSO-E
- Assessing the effects of the German nuclear decommissioning
- Analysing the connection between Balcans and Hungarian power price
- Forecasting prices for Easterns and Southeast-European countries
- National Energy Strategy 2030
- Assessment of CHP investment
- Forecasting power plant gas demand
- Forecasting power sector CO_2 emmissions

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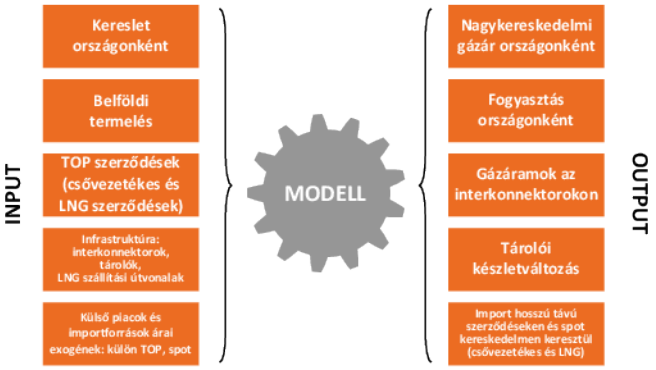
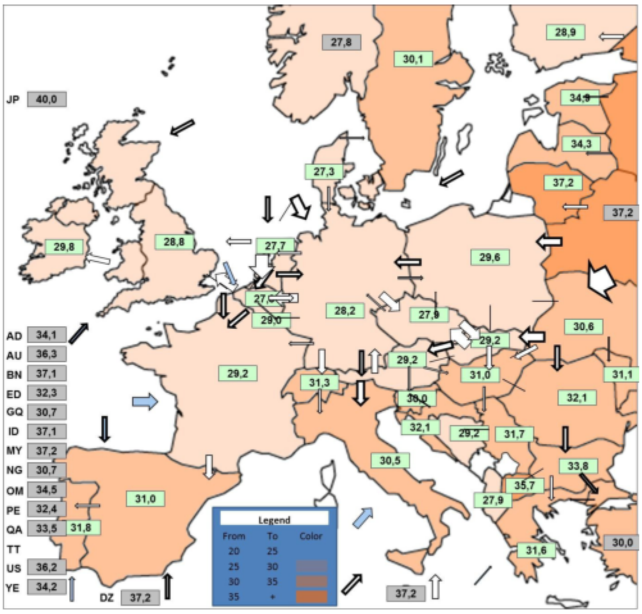
EUROPEAN GAS MARKET MODEL (EGMM)

EGMM is the natural gas market model of REKK developed since 2010 modelling 35 countries





ASSUMPTIONS

- Perfect competitive market
- Modelling period of one year (12 months)
- LTC and spot trade in the modelled countries, pipeline and LNG suppliers
- Physical constraints are interconnection capacities
- Trade constraints: TOP obligation
- Model includes domestic proiduction and storages
- Model calculates with transmission nd storage fees

USAGE

- Provides benchmark prices for the region
- Facilitates the better understanding of the connection between prices and fundaments. Eg. LTC market changes or storage changes.
- Price forecasts
- Allows analysing the effects of public policy interventions
- Analysing trade constraints
- Assessing effects of interconnector capacity expansion
- Security of supply scenario analysis

RESULTS

- Gas flows and congestion on interconnectors
- Equilibrium prices for all countries
- Source composition
- Storage levels, LTC flows and spot trade
- Welfare indices

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Effects of the Ukrainian gas crisis
- Welfare effects of infrastructure investments (TAP)
- Regional security of supply scenarios and N-1 assessments
- National Energy Strategy 2030
- Regional storage market demand forecast

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