REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q1 2014

REKK 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.

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- Security of supply
- Market entry and trade barriers
- Supplier switching

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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,

From now on our Hungarian Energy Market report will be published with a new design. We truly hope that you will continue to appreciate the content under the revitalised cover. We are eager to hear your feedback on the presented themes, your opinion on the style and length of the articles, and your suggestions on topics to be covered in upcoming issues.

In our first article we take a look at the second round of the utility bill cut, and in particular the November 2013 reduction of the price of electricity and natural gas. In addition to inspecting the impact that the utility bill cut delivered to the revenue of market players, we also examine the extent to which the continued reduction of regulated prices is in harmony with European electricity market trends, and we also analyse the burden posed by the second round of the utility bill cut to wholesalers with important positions in the electricity and natural gas markets.

Our second article reviews the power plant investments of Hungary for the last few years. We seek to understand how the capacity balance of the country is affected by the completion of the investments launched before the crisis, and the power plants closures and cancelled investments driven by a deteriorating market environment. Has the security of supply eroded, is the system more difficult to operate than before, is there an increased need for regulatory intervention?

In the third article we look at the problems of renewable support schemes and the corresponding reform concepts of the EU. Demand for support in excess of the capabilities and willingness of society and the central budget have resulted in ad-hoc regulatory interventions in a number of member states. Because of these regulatory deviations, in November 2013 the European Commission released its recommendations to reform renewable support schemes. We make use of the Czech and Romanian interventions to illustrate the potential regulatory solutions on the edge of what is legally still acceptable, then we review the main pillars of the reform plans of the EU targeting the "marketisation" of support schemes as well as the market integration of renewable producers.

We complete the report with an introduction of the 2030 climate policy plans of the EU. The current regulatory instrument applied by the EU to curb the emission of greenhouse gases, the emission trading system (ETS) has for years been suffering from a substantial oversupply and low prices, thus in its current form it is not capable of reaching demanding emission reduction targets. A uniform climate protection "package of proposals" has been composed of the previous concepts to reform the ETS and the 2030 emission reduction targets. In our article we present the system of 2030 emission reduction targets and instruments, drafted by the European Commission in January 2014, to be finalised by the member states during 2014.

Péter Kaderják, director

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Editor-in-chief:
Lajos Kerekes

Authors:
Antal Hum, Lajos Kerekes, Péter Kotek, Zsuzsanna Pató, Adrienn Selei, László Szabó

Published by:
REKK Energiapiaci Tanácsadó Kft.

For further information please contact:
Zsuzsanna Decsák
Tel.: (+36 1) 482 7073
Fax: (+36 1) 482 7037
E-mail: rekktanacsado@gmail.com

www.rekk.eu

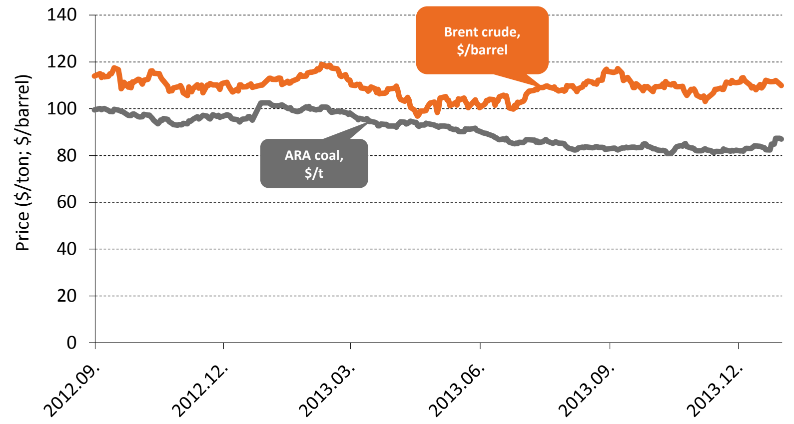
Energy Market Developments

During the fourth quarter (October-December 2013) only minor changes were registered in regional energy markets. The price of crude oil rebounded after a declining phase. The price of natural gas slightly increased, while the price of coal stayed idle until the last week of the year, when it started to ascend. During the quarter German electricity prices exhibited a modestly declining trend again.
The quarterly electricity consumption decreased by about 0.5% compared to the figure from a year ago. The share of import rose to some extent, once again a little more than a third of electricity consumption was satisfied through import. As a result of the high import ratio and restricted cross border capacities, Hungarian day-ahead prices continued to be the highest in the region.
In the gas markets storage facilities continued to be filled to a low level, the end-of-December value of 29% (1.57 bcm) was 30% lower than the volume stored at the end of 2012.

International price trends

During the fourth quarter of 2013 the spread between the prices of the two dominant energy carriers, oil and coal, has not widened any further. The price of Brent crude stayed within the $103-112 range during the quarter, with a closing price of $110 for the year. The price of EEX traded ARA coal, on the other hand, changed very little during the quarter, oscillating between 81 and 85 $/ton until the last week of the year, when it suddenly sprang above $87, but fell back below $85 by the end of January 2014.

Figure 1 The price of 2014 ARA coal futures traded on EEX and the spot price of Brent Crude between September 2012 and December 2013

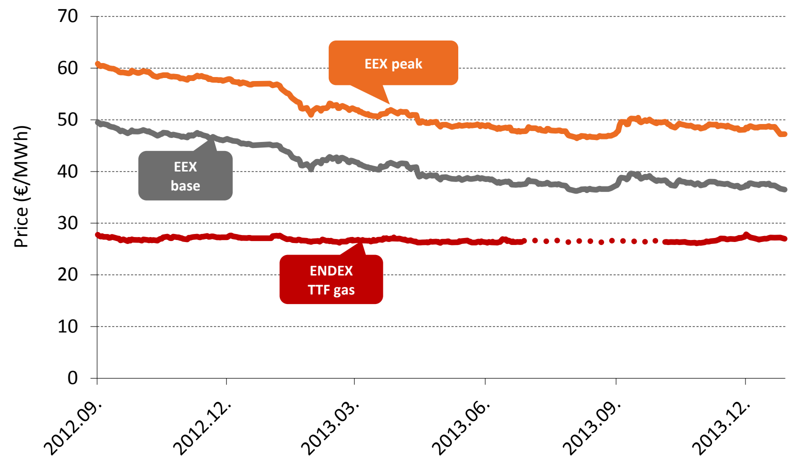


source: EEX, EIA

The gently declining trend of the price of futures electricity reappeared during the fourth quarter: the price of the German baseload electricity fell by €1.5 to 36.5 €/MWh between early October and late December, a notably lower level than the 45 €/MWh price a year ago. The price of peak electricity dropped by the same degree for the last one year, the 47 €/MWh price at the end of the year is €10 lower than the December 2012 price level. The futures price of gas exhibited a modest decline of just €0.5 during the quarter, with the TTF annual futures closing the year of 2013 at €27.

Emission allowances with December 2013 delivery were traded at 5 €/t in the beginning of the quarter. In early November, however, the price level of EUA started to decrease, all the way until 4.3 €/t, before bouncing back again to 5 €/t in early December. With the exception of a moderate temporary decline, this price level was maintained all through the end of the year.

Figure 2 The price of 2014 futures electricity and natural gas between September 2012 and December 2013



source: EEX, ENDEX, Gaspool

Note: TTF data between 1 July 2013 and 4 October 2013 is from the NCG since ENDEX data in this period was not available.

Overview of the domestic electricity market

During the quarter the working day and temperature adjusted electricity consumption amounted to 10.0 TWh, 0.1 TWh, or about 1% higher than the level of consumption a year ago. Looking at monthly changes, the adjusted consumption grew by 2.1% in October and

1.4% in November compared to the corresponding months of the previous year, while in December it declined by 0.5%.

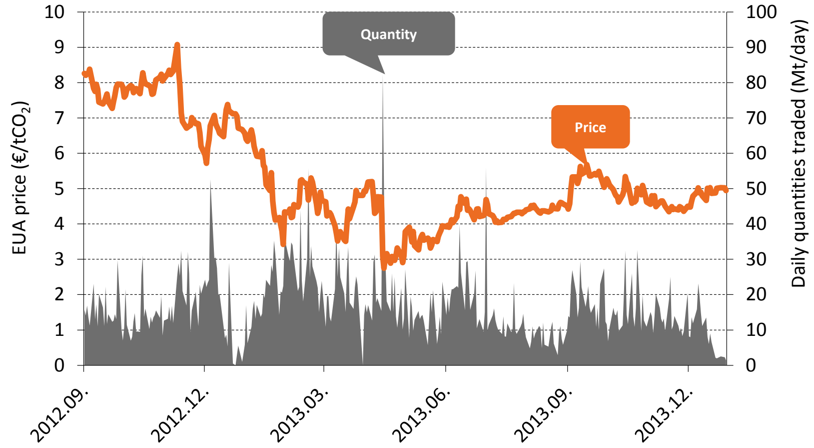
The price spread between the sales of domestic power plants and import sources has been wide open since the spring of 2012, thus an increasing share of domestic consumption has been supplied from import for the last year and a half. During the third quarter the share of imports exceeded 34%, twice as much as the 18% net import ratio a year earlier. The import deficit for the first three quarters of 2013 already surpassed the full 2012 level, while for the whole of 2013 an import ratio in excess of 30% is registered, with the volume of the annual import reaching 12 TWh.

At the monthly cross border auctions the price for the Slovakian import capacity exceeded 4 €/MWh in October, and topped 5 €/MWh in November and December. At the same time, the price at the Austrian border section was above 4 €/MWh in October, while in December it leapt above the particularly high level of 8 €/MWh (during November monthly cross-border import rights were not allocated for the Austrian border). Compared to the prices of the same periods of 2012, nevertheless, not even the 8 € value is exceptionally high. For the rest of the border sections the price of cross border capacities stayed below 1 €/MWh, with the exception of the Romanian border, where the November and December prices increased slightly above 1 €/MWh.

Annual capacity auctions for 2014 were also completed during the quarter. The price for Austrian and Croatian import capacities continue to greatly surpass the prices of all other border sections. With regard to export capacities, the prices for the Austrian, Serbian and Romanian borders declined, while capacity prices toward Slovakia and Croatia did not really change.

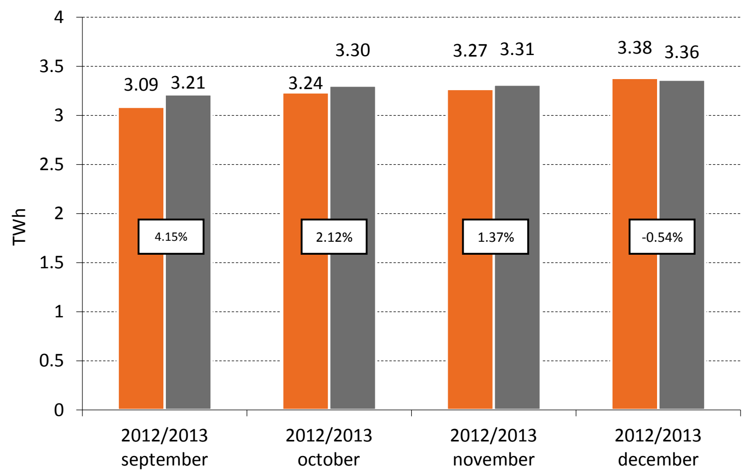
During October next day HUPX prices moved away again from the prices of the other exchanges of the region. During the month the next day price for Hungary exceeded the price of the Ger-

Figure 3 The price of CO2 credits with December 2013 delivery and the daily traded volume between September 2012 and December 2013



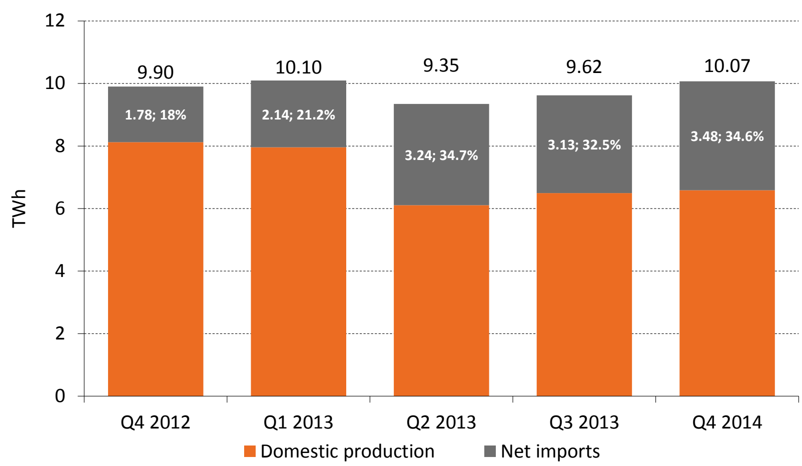
source: theice

Figure 4 Temperature and working day adjusted electricity consumption between September 2013 and December 2013 relative to the same period of the previous year



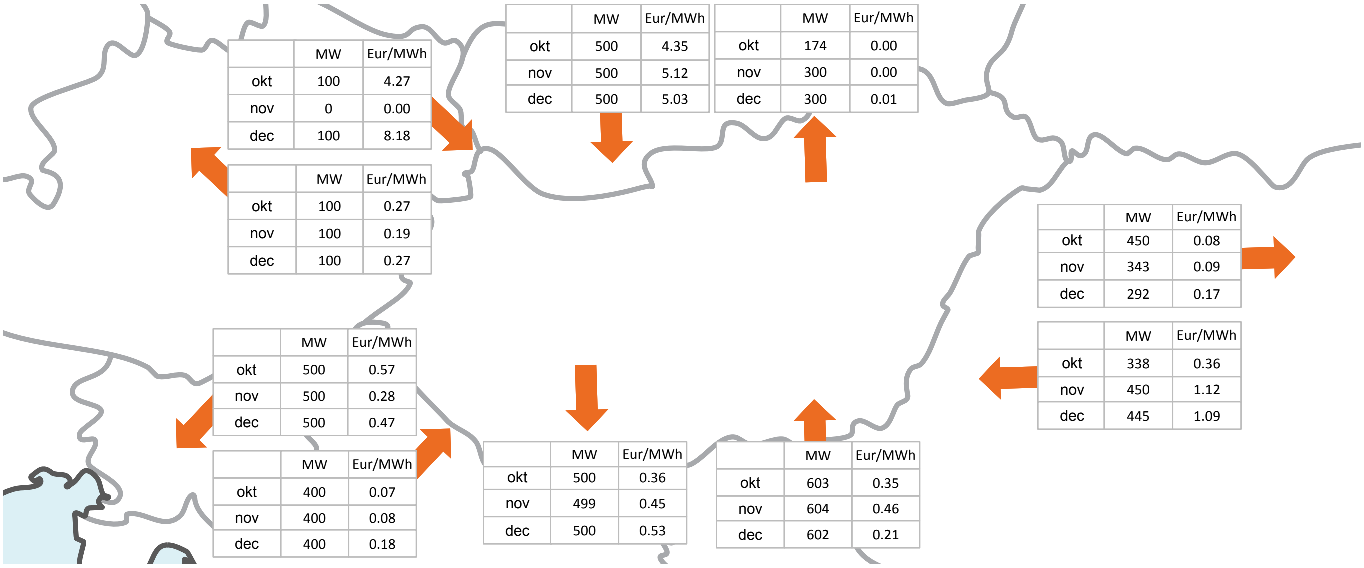
source: MAVIR

Figure 5 Quarterly domestic production and net imports between Q4 2012 and Q4 2013



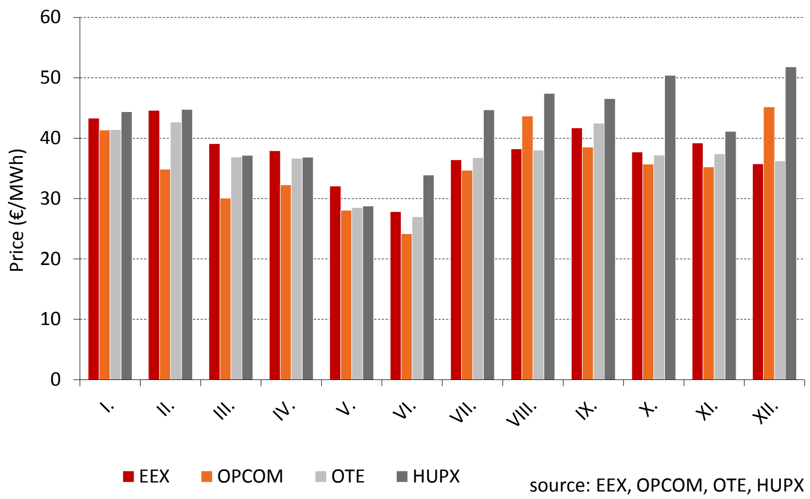
source: MAVIR

Figure 6 Results of monthly cross-border capacity auctions in Hungary, Q4 2013



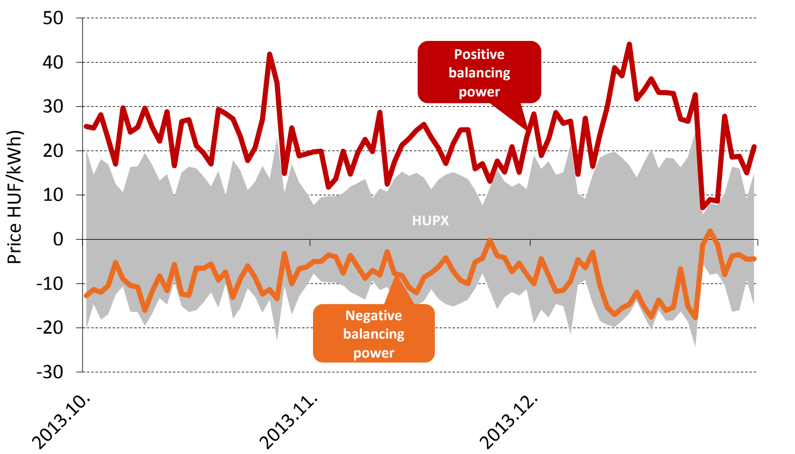
Note: The capacities in the figure indicate actual auction-based allocated capacities on the Slovakian, Romanian and Serbian border sections, while for the Austrian and Croatian borders the values stand for CAO published capacities offered at the auction (PTR)

Figure 7 Comparison of day-ahead baseload power prices on EEX, OPCOM, OTE and HUPX between January and December 2013



source: EEX, OPCOM, OTE, HUPX

Figure 8 Daily average of the balancing energy prices and the spot HUPX price, Q4 2013



source: MAVIR, HUPX

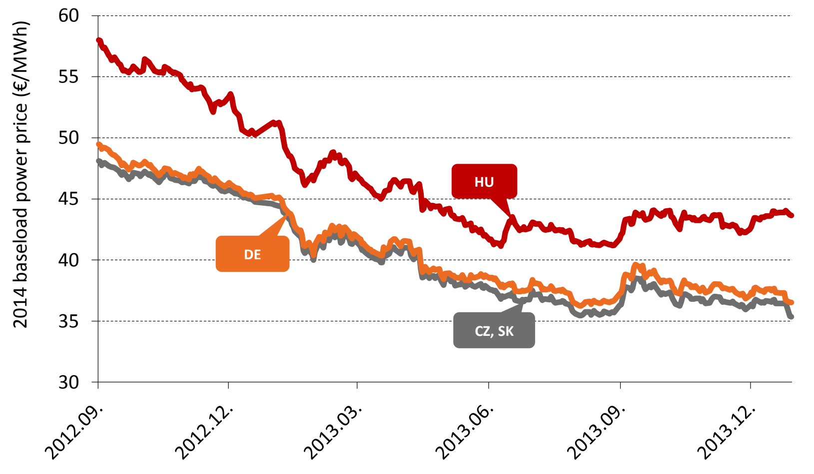
Note: The upper edge of the grey range in the figure is determined by the day-ahead price of HUPX, while the lower edge is the opposite of the same price. According to the Trading Rules of MAVIR the price of positive balancing power is limited to the day-ahead price on HUPX, while the negative balancing power is constrained by the opposite of the day-ahead price.

man EEX exchange by 13 €/MWh on average. In November prices notably converged, the price spread temporarily fell to 2 €/MWh, before reaching a new record of 16 €/MWh in December. The November convergence of prices can be explained from two different directions: the high production level of the Balkan hydro power plants, the restart of the Slovenian Krsko nuclear power plant and the lower domestic demand associated with warmer than usual weather in Hungary together decreased the prices in the Hungarian market, while colder weather in Germany and the lower electricity production of German wind power plants resulted in increasing prices in the German market. In December, however, German wind power generation gained momentum again, while Hungarian prices were raised by the bottleneck on the Austrian-Hungarian border section, contributing to the significant widening of the EEX-HUPX price spread. This trend was further enhanced by the unexpected downtime of the Mátrai Power Plant on two separate occasions. During the quarter Czech prices continued to stick to German prices, in October and November Romanian prices stayed slightly below EEX prices, while in December they exceed EEX quotes by more than 9 €/MWh.

The wholesale price is also impacted by the costs arising from the deviation from schedule and balancing energy prices. The system operator determines the accounted unit price of upward and downward regulation based on the energy tariffs of the capacities used for balancing. The order of using these capacities is established based on the energy tariffs offered on the next day regulatory market. The system for charging balancing energy has been developed by MAVIR so that it provides incentives to market participants to try to manage foreseeable deficits and surpluses through exchange based transactions - in other words, covering the expected deficit and surplus through the balancing energy market should not be attractive for them. For this purpose, the price of upward balancing energy cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing energy than the price at the exchange. During the quarter the price of both positive and negative balancing energy was about the same as in the previous quarter, positive energy costing 23.3 HUF/kWh on average, while the average price of negative energy was -8.5 HUF/kWh.

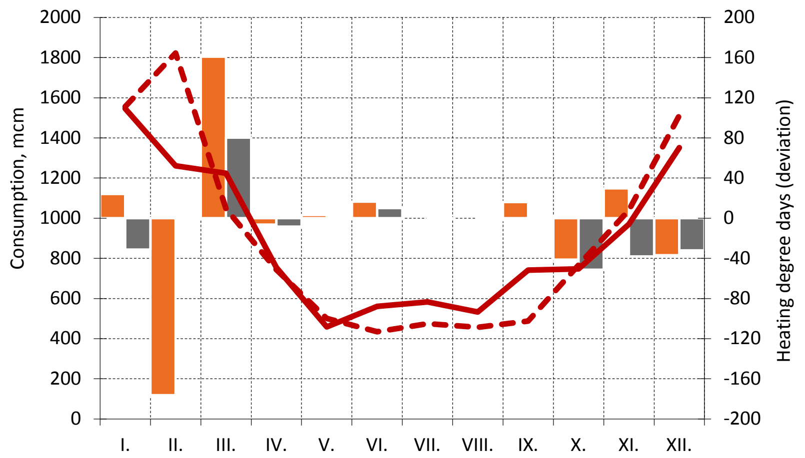
During the third quarter we did not observe meaningful, trend-altering changes in the price of baseload power for next year's delivery. The price of the 2014 Hungarian baseload product fell from 44 €/MWh in the beginning of the period to 42 €/MWh by early December,

Figure 9 Baseload futures prices quoted for 2014 delivery in the countries of the region between September 2012 and December 2013



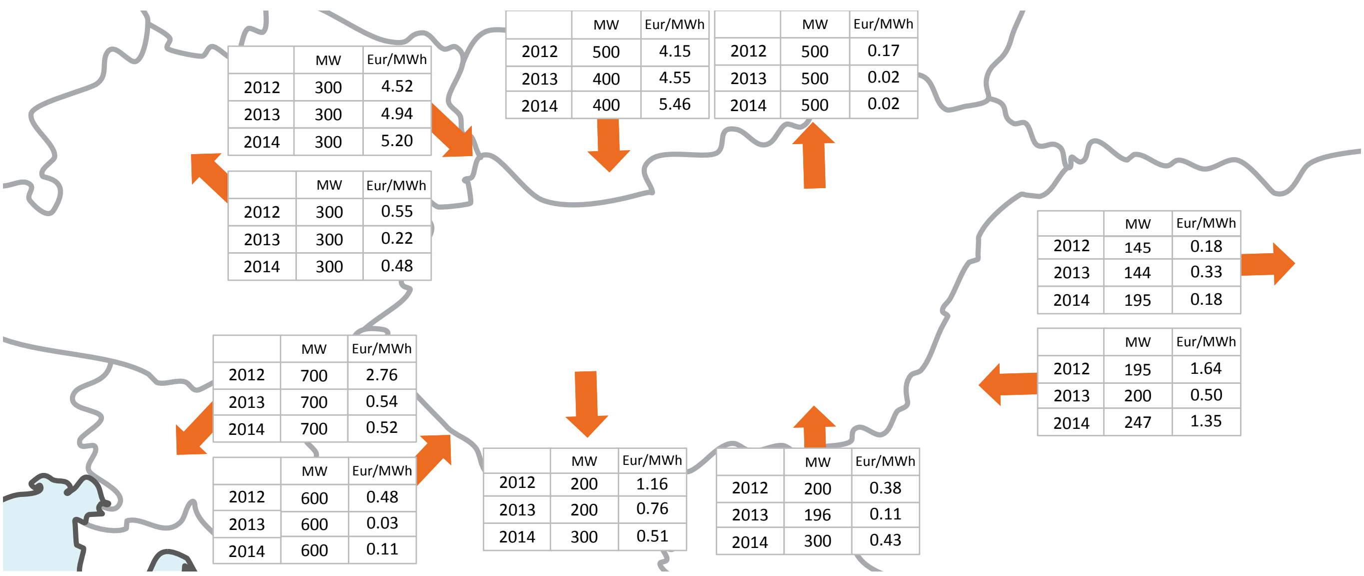
source: EEX, HUPX, OTE

Figure 10 Monthly natural gas consumption between January and December 2013 compared to the data from the same months of the previous year, and compared to the difference between the monthly heating degree days and the multi-year average hdd figures and those of the previous year



source: FGSZ; European Climate Assessment & Dataset

Figure 11 Results of annual cross-border capacity auctions in Hungary for 2012, 2013 and 2014



	MW	Eur/MWh
2012	300	4.52
2013	300	4.94
2014	300	5.20

	MW	Eur/MWh
2012	300	0.55
2013	300	0.22
2014	300	0.48

	MW	Eur/MWh
2012	500	4.15
2013	400	4.55
2014	400	5.46

	MW	Eur/MWh
2012	500	0.17
2013	500	0.02
2014	500	0.02

	MW	Eur/MWh
2012	145	0.18
2013	144	0.33
2014	195	0.18

	MW	Eur/MWh
2012	195	1.64
2013	200	0.50
2014	247	1.35

	MW	Eur/MWh
2012	700	2.76
2013	700	0.54
2014	700	0.52

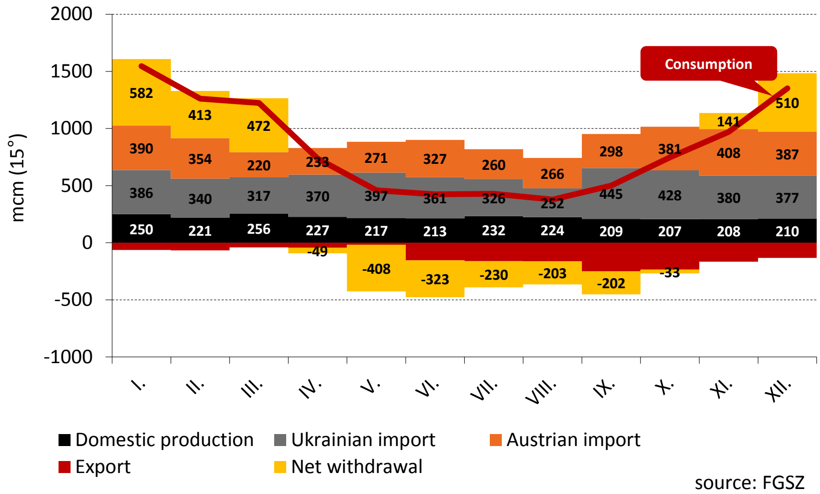
	MW	Eur/MWh
2012	600	0.48
2013	600	0.03
2014	600	0.11

	MW	Eur/MWh
2012	200	1.16
2013	200	0.76
2014	300	0.51

	MW	Eur/MWh
2012	200	0.38
2013	196	0.11
2014	300	0.43

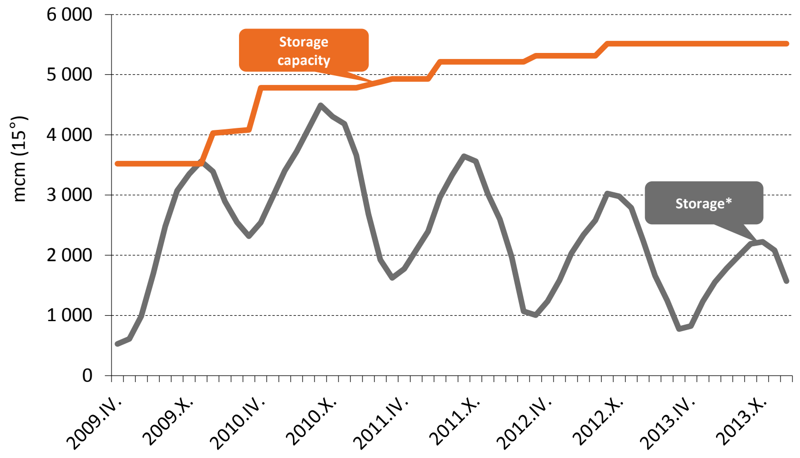
Note: The capacities in the figure indicate actual auction-based allocated capacities on the Slovakian, Romanian and Serbian border sections, while for the Austrian and Croatian borders the values stand for CAO published capacities offered at the auction (PTR)

Figure 12 The source structure of the gas market of Hungary by month between January and December 2013



source: FGSZ

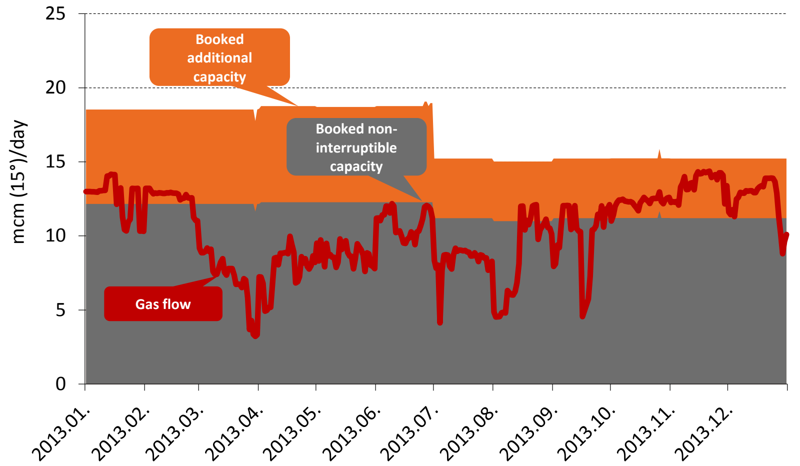
Figure 13 The working gas storage capacity of commercial storage facilities and their stocks by month



*At the end of the period

soruce: FGSZ

Figure 14 Transmission at the Baumgarten entry point between January and December 2013, together with booked interruptible and non-interruptible capacities



source: FGSZ

regaining the 44 €/MWh level by the end of the year. The price of the German annual baseload product was about 5.5 €/MWh lower during October and November, 6.2 €/MWh lower on average in December, while the Czech prices were traded at a discount of 1 €/MWh compared to the German market, similarly to the previous quarter.

Overview of the gas market in Hungary

The heating degree days (HDD) on the right hand axis of Figure 10 indicate the heating requirement. To calculate the HDD we look at the daily mean temperature. If it is below 16 degrees Celsius, then the daily HDD is the difference between the 16 degrees and the daily mean temperature. The monthly HDD is the sum of the daily heating degree days. By comparing the actual monthly HDD to the value from the previous year and the average HDD values from many years we can determine how cold the given month is in relative terms. Thus positive values stand for lower temperatures and higher gas consumption, and negative values stand for higher temperatures and lower consumption.

The natural gas consumption of the fourth quarter lagged 249 mcm behind the gas use of the previous year: this is explained mainly by the milder than usual weather. The October and December values of the monthly HDD were lower than the figures from last year as well as the multi-year average, while the November HDD exceeded the same value from last year, but the weather in this month was still warmer than the multi-year average. The annual gas consumption for 2013 was 10.03 bcm, lower than the 2012 figure of 10.84 bcm.

Domestic quarterly production was 625 mcm, less than the corresponding value of 666 mcm a year ago. The 1.83 bcm of quarterly net import arrived through the Mosonmagyaróvár (from Austria) and Beregdaróc (from Ukraine) entry points in a 50:50 split.

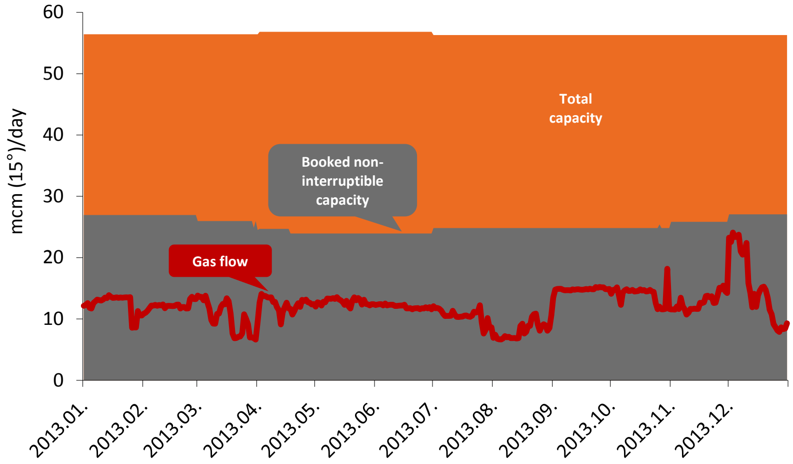
The capacity utilisation of natural gas storage facilities stayed low during the fourth quarter, in early October commercial storage sites were filled only to 40%, before declining to 29% by the end of the year. Storage facilities contained 1.6 bcm of gas at the end of the quarter, 30% less than a year ago. Actual stored volumes, therefore, continue to stay substantially below the mobile gas capacity of the domestic commercial storage facilities.

During the quarter 1174 mcm of gas arrived through Baumgarten, 42% more than during the previous quarter, but the same as the value for the fourth quarter of 2012. Utilised capacities were 14% higher than reserved, non-interruptible capacities, while during the fourth quarter 84% of the total reserved capacities were used.

During the fourth quarter 1.28 bcm of gas was imported through the Eastern border, 453 mcm, or 55% more gas arrived to Hungary through Beregdaróc than last year. This substantial annual increase, however, can be traced back mainly to the extremely low import of last year: the fourth quarter import in 2011 amounted to 1.05 bcm, which is less than the 2013 value only by a lower extent, 22%.

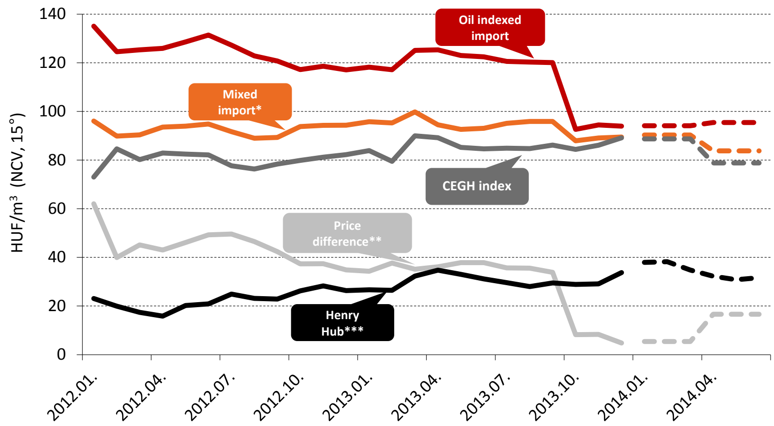
The oil indexed gas price declined from the 120 HUF/m^3 level of the previous quarter to 93-95 HUF/m^3: this is almost fully explained by the autumn 2013 renegotiation by E.ON of the price formula in the gas import contract, as a result of which the oil indexed gas price fell by 20%. Another consequence of the renegotiation of the gas price formula is the drop of the mixed import price valid for universal service providers - consisting of 70% TTF exchange and 30% oil indexed price - from the 95-96 HUF/m^3 level of the previous quarter to 88-90 HUF/m^3.

Figure 15 Transmission at the Beregdaróc entry point between January and December 2013, together with total available capacity and booked non-interruptible capacity



soruce: FGSZ

Figure 16 Past and forecasted future international and domestic wholesale gas prices



source: CEGH, EIA, ENDEX

* 30:70 weighted average of the oil indexed and the ENDEX TTF gas price on the power exchange.

** The difference between the oil indexed and CEGH price in case of actual data, and the difference between the oil indexed and the Endex TTF forward price in case of forecasted data.

*** Cubic meter price of the Henry Hub wholesale gas price, exchanged at the medium exchange rate of the Central Bank of Hungary.

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The second utility bill cut

The January 2013 reduction of regulated electricity and natural gas prices was followed by another round of universal service price reductions, while the third wave of price decrease should soon arrive to consumers. We provided a detailed analysis of the measures under the first phase of the utility bill cuts in one of our previous issues (Hungarian Energy Market Report, 1st issue of 2013). This time we take a look at the "second round" of utility bill cuts within the electricity and natural gas markets.

Electricity

As a second step of the utility bill cut, as of 1 November 2013 the regulator targeted a price decline of 11.1% compared to the previous month, resulting in a total 2013 price decrease of 20% together with the first phase of the utility bill cut for household electricity consumers that belong to the universal service segment. We should take note that the 20% utility bill cut only applies to households, and not to the full universal consumer segment. In our analysis first we describe the measures of the second round in detail, covering both universal service prices and system use fees. Then we review the extent to which measures on the utility bill cuts to date can be justified by the development of market prices. From the perspective of our theme it is proper to investigate the extent to which price regulation tracked the declining trend observed for market prices.

Building blocks of the second utility bill cut

During the analysis we describe the measures using the logic of the regulatory changes. These measures are contained in the MEKH decree regulating the change of network access fees, the changes of the Act on Electricity, and the NFM decree on universal service prices.

Network access fees are set by MEKH Decree number 4/2013. Table 1 describes the changes of the different components of the network usage fees (base fee, capacity fee and volumetric fees) as part of the second round of utility bill cut with respect to different connection levels.

As illustrated by Table 1, additional cross financing among large and small consumers has not taken place during the second round of the utility bill cut, an important feature of the first round of cuts. The network access fees for consumers connected to high and medium voltage essentially stayed the same. The base fee of low voltage consumers (including households) was reduced by 11.1%, while volumetric fees were not cut uniformly "across the board". In this case different levels of reduction took place for different categories, but for the largest group (profiled consumers) fees were reduced by 1% only. Thus, in the case of network access fees, a "deficit" has emerged within price reduction, since the 11.1% reduction of volumetric fees was not completed for household consumers. As shown later on in our article, this loss is offset by the regulation of other areas.

The MEKH decree contains two more important measures as well. On the one hand, it retained the formerly reduced and standardised 1.316 HUF/kWh price margin for universal service providers, not applying the 11.1% base reduction in this area either. As another important measure, the nation-wide comparative price of market based electricity purchase was reduced from 17.6 HUF/kWh to 15.15

Table 1 Network usage fees in 2013

	between 2013 I-X			from 2013 XI			Change %		
	Distribution base fee	Distribution capacity fee	Usage fees**	Distribution base fee	Distribution capacity fee	Usage fees**	Distribution base fee	Distribution capacity fee	Usage fees**
	HUF/year	HUF/kW/year	HUF/KWh	HUF/year	HUF/kW/year	HUF/KWh	HUF/year	HUF/kW/year	HUF/KWh
High voltage connection	211 380	1 467	2.62	210912	1467	2.61	100%	100%	100%
High-/medium voltage connection	105 684	4 216	3.88	105456	4216	3.88	100%	100%	100%
Medium voltage connection	105 684	7 530	5.51	105456	7865	5.41	100%	104%	98%
Medium-/low voltage connection*	3 528	-	11.66	3516	-	11.84	100%		102%
Low voltage connection I. (profiled)	1 728	-	15.64	1536	-	15.52	89%		99%
Low voltage connection II. (scheduled)	570	-	5.46	504	-	5.24	88%		96%
Low voltage connection III. (non-profiled)	35 232	8 568	11.28	35148	8640	11.02	100%	101%	98%

* profiled, whole day

** these include the distributor volumetric fee, the reactive energy fee, the fee for distribution losses and the balancing fee.

Table 2 Internal structure of universal service prices in 2013 (HUF/kWh, assuming average consumption)

		DÉMÁSZ			E.ON			ELMŰ			ÉMÁSZ		
		2013 I-X	2013 XI	%	2013 I-X	2013 XI	%	2013 I-X	2013 XI	%	2013 I-X	2013 XI	%
Distribution base fee (without VAT)		1728	1536	88.9	1728	1536	88.9	1728	1536	88.9	1728	1536	88.9
Universal service fee		19.56	16.77	85.7	19.09	16.35	85.6	19.48	16.7	85.7	19.27	16.51	85.7
Volumetric system service fees		13.99	14.07	100.6	13.99	14.07	100.6	13.99	14.07	100.6	13.99	14.07	100.6
Fee for other financial instruments		1.46	0		1.46	0		1.46	0		1.46	0	
Total fee, volumetric	without VAT	35	30.84	88.1	34.54	30.42	88.1	34.92	30.76	88.1	34.71	30.58	88.1
	with VAT	44.06	39.16	88.9	43.47	38.63	88.9	43.96	39.07	88.9	43.69	38.83	88.9
Total fee, including base fee	without VAT	35.72	31.48	88.1	35.26	31.06	88.1	35.64	31.4	88.1	35.24	31.22	88.6
	with VAT	44.97	39.97	88.9	44.38	39.45	88.9	44.87	39.88	88.9	44.61	39.65	88.9

Source: NFM Decrees 78/2012 and 4/2011, amended multiple times

HUF/kWh by the Decree. The method to determine this price is not available, currently its level is not set by regulation. Essentially, the comparative price of purchase is the recognised price of the market based purchases of universal service providers, but when supplying the service providers, MVM is not obliged to use this price. The price is established through negotiation between the service providers and MVM. We do not have accurate information on the purchase price, but based on the data published by the MEKH we can deduce that the service providers were very likely able to secure this price reduction when dealing with the MVM. The average price of electricity purchased from electricity traders fell from the 17-18 HUF/kWh characterising the January - October 2013 period to 15.5 HUF/kWh by the months of November and December (source: MEKH data on the corporations of the electricity sector). This implies that MVM has a large contribution to the second round of the utility bill cut, about 2 billion HUF/month, based on the average volume sold to universal service providers. In parallel, the burden falling on universal service providers obviously declines.

As part of the second round of the utility bill cut the Act on Electricity also got amended. While in the first round households were relieved of the burden posed by the purchase obligation regime, the current "package" removed the burden related to other financial instruments from the price setting of household consumers. With this measure three fee components do not any more fall on household consumers: the coal industry restructuring subsidy (0.17 HUF/kWh), the discount provided to electricity sector employees (0.2 HUF/kWh) and the subsidy to restructure CHP generation (1.71 HUF/kWh). For all other consumer groups the burden posed by other financial instruments increased to 2.08 HUF/kWh after the listed items were reallocated. Most of the supplemental burden of 0.6 HUF/kWh (compared to the previous level of 1.46 HUF/kWh) was probably created by shifting the burden to a narrower base, ultimately leading to renewed cross financing between large and small consumers. However, the role of additional cost increasing factors in a higher price cannot be rejected either. Importantly, in the examined case only the position of households improved, the non-household consumers under the universal service segment continue to pay the fee component under discussion.

All of the household consumer price change since 1 November 2013 has been determined by the amendments of NFM Decree No 4/2011 regulating universal service prices. The Decree sets the price for consumers supplied with universal service by consumption categories (general, time of use tariff, public institution) split to universal service providers. Within this, base and volumetric categories are also separately set by the Decree.

Table 2 describes the internal structure of the prices of household consumers with an average consumption profile, and how it changed between January and November 2013, separately for each service provider.

The base fees of distribution decreased by the targeted 11.1%, while universal service fees fell more substantially, by 14.3%. This decline and the termination of the individual fee components paid for by households (and their transfer in order to burden other consumer groups) together compensate for the unfulfilled cut of network access fees, already mentioned above, so that the total change of household prices would indeed reach the targeted level of -11.1%. Table 2 nicely illustrates that with respect to average prices including VAT the measures in question attain the targeted level, in other words, household consumers can certainly observe a 20% average reduction of their electricity bill compared to December 2012 prices.

The burden of the measure is again born by several groups. The reallocation of the other financial instruments raises the burden falling on non-household consumers, while MVM contributed to the utility bill cut through the reduction of the price of electricity sold to universal service providers. Even though the price margin of universal service did not change during the second round of the utility bill cut, the 11.1% reduction of the base fee still increases the burden falling on service providers, since this directly reduces the revenue of universal service providers. In case of universal service fees the approximately 15% reduction is directly proportional to the 15% reduction of the MVM purchase price, therefore service providers in this field have more or less escaped the negative consequences of the second round of the utility bill cut.

Market prices vs. utility bill cut

With the short analysis below we would like to examine how much room had been available to reduce domestic universal service prices, that is, the extent to which domestic price regulation was capable of carrying forward the declining trend of market prices to final consumer prices .

As part of our analysis we made the following simplified comparison. On the one hand, using the futures prices of EEX (quarterly average of the daily closing prices of the off-peak and peak EEX Phelix annual futures products) we calculated an off-peak and a peak market price that can properly represent the price range attainable by a universal service provider in case it acquired the desired volume directly in the market. Instead of next day prices we used much more predictable and less volatile annual futures prices. Thereby we aimed to model the security seeking behaviour of universal service providers, since the service provider always reserves the required volume of electricity in advance for a year. We adjusted this value with the fees of the Slovakian-Hungarian border section (as the most important border) so that our price corridor would cover transit fees as well. This price corridor is highlighted with yellow in our figure. We did not weigh off-peak and peak prices in order to create a price corresponding to a mixed universal service consumer portfolio, since it would be difficult to determine the share of off-peak and peak products within a universal service portfolio. The price of the universal service portfolio, however, can definitely be expected to fall between the prices of the off-peak and peak products.

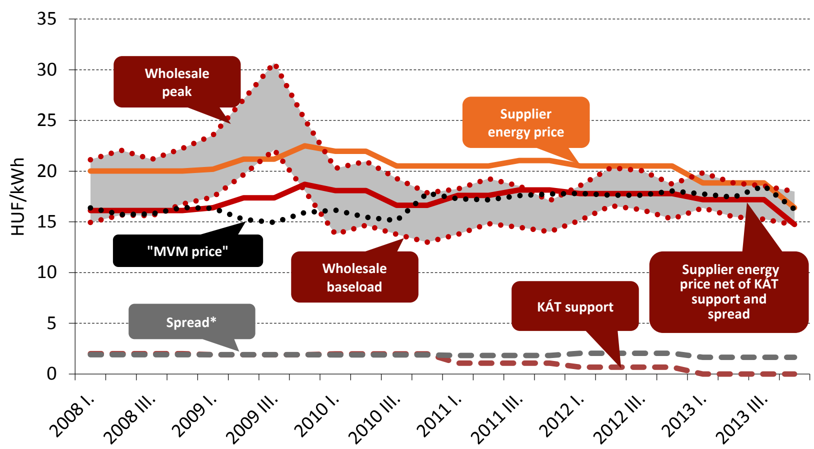
From the other direction, we cleaned the average service provider energy fee from two items in order to make it more comparable with the previously created market price corridor. The two items are the obligatory purchase regime fee and the price margin of the service provider, which are also excluded from market prices, therefore - to ease comparison - we subtracted them from the energy fee. By subtracting the two items, we calculated a cleaned service provider energy fee (indicated by the red line in the figure).

We compared these two calculated items (market price corridor and cleaned service provider energy fee) in the figure below.

The figure nicely shows that during the Q1.2008 - Q4.2013 period the cleaned service provider energy fee mainly stayed within the market price range, that is, price regulation kept the energy fee of the universal service in accord with the market. As a result of the first round of the utility bill cut the energy fee of the universal service sustained its position within the range, but the second package forced it to the bottom of the calculated market price corridor. In short, the energy fee is close to market based baseload prices, questioning its longer term sustainability. Furthermore, it would be interesting to know if the current strategy of utility bill cuts would also track a potential longer term ascending trend of wholesale markets.

Our comparison applies only to the energy fee portion of the universal service price, while we did not take on the benchmarking analysis of the level of additional items: the base fee, the network access fee, and the price margin of the service provider.

Figure 17 Comparison of the universal service provider energy fee

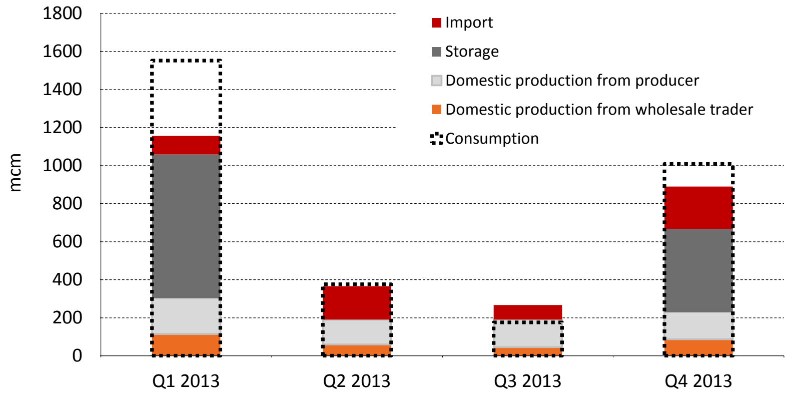


source: REKK calculation

Natural gas

The second round of the utility bill cut that entered into force on 1 November 2013 reduced the base fee and network access fee of gas consumers eligible for universal service by 11.1%, similarly to household consumers of electricity. Within the natural gas market the burden of this measure was shared by market participants - like in case of the 1 January 2013 utility bill cut. In our analysis first we review the regulatory changes related to the universal service of natural gas. Then we quantify the total burden that fell on the participants of the natural gas market during the last two months of 2013, originating from the fee reduction in the consumer segment. Finally, we identify the actual burden realised by each of the participants of the gas sector supply chain.

Figure 18 The volume of preferential natural gas sources transferred to universal service providers in accord with NFM Decree 19/2010



source: 78/2012. NFM, 19/2010. NFM, 13/2013. NFM, 34/2013. NFM, 58/2013. NFM Decree, Natural gas company's data by MEKH

The decrees creating the basis for the second round of utility bill cut

On the consumer side the utility bill cut was implemented by NFM Decree 64/2013, which amended KHEM Decree 28/2009. According to this amendment the base fee and the volumetric fee decreased by 11.1% for each household user and residential community. Decree 64/2013 also amended KHEM Decree 29/2009, reducing the price margin of universal service providers by 27%: the margin set by the first round of utility bill cut decreased from 174 HUF/GJ to 126 HUF/GJ.

Furthermore, MEKH Decree 1/2013 on the application of the natural gas network use fees was also amended, resulting in the decline of distribution fees - up to the universal service level - and the storage facility fees. The base fees of distribution declined by 11%, while volume based fees declined more steeply, by 46% on average for consumers below 20 m^3/h, and by 51% for consumers above 20 m^3/h. The capacity fee of storage declined by half, while the volume based fees of storage stayed unchanged.

By amending NFM Decree 19/2010 the regulator continues to provide universal service providers access to a source of natural gas that is cheaper than in the market. The regulator makes the cheaper source of natural gas available by freeing stored stocks, and handing the more advantageous Baumgarten import and domestic production to universal service providers. In 2013 the Decree was amended four times, setting the volume of preferential gas, its sources and its price for each quarter and each service provider. During 2013 the regulator allocated in total 92 PJ - 2.7 bcm at a heating value of 34.4 MJ/m^3 - preferentially priced natural gas to service providers. This volume made up 86% - 3.1 bcm - of the 2013 gas use of household consumers falling under universal service, and 88% during the fourth quarter.

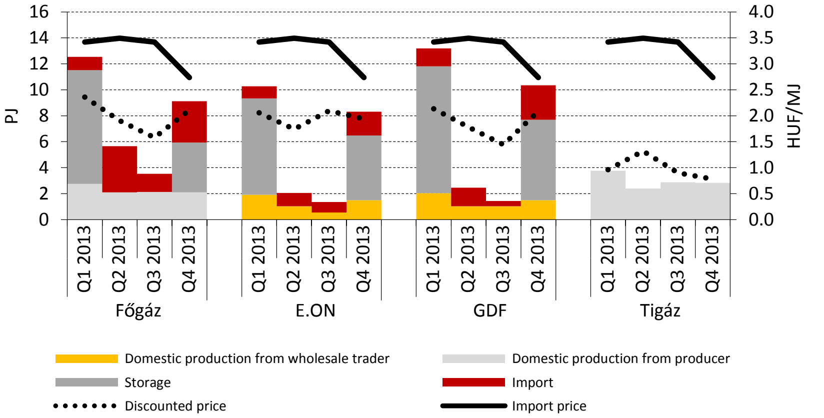
Individual service providers were granted different levels of the preferential sources of gas. In the last quarter of 2013 most preferentially priced natural gas was provided to GDF Suez, this group received 34% of the gas regulated through the decrees, of which 60% was gas from the storage facilities, 26% from import and 14% from domestic production. Főgáz was the second largest beneficiary with 30% of the total allocation, of which 42% originated from storage, 35% from import and the rest, 23% from domestic production. The universal service gas segment of E.On received 27% of the total volume of gas, with a similar source structure as GDF. The Decree granted the lowest volume of gas to Tigáz, 9% of the total allocated quantity, all of it based on domestic production.

The natural gas allocated through the Decrees assured an extremely large price discount to universal service providers in comparison to their recognised costs during the whole year: during the first and fourth quarters - which are especially relevant because of the increased gas use - the gas regulated through decrees was 20-40% cheaper than the price of the mix containing 60% exchange based and 40% oil indexed gas.

The cost of the second round of utility bill cut and the market participants that finance it

We calculate the costs of the recent utility bill cut compared to the first round of the cut. We compare the 1 November 2013 status of KHEM Decree 28/2009 with its preceding status, and quantify the revenue loss in the sector generated by the price

Figure 19 The volume and price of preferential natural gas sources transferred to universal service providers in accord with NFM Decree 19/2010, broken down to service providers



source: 78/2012. NFM, 19/2010. NFM, 13/2013. NFM, 34/2013. NFM, 58/2013. NFM decrees, Natural gas company's data by MEKH, REKK calculation

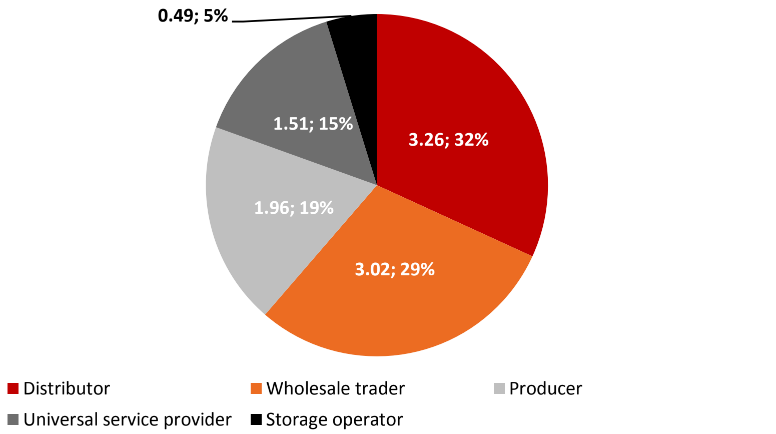
change in the months of November and December, and how this revenue loss was distributed by the regulator among market participants.

To calculate the "cost" side of the utility bill cut we need to make a few assumptions: with respect to the number of consumer we apply the number of 2011 household consumers, while the consumption of November and December 2013 is assumed to be the same as the consumption of the same months of 2012 (presumably the regulator also used the consumption figures of the previous year when setting the fee components). Since we make the estimate for two months, we use one-fifth of the annual base fee to calculate the base fee of the period in question. According to our calculations consumers gain HUF 10.3 billion during November and December, that is how much less they pay compared to the universal service fee established by the first round of the utility bill cut.

A more interesting question is what the "revenue" side is composed of. To calculate this, we used year 2011 customer numbers and year 2012 consumption again. According to our calculations, most of the burden falls on the distributors: they have to cover 30% of the revenue loss, or HUF 3.3 billion, due to the decrease of the base fee and the volumetric fee. Next in line is the wholesaler (E.On Földgáz Trade, later the Hungarian Natural Gas Trader - Magyar Földgázkereskedő) with 29% of the total revenue loss, or HUF 3 billion - as a result of the reduced price of natural gas handed over to universal service providers. As the natural gas producer, MOL contributes to the package of measures with 19% of the full sum, worth close to HUF 2 billion, as the preferential price of natural gas it extracts declines. The revenue loss of universal service providers adds up to HUF 1.5 billion due to the decrease of their price margin. The lowest loss is booked by the operator of the storage facility, at almost half a billion HUF. The participants together suffered a revenue loss of HUF 10.24 billion during November and December 2013, which is not much different from the HUF 10.3 billion calculated on the "cost" side. The actual consumption of 2013, nevertheless, was slightly different from the 2012 consumption, thus it would be interesting to know the extent to which the regulated fee components covered the utility bill cut. As a result of the mild winter the 2013 consumption fell 100 mcm short of the 2012 figure, therefore the sum collected from market participants on the "revenue" side overcompensated the costs to some degree - providing funds of HUF 9.8 billion instead of HUF 9.3 billion, HUF 500 million more than required.

Yet another issue worth looking at is how much the price of the natural gas product, as a cost item of the wholesaler, has changed since January 2013. A substantial drop in itself would already ensure a cut in utility bills. For the calculation we assumed that the gas purchase of the wholesaler is composed of 60% oil indexed and 40% exchange based (TTF) gas. While in 2013 prices on the exchange essentially did not change (see Figure 2), the oil indexed contractual price notably shifted: in November 2013 E.On successfully renegotiated the price formula of the gas import contract, as a result of which the oil indexed gas price fell by 20%, reducing the price to be paid by the importer from the 118 HUF/m^3 of the first quarter to 94 HUF/m^3 in the fourth quarter. This measure alone generated savings of HUF 2.55 billion for the wholesaler, financing one-quarter of the full cost of the utility bill cut.

Figure 20 Distribution of the burden of the second utility bill cut among sector players (billion HUF, %)



source: REKK calculation

Power plant investment activity and power balance in Hungary

The development of the European electricity markets has not favoured power plant investments for the last few years. The price of the annual baseload products quoted on the German markets has been trending lower since early 2011: at present 2015 baseload prices are barely above 35 €/MWh. The relative price increase of natural gas, the collapse of the price of carbon credits, and the decline of the peak-baseload spread prompted the operators of natural gas fired power plants to write off several billion euros of losses, close a number of plants and restrain their investment activity. In the largest European countries worries over the security of supply intensified, as a result of which the United Kingdom, France and Germany have all voiced their support for the future introduction of capacity mechanisms.

In many of ways the Hungarian situation looks a lot like the Western European one. Hungarian natural gas fired power plants are characterised by extremely low capacity utilisation, massive losses and the inactivity of some of the generating units. These gloomy circumstances, however, are instilled by the completion of a number of earlier investments and the entry of new, highly efficient power plant units into the market. In this article we seek to investigate the impact of all these processes together on the security of supply of the whole electricity system. Below we review how the domestic investment activity and the power plant portfolio changed during the post-crisis years, then we examine how the capacity balance changed in view of these numbers.

Capacity withdrawals and power plant closures

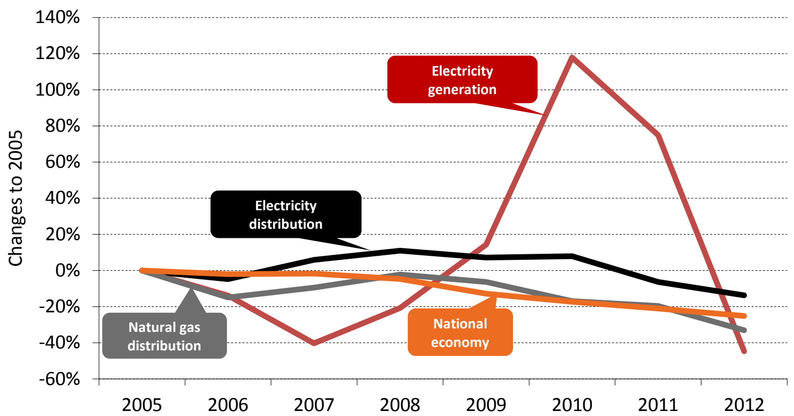
The period following the 2008 economic crisis can be subdivided into two distinct phases from the perspective of investments. During the first few years (between 2009 and 2011) the volume of power plant investments was still steeply rising, as pre-crisis investment decisions were executed. While the investment level of the national economy started to decline right after the crisis erupted, the investments in the electricity generating sector in 2010 and in 2011 were over two times higher than in 2005. This is a textbook example of investment cycles: the "delayed" rise of power plant investments was followed by a dramatic drop in 2012.

The impact of the temporary rise of the volume of investments and the subsequent drop is also apparent through the capacity indicators of the domestic power plant fleet. The surge of the volume index indicates the successful completion of the Gönyűi CCGT (433 MW), the Dunamenti G3 CCGT (410 MW), and the Bakonyi OCGT (120 MW) investments: the 2011 entry into operation of these three large power plants increased the installed capacity of the domestic electricity system by almost 1000 MW.

In parallel with the entry of the new units, however, the closure of power plants that started to generate heavy losses under the unfavourable economic environment also began. In 2011 the Tiszapalkonyai Power Plant (200 MW) and the Borsodi Thermal Power Plant (137 MW), in 2012 the Tiszai Power Plant, that was squeezed out of the wholesale market (900 MW), while in 2013 the DKCE (95 MW) and the NYKCE (47 MW), that gradually became unprofitable following the termination of the feed-in tariff, decided on the temporary (3 year long) suspension of their producing permits. The net impact of the above changes is that the currently available total capacity of those power plants of the electricity system that have over 50 MW of capacity is about 1000 MW less than the 7000 MW level typical of the pre-crisis years.

In addition to the volume index of investments and capacity indicators there is also a less exact indicator of the trends in the field of power plant capacity development: changes in investment plans. The most reliable collection of domestic power plant development plans is the so called Plant Tracker published by Platts twice a year. By comparing the 2010 and 2013 lists it becomes apparent that former predictions counting on 6000 MW of generating capacity to enter the market between 2012 and 2015 are not

Figure 21 Investment volume indices calculated with a 2005 base



source: KSH

Table 3 Change in power plant capacity development plans between 2010 and 2013

Power plant	Investor	Capacity	Type	Planned launch of operation	
		MW		2010 status	2013 status
Dunamenti G4	GDFSUEZ	400	CCGT	2012	suspended
Nyírtass	Emfesz	400	CCGT	2012	cancelled
Nyírtass	Emfesz	400	CCGT	2013	cancelled
Százhalombatta	MOL-CEZ	800	CCGT	2013	suspended
Borsod 2	AES	260	Lignite	2012	cancelled
Vác	D100 Invest	100	pumped storage	2014	cancelled
Nyírtass	Emfesz	1600	CCGT	2015	cancelled
Mohács	E.ON	400	CCGT	2015	cancelled
Csepel 3	Alpiq	430	CCGT	2015	2016
Sima	MVM	600	pumped storage	2015	cancelled
Mátra 2	RWE	440	Lignite	2015	cancelled
Tisza 2	IFC	185	CCGT	-	2015
Almásfüzitő	Euroinvest	800	CCGT	-	2017
Szeged	Advanced Power	920	CCGT	-	2017

source: Platts Energy in East Europe, Issue 269, July 12, 2013

fulfilled: with one exception all of the envisaged projects were either cancelled or suspended.

Next we examine if as a result of the above described decline of capacities and the change in the behaviour of investors there is any reason to worry about the security of supply.

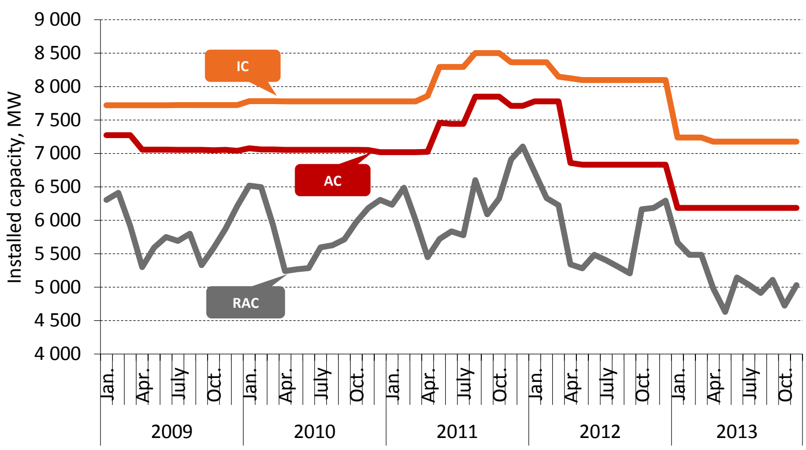
A number of indicators can be used to measure the operating security of the electricity system. A widely applied and relatively easy to calculate indicator compares the installed capacity and peak consumption for selected periods. This indicator, however, may lead to faulty conclusions since it disregards important factors like the planned maintenance of power plants, the surplus capacity available via import, or the system reserves booked by the system operator. To eliminate this problem, in order to test the operating security of the system MAVIR applies the so called remaining capacity (RC) - also used by the ENTSO-E - which also considers the above mentioned factors, and can be calculated with the following formula:

$$MT = TIT + ImportTIT - P - RIT$$

where
RC is the remaining capacity;
RAC is the reliably available capacity which is the difference between the net generating capacity (NGC) and the permanent and temporary non-usable capacity, maintenance and overhauls, and outages;
Import RAC is capacity from import sources;
P is the peak load;
SSR is the upward and downward system services reserve.[1]

The expected value of the remaining capacity varies by countries, generally it is equal to 5-10% of the installed capacity. MAVIR set this value to 500-510 MW with respect to the inspected years (darker interrupted line in the figure below), equivalent to 5% of the January installed capacity (lighter interrupted line). For the period of 2010-2013 the remaining capacity of the Hungarian electricity system is depicted by the figure in absolute terms (expressed as MW) and as a percentage of the installed capacity in a monthly breakdown.[2] Since, of the data used for the calculation, the peak load of the system can display substantial variations within a month, results may be substantially influenced by the actual peak load used

Figure 22 Capacity data of power plants above 50 MW (MW)



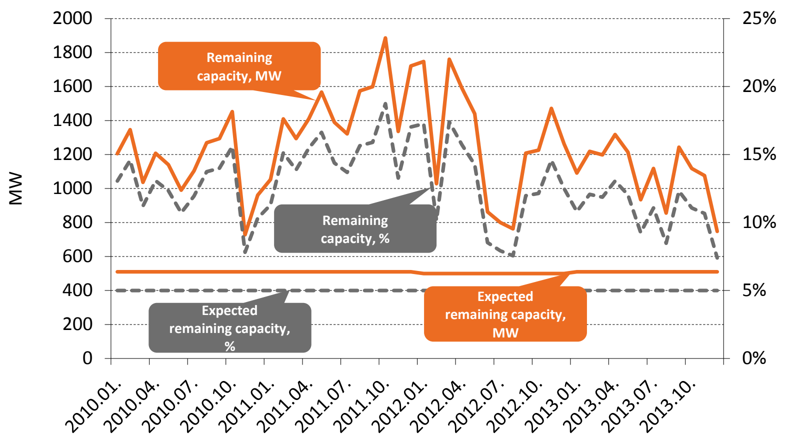
source: MEKH

IC: Installed capacity
AC: Available capacity
RAC: Reliably available capacity

[1] *Primary, secondary and tertiary reserve capacity, in total 845 MW in 2010, 840 MW in 2011, 837 MW in 2012, 841 MW in 2013 (source: MAVIR annual capacity plan).*

[2] *Calculations for the 2010-2012 period are based on the monthly data released by MEKH and MAVIR in their publication "Statistical data of the electricity system", while for 2013 we used monthly values aggregated from the daily figures published in the 2013 annual capacity plan of MAVIR.*

Figure 23 The actual and expected value of the remaining capacity expressed in MW and as a percent of installed capacity, 2010-2013



source: REKK calculation, based on MEKH, MAVIR

for the calculations. To compute the monthly values shown in the figure we used the maximum system load of the given month. Notably, this method leads to a conservative, pessimistic estimate for the remaining capacity.

As the figure shows, despite the conservative method of calculation the remaining capacity clearly exceeds the expected values for the whole period of the analysis, suggesting that security of supply related problems should not be a concern. Even though compared to the previous years the 2013 remaining capacity (especially for December) declines a little, this tendency does not seem to carry on to 2014 (the average remaining capacity for January 2014 is at around 1500 MW according to the 2014 capacity plan of MAVIR, which is higher than the corresponding value from January 2013).

As the above figure depicts data aggregated for each month, potentially serious problems appearing on specific days may be hidden. However, it is reassuring to know that with respect to daily data there are only a low number of instances through the inspected period when the remaining capacity stays below the expected value.

Importantly, within the above analysis remaining capacity always stands for remaining capacity calculated to include import as well. MAVIR, however, also calculates remaining capacity by considering only domestic generating capacities as actually available capacity. In this case through much of the inspected period the expected level of remaining capacity is not attained, in fact, there is negative domestic remaining capacity. In our view, however, as a result of intensifying international cooperation and an increasing share of import in meeting domestic demand, available import options also have to be considered when system security is assessed. Therefore, as a measure of operating security we consider the above described import adjusted remaining capacity indicator as more appropriate than those which rely purely on domestic capacities. We should note, however, that even this indicator is not perfect, since it makes use of actual import volumes instead of the potential import capacity.

Another often cited precondition of the secure operation of the electricity system is the availability of sufficient levels of system reserves at the disposal of the system operator to ensure the flexibility of the system. While there is widespread concern that the current difficulties of natural gas fired power plants may lead to supply side scarcity - mainly with regard to secondary reserves -, for the time being these fears seem to be unwarranted. Experience from the tenders of the last few years to acquire system level reserves shows that there is ample regulatory capacity; the potential supply is almost an order of magnitude higher than the volume of reserves recommended by the ENTSO-E. As an interesting new development due to a regulatory change only those traders can participate in the tenders this year that have possessed an electricity trading license for at least three years. While this amendment adversely affects some of the influential market participants of the recent past, and makes market entry more difficult, the supply side has not really been impacted yet, since the participants in question can offer their capacity through other participants. We should remember that in spite of the uncertainty of the level of capacities to be created in the future we probably do not have to fear an absence of secondary capacities even in the long run, since some of these capacities can also be acquired from abroad through various arrangements. Foreign procurement may be facilitated by the more intense international cooperation that is expected with respect to regulatory reserves.

The adverse electricity market developments of the last few years (delayed or cancelled power plant investments, temporary or final closure of loss-making power plants) may raise concerns over the security of supply in many observers. The analysis of the remaining capacity indicator that is usually used to inspect the operating security of the electricity system, nevertheless, demonstrates that security of supply problems are not to be feared yet. Based on the examination of the supply side of the secondary reserve market we can conclude that there is ample reserve capacity, thus we should not fear that the current market situation endangers the flexibility of the Hungarian electricity system.

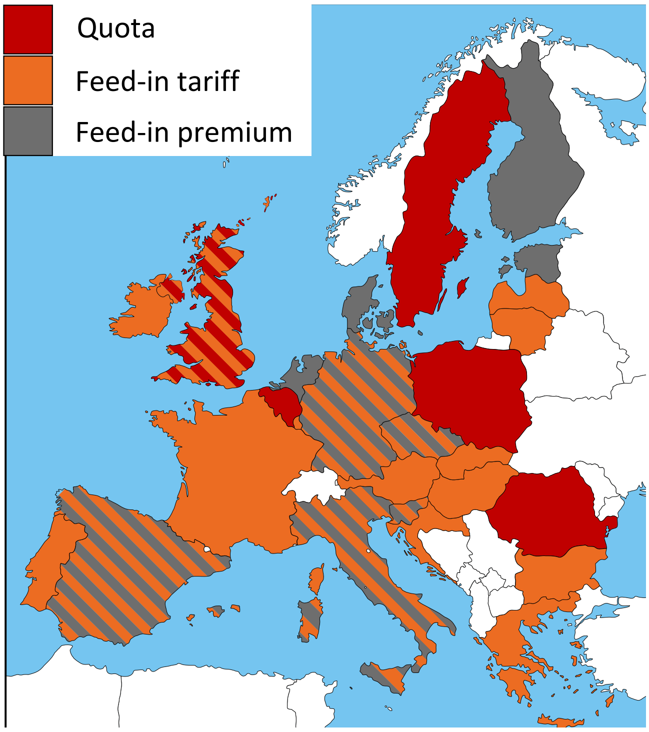
Problems related to the support schemes of renewable based electricity generation and the reform concepts of the EU

Recently a number of EU member states have substantially and unexpectedly tightened their renewable electricity support schemes. These amendments have in some cases also trimmed the support enjoyed by already existing generating facilities (Romania, Bulgaria, Czech Republic) as a result of which a number of investors, facing the loss of their assets, have opted to resolve the conflict through legal action.[3]

These regulatory interventions have been triggered directly by the steeply rising financing requirement of these support schemes as well as the subsequent increase of the final consumer price of electricity. (In most countries the burden of financing the support schemes falls on the consumers and its cost per kWh is often separately indicated on their invoice.) The quickly growing total cost is driven by the high level of support, which turned renewable electricity generation into a highly profitable and low risk investment. As a result - and due to the short lead time of installing photovoltaic (PV) and wind power plants - installed capacity, the volume of production and the sum of subsidies to be paid all soared. The excessive level of subsidies may be traced back to the unit subsidy having been set improperly, at a much higher rate than costs, but it may also be explained by the inflexibility of the support regimes, namely that they are not capable of adjusting to the declining costs of technology.

In Europe, in order to achieve national renewable electricity targets, Member States operate national support regimes of various efficiency that are difficult to compare. Feed-in tariffs (FIT) are in place in 13 countries, a purchase premium is employed by 5 countries, a mixed system of FIT/purchase premium prevails in 4 countries, similarly to green certificates (see Figure 24). In the United Kingdom and Italy the support regimes are greatly mixed. Not only the method of support, but also its level is highly diverse. According to the 2013 survey of the Council of European Energy Regulators (CEER) the subsidy per unit of production fell between 6 and 126 €/MWh in 2010.[4] Differences of similar magnitude are indicated by the estimates of REKK for the countries of the Danube Region using 2012 data (Subsidy values between 20 and 250 €/MWh).[5] In a number of countries (for example Spain, Romania, Czech Republic) renewable support increased the price of electricity by 10-15%, hardly appealing from the perspective of politicians. According to the estimates of REKK the 2013 renewable support in the Czech Republic reached 0.86% of the GDP, co-financed by consumers and the central budget.

Figure 24 Renewable support schemes in the European Union



source: European Commission Guidance for the design of renewables support schemes (Commission Staff Working Document, Brussel, 5.11.2013, SWD (213) 439 final)

Modification of the Romanian and Czech support systems

In 2013 Romania notably reduced the support provided to renewable investments and introduced a number of new measures raising the uncertainty surrounding the investments. Since 2005 Romania has been supporting renewable electricity production through green certificates: for every MWh of electricity - depending on the technology - the producer receives 1-6 green certificates that can be sold independently of the electricity. The demand for green certificates is generated by the government imposed specific purchase obligation falling on traders and importers. The annual quota (which determines the volume of purchase obligation as a ratio of sold electricity) gradually grows from 8.3% in 2010 to 20% in 2020. The support covers all technologies except for hydro power plants with installed capacities in excess of 10 MW (Table 4). Until spring 2013 at a unit price of €55 per certificate, equal to the administrative price ceiling, this regulation ensured a rather higher support for some of the technologies.

[3] The CEZ, for example, has turned to the European Commission due to its annual income loss of EUR 66 million at its Romanian investments.

[4] CEER: Status Review of Renewable and Energy Efficiency Support Schemes in Europe C12-SDE-33-03, 2013. június

[5] REKK (2013): Renewable Electricity Market Monitoring in the countries of the Danube Region, 2013

Naturally, such a high price of certificates is not guaranteed for the whole duration of the support period.

As a result of the support level introduced in 2010 substantial wind and PV capacities have been installed in a few years. The negligible wind generating capacity of 2009 (14 MW) reached 2165 MW by mid-2013. The penetration of PV systems took off in 2012, having climbed to 455 MW by today. In 2012 the Government empowered the Romanian regulatory authority to regularly evaluate the adequacy of the support level and made it possible to reduce the number of green certificates per MWh granted to new entrants in case support proves to be "excessive", but the appropriate law makes this intervention possible only after 1 January 2014, and 2015 in case of PV.[6]

In April 2013 the authority finally declared that the support provided to wind and PV generators is too high, that is, it exceeds the 10% internal rate of return used as a benchmark. Due to the 2012 Act, however, the authority did not have the power to reduce the subsidy, that is, to lower the number of green certificates supplied in connection with the two technologies, therefore in order to mitigate the increase in prices the government utilised an alternative solution, the temporary retention of the allocable certificates. In accordance, from 1 July 2013 new generating units of specific technologies are supplied with less green certificates than their assigned number per MWh.[7] Wind power plants receive only one green certificate instead of two, PV gets 4 instead of 6, and hydro power plants are provided with only one instead of three by the TSO responsible for the supply of green certificates (Transelectrica).

Retained certificates will be gradually allocated to producers after March 2017 (hydro and PV) and January 2018 (wind). The lower number of issued certificates, on the one hand, results in a direct loss of revenue until 2017, while on the other hand it also carries a market risk since an increasing supply of green certificates may easily drive the price away from the previously stable 55 EUR, the administrative price ceiling of the current system. In order to keep the burden falling on consumers under control, the regulatory authority (ANRE) - based on the new regulation - sets an annual capacity constraint on the number of new units that can enter the support scheme. Those that have failed to access certificates for the current year may "queue" for next year's allocation. Furthermore, the decree has also banned the bilateral sale of green certificates. Investors face increased costs as network companies may require a financial deposit in exchange for the network access right, and they only return the deposit if the generating unit starts operation by a certain date. The primary purpose of this measure is the elimination of rent-seeking companies.

In the Czech Republic renewable electricity producers can choose from the feed-in tariff set by the decree and a fixed premium supplementing the market price. As a result of the high support level in effect until 2010 and the unlimited network connection capacity, approximately 2 GW of PV capacity had been built by 2012. The annual change of the feed-in tariff is limited by law to 5% at most. Due to the escalation of the total costs, however, from 2011 ground-mounted PV units have been excluded from support, issuing new network connection permits has been suspended, and a 26% tax was introduced on those ground-mounted PV producers that were installed between January 2009 and December 2010 and have a capacity in excess of 30 kW. Due to the retroactive nature of taxation a group of senators called upon the Constitutional Court, unsuccessfully. According to the new rules that entered into force in 2013 only small scale units are eligible for feed-in tariff (in case of PV roof-mounted units with a capacity of less than 30 kW, hydro plants below 10 MW, and other technologies below 100 kW), price premium is available for the rest.[8] The 26% PV tax, originally planned to be temporary, stayed in force, and only roof-mounted solar panels with a capacity below 30 kW can be exempted.

In accord with the changes adopted in October 2013 only those producers are eligible for feed-in tariff that enter the market before the end of 2013.[9] Wind, geothermal and biomass technologies below a capacity of 100 kW are eligible only if they had secured a final construction permit before October 2013 and start operation by the end of 2015. As a result - with the exception of hydro power plants - support through feed-in tariffs essentially becomes non-existent for new entrants. The 26% tax imposed on the feed-in tariff of PV is reduced to 10%. In order to mitigate the increase of the price of electricity, the support to be paid by consumers is limited to 495 CZK/MWh by law (equivalent to 6.24 HUF/kWh using current exchange rates). Any support above this limit is financed by tax payers through the general budget. The absolute cap on support is 4500 CZK/MWh (about €180/MWh), that is, potentially most of the support is covered by general tax revenues, separately from electricity consumption.

[6] *Act 134 of 2012*
[7] *Act 57 of 2013*
[8] *Act 165 of 2012*
[9] *Regulation No. 310/2013*

Table 4 The main features of the Romanian support scheme

Technology		Green certificate/MWh	Length of support period (year)
Hydro power plant below 10 MW	built after 2004	3	15
	renovated	2	10
	built before 2004 / not renovated	0,5	3
Wind power plant	new	2 until 2017, 1 afterwards	15
	used turbine	2 until 2017, 1 afterwards	7
Biomass, biogas, geothermal	new	2	15
	new (produced from energy crops)	3	15
	highly efficient combined generation	1 more	15
Landfill gas and biogas from sewage	new	1	15
	highly efficient combined generation	1 more	15
PV	new	6	15

source: ANRE

The reaction of the European Commission to the deviations of the renewable regulation of the Member States

The European Commission - as a response partly to the renewable related regulatory deviations, and partly to the national capacity market plans - published a detail opinion on the role of public interventions (C(2013) 7243 final). The Commission acknowledges the necessity of interventions in the interest of the climate and security of supply related goals of the EU, but only if applied temporarily and in a limited way. The purpose of the published guidance is the creation/transformation of the national renewable support schemes and the reserve capacities needed to supplement renewables in a way that is as market compatible as possible. With respect to the renewable support systems the following normative statements are made.

All regulatory changes with a retroactive effect are to be avoided. These erode investor confidence, and consequently increase the capital cost of investments, materially impacting the development of the whole sector. The right of investors to the returns foreseen when the decision on the investment had been made cannot be impaired. At the same time, they cannot receive excessive support either, since that unreasonably increases the price of energy, and qualifies as illegal state aid. In accordance with this dual expectation support schemes need to be developed that are capable of adjusting to the continuously declining costs of production through predefined algorithms, making abrupt regulatory changes with a retroactive effect unnecessary. Germany, for instance, reformed its own system in this way, with the feed-in tariff being adjusted to new installed capacities based on a method announced in advance. A similar market compatible method of cost restriction is setting the maximum annual value for new capacities or the sum available for support (e.g. the Netherlands).

The Commission's view is based on the principle that the positive discrimination of renewable based electricity gradually needs to be removed, and renewable producers have to be integrated into the operation of the energy market. Their exposure to market prices has to be increased, while step-by-step their support needs to be withdrawn as the costs of production further decline. In the short run, this practically requires the replacement of feed-in tariff systems with a price premium or a green certificate system. Under current feed-in tariff schemes investment decisions are typically not independent of the technology, while decisions on production (and sales) are not market specific. Moreover, setting the support level in an optimal way is difficult due to the regulatory authority being poorly informed. This is why the Commission proposes the application of competitive allocation mechanisms both in setting renewable support and to allocate capacities, contributing to the more efficient use of public funds. A long established relevant case is the SDE+ system of the Netherlands, under which - within the limits of the pre-set total annual budget - investment schemes can be submitted six times a year in exchange for a growing premium. The limited nature of the budget prompts bidders to enter the support scheme at their actual level of production costs.

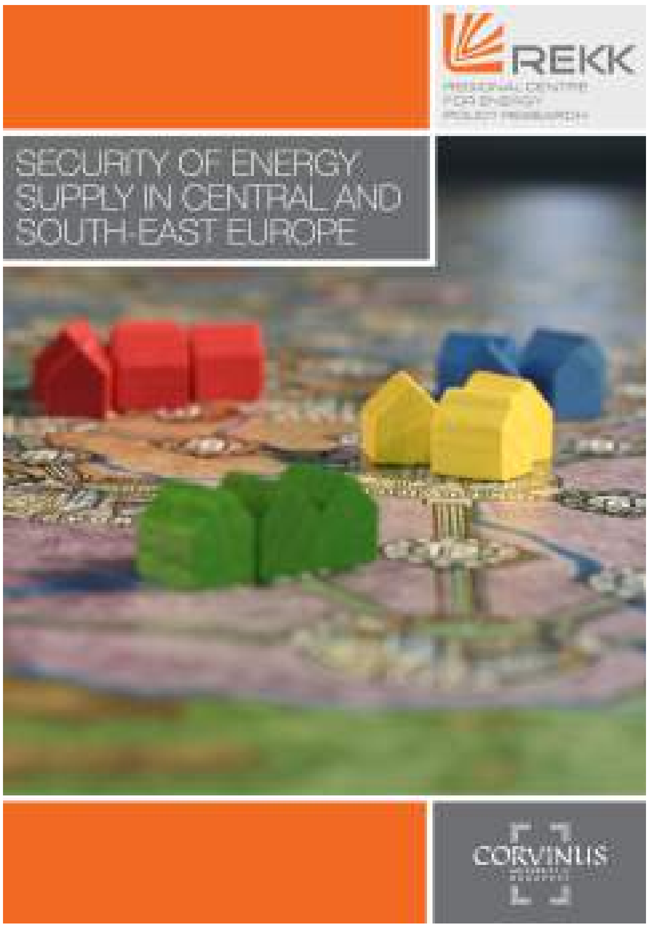
Other important fields through which the market integration of renewable production and technology-neutrality can be fostered are the balancing market and network integration. Today renewables are frequently not obliged to keep schedule and they do not bear the full cost of balancing them and their connection to the network. These questions are also

[10] *The Commission regards R&D grants as the best incentive for new technologies.*

regulated on the national level, there is not a uniform European practice. The efficient utilisation of resources, however, presumes that each producer is responsible for its deviation from schedule and decides on its production based on the price signals of the market. With respect to network access costs the Commission believes it is more important for investment decisions to align with the availability of resources ("where the wind blows") than having an optimal adjustment to the network layout ("where the network is strong"), that is why it recommends the practice of the reallocation of network costs (placing the burden on the rest of the network users) already characteristic of a lot of countries ("shallow cost"). It also underlines the importance of liquid intra-day trading and gate closure with respect to scheduling in order to reduce the balancing cost of weather dependent technologies.

While the above Commission guidance is not legally binding, it serves as the starting point for future inspections on state aid, therefore it is an important landmark for member states. In 2009 the European Union opted for national support systems, even though a uniform European renewable market would provide a more efficient mode of reaching the 2020 targets of the EU. The so called flexibility mechanisms - through which differences in costs and conditions could be taken advantage of -, however, are not really viable, that is why the Commission calls for the "marketisation" of support systems and the market integration of renewable producers. Meanwhile the competitiveness of renewables rapidly improves and once installing such capacities becomes profitable without any support, then a new chapter will open in the history of renewable electricity generation, in which the central issue is not any more the proper conditions for renewable support, but ensuring the necessary development of networks and sharing the costs among network users. Creating networks capable of serving renewable capacities requires substantial investments, while at present renewable producers and households with micro power plants ("prosumers") typically do not contribute to network costs in proportion to their use, raising the need to review network tariff systems.

Security of Energy Supply in Central and South-East Europe



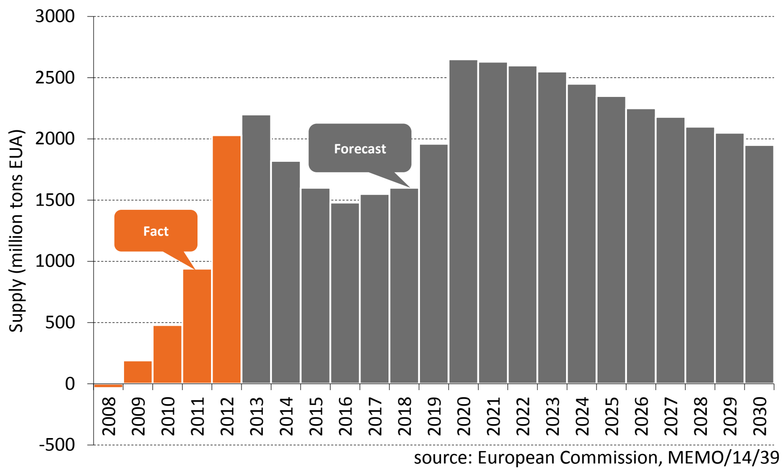
REKK has published the volume containing the studies of the SOS project started in 2009. The papers of this book were motivated by the wish to get a better understanding of the threats and challenges to gas and electricity supply security in a number of countries in Central and South Eastern Europe (CSEE). 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.

The 2030 European climate policy plans

The common action against climate change has been progressing rather slowly for years now, both on the European and the international scene. While in the latter case many of the large greenhouse gas (GHG) emitting countries have resisted a new overarching global agreement, within the European Union the main instrument for GHG reduction, the emission trading system, has not fulfilled its duty due to the low price of carbon.

Figure 25 Surplus in the emission allowance market between 2008 and 2012, and forecast until 2030



source: European Commission, MEMO/14/39

Even though the 2020 EU target of a 20% reduction of GHG emissions seems likely to be achieved, this is not driven by the efficient emission abatement of the companies and governments, but the economic crisis. Between 2011 and 2012 within the emission allowance (EUA) market a substantial surplus — equivalent to the supply of a full year — accumulated (Figure 25).[11] As this surplus is not predicted to leave the market, the low price (5 EUR currently) is also likely to last.

The low European carbon price does not provide an incentive for the companies under the emission trading system to curb their GHG emissions, therefore the central instrument of European climate policy can shepherd the economy towards low carbon technologies only on a limited scale.[12] Therefore in 2012 the Commission released a study containing a number of proposals to be publicly discussed, as a result of which the planned 2014, 2015 and 2016 auctioning of a total number of 900M EUAs was delayed until the end of the compliance period in 2019 and 2020 („backloading").[13] The rearrangement of supply within the period, nevertheless, is sufficient only to balance the increased supply originating from the transition between the second and third trading periods, and it does not affect the surplus in supply, therefore it does not enhance the effectiveness of the trading system either. The reason for the additional supply at the end of the period is the arrival to the market of the international credits that expire at the end of the second period, as well as the early sales of third period EUAs, which has paradoxically taken place in order to fill the NER300 financial fund that was created to finance renewable projects and CCS, the latter viewed as an important tool in the fight against climate change.

In its 2012 allowance market evaluation the Commission disclosed a number of potential structural solutions, namely: definitive credit withdrawal, increasing the factor that at present narrows supply by 1.7% per year, adding new emitting sectors, restricting the import of international credits, and setting a price threshold. Following the public debate of the evaluation the draft regulation on reserves was prepared. The Commission communication (COM(2014) 15)) published in January 2014 proposed that a market stability reserve is established as part of the structural reform of the emission trading system.

The reserve would be put to use from the beginning of the next compliance period (from 2021) based on predetermined rules, without an opportunity for Member States or the Commission to intervene. At the end of the compliance period the reserve would not cease. Based on the current proposal if the number of allowances available in the market in a given year in excess of the volume of emissions ("market surplus")[14] exceeds 833 million, then 12% of this amount is automatically placed into the reserve, and the quantity to be auctioned is reduced with the same figure. 100 million units are released from the reserve if the market surplus of the previous year is lower than 400 million, or if - through 6

[11] The supply, consisting of emission allowances as well as the international credits imported to the ETS, grew from 2076 Mt in 2008 to 2336 Mt in 2012 as the import of international credits accelerated.
[12] COM(2011) 112: A Roadmap for moving to a competitive low-carbon economy in 2050
[13] Report on the state of the European carbon market in 2012
[14] The market surplus in year X = (number of allowances allocated between 2008 and year X + number of international emission credits imported to the ETS between 2008 and year X) - (total emissions between 2008 and year X + number of reserved allowances in year X)
[15] Proposal for a DECISION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme and amending Directive 2003/87/EC, COM(2014) 20 /2

successive months - the price of the EUA exceeds three times the average of the previous two years (independently of the size of the market surplus). The reserve, therefore, mitigates the price volatility of the EUA by automatically adjusting supply.[15]

The most important goal of the document, however, is not simply the reform of the ETS, but strengthening the climate policy of the EU by setting energy and environment related targets for 2030 that can contribute to the achievement of a low carbon Europe envisaged for 2050, and signal the political determination behind the ambitious emission abatement targets also to investors.

The newly proposed target for 2030 is the 40% reduction of GHG emissions (compared to the 1990 level), specifically through abatement measures within the EU, that is, without the option of importing international credits (ERU, CER). To accomplish this goal, the emission reduction requirements have been estimated as 43% for the ETS sector and 30% for all other sectors together (compared to the 2005 level). In order to fulfil this target, the Commission proposes the structural reform of the ETS system: the 1.74% annual reduction of the allowances allocated to the participants of the trading scheme will increase to 2.2% from 2020, that is, the supply will narrow at an increasing speed. The shrinking supply may result in allowance prices that are much higher than so far. Depending on the share of renewables and the intensity of energy efficiency measures the price may fall somewhere in the 11-53 €/t range after 2020.

The emission reduction target of the sectors outside the ETS are shared among the member states similarly to the current practice ("Effort Sharing"), therefore each member state has to comply with its individual, national requirement. The basis for distributing the target among the member states, however, is not expected to be the economic capacity (GDP), but the unit cost of emission reduction. Thus, for member states that have higher energy intensity, and typically weaker economy, a higher emission reduction target is set. The impact assessment of the Commission shows that member states the GDP of which is less than 90% of the EU average will be obliged to spend annually €3 billion more on emission reduction compared to the EU average increase between 2021 and 2030. Hungary, based on its economic status, was assigned a relatively generous target for the current period (10% emission reduction), but according to the proposal it will have to make deeper cuts within non-ETS sectors from 2020.

In its statement the Commission also makes a proposal to increase the share of renewable energy (measured in proportion to final energy consumption) to 27% while current sector policies would be sufficient for reaching an estimated 24% share As a critical amendment the EU target has not been further distributed to member states, instead, member states have to present to the Commission well before 2020 the renewable share they intend to reach by 2030 as well as the method of reaching it. If these actions do not guarantee that the 27% share for the EU can be attained, then the Commission will recommend supplementary interventions (e.g. introduction of member state specific targets). As an additional novelty, a separate target for biofuels will also be absent (in contrast with the current 10% blending ratio), the penetration of renewables within transport is to be taken care of by the chapter on transport development (based on the Transport White Paper).

The Commission does not propose a quantitative energy saving target for 2030, even though actual savings will likely stay behind the 20% target for 2020. At the implementation deadline of the 2012 Energy efficiency directive (June 2014) it will evaluate if the 20% savings for the EU as a whole can be attained through the national energy saving targets of the member states. According to the estimates of the Commission the 40% GHG reduction would involve energy savings of 25%. If the Directive in itself does not ensure the attainment of the 2020 savings target, then the Commission is likely to take on a stronger stance.

The proposal would amend the current theme-specific reporting (renewable energy, GHG emission, energy efficiency): member states have to submit even before 2020 their comprehensive energy policy concept, providing a uniform framework for their GHG, renewable and energy efficiency related plans and quantifying the contribution of each measure to the targets of the EU. This is expected to make the plans submitted by the member states more consistent (similar assumptions, actual data etc.). While the application of renewables and energy saving greatly contribute to the competitiveness of the EU and its

Table 5 The EU GHG and renewable targets and expected values for 2020 and 2030, with actual 2012 values

	2012	2020 REF	2020 target	2030 REF	2030 target	Note
GHG emission	18%	24%	20%	32%	40%	Compared to 1990 levels
Renewable share	13%	21%	20%	24%	27%	As a share of the final energy use of the given year

source: REKK

heightened security of supply, - since these energy policy targets depend on a number of additional factors - the proposed 2030 targets in themselves do not guarantee the advance of these - politically important - areas. Therefore the Commission plans to monitor these two areas, and suggested a number of indicators for this purpose:

- comparative analysis of the energy prices of the EU and its key trading partners,
- the share of domestic sources of energy in total consumption and the diversification of the energy import,
- the development of network connections, with a special focus on the countries where it stays below 10% of the installed generating capacity,
- the level of market concentration and competition, and
- the extent of technological innovation (sources, patents etc.).

The Commission decided not to subordinate its sectoral concepts (renewables, energy efficiency) to a single emission reduction target, letting the member states and the market devise the method of GHG mitigation. This may be explained on the one hand by its intention to ensure the continued growth of renewable capacities either in order to further lower the unit costs or for reasons related to industrial policy. On the other hand the Commission may wish to avoid GHG reduction arising from fuel switch (from oil and coal to gas). Both of the proposed 2030 targets of the EU are higher than the values expected under current measures (2030 REF), in contrast with 2020 when the reference path seems to assure the 20% target for both cases (Table 5).

During the negotiations, of the large member states Germany, Italy and France have all opted for the obligatory renewable target, the UK, however, firmly rejected it. This is probably because the English society (and the prevailing British government) is much more open to less "green" emission reducing technologies and it intends to comply with its legally adopted GHG reduction target (34% reduction by 2020 and 80% by 2050) in a technologically neutral way and in line with allowance prices. Consequently, it plans to focus government resources not on support to renewable energy sources, but instead it advocates the reconstruction of the nuclear power plant fleet, the deployment of CCS by coal and gas fired power plants, and the expansion of shale gas production. The most recent sign of the above policy of the British government is that it offers a tax break to companies fracking shale gas, and local councils would be allowed to keep 100% of business rates from fracking operations instead of 50% as before. In order to gain support for the 40% level of GHG reduction, the national obligatory renewable target was dropped from the proposal.

The Commission expects that - following the approval of the Parliament and the Council - in early 2015, long before the end-of-year UN climate summit in Paris, the EU would officially announce its 40% GHG reduction commitment to the international community. The future of the proposal on the 2030 targets, nevertheless, is still up in the air. With a modest majority (341 'yes' and 264 'no' votes), the European Parliament found the proposal of the Commission to be unsatisfactory, and believes that in addition to the 40% GHG target two more - rather ambitious - targets should be imposed on each member state: a 40% energy saving goal and a 30% renewable share. The original proposal is expected to be discussed by the European Council during its spring session in March.

ERRA courses

REKK provides one-week long intensive education courses and e-learning trainings since 2004 for the ragulators of the ERRA countries from the different areas of the energy sector. In 2014, the following ERRA courses will be launched:

- Energy Regulation in Emerging Markets: Abu Dhabi, 13-17. 04.2014.
- ERRA Summer School: Budapest, 23-27.06.2014.
- Principles of Natural Gas Regulation: Budapest, 09.22.-26.2014.

For further information please visit:

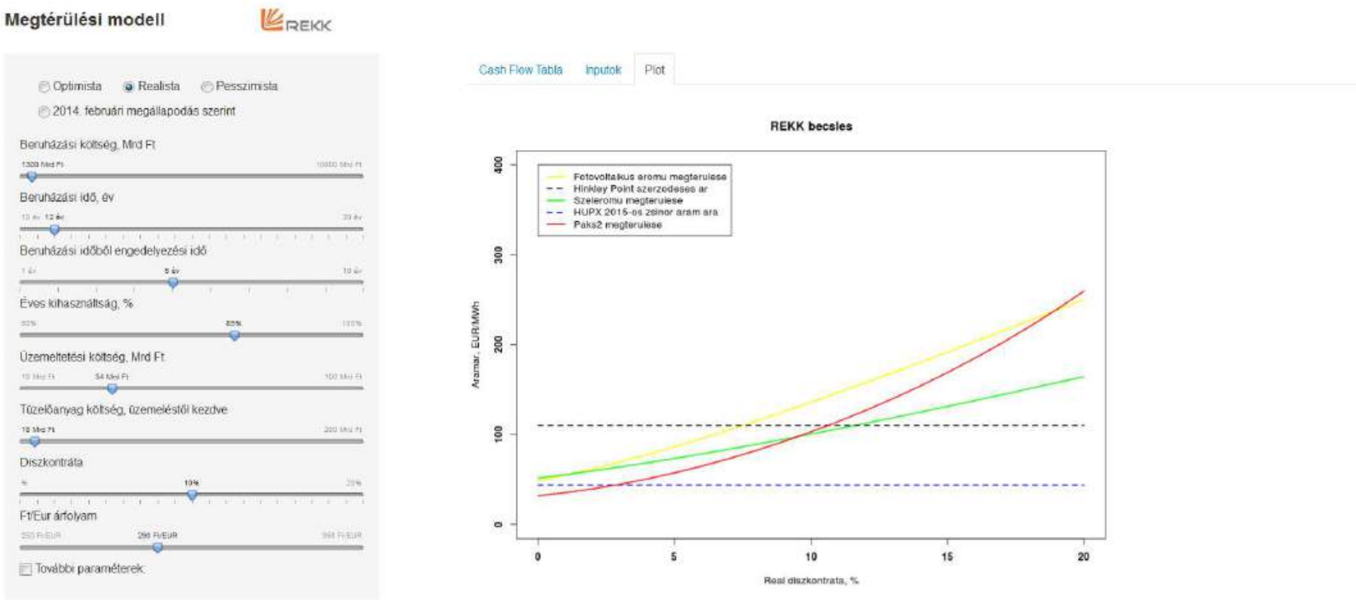
www.erranet.org

ERRA

ENERGY REGULATORS REGIONAL ASSOCIATION

[16] *http://www.theguardian.com/environment/2014/jan/13/fracking-shale-gas-incentives-councils*

Interactive model to calculate return of nuclear investment



The agreement about the nuclear capacity building signed by the Russian and Hungarian governments on 14 January 2014 indicates the beginning of a significant investment concerning the Hungarian power market. The capacity development may happen to be the most influential state supported investment of the 21st century in Hungary. Therefore our research team feels its responsibility to enhance the transparency and scientific grounds of the social discourse. To do so, we publish the following documents on our website:

- Working paper by REKK titled „Business models and expected return of nuclear investments".

In the study, the following questions are answered:

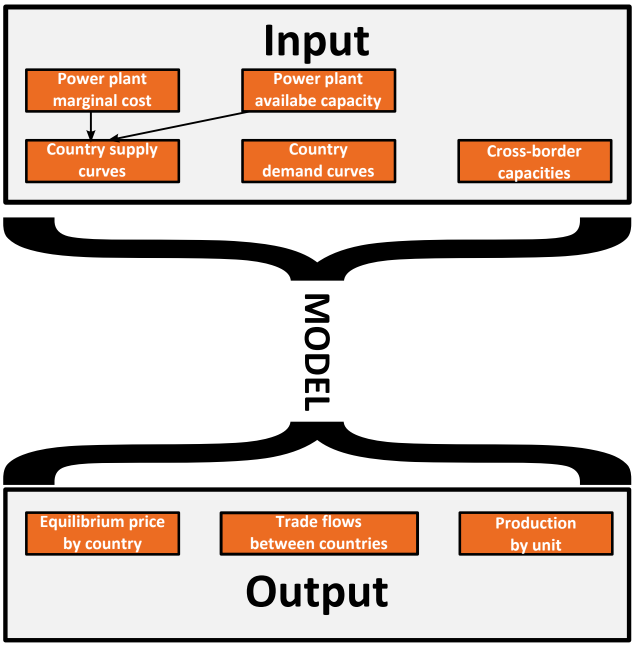
- What are the business models used during planning, commissioning and operating phases to mitigate financial/economic risks in OECD countries planning to build or building nuclear capacities?
- Which factors influence the most the financial return of a nuclear power plant project? Based on international data, what can be expected about the financial return a Hungarian nuclear project?

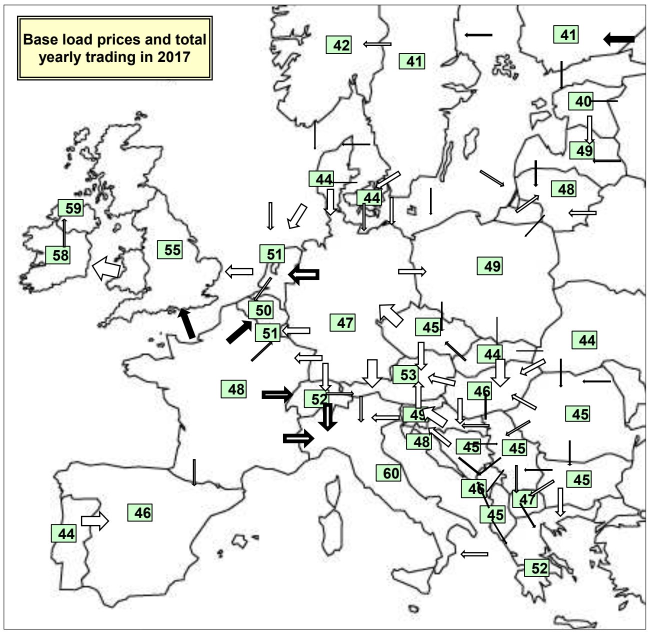
- The model utilised in the study can be accessed in Excel and R format (https://rekk.shinyapps.io/nuclear_en).
- We think that by making the inputs used and the modelling framework available, our reasoning and calculation will be easy to check and free to criticise. Those interested can make calculations on their own by changing the input data.

- A short update of the model, which incorporates the information surfaced by the 14 January 2014 agreement.

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

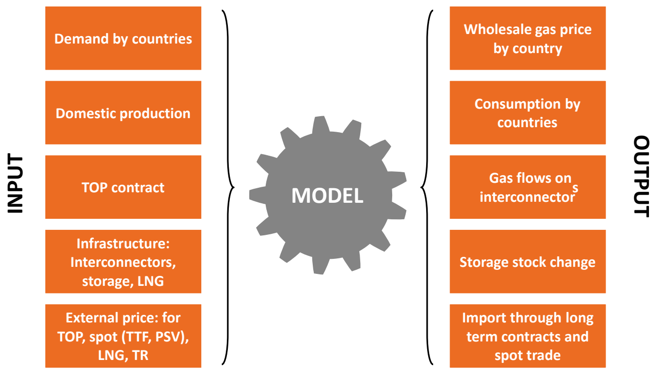
- Ranking of Project of Common Interest (PECI) projects
- Evaluating the TYNDP of ENTSO-E
- Assessing the effects of the German nuclear decommissioning
- Analysing the connection between Balcans and Hungarian power price
- Forecasting prices for Easterns and South-east-European countries
- National Energy Strategy 2030
- Assessment of CHP investment
- Forecasting power plant gas demand
- Forecasting power sector CO2 emmissions

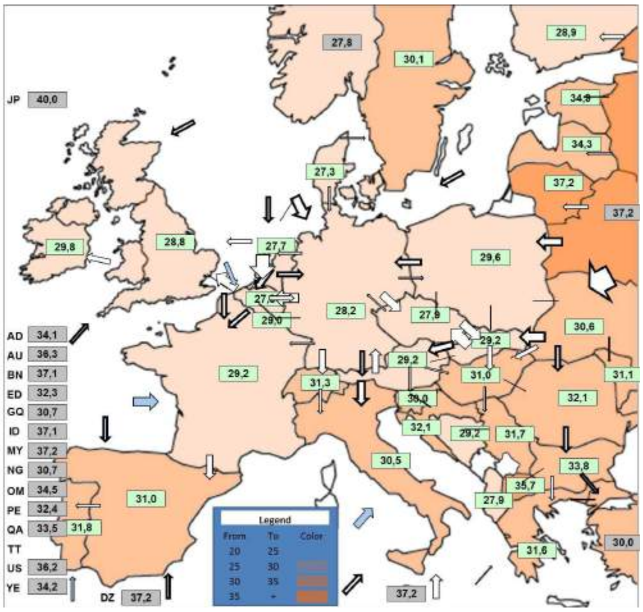
Contact: András Mezősi

andras.mezosi@uni-corvinus.hu

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 scenarion 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

Contact: Borbála Takácsné Tóth

borbala.toth@uni-corvinus.hu