REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q3 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

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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

Consultancy

- 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,

In our autumn report, we first examine the decrease in European natural gas prices that has taken place in the last six months. Following the introduction of the background to the developments on the Western hubs, we provide an account of the probable future price changes in the second half of the decade. The aim of our report is not to predict the future prices, but to direct attention to those factors that will likely influence future price changes, and can therefore have a serious influence on the profitability of gas power plants.

Our second article covers a perennial topic: the high price level that has characterised the domestic electricity market for close to a decade now and consistently surpasses regional prices. Since the opening of the market, the debate on what leads to these higher prices on the domestic electricity market periodically resurfaces. Explanations to date ranged from citing the dubious practices of the companies and electricity traders that have a dominant position on the domestic market and can exploit imperfections in regulation, to the price-inflating effects of the Balkan droughts. Our journal has published analysis on the prices of the domestic electricity market a number of times. This time, we would like to contribute to the conversation with our results from examining data from recent years using traditional methodological tools.

Our third article highlights this year's milestones in the European electricity market integration process. The day-ahead coupling, which has been steadily progressing in recent years, resulted in significant price-convergence on the power exchanges of the participating countries. Following the market coupling of the North Western European power exchanges in February, the countries of the Iberian Peninsula also joined the European market coupling, and therefore today there are 17 countries participating in the project. This process, parallel to but evolving separately from the Czech-Slovakian-Hungarian market coupling process, has a major dampening effect on the domestic electricity market's typically high prices. In our article, we summarise and evaluate the recent developments of the European market coupling, and the opportunities for the future integration of the domestic electricity market.

In the last article of our report, we examine the price regulatory and subsidy conditions for the proliferation of renewable energy based district-heating production. Promoting heating production that is based on biomass and geothermal energy and increasing the share of district-heating production constitute an important pillar of the domestic energy policy. However, the current domestic regulatory environment does not drive and in some cases actually inhibits the realisation of necessary investments. Our commentary examines the reasons of and potential solutions for this problem.

Peter Kaderjak, director

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Energy market developments

In Q2 of 2014 there were only minor changes in the crude oil and coal prices, however the price difference between the two has further increased. In terms of internationally significant natural gas prices, we saw that while the spot price of the imported Japanese LNG, which is effectively a reference price in Asia, and the American Henry Hub barely changed, the Dutch TTF hub day-ahead price continued the decline that was observed in the previous quarter, and in the first half of the year lost 10 €/MWh or almost 40% of its value. Due to the decline of the natural gas futures price and the stagnating German day-ahead electricity price, a significant improvement could be observed in clean spark spread (the difference between the electricity and coal prices), demonstrating the profitability of natural gas power plants.

The domestic electricity consumption of 9.5 TWh shows a slight decrease in comparison to Q1, while the import share has set new records as it constituted 43% of the average quarterly consumption. The Hungarian day-ahead price of baseload power remains the highest in the region, and in Q2 the price of the HUPX broke away again from the German, Czech and Slovakian prices. At the same time, we observed that the metered prices of the connected Hungarian, Slovakian, and Czech power exchanges diverged from each other in comparison to the previous quarter: while in Q1 the Hungarian and Slovakian prices equalized in almost three quarters of the hours, in Q2 this was only true for less than half of the hours.

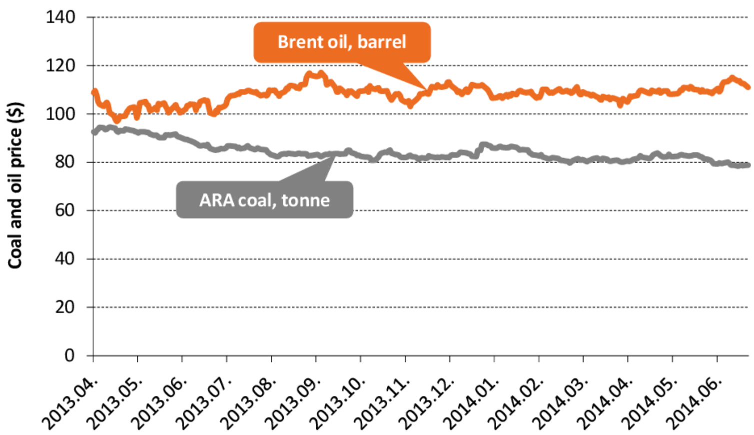
In Q2, Hungarian natural gas consumption only lagged behind the consumption in Q2 of 2013 by 6%, however this is almost entirely attributable to the mild April weather. Between January and March, domestic natural gas production decreased from 614 million m^3 in the previous quarter to 560 million m^3. Meanwhile, Hungary imported 2.66 billion m^3, 63% of which was from Ukraine and 37% of which was from Austria. The utilization of the Hungarian storage capacities remains low in a regional context, with only 18% of the commercial storage capacities utilized by the end of June 2014.

International price trends

In Q1 of 2014, the difference between the prices of the two main energy carriers, oil and coal increased due to the fall in coal price and the rise in oil price in June. In Q1, the price of Brent crude oil per barrel fluctuated between 103 $ and 115 $, and closed the quarter at 111 $, which was 5 $ higher than in the previous quarter. Meanwhile, the price of EEX-traded ARA coal futures moderately increased between early April and mid-May, then more noticeably decreased from 83 $ to 79 $ in less than a month, a level that remained constant until the end of the quarter (*Figure 1*).

Figure 2 shows the price changes of several significant natural gas markets. Compared to Q1, from the four selected prices only the price of the Dutch TTF hub spot showed a significant change by June 2014: the Dutch prices decreased from 22.9 €/MWh at the end of March by 5.5 € to 17.4 €/MWh – at the same time, compared to the end of 2013 the total decrease in the price of TTF was more than 10 €/MWh. This notable drop is mostly due to the unusually mild European weather during the first half of the year, and due to the fact that the production of hydropower, wind power, and solar energy were average or above average during the first six months of the year.

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



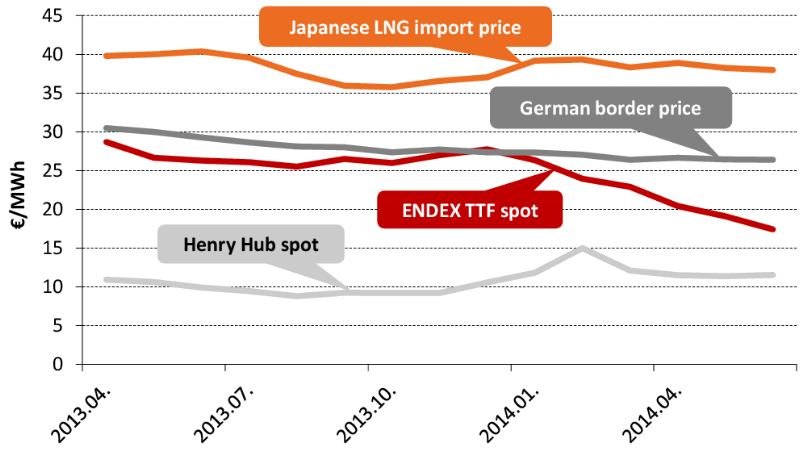
Source: EEX, IEA

In the Asian region, the average price of the Japanese-imported LNG slightly decreased in comparison to the 38.33 €/MWh value of the previous quarter, and closed the quarter at 37.98 €/MWh, while the spot price of the North American baseline Henry Hub decreased from 12.10 €/MWh (4.9 $/MMBtu) to 11.52 €/MWh (4.59 $/MMBtu) in the April-to-June period (during the quarter, Japanese yen and the American dollar both slightly gained on the euro). Meanwhile, in Germany the price of the Russian gas imported under the long-term contracts was stable, the 26.41 €/MWh price level was only 0.02 € higher than the March price.

The previously observed decrease in the German futures prices did not continue in Q2: the baseload price effectively remained constant in comparison to the 34.27 €/MWh value at the end of March, closing the quarter at 34.52 €/MWh, the price of peak load electricity slightly decreased from 43.92 €/MWh to 43.38 €/MWh. The price of emission rights (EUA) with a December 2014 expiry increased by 1 €, and these rights were traded for almost 6 €/ton at the end of the quarter (*Figure 3*).

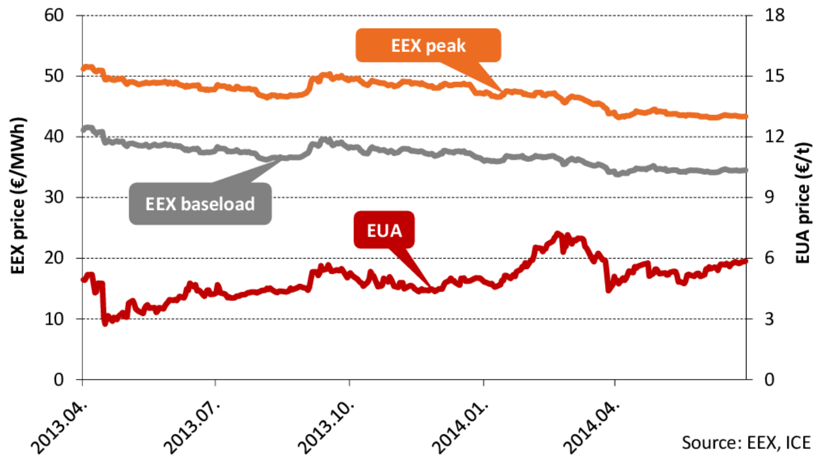
The commercial return on production at gas and coal power plants can be examined through two price-differences: with clean spark spread for gas power plants and with clean dark spread for coal power plants. Both indicators show the difference between electricity exchange prices and the costs incurred at the producing power plant, where the production cost is the total of the cost of gas (spark spread) or coal (dark spread) necessary for the production of one MWh electricity and the cost of the omission rights used for off-setting the CO_2 emission incurred for the same amount of electricity production. *Figure 4* shows the monthly averages of the above mentioned indicators for the German EEX baseload spot price, based on the Dutch TTF hub spot gas price and the ARA coal futures price. The clean dark spread showing coal power plant profitability stopped decreasing in Q2 of 2014, remaining slightly below 11 €/MWh. The changes in clean spark spread are much more interesting: the previously strongly negative value gradually balanced out with the significant decrease in the TTF gas price, and in June it was a positive value on an increasing number of trading days, its monthly average was –1 €/MWh. This balancing out means that the operation of gas power plants is increasingly profitable due to low European gas prices.

Figure 2 **Internationally significant natural gas prices from April 2013 to June 2014**



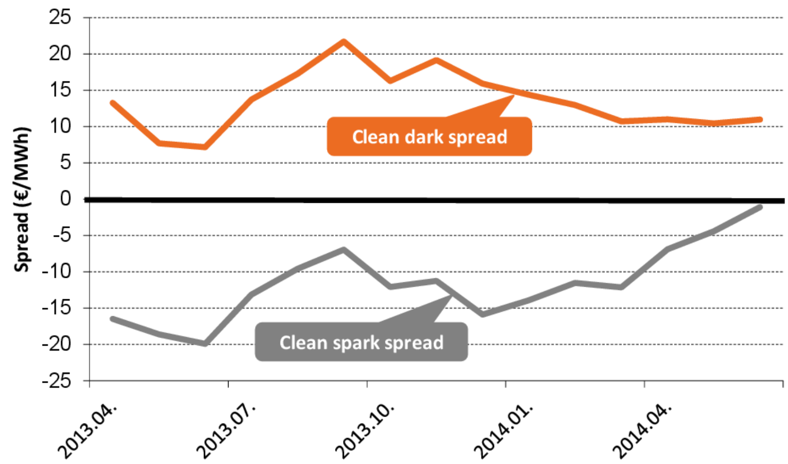
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 **Changes in the annual futures price of the EEX electricity and the futures price of CO2 quota with a December deadline between April 2013 and June 2014**



Source: EEX, ICE

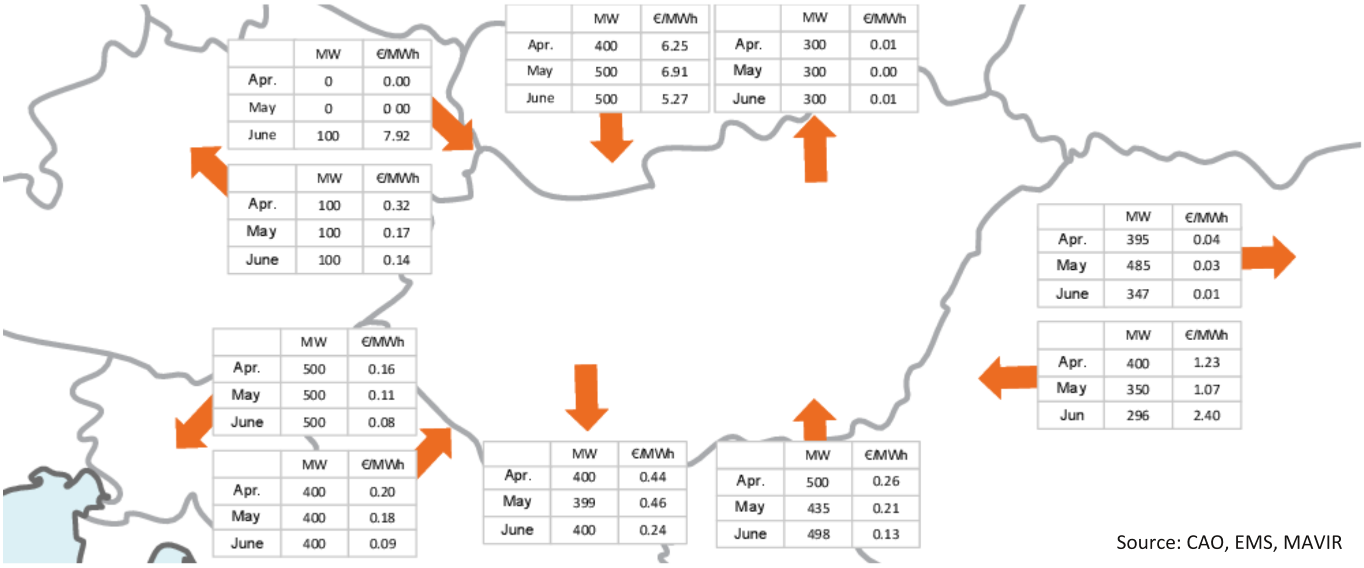
Figure 4 **Clean spark spread (gas-fired power plants) and clean dark spread (coal-fired power plants) on the German market between April 2013 and June 2014**



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

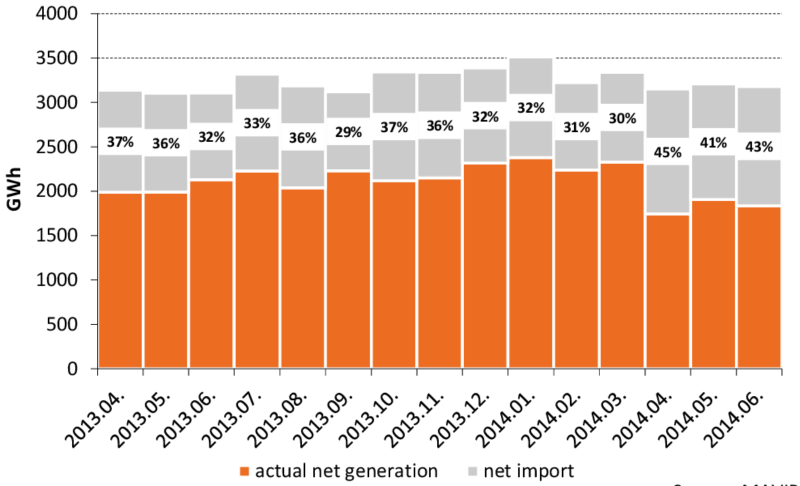
Note: In our calculations, we assumed a 50% efficiency for gas power plants and a 38% efficiency for coal power plants.

Figure 5 **The results of monthly cross-border capacity auctions in Hungary, Q2 2014**



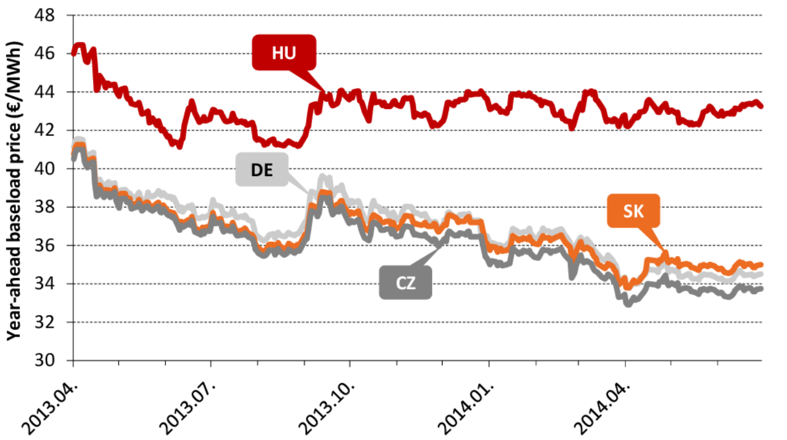
Source: CAO, EMS, MAVIR

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



Source: MAVIR

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



Source: EEX, HUPX, OTE

Overview of the domestic electricity market

At the monthly cross-border auctions in Q2 (*Figure 5*), the price of the Slovakian import-capacity fluctuated between 5-to-7 €/MWh, while the price of the Romanian import-capacity was slightly over 1 €/MWh in April and May, and it was over 2 €/MWh in June. During April and May, similarly to the previous quarter, no import-capacity right was distributed from Austria through monthly auction due to the daily distribution of capacities. However, an auction did take place for June, where the price of the capacity was 7.9 €/MWh. The price of the import-capacity at the rest of the borders did not reach 1 €/MWh in either month.

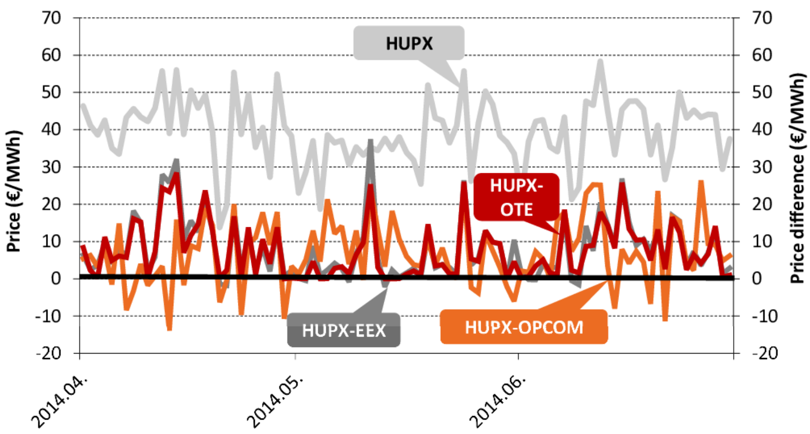
In Q2, the electricity consumption (*Figure 6*) was 9.54 TWh, which was a slight increase of 2% compared to 9.35 TWh in the previous year. At the same time, while in April the average annual consumption only increased by 0.3%, this value was 3.4% in May and 2.3% in June. The difference between the trading prices of the domestic plants and the import-sources has increased since the spring of 2012, therefore in the last two years the imported amount constituted an increasing share of the domestic consumption: following the 18-20% level that was prevalent in early 2013, the import was over 30% in all but one month. In Q2 of 2014 the average share of the import significantly grew again: during the quarter the average share was 43% (4.1 TWh).

After a minor decrease, the price of the 2015 baseload futures (*Figure 7*) stagnated in Q2 on the German, Slovakian, and Czech markets, compared to the end of March level, however this meant a 1-1.5 € decrease on all markets in comparison to the average of the previous quarter. While the prices of the three cited markets move closely to each other, the Hungarian futures prices continued to move separately from these, and further moved away from the other markets. Compared to Q1, the quarterly average of the Hungarian futures prices was unchanged at 43 €/MWh, however this meant that while in Q1 the Hungarian prices were above the German EEX futures prices by an average of 7.1 €, by Q2 of 2014 this difference grew to 8.5 €. Following the 1 €/MWh in the previous two quarters, the Czech prices only showed a 0.77 €/MWh discount in comparison to the German market, while the Slovakian prices, unlike the previous 12 months, surpassed the German price level.

Figure 8 shows the day-ahead baseload price of the HUPX, and the HUPX price differences from the three other power exchanges (the German EEX, the Czech OTE, and the Romanian OPCOM) for Q2 of 2014. The Hungarian day-ahead electricity prices surpassed the German and Czech market price levels on almost all days of Q2, and tended to be more expensive than the Romanian market. The unplanned suspension of some of the Matra Power Plant blocks temporarily increased the HUPX prices in April and June, and in May the suspension of the Serbian power plants due to the floods increased the Hungarian prices, since there was a supply shortage on the Balkan markets. While in Q1 of 2014 the HUPX prices on average surpassed the average of the other three power exchange prices by 3.9 €, in Q2 the average price difference rose to 7.5 €.

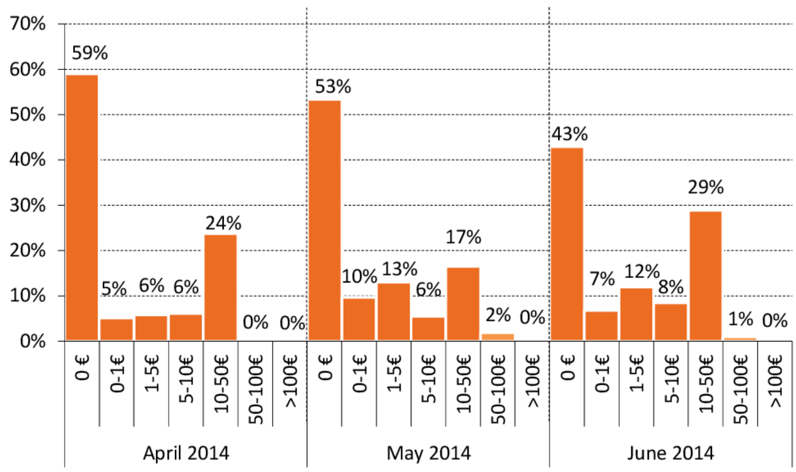
We examine the effect of the day-ahead market coupling through metered price differences at the Hungarian and Slovakian power exchanges. *Figure 9* shows

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



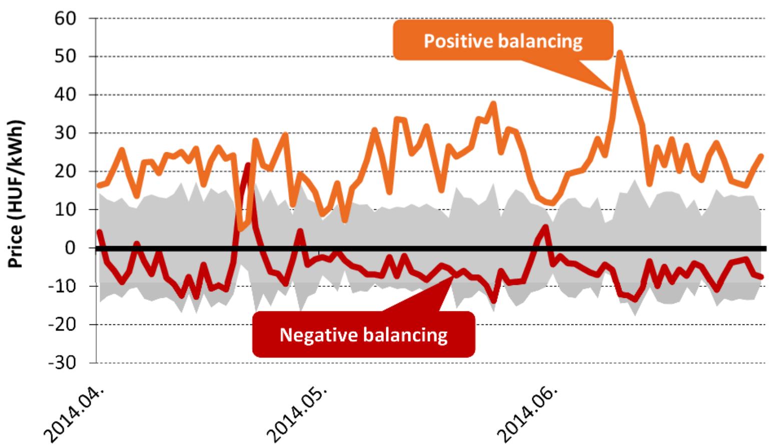
Source: EEX, OPCOM, OTE, HUPX

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



Source: REKK calculation based on OTE data

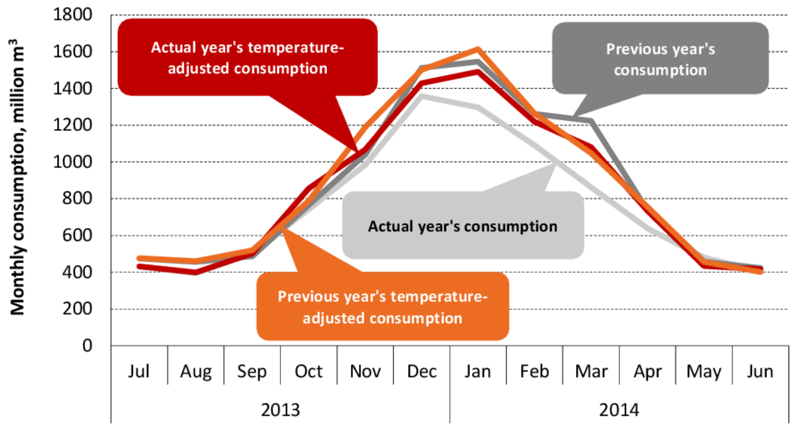
Figure 10 **The daily averages of the balancing energy and HUPX spot price in Q2 of 2014**



Source: MAVIR, HUPX

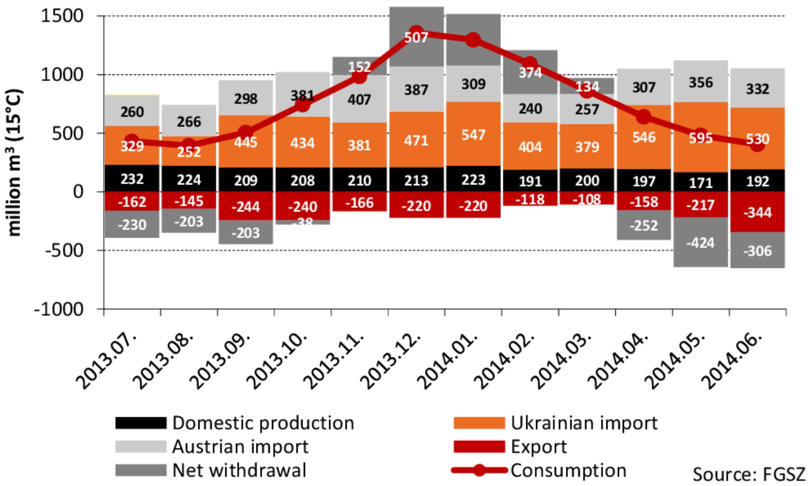
Note: In this figure, the top border of the grey area is determined by the HUPX day-ahead price, and the bottom border is determined by minus one times the HUPX price. In accordance with the MAVIR Trading Rules, the HUPX day-ahead price determines the lowest positive balancing energy price, while minus 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 July 2013 and June 2014, compared to the corresponding monthly consumption figures of the previous year**



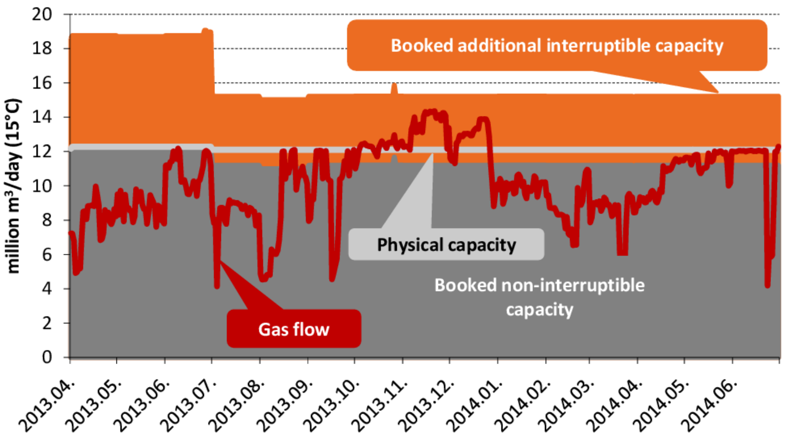
Source: FGSZ, European Climate Assessment & Dataset, and REKK calculations

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



Source: FGSZ

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



Source: FGSZ

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

how often and in what percentage of the meters that the Hungarian and Slovakian prices match and break away from each other in the April-June period. It can be seen that the prices were the same in 59% of the meters in April, in 53% of the meters in May, and in 43% of the meters in June – the June figure in particular is significantly lower than the previous quarter's numbers. It is important to note that in June almost three quarters of the metered prices surpassed the Slovakian futures by at least 10 €. The Slovakian prices did not surpass the Hungarian prices at any hour during the quarter, but were often higher than the Czech prices, as opposed to the previous quarter, the frequent divergence of the two markets is especially evident during April.

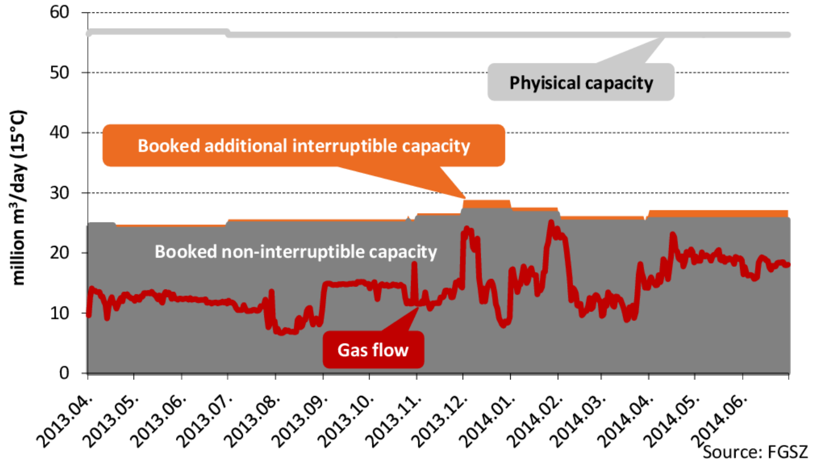
The wholesale price is influenced by the cost of departing from the timetable and by the balancing energy price. The system operator sets the accounted unit price of the balancing energy purchase based on the energy prices of the utilized capacities used for the balancing. The order of utilization is created in line with the energy prices offered on the day-ahead balancing market. The MAVIR created the accounting system for balancing energy in such a way so as to motivate the market participants to deal with the foreseeable shortage or surplus through power exchange transactions – so that off-setting foreseeable demand by purchasing on the balancing energy market and trading foreseeable surplus would not be profitable. To achieve this, the price of the upward balancing energy cannot be lower than the HUPX price applicable for the corresponding period, and when purchasing the downward balancing energy, the system operator does not pay more than the futures price. In Q2 the price of the positive balancing energy was an average of 22.7 HUF/kWh, which surpassed the previous quarter's 18.1 HUF/kWh, while the price of the negative balancing energy was -5.2 HUF/kWh, which means no significant departure from the -5.1 HUF/kWh figure of the previous quarter (*Figure 10*).

Overview of the domestic natural gas market

Figure 11 shows the actual natural gas consumption for each month and the corresponding consumptions for the months of the previous year. The figure also shows the heating demand adjusted consumption, which depends on the daily mean temperature. We can also see that April was the only month in Q2 of 2014 when the natural gas consumption was noticeably below, by 100 million cubic meters, the previous year's corresponding consumption, however this can mostly be explained by the April weather that was milder than in the previous year. During May and June the unadjusted and temperature-adjusted consumptions were not significantly different from the corresponding monthly figures of 2013.

The Q2 figure of domestic natural gas production was lower at 560 million m^3 than the 614 million m^3 of the previous quarter. The import was 2.66 billion m^3, while the export was 0.72 billion m^3, therefore the net import was 1.95 billion m^3: this means a 15% increase in comparison to the previous quarter. 62.7% of the import arrived from the Beregdaróc (Ukraine) entry point and 37.3% arrived from the Mosonmagyaróvár (Austria) entry point (*Figure 12*).

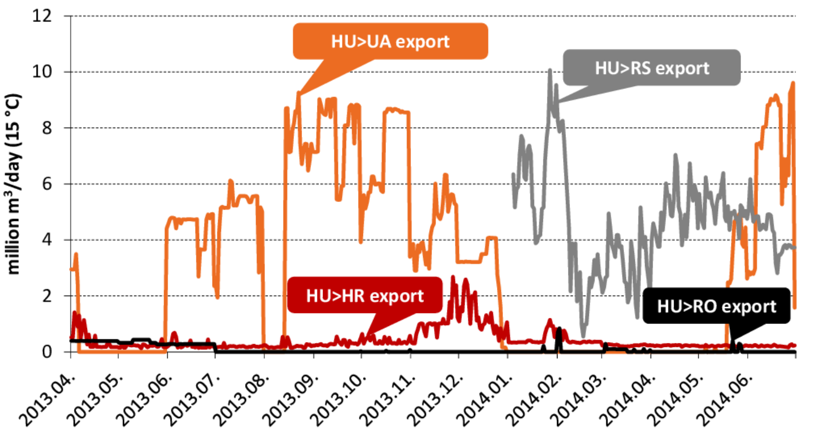
Figure 14 **Natural gas volume at the Beregdaróc (Ukrainian) feed-in point from April 2013 to June 2014, alongside contracted firm capacity and interruptible capacity**



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 April 2013 and June 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.

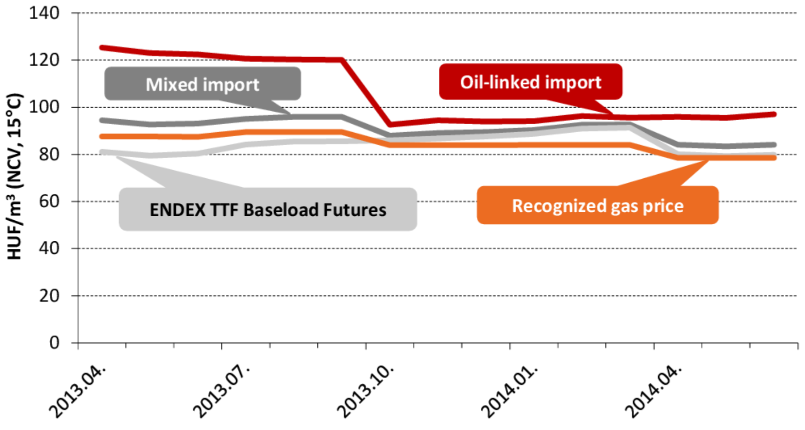
At the end of June in Hungary, the use of commercial natural gas storages owned by the Hungarian Gas Storage Ltd was 17.8%, while this value was 75.1% for the strategic storage at Szőreg, this meant a 35.44% utilization in terms of the total storage average. Also based on data from the end of June, storage facilities were used at 68% in Austria, 76% in the Czech Republic, 74% in Poland, and 76% in Germany – therefore, utilization of the Hungarian storage facilities remains significantly lower than in the rest of the region.

In Q2, 994 million m^3 natural gas arrived from the direction of Mosonmagyaróvár (*Figure 13*), which surpassed the previous quarter's value by 23%, however it was 20% lower than the value recorded in Q2 of 2013. During the quarter, 90% of the physical capacity was utilized at the entry point, and 72% of the total contracted capacity was utilized. At the monthly import capacity auctions for the Mosonmagyaróvár point 41.9 million MJ/day capacity was offered in each month of the quarter, and all three auctions proved to be unsuccessful: according to the FGSZ, the auctions closed with 25% underbidding in all three cases.

In Q2, a total of 1.67 billion m^3 natural gas was imported on the Ukrainian border (*Figure 14*), which means that the amount of natural gas that arrived to Hungary from Beregdaróc was 48% higher than in Q2 of 2013. The physical capacity utilization significantly increased but was still only 33%, while 68% of the total contracted capacity was used.

Figure 15 shows the volumes of natural gas exported by Hungary to Ukraine, Croatia, Romania, and Serbia. The total exported volume to these four countries between April and June 2014 was 718 million m^3, which surpassed the 425 million m^3 value of the previous quarter, and is due to the fact that, according to the FGSZ, shipments to Ukraine were re-started in May 2014. 61% of the total export was directed to Serbia, 36.1% to Ukraine, 2.8% to Croatia, and 0.1% to Romania.

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



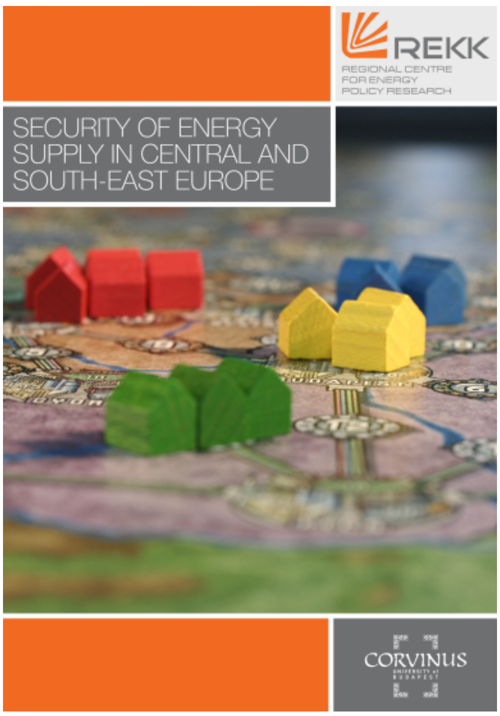
Source: REKK calculations based on EIA and ENDEX data

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 that the oil-indexed price slightly increased in Q2 of 2014 in comparison to the previous quarter, the average for April to June was 96.2 HUF/m^3. At the same time, the weighted import price, consisting of 75% TTF futures price and 25% oil-indexed price and recognized for universal service providers, significantly decreased and dropped from 84 HUF/m^3 in Q1 to 78.5 HUF/m^3 in Q2. This is mostly due to the strong decline of the TTF futures price: as a result of the Dutch hub price the difference increased between the TTF futures price and the oil-indexed import price in Q2. It is also clear that applying the foreign exchange rate set by decree for the calculation of the recognized natural gas price – currently 280.3 HUF to 1 € and 220 HUF to 1 $ – continues to underestimate the source costs (the price of 'mixed import'), in Q2 this calculation method resulted in a recognized price that was on average 5.3 HUF/m^3 lower than the actual import price.

[1] *From 1 April 2014, the basis of the calculation changed from the previous 70% TTF futures and 30% oil-indexed price to 75%TTF futures and 25% oil-indexed price.*

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.

Natural gas prices in Europe: what does the summer price drop allow?

Western European spot markets suffered rarely experienced price drop during the spring of 2014: NBP, the trend setting exchange platform for continental markets, have seen a price decrease of 40% within just a few months. As a consequence the profitability of British gas fired power plants significantly increased: in December last year the profitability index of coal fired power plants, the clean dark spread, was 33 €/MWh above the profitability index (clean spark spread) of the natural gas fired power plants, meanwhile the enormous competitive advantage diminished to 5 €/MWh by July this summer. How long can this decreasing trend go on at the continental markets and what does it allow? Is it sufficient to save the natural gas fired power plants from economic contraction and turn their operations into a profitable enterprise again?

Background of the spring price drop

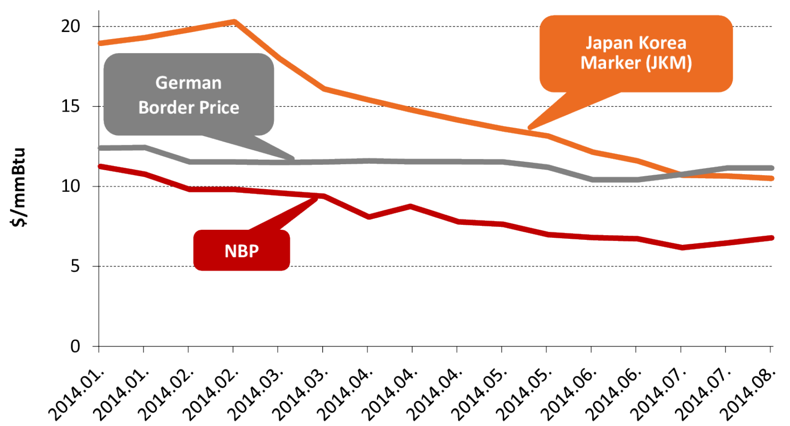
At first, market participants explained the phenomena of unprecedentedly low natural gas prices at the Western European markets with the mild European winter and the drop in seasonal consumption that has been stagnating for years. However, the seemingly simple connection between the demand and the prices at the European natural gas markets is far more complex: during the recent years of low-growth economy (between 2010 and 2013) the European natural gas consumption fell by 15%, but the spot prices of natural gas increased almost by 50% during the same period. Thus, the recent past shows that gas prices at the TTF are heavily influenced by other factors as well.

The price trends of the European natural gas markets have been strongly connected to international LNG markets and Asian natural gas demand. In recent years the price increase on the European markets was triggered by a huge Asian demand and high Asian prices. The unprecedented drop in demand on the Asian markets this spring and the noticeable price spread on these markets could explain the spring price decrease. The above average (warmer) weather conditions and the launch of the new Papua New Guinean LNG Terminal boosted supplies, as a consequence Japanese and Korean energy consumers cut their Qatari purchases by 26% and 20% accordingly. The JKM (Japan-Korean-Marker), Platts listed price index of Asian natural gas spot prices, showed a 50% drop between March and August, which thus reached its lowest point in the last three years.

For the above mentioned reasons the flexible (not long term contracted) LNG shipments were diverted to Europe from the congested Asian markets: NBP is an obvious target for LNG shipments that are searching for new markets as it offers high liquidity and is capable of receiving the largest tankers in its ports. Within the last three years, European LNG imports contracted drastically (by more than 50%) due to the robust demand on the Asian markets and, contrary to this, between April and July the British terminals received almost 20% more LNG cargo compared to the previous year.

These diverted LNG deliveries to the British market coupled with a low seasonal demand caused a 37% drop in prices on the NBP. The price decrease on the British market was matched by the continental markets (TTF, NGC), leading to a 32-36% price drop, however it only moderately affected the profitability of European natural gas fired power plants, compared to Britain. The fragile power plant capacity balance on the British market and the applied carbon price thresholds (if there are low quota prices, British power plants are charged with an auxiliary carbon tax) provide a significantly more beneficial market environment for British CCGTs, in contrast to their European counterparts.

Figure 17 **European monthly and Asian spot LNG natural gas prices in 2014**



Source: Platts

There are no signs of fuel switch on the continental electricity markets, or improvement in expectations. The price drop on the TTF enabled a temporary profitability of natural gas power plants on the Belgian and Dutch markets, whereas on the German market it could only reduce the losses of the CCGT fleet. There are no signs of change, which is signalled by the Verbund's announcement in May to temporarily stop the operations of additional CCGT plants.

Most of the industrial stakeholders reckon that the current situation and the spring price drop is temporal, caused by a mild winter and by an interplay of beneficial circumstances. It is expected that in the near future the prices will restructure (a return to their previous levels). TTF forward price shows a slight 10% easing; the price spread calculated on 2015 futures price is massively negative.

Modelling results

The spring natural price drop can be accredited to seasonal demand decrease and the realisation of a price gap in the Asian markets. In the light of this correlation, is it possible to assess the price changes of the European prices, taking into account a different demand decrease or Asian price changes? Is the correlation between European and Asian markets as strong as the explanations of this spring events suggest? Next, we will examine the effects of European natural gas demand changes and Asian natural gas price drops on the European natural gas wholesale prices with the REKK-developed European Natural Gas Model (EGMM).

The EGMM simulates the wholesale market of 35 European countries: it determines the market clearing prices, assuming perfectly competitive markets and taking into the account each country's demand, supply and storage volumes, the physical infrastructure and the contractual limits. These equilibrium prices, provided by the model, are wholesale marginal prices that reflect the price of the most expensive source necessary for covering the determined demand.

Compared to the reference scenario[1], we examined the effects of a 5-15% decrease in European gas demand and the effects of a 10-40% Japanese price decrease on the Western European wholesale gas prices. For reasons of convenience the European prices were identified with the German prices. The relevance of Japanese price – which is the benchmark of Asian prices in the model – is that its level influences the amounts of LNG that are diverted to the European markets, thus it can significantly influence the European prices.

Table 1 shows the effects of a drop in European natural gas demand and Japanese price decrease on German prices. The modelling results suggest that natural gas prices not only react flexibly to the demand decrease, but also to Japanese price level changes. When these two factors occur at the same time, they unlash a significant price change: a 10% drop in European natural gas demand and a 20% decrease in Japanese price trigger a 30% price drop in German prices. Identical effects can be observed on other European markets as well.

Similar effects can be observed at the Eastern European markets, where the decrease in demand and a drop in Japanese prices result in a smaller price decrease. For example, the above discussed 10% demand and 20% Japanese price decrease, only leads to a 20% decrease for Hungarian prices. This is not surprising in light of the fact that these (Eastern European) countries have a significant dependence on Russian gas, thus, these are less flexible in terms of absorbing whole-sale price drops, demand decrease, and international price fluctuations.

Long term perspectives

The markets expect prices to stabilize at their previous levels and in the near future the European natural gas fired power plants still will not be able to pull out from the economic crisis they have been struggling with for years. Coal prices world-wide are at a significant low and for many years to come the European natural gas demand will not return to their higher levels prior to the economic depression. No sudden change is expected in 2015 or in the years to come.

Table 1 **Effects of the European demand and Japanese price decrease on the German wholesale natural gas prices**

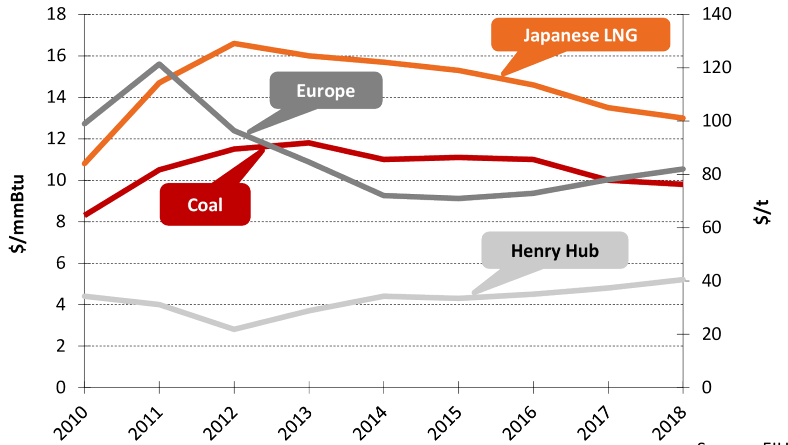
		Japanese Price Assumption				
		Reference	-10%	-20%	-30%	-40%
Demand Assumption	Reference		-7%	-16%	-27%	-38%
	-5%	-10%	-13%	-23%	-35%	-45%
	-10%	-13%	-13%	-30%	-41%	-51%
	-15%	-39%	-39%	-39%	-48%	-59%

Source: REKK modelling

[1] *The reference scenario contains data of demand and the infrastructure of 2014.*

However, these discussions on the market are quite narrow. Many interpret the European natural gas prices in the context of European economic development, continental demand, and coal prices. The aspects of LNG market developments, expected periods of supply waves, the unravelling of Asian price setting mechanism changes, and demand uncertainties, as well as the expected changes in the second half of the decade are rarely discussed.

Figure 18 **Expected developments of natural gas prices up to 2018**



Source: EIU

The future of European natural gas prices in a 3-5 years period are not as strictly determined, as the comments on spring changes suggest. The medium term forecasts, despite the stagnating demand, forecast a noticeable 10% decrease in European prices from 2017 onwards. In the case of coal prices, however, a gradual increase (of 16% until 2018) is expected that can shrink the overwhelming competitive advantage of coal fired power plants.

The trigger of the forecasted price decrease in the second half of the decade is the new LNG capacities under construction and LNG projects with final investment decisions (FID) that will come online and provide significant export capacities and supply on the LNG markets after 2017. A leading figure of this investment boom is Australia, where seven terminals are under construction, these will provide an additional 80 billion m^3 for annual export capacities.

The highly likely LNG supply increase itself would not cause a price drop if it is not coupled with Asian market demand contraction. The LNG demand growth of the region's large natural gas consumers are assured by several factors. The installed capacity of the Japanese CCGT power plants are limited, the planned restart of the nuclear power plants and the strong diversification intentions of electricity supply can limit the increase of additional LNG demand. China, the other relevant Asian consumer, intends to increase the role natural gas plays in its energy mix and its natural gas consumption is increasing rapidly (IEA forecasts a 90% increase by the end of the decade), nevertheless the boosting of unconventional production and Russian imports will somewhat limit further increase in LNG demand.

Besides the limits of Asian demand growth, there is also a pricing factor that supports the decrease (assumed at 15-20%) in the regional natural gas prices. The large Asian consumers, particularly India and Japan, are more and more unsatisfied with the current oil indexed price mechanism that sets extraordinary high natural gas prices. Therefore, large consumers in the region became shareholders in several North American shale gas and LNG investment projects: around one third of the LNG export terminal capacities coming online between 2017-2020 are financed by Japanese, Indian and South-Korean companies. The aim of these investments is to secure import sources that offer favourable market pricing to the affected consumers. A frequently quoted example in favour of this claim is the long term contract between the Indian GAIL and the Sabine Pass terminal that is settled solely on prices indexed to Henry Hub prices.

The easing of import demand (and the penetration of market pricing) in the Asian region, coupled with a supply boost through the wave of new LNG terminals will further decrease the previously seen unusually high price levels. Easily re-routable LNG capacities not bound with long term contracts will appear again on European markets that can support a price level decrease at the continental spot markets.

Mid-term expectations face serious uncertainties, mainly from the demand side. If the ambitious Chinese shale gas production plans lag behind the expectations due to the risks in unconventional production technology, it would significantly increase the country's import needs, at the same time the slowing of the economy could dampen this demand. There are many uncertainties regarding the scale of capacities and timing of the Japanese nuclear power plant restarts, and there are questions raised about the efficiency of achieving the country's resource diversification targets. On the supply side, uncertainties are limited in light of investment decisions known up to 2018, however, later on the possible LNG price drop and the inflation of costs, which is already a heavy burden for investments currently under realisation, may lead to suspensions of several investments.

The idea that the price drop observed on the European spot markets this spring is a short-lived temporary condition seems to be slightly misleading. While true in the short-term, in the mid-term several factors suggest a slight decrease in natural gas prices. Despite the fact that calculating the mid-term natural gas prices remains a difficult task due to the various unknowns, following the trends of the previously discussed significant variables can reduce uncertainties of expectations.

Regulatory Prerequisities of A Successful Renewable District Heating Program in Hungary - workshop

The Regional Centre for Energy Policy Research (REKK) is organising a workshop for energy sector professionals concerning the possibilities of the district heating with renewable energy on the **13th of November 2014**.

The purpose of the one-day event is to facilitate discussion on switching of district heating services from fossil to renewable energy sources.

Draft programme:

- Section 1: Hungarian renwable DH experiences
- Section 2: International experiences presented by foreign speakers
- Section 3: The regulatory environment of renewable district heating

The workshop is targeted at:

- market players,
- DH producers and suppliers,
- project promoters (hungarian and foreign speakers),
- Regulators.

For further information please visit: www.rekk.eu

Why is the domestic electricity market expensive? The reasons behind the different domestic and German electricity prices

The electricity prices that have characterised the domestic wholesale market since the start of the deregulation surpass the price level of the neighbouring – Slovakian and Czech – markets and the German wholesale prices that are used for reference. The difference in 2007 reached 14 €/MWh, then it disappeared in the first few years of the economic downturn, and in the last two years it fluctuated between 3 and 10 €/MWh. In our analysis, we are looking for an explanation for the difference between the day-ahead hourly electricity prices – from now on referred to as spread – on the Hungarian (HUPX) and the German (EEX) power exchanges.

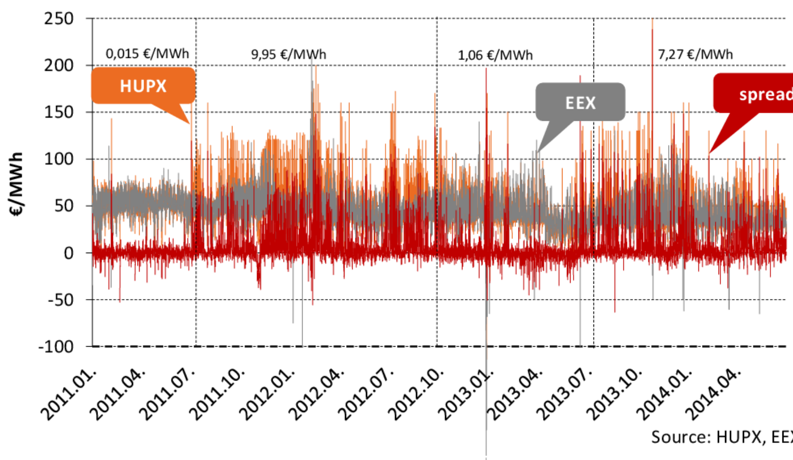
First we clarify some basic concepts. There are different ways of price comparison. We can observe the day-ahead market (DAM), and also futures market (PhF). The futures prices of products deliverable next year are closely connected to the spot market prices, but at the same time, usually respond slower and therefore they are less volatile prices. An odd short-term change (bottle-neck on the border or taking out a power plant from the system) can significantly increase the difference in day-ahead prices, but would not be so noticeable in futures prices. At the same time, the spot price differences gradually seep into the futures markets, thus the futures price difference strongly converges to the average day-ahead spread of the previous year. The present analysis focuses on the spot market price difference, but due to the above logic, our conclusions are relevant for the futures markets as well.

The *Figure 19*, showing the changes in spot market spreads between January 2011 and June 2014, demonstrates that from January 2011 to July 2011 the Hungarian and German prices moved closely together. During this period, the average spread was almost negligible, only 0.015 €/MWh. Following this, however, the prices more frequently split from one another. This was mostly due to the increasing Hungarian price, and not to the lower German price. In the period from July 2011 to the Czech-Slovak-Hungarian market-coupling in September 2012, the average spread was 9.95 €/MWh. Following the coupling, this difference decreased visibly, and until the June 2013 the average spread was only 1.06 €/MWh. In the last year, however, the Hungarian prices increased again and between June 2013 and July 2014 the price difference increased to an average of 7.27 €/MWh.

By looking at the average daily prices on the futures market, the slow reaction to the spot market becomes visible. Following the negligible or at times negative difference that characterised the two years following the economic downturn, the two prices start to slowly split from July 2011 onwards, and by July 2012 the price difference is 10 €/MWh. After the market-coupling, the prices start to converge again, but the initially low spread is not reached again. From the summer of 2013, an increase in the price difference on the PhF market is visible, parallel to the increase in spread on the spot market. In the analysed period, the average futures spread was 5.19 €/MWh, while the average spread on the spot market was 6.36 €/MWh. This is presumably due to price spikes, a feature only present on the day-ahead market (*Figure 20*).

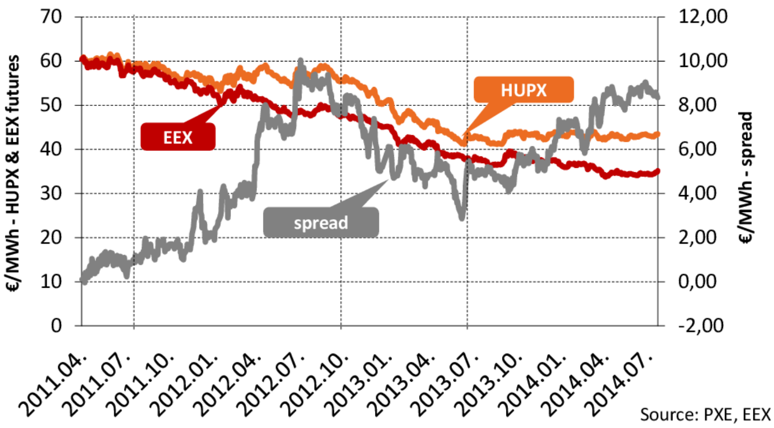
In terms of the spot market, the most visible trend is probably the sudden change in July 2011. In relation to this, the Hungarian Energy Office conducted an investigation that examined a number of potential causes. Based on their analysis, the reason for the increasing spread could be a regulatory change: the integrated power plants removed from the mandatory transmitting system were not profitable in the new regulatory environment. During the summer, these were not necessary for heat production, therefore the domestic supply suddenly plummeted, which could have led to the higher prices and the

Figure 19 **Hourly prices on the HUPX and EEX and price differences between the markets**



Source: HUPX, EEX

Figure 20 **The average daily price difference of the HUPX and the EEX baseload futures deliverable in the next year**



Source: PXE, EEX

Precipitation in the Balkans, the northern cross-border and the unplanned layoffs: what can these explain?

resulting price difference. But this difference persisted in the longer term, despite the partial relaunch of the integrated production at wintertime. The above-mentioned analysis argues that the cause of this could have been the Balkan drought periods. The Energy Office also examined the northern (Austrian and Slovakian) cross-border capacities, however no capacity-reduction was observed there, only changes in the scheduling behaviour, which we will look at in detail.

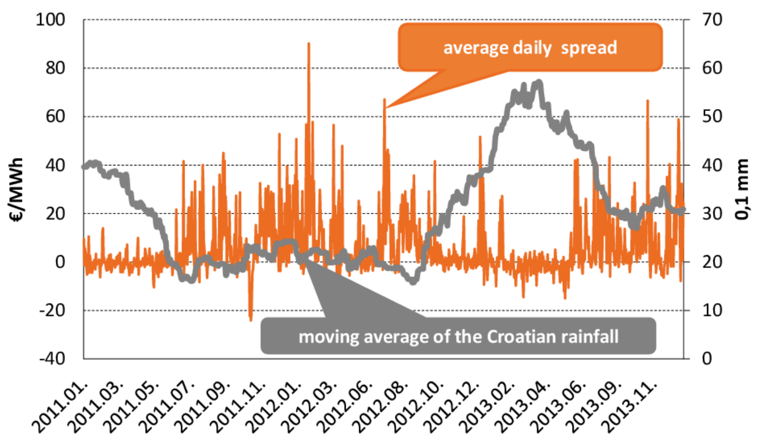
Other sources dealing with the divergence of the Hungarian prices from the regional prices also mentioned some of the above causes: the low level of Balkan precipitation, the limited cross-border capacities at Austria and Slovakia, the unusually high summer temperatures, and the recent drop in production at the domestic power plants. Taking into account all of these factors during the course of the analysis for the period between 2011 and 2013, we examined if the amount of rainfall in the Balkans, the unplanned power plant layoffs, and the developments at the northern cross-borders, were able to explain the resulting price difference.

In periods of draught, hydropower generation in the Balkans greatly decreases, which significantly increases the demand on the electricity import arriving from Hungary. In the following, we examine the average precipitation levels of four countries: Bosnia, Croatia, Serbia, and Romania. Between 2007 and 2012, hydropower production constituted more than 25% of the overall production, in the case of Croatia this was around 50%. Thus, the six month moving average of precipitation, which defines the hydropower generation of the observed countries, has a significant impact on the demand for import in the region.

In *Figure 21*, the periods characterising the HUPX-EEX spread can be recognised relatively easily: the high spread between July 2011 and September 2012 corresponded to the drought period in the Balkans, then the 6-to-12 months period after the market coupling witnessed increased rainfall, and this is followed by a drier period from the summer of 2013 that corresponds to another increased spread.

The second examined variable is the unplanned layoff of the blocks of two defining actors of the domestic power plant portfolio – the Paks and Matra power plants – which could increase prices by limiting the supply side. Since these plants are mostly producing continually, a sudden termination of a block could cause a supply shock on the Hungarian market.

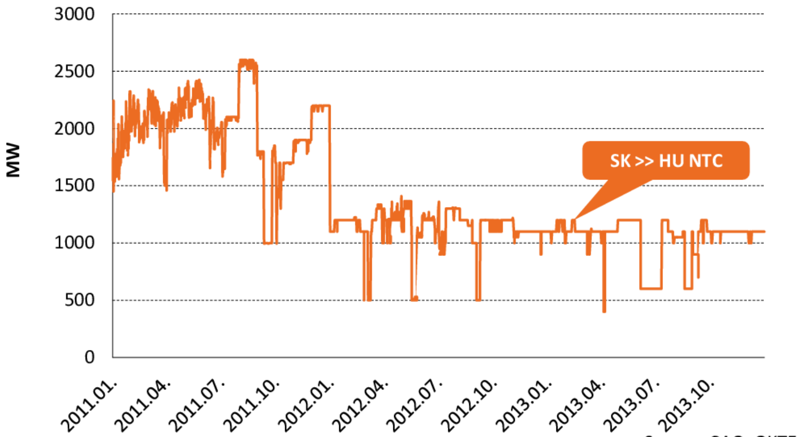
Figure 21 **The six-monthly moving average of the Croatian rainfall**



Source: European Climate Assessment & Dataset

Thirdly we examined the northern (Slovakian and Austrian) cross-borders. Here, we found a number of interesting elements and while the causal relationship was not entirely evident in all cases, it is worth listing them. The change in scheduling behaviour mentioned earlier can be observed on both borders: from July 2011, when the spread suddenly and significantly increased, the trader behaviour showed a similarly sudden change. From 1 July, the capacity rights distributed earlier on long-term (annual and monthly) auctions were used up to the maximum, while only 20-40% of the rights had been utilised on the Austrian border previously, and on the Slovakian border this number was around 20% at the beginning of the year. The unused capacities are always re-allocated on the daily auctions, which means that the change results in a significant decrease in the offered daily ATC amounts.

Figure 22 **The sum of long-term contracted and utilised cross-border capacities and cross-border capacities offered on daily auction, on the Slovakian-Hungarian border, towards Hungary**



Source: CAO, OKTE

However, the causal relationship between the increase of the utilised cross-border capacities and the development of the spread remains spurious. The trader behaviour mentioned above (which could have been caused by the decrease in the domestic cogeneration or the increasing demand from the Balkan countries) could have contributed to the increase in spread through the decrease in the daily ATC, however it could also be its consequence: as a result of the price increase experienced on the HUPX, the import capacity became more valuable, motivating the traders to utilise a larger share of these capacity rights.

From 1 July 2011, the relationship between the net physical flows and schedules has also changed suddenly. While in the first half of 2011 these two closely moved together, the physical flows on the Slovakian border significantly increased from July onwards, with the schedules remaining roughly unchanged. In the case of the Austrian border, both values increased significantly; later on the schedules were larger here. According to the TSOs of the region in the following period increased loop flows were noted. In the case of the Slovakian border mostly in the direction of Hungary, and in the case of the Austrian border in the direction of Austria. This could provide an explanation for the above processes. The significance of the increased loop flows is that this can prompt the TSOs to decrease the distributable capacity rights on the affected cross-borders, which can understandably have an effect on the spread between the two markets.

Considering the fact that the above figures are net values, we also examined other data that is relevant to the northern cross-border capacities. We aimed to measure the suitability of the capacities, assuming that if there is scarcity, the German and Hungarian prices cannot level out, while if there are sufficient capacities, this process can take place. We examined how the amount of the distributable cross-border capacities fluctuated in the given hours: we totalled the capacities contracted and utilized on long-term (annual and monthly) auctions with the ATC amounts available on daily auctions. Due to the unchanged built-in capacities, the level of available capacities can only change if the system operators see a rationale for stocking up a certain capacity, for instance, due to the presence of the above-mentioned loop flows.

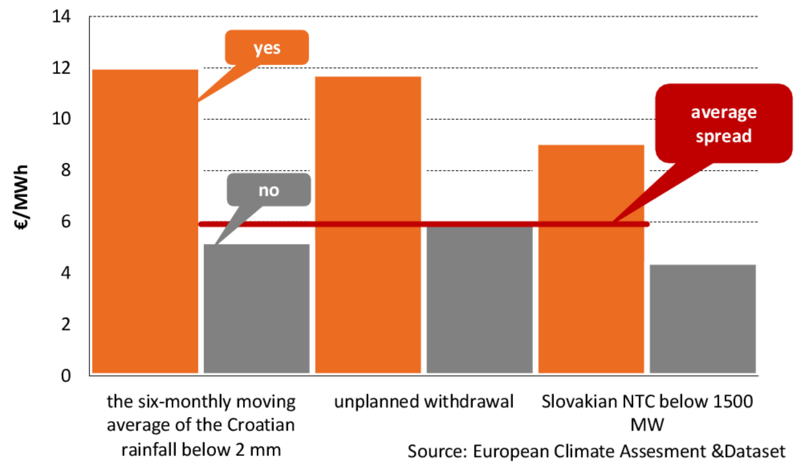
As we demonstrated, the loop flows indeed increased after July 2011 on the Hungarian-Slovakian border, however in our opinion this does not explain the significant capacity cutback from 2012 onwards. In comparison to the average capacity of 2000-2500 MW in 2011, a notable decrease took place from 2012 onwards. Since then, this amount has not surpassed 1500 MW and it has averaged around 1100-1200 MW (*Figure22*).

We attempted to show the effect of the examined variables on the spread in a number of ways. We first applied a regressive analysis on the data. During this process, three variables stood out. First, based on the analysis, it can be said that in the examined period the less rainfall the Balkan region experienced, mostly in Croatia, the higher the price difference was. Second, when there were unplanned layoffs, the resulting spread was also higher. Third, the effect of the Slovakian-Hungarian NTC value was noticeable: the less capacity was allocated, the higher the price difference became.

Following the regressive analysis, we attempted to demonstrate the effect of individual variables on the price difference with the use of pivot tables. The average spread for the analysed period was 5.91 €/MWh. Taking this as base value, we looked at changes showing in the average spread value when we calculate it only from the hours characterised by given lower or higher values of our other variables (Croatian precipitation, Slovakian NTC, and unplanned power plant layoffs).

We first examined the effect of the precipitation levels in the Balkan, and then also separately looked at the six-monthly moving average of the Croatian rainfall. We examined whether there is a difference

Figure 23 **Examining effects of the individual variables on price difference**



Source: European Climate Assesment &Dataset

Lastly, we divided the data: we separated and individually examined those hours where the spread was over 50 €/MWh. We calculated the average values of the individual variables in these latter hours and compared these to the average spread values of the entire period.

The effect detailed above is very noticeable in this case as well: in those hours where an unusually high spread was present, the ration of the hours with unplanned withdrawal was higher than average (especially at peak hours), and the Slovakian-Hungarian NTC and the amount of the Croatian rainfall were lower.

The results that came out of the above examinations and connections can be summarised as follows:

- On 1 July 2011, a structural change manifested on the market that, among other effects, increased the price difference, the usage of the capacity allocated for the northern borders on long-term auctions, and modified the relationship between the physical flows and schedules on these borders.
- From 2012, the total distributable cross-border capacity for the Slovakian-Hungarian cross-border significantly decreased. However, the resulting effect on the price difference was balanced out by the Czech-Slovakian-Hungarian market coupling that took place in September and the Balkan rainfall that increased in the second half of the year.
- In the periods characterised by higher price difference, the precipitation in the Balkan and the Slovakian-Hungarian cross-border capacities were lower than average, and the unexpected layoff of the Hungarian power plants also showed a close correlation with the price difference in the given hours. The impact of these three variables on the price difference is especially significant in peak hours.

if the (six-monthly moving average of) daily rainfall is below 2 mm and if this value is above 2 mm. In the latter case in Croatia, the average spread was 5.0 €/MWh, while it increased to 9.5 €/MWh in the "drought" hours. Narrowing the examination to peak hours, the difference is even higher: in the case of more rainfall the average price difference was 5.2 €/MWh, while in periods of drought it was 12.0 €/MWh (*Figure 23*).

Secondly, we examined the unplanned power plant layoffs. The average spread of those hours where some unplanned layoff happened at the Paks or Matra blocks came to 8.2 €/MWh, while the average price difference was only 5.4 €/MWh when no unplanned layoff happened. If we only examine the peak hours, these two values are even further apart from each other: the spread was 11.8 €/MWh with layoffs, while the spread was only 6.0 €/MWh without layoffs. At the same time, the extent of the layoff had no effect on the changes in the spread.

Lastly, we also examined the effects of the Slovakian-Hungarian NTC, and the results here were also similar to those of the regression analysis. The average spread value for those hours where the calculated NTC was above 1500 MW came to 3.7 €/MWh, while it came to 6.9 €/MWh where the NTC was below 1500 MW. Restricting the examination to peak hours, the impact of the available cross-border capacities on the price difference is more significant: the two values were 9.1 €/MWh and 4.4 €/MWh.

Table 2 **Examining sticking out peak hours**

	Average	
	Every hour	Hours above 50 €/MWh spread
Moving average rainfall in six months in Croatia (0,1 mm)	30,27	25,36
Hours with unplanned withdrawal	18%	26%
Peak hours with unplanned withdrawal	7%	16%
SK-HU NTC (MW)	1393	1274

Source: REKK

Developments along the road to an integrated European electricity market

One of the principal goals of the European Union is to implement an integrated European electricity market. Despite the fact that the unification of the day-ahead market coupling by the original deadline of the end of 2014 is unlikely to be met, significant integration activities have taken place on the European electricity markets recently. This study summarises recent developments and anticipates future developments in achieving day-ahead market coupling. The main advantage of market coupling is that it provides an opportunity for employing the so-called implicit auction, where the electricity and the capacity rights are sold to the market participants together as tied products.

Although the European target model is the flow-based market coupling based on flow-based capacity calculation, previous European attempts at market coupling were NTC-based. This means that the relevant system operators specify the capacity available for day-ahead auction at each border, and then a central algorithm building on the overall sale and purchase price offers of the integrated markets, simultaneously defines the prices and trading flows applicable in the individual price-zones, thereby maximising social welfare (the sum of the consumer surplus, the production surplus, and the auction income). This results in electricity flowing from cheaper markets to the more expensive ones until the different price-zones are equalised, assuming that a sufficient cross-border capacity is available. If these capacities are scarce, a price difference equalling the cost of the capacity right will remain between the two connected zones.In comparison to explicit auctions[1], market coupling results in a wide range of effects that maximise welfare: it makes the allocation of cross-border capacity more effective, it increases market liquidity due to the increased volume and therefore decreases price volatility, it provides more stable price-forecast, and it can improve supply-security for the relevant markets[2].

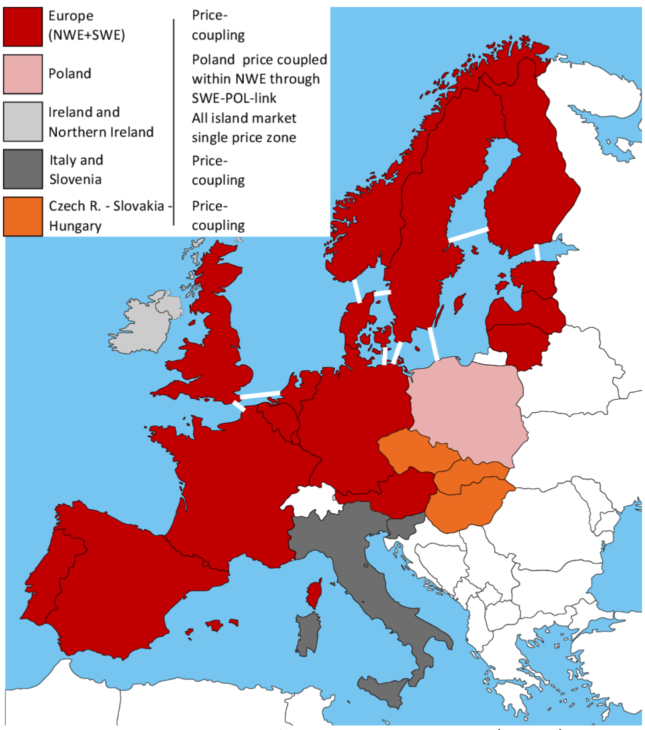
In terms of the integration of the European day-ahead electricity markets, the 4 February 2014 launching of the North-West European NWE price-coupling project was a significant step forward, affecting the regions of Northern Europe (Denmark, Finland, Norway, Sweden), Central Western Europe (France, Germany, and the Benelux states) and the United Kingdom. The Baltic states and Poland, which had already been connected with the northern region, and Austria, which shares a unified price zone with Germany, are also connected with the larger region, thus the NWE Price Coupling project connects the day-ahead markets of a total of 15 countries.

The 13 May 2014 launch of the coupling of the South Western European and the North Western European electricity markets was an important next step on the road towards the European integrated electricity market; as with the joining of Spain and Portugal there are 17 participant states in the market coupling initiative today (see the red areas of *Figure 24*), which means an annual consumption of approximately 2400 TWh from Portugal to Finland. The average daily trading amount in the connected region is 3.2 TWh, which means a trading value of over €200 million.

History

Before we evaluate the current situation and likely future directions, we briefly review the past developments that lead to the present state. The first European market coupling project, connecting the French, Belgian, and Dutch day-ahead markets (trilateral market coupling) was launched in 2006. Fol-

Figure 24 **Regional day-ahead market coupling initiatives in Europe**



Source: Matti Supponnen: Energy market update, 2014

[1] *Separate trading of the electricity and the cross-border capacity right.*
[2] *For a more detailed account on the effects of market coupling in terms of increasing social goods, see issue 4 from 2012.*
[3] *Belgium, Denmark, Estonia, Finland, France, Germany, Austria, United Kingdom, Latvia, Lithuania, Luxemburg, Holland, Norway, Poland (through the SwePol interconnector), Portugal, Spain, and Sweden.*

lowing this, the CWE market coupling was realised with the joining of Germany and Luxemburg in 2010. Also in 2010, the ITVC project (Interim Tight Volume Coupling) was launched, which connected the CWE region with the Nord Pool market through volume coupling. The NWE market coupling was implemented in 2013, with the United Kingdom's participation.

The market coupling projects put forward by the relevant stock exchanges and system operators resulted in significant price-convergence on most of the relevant markets. In addition to welfare-maximisation, one of the most notable reasons for implementing these initiatives (which were supported by the European Council) was that the implicit allocation of the day-ahead cross-border capacities directed the short-term eletricity trading to the organised markets, which mean[1]t a significant increase in trading and revenue for the stock exchanges that had a stake in market coupling. The increased stock exchange trading also increased liquidation, providing a more reliable price-indication on the day-ahead markets, which resulted in ad[2]equate support for these rojects in terms of the regulation as well.

In February 2014, the pervious market algorithm used in the Northern and Central Northern European regions and the ITVC approach were replaced by the so-called PRC solution (Price Coupling of Regions), which allows price-based market coupling on all NWE borders. The PCR project was originally initiated by seven European electricity stock exchanges[4], however it also welcomes the joining of further European stock exchanges. This algorithm will be applied, for example, in the case of the IBWT project[5], which is expected to launch in December 2014 and will include the Italian borders as well. The explicit aim of the project was to develop a common price coupling methodology that in the future will be able to fairly and transparently determine the price, while also maximising welfare effects when allocating the cross-border capacity of the relevant region.

The attraction of the PCR, which is the shared property of the European stock exchanges that participate in this cooperation, is likely also the fact that with the help of this project the large European electricity exchanges could prevent the surfacing of a situation where the programmes of the individual stock exchanges compete against each other. With the use of a central optimising algorithm, individual stock exchange accounting remains and all relevant stock exchanges can continue using their own trading platform, while also providing compatibility with the central market-coupling algorithm.

What can we expect from the PCR?

Although the introduction of the PCR solution is undoubtedly a positive and major step on the way to an integrated European electricity market, we should not expect a significant pan-regional price change or a price-convergence stronger than the present state from the Western European electricity markets. We must remember that, as we alluded to earlier, the majority of the relevant markets have already been connected, therefore the efficiency improvement based on the available cross-border capacities has already been mostly maximised.

The positive effects of introducing the PCR solution can be seen in two areas. On the one side, due to the price-based market coupling introduced in the entire relevant region, it allows for a more effective capacity-allocation among those price zones where previously explicit allocation was in place (such was the French-Spanish border until May 2014) or where quantity-based implicit capacity allocation was used. An example for the latter case is the connection between the Central Western European and the Northern Baltic regions (ITVC), where the offers from the two zones were treated jointly when setting the inter-regional optimal flow, following which the optimal prices were calculated separately in each region with different algorithms, taking into consideration the previously defined flows. The disadvantage of this method is that it does not yield particularly effective outputs, which would not occur in the case of price-based coupling (for example, a price difference can be present between two markets even if there is no bottle-neck on the border). On these borders, therefore, the introduction of the PCR can somewhat increase efficacy and can result in a higher price-convergence. The other advantage of the PCR solution is that the applied algorithm is a hybrid in that it can handle the different combinations of NTC-based and flow-based allocations, consequently aiding the timely realisation of a market construction that corresponds to the target model.

In line with the target model of the day-ahead market coupling that is to be implemented in the long term, flow-based allocation can be introduced this year the Central Western European region. This would mean centrally and regionally defined available capacities, which process the flow-affecting effects of the commercial dealings at all of the relevant border crossings, the effects these have on each other, and the internal network units are taken into consideration simultaneously, enabling a better mapping of physical flows. This all aids the better usage of the available capacities, while also provid-

[4] APX, Belpex, EPEX SPOT, GME, Nord Pool Spot, OMIE, and OTE

[5] Italian Borders Working Table, which includes the Italian-Slovenian, Italian-Austrian, and the Italian-Swiss borders.

ing expanded trading opportunities with the same level of supply-security and prevents non-desired loop-flows.

At the same time, the countries outside of the CWE region will continue to be connected to the region on an NTC-basis, since the network is not overly looped in the case of these states, and therefore there is no need for flow-based allocation. Based on the results of parallel running, during the course of 2013 the flow-based allocation would have increased welfare by €79 million (€257k a day) in the CWE region, and the resulting prices would have shown a more significant convergence at an increase of 15-20%[6].

What can Hungary and the CEE region expect before integrating with Western Europe?

On 11 September 2012 the Czech--Slovakian-Hungarian NTC-based day-ahead market coupling was launched, which aims to reach the highest possible compatibility with the EU target model. At present, the national regulating bodies, transmission system operators and the operators of the organised electricity market of the relevant countries are working together on expanding the three-sided project to Romania (4M MC project), and at the same time changing to PCR, which is planned to be implemented from 11 November 2014. Following this, the Hungarian wholesale prices can further decline due to lower prices at the Romanian electricity market and the significant volume of the Romanian market, provided that appropriate cross-border capacities are allocated during the market coupling process. Serbia and Croatia also signalled their interest in joining the initiative, which is likely to be realised in 2016 following adequate preparations.

In the Central Eastern European (CEE) region, which includes the seven states (Austria, Czech Republic, Poland, Hungary, Germany, Slovakia, and Slovenia), this incrementally growing market-integrating initiative could be the best way forward as, in compatibility with the Western European solution, it still enables the exploitation of the welfare-maximising effects of market coupling until the integration of the entire CEE region and the region's joining of the NWE market coupling are completed.

The main motivation for this bottom-up initiative was precisely the fact the market-integration negotiations for the CEE region had initially proceeded slowly, before eventually grounding to a halt. The originally planned first step in the region was the introduction of the flow-based explicit allocation, however due to various conflicting interests the detailed rule formulation was so drawn out that eventually the entire initiative lost its purpose, since the introduction of an implicit auction across Europe is increasingly wide-spread and is becoming unavoidable.

With this recognition, the regional negotiations have been revived, which resulted in a memorandum of understanding on a regional solution in April 2014 between the key actors of the electricity market sectors in the relevant states and the EU Agency for the Cooperation of Energy Regulators. According to this understanding, market coupling in the relevant countries in Western Europe would take place based on the PCR solution, and the determination of the cross-border capacities would take place from the start with the implementation of the flow-based process, where the methodology is compatible with the flow-based algorithm that will be used in Western Europe.

Before the CEE solution can be launched, however, significant obstacles still need to be tackled, therefore the earliest the launch can take place is in 2-to-3 years, and only following this can the region join the Western European market coupling. Some of the many obstacles along the road to reaching agreement have unique significance, such as the debates that connect to flow-based allocation and take place between the relevant system controllers in relation to distributing the auction-revenues. In addition, serious debates are caused by the questions of rethinking individual price-zones (for example, ending the unified price-zone of Austria and Germany) and handling loop flows.

A further variant that complicates reaching agreement is that the regional market-integration initiatives overlap with each other, thus the states of the CEE region have already integrated with other, extra-regional countries, which complicates harmonising processes within the region. For instance, at present it is not clear in what status the Romanians, who are joining the 4M market-coupling, take part in the CEE-region market coupling[7].

It is therefore evident that the realisation of the Central Eastern European regional solution, partnering with the Western European initiative is presently on hold, and in the meantime initiatives similar to the Czech-Slovakian-Hungarian-Romanian market coupling should be welcomed as interim steps, which aid the exploitation of the regional advantages of market coupling along the way to the unified European market.

[6] *Status report on the CWE flow-based market coupling project.*

[7] *A similar issue is present in the case of Slovenia that is already connected with the Italian market.*

Constrains on the Hungarian renewable-based district heating production

A frequently emphasised aim of domestic energy policy is increasing the market share of renewable energy based heating and district heating generation. The National Energy Strategy considers renewable-based heat generation as one of the most efficient method for decreasing the dependence on natural gas and for increasing supply security, with a particular emphasis on using biomass-based and geothermal energy sources. By 2020, the National Renewable Energy Usage Action Plan (NREAP) intends to increase the share of renewable energy sources in the total domestic heat consumption from the present 13.6% to 18.9%, this way contributing to decreasing the dominance of natural gas based heat production.

In both the domestic and the EU-level energy strategies, increasing the share of renewable-based heat generation is connected with increasing the role of the district heating sector in heating supply and the need for the expansion/modernisation of the district heating generation and servicing infrastructure. According to domestic plans, about two-thirds of the renewable-based heat generation capacities planned to be built by 2020 will be in the district heating sector. This means that the district heating share of renewable energy based heat generation will increase to over 80% by 2020.

The actual developments in comparison to the ambitious plans above show a rather mixed picture. Although the volume of renewable-based district heating surpasses the level predicted in the NREAP for 2014, it is questionable whether the conditions are present for the significant increase planned for the next 6 years. In the last 4 years, almost 85% of renewable heat generation increase was due to the growing use of domestic biomass; in our estimation, the share of renewable energy sources in the district-heating sector will not exceed 15% even following the investment projects at Pécs and Miskolc.

The significant growth expected from renewable-based district heating generation can only be realised within the framework of an adequate price regulatory and subsidising system. The present article aims to explain whether the current conditions are adequate for stimulating the targeted growth, and if not, then what changes are necessary to achieve the proposed energy policy goals. We first examine the obstacles hidden in the current district heating price regulation, then we look at the shortcomings of the subsidising system.

The obstacles of district heating price regulation

The current administrative regulation of district heating price does not truly incentivises the spread of renewable-based district heating generation or other investments in district heating generation. However, before we highlight the most critical elements of the current regulation, it is worth recalling the short but instructive history of the regulation of district heating generation.

The two decades following the regime change was a period of gradual dismantling of the rigid centralised district heating price regulation. In the 1990s, the – centralised – administrative price regulatory rights were transferred to local governments, then from the mid-2000s these rights were gradually narrowed down. The regulation of producer district heating price – partly due to the cogeneration subsidy – terminated, and the setting of the residential district heating supplier prices was brought under normative conditions.

This situation changed significantly in 2011. District heating generation and supply for institutions (buildings in central and local government ownership) that were previously managed separately from residential district heating prices were brought under official price regulation. From this point onwards, the preparation of prices was done by the Hungarian Energy Office (HEO), and the price setting rights were transferred from local governments to the minister responsible for energy policy.

As the first element of the new regulation, district heating prices were frozen at the 31 March 2011 price, and residential prices were decreased twice (by 6.5% in the autumn of 2012, and by 11% in the autumn of 2013). The relevant decree set out detailed performance and heat charges for district heating producers, defined at individual levels for each producer, and in the case of district heating suppliers individual weighted subsidies (different for each supplier) were defined. These subsidies were needed to compensate for the loss incurred by the inconsistency between the frozen and then gradually decreased residential prices and the wholesale prices paid to the district heating producers. The normative subsidies paid to previous cogeneration producers were therefore replaced with the individual subsidies paid to suppliers, the source of which were constituted by the cogeneration restructuring fee built into the electricity prices and the ad hoc charges levied on the natural gas sector.

A number of problems surfaced with the present district heating price regulation, which inhibit the modernisation of the district heating sector and make it very difficult to finance new district heating generation investments, especially for those renewable-based heat generation facilities that have high investment costs.

The most pressing problem is the lack of transparency, normativity and predictability. Neither the detailed methodology of price regulation, nor the frequency of this is known, furthermore the extent of the acknowledged costs is also unclear, the HEO practice can be contested due to the lack of normativity; all of this leads to unpredictable producer prices for the investors. Usually a 15 to 20-year heat supply contract is necessary for financing district heating producer investments, which is not supported by the above price regulatory practice.

For district heating producers already in operation, the above issues could be resolved by benchmark-based price regulation that is predictable in the long term, and for district heating producers newly entering the market the problems could be resolved by an entirely market-based price setting. The benchmark type price regulation would define the district heating producer prices based on the average investment and operational costs of the individual heat generation technologies, instead of individual cost determination. If the new district heating producer investments were chosen through open tenders set up by the suppliers (that is, in perfect competition), then there would not be a need at all for official price regulation for these producers.

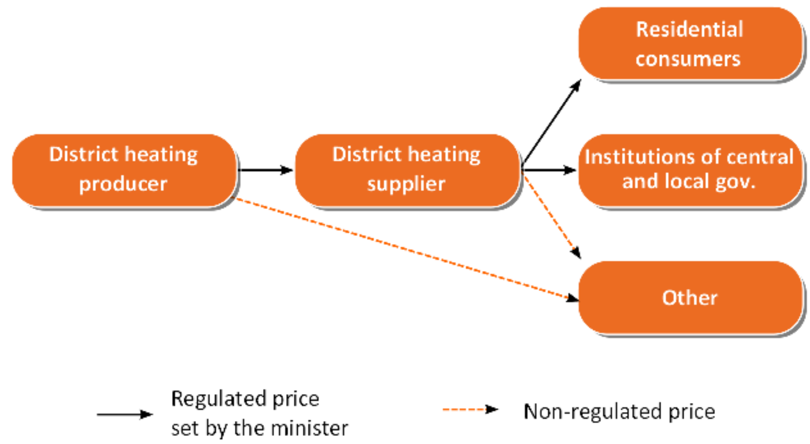
In the case of restructuring the producer price regulation, the supplier-based price regulation cannot be sustained in its present form either: a price regulation, based on regular price reviews and on the above-presented pricing between district heating producers and suppliers, could be applied in 3-to-5-year price cycles to district heating consumers eligible for residential and universal natural gas consumption. In the absence of price cycles or until these are set up, a price regulation is necessary that is determined in advance based on widely accepted principles and that rests on a methodology that is stable and transparent in the long term.

The unique cost-structure of renewable-based (biomass-fuelled or geothermal energy based) heat generating facilities (that is, the dominance of capital costs and the relatively low level of operational costs), makes these particularly well-suited for long term price regulation. These unique features are most marked in the case of geothermal heat generation, where the operational costs (since there is no fuel cost) are quite negligible. Due to this, during the price regulation there is no need to apply regular, fuel cost indexed price correction. The district heating producer costs set at the start of the investment – benchmarked to similar geothermal investments – can be in place for 4-5 years for these producers.

A less severe, but annoyingly inefficient regulatory element is the obscure application of the 4.5% profit limit relevant for renewable-based district heating producers. Based on the present regulation, during the calculation of the profit limit the capital repayments and interests of loans can only be recognised as acknowledged costs if these are individually examined, which results in a wholly unpredictable income situation for the affected producers. The system aimed at limiting profit-making considers (surplus) profit as illegitimate, even when it is achieved following a well-prepared, well thought out investor decision, alongside an effective corporate operation and with the application of official prices, which sends an extremely negative message to the investors who are already taking a higher-than-usual risk with renewable-based projects.

The rationale for the profit limit in a system that is based on official price regulation is already questionable, not to mention the obvious possibility of its evasion, and thus its strongly questionable efficacy. By discouraging private capital and fostering hesitation in investors, the retention of this regulatory element carries much more severe risks, than its removal, therefore it would be advisable to abolish decrees on the profit limit in the near future.

Figure 25 **District heating price regulation post - 2011**



Source: REKK

Existing and missing subsidies

The reform of the district heating price regulation removes numerous obstacles that inhibited the necessary investments, at the same time on its own it is not able to guarantee the desired level of growth in renewable heat generation. Without an adequate support scheeme, projects with high investment cost and initial risks are not able to compete with fossil (mainly natural gas) powered facilities that have low investment (and higher operational) costs but are less compatible with energy policy aims. Therefore, the application of environmental and sustainability subsidies attached to district heat generation, primarily the investment and operational subsidies of renewable-based heat generation cannot be avoided.

There are already programmes in place at present that support the use of renewable energy sources and the modernisation of district heating systems, but ring-fencing of funds/sources targeted at incentivising renewable-based heat generation has not taken place. The main subsidy package that was available for renewable heat generation projects was the EEOP, which provided an average of 42 billion HUF investment subsidies between 2011 and 2013 for renewable energy production projects.

But what was this sufficient for? In the three years between 2011 and 2013, the renewable energy based district heating production increased by 0.5 PJ per year by rough estimates. Thus, in terms of the timeline, we are doing quite well. However, the National Renewable Energy Action Plan aims to achieve 80% of the overall growth targeted by 2020 in the second half of the decade, which would mean an average annual increase of 3.5 PJ for the remaining period. That is, the annual increase in renewable energy capacity in the future would need to be seven times that of the increase in previous years. This of course does not necessarily mean a demand for subsidies seven times that of the previous years, but this illustrates the extent of efforts we will need to make to achieve our energy policy aims.

Of course, the discussion on incentivising investments targeted at renewable heat generation cannot be minimised to the volume of investment subsidies. The list of potential subsidies is quite long: it ranges from non-repayable investment subsidies through operational subsidies matching the production levels to various risk-mitigating constructions. A good support shceeme operates with an appropriately varied system of methods, so that investments differing in technology, investment and financing construction, and scale can each find a suitable method.

The operational subsidies paid proportionately to the produced energy (e.g. the mandatory off-take or the system of the tradable green certificates) are widely spread mostly in the electric energy sector, while their application in the heat generation sector is quite rare (although in the Scandinavian countries indirectly subsidising sustainable energy generation by providing exemeption from environmental taxes is not an unknown concept). In recent years, the United Kingdom and Germany both took steps to establish a subsidising system that features operational subsidies aimed at heat generation. These developments highlight the recognition that renewable energy usage that solely serves heat generation also has to be eligible for these subsidies in order to achieve the energy policy aims (meaning that operational subsidies are not only granted for the electrical energy streams with cogeneration).

In Europe, various types of investment subsidies are much more prevalent currently: in addition to non-repayable subsidies, subsidised loans, state guarantees and risk insurances, various combinations of these are also included here. It is worth emphasising that there are numerous sub-types of non-repayable investment subsidies: the level of which can be defined based on the technology, the built-in capacity, the area, or the customers who are served.

For projects that are "hydrocephalic", with high investment cost and initial risks, investment subsidies aiding financing, and more precisely, non-repayable subsidies, subsidised loans and state guarantees could be most relevant in the first place. Therefore, it is very important that in the coming subsidiary cycle not only non-repayable subsidies accessible through the Environmental and Energy Efficiency Operational Programme (KEHOP) are available for renewable heat generation investments, but that these are supplemented by other subsidising forms, chiefly by subsidised loan opportunities combined with state guarantees.

Due to the different particularities of the various types of heat generation investments, it is essential to establish a complex renewable heat-subsidising system that is made up of various types of subsidies. The need for this is well exemplified by the necessity to manage the special risks attached to geothermal investments. A particularity of geothermal investments is the exact depth of the reservoir containing the hot water and the water-yield and water temperature that define the performance of the heat generating facility, which can only be precisely determined after initiating the project, during the drilling of the test well. The fundability of the project demands that the investor manage these risks in some way; because in the absence of this, the use of the otherwise available non-repayable subsidies can be jeopardised too. Due to unsatisfactory risk management on the market, a number of countries recognised that to minimise the above risks, it is necessary to establish investment loan guarantee systems with strong state input or risk funds that allow for subsidised capital injection or safeguard against risks occurring during the initial phase of the projects.

It is not possible to increase the role of renewable energy sources in district heating generation and meet the energy policy aims by using only one method. Settling the district heating producer prices or increasing the volume of subsidies is not enough on its own to ensure the targeted growth; this is only possible with the creation of an appropriately incentivising investment environment, where the prerequisite is the establishment of a multi-layered subsidising system that can manage the long term predictability of the price regulation of district heating generation and the special problems of renewable heat generation.

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.

To provide further information on the content of the Quarterly please contact Zsuzsanna Decsak.

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The major economic impacts of the 2030 European GHG emission reduction target on Hungary

Commissioned by: ECF (European Climate Foundation)

In early 2014, the European Commission published its recommendation for the climate and energy policy frameworks between 2020 and 2030. This study analyses the effects of the abovementioned recommendation to Hungary, focusing on three key areas with high importance from an economic and energy policy point of view:

- Analysing the effects of the various levels of possible European GHG reduction targets on the financial viability of Paks 2 nuclear power station, a priority investment proposed by the Hungarian State. This study analyzes how different ETS quota reduction scenarios would affect the return on the nuclear power plant investment based on simulations of the European Electricity Market Model (EEMM) of REKK.
- Calculating the expected auction revenues of the Hungarian state budget between 2021 and 2030 in case of various ETS quota reduction scenarios.
- Providing an overview of the expected emission levels in sectors under the so-called Effort Sharing Decision (ESD) – i.e. non-ETS sectors – until 2030 for Hungary, and assessing how these relate to the emission reduction obligations of Hungary following various possible implementation scenarios.

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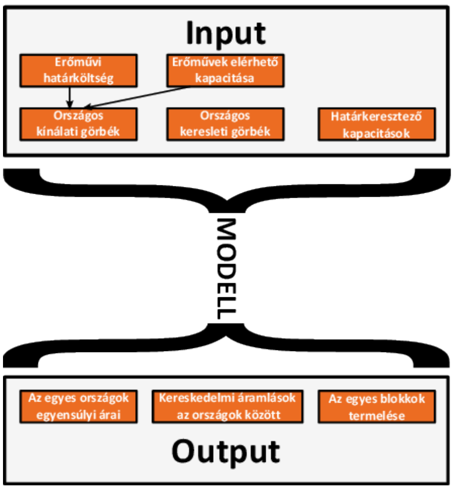
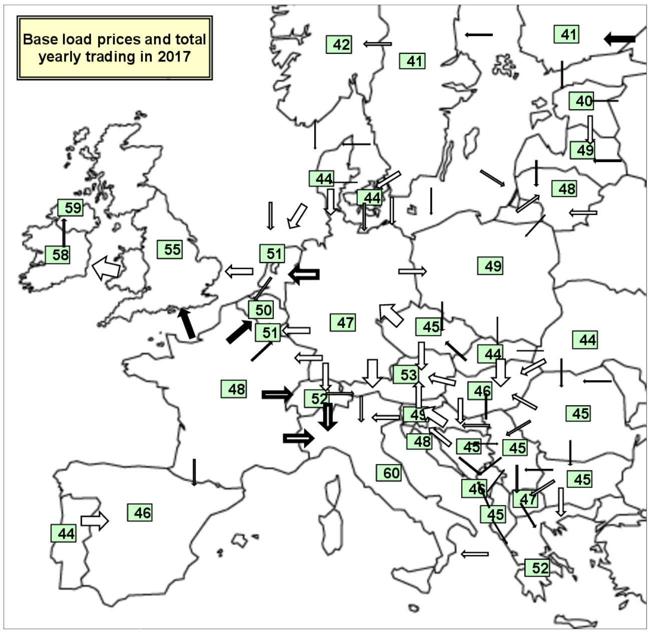
EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

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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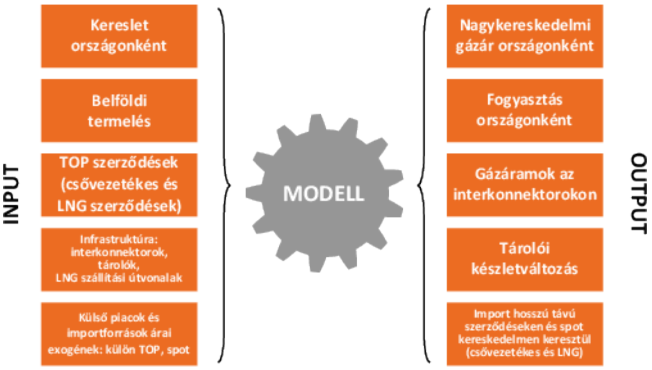
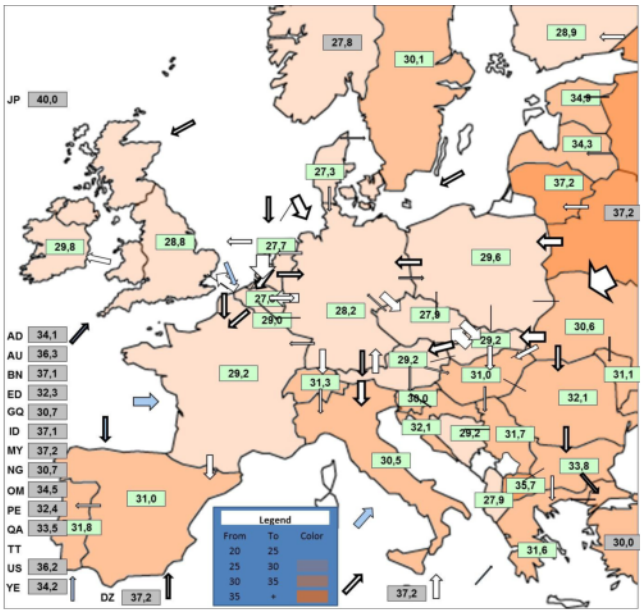
EUROPEAN GAS MARKET MODEL (EGMM)

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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