Hungarian Energy Market REPORT

2nd Issue 2013
Dear Reader,

We are delighted to present to you the second issue of Volume 5 of our Report.

In addition to reviewing the energy market developments of the first quarter of 2013 we publish two analyses, a working paper and the conclusions from our recent workshop.

In our previous issue we covered the current market conditions of Hungarian gas storage facilities and the difficulties they face. Our first article expands this analysis to the countries within the Danube river basin. On top of portraying regional storage capacities, we evaluate the adequacy of storage capacities from the perspective of the security of supply, with use of the REKK gas market model. According to our results, due to the tighter integration of regional markets, the storage capacities within the region will be able to ensure undisturbed gas supply until 2020 without the expansion of capacities. Without coupling markets, however, a gas crisis, similar to the 2009 emergency, may again take place in the region.

Our second article looks at the reasons behind the distressed market position of our natural gas fired power plants. Due to the trends in world energy prices for the last two years gas based producers are not only unable to recover their investment costs, they cannot even pay for the variable costs of production any more. This lead to the expansion of coal based production in Europe, and increased imports to Hungary.

From the perspective of both the long term operation of electricity systems with growing renewable capacities and system security it is important that sufficient regulating capacity is available for system level regulation and to meet peak demand. Under the current business model of electricity generation power plants mainly receive a compensation only for the produced electricity, which may interfere with the realisation of investments needed for the long run. Capacity mechanisms may offer a solution to this problem, the operation of which is the topic of our working paper.

Our fourth article sums up the conclusions from our March workshop where we examined the opportunities for gas market integration within the Visegrad Four group and the advance the group has made so far. At the workshop, among others, the Polish V4 presidency described the priorities of the draft gas market target model. We hope you find lots of useful information in our Report. We look forward to your recommendations or questions concerning the content or the composition of the Report.

Péter Kaderják, director
ENERGY MARKET DEVELOPMENTS

During the first quarter of 2013 the fall of electricity prices continued, while the price of natural gas stayed unchanged. The purchase price of carbon-dioxide credits dropped all the way to 3.5 EUR/t. Domestic power production fell 10% short of last year’s figure, and the ratio of import notably exceeded the values typical for the quarter. The quarterly domestic electricity consumption, on the other hand, was essentially the same as last year. In January and February the cross border capacity from the Austrian direction heavily shrank. The price of import capacity substantially deviated from zero only for the Slovakian and Austrian border sections, while the price of export capacity exceeded 1 EUR/MWh for the Serbian direction. The price of spot baseload power on regional exchanges continued to fall, and in March, for the first time in a long while, HUPX exhibited lower spot product prices than the German exchange. Futures electricity prices also declined and the premium fetched by the Hungarian exchange slightly decreased.

The natural gas consumption of the first quarter fell 400 million m³ short of last year’s gas use. The source structure slightly changed, the share of Eastern imports grew at the expense of the storage sites and Western import. By the end of the withdrawal period domestic commercial storage facilities were depleted to 17% of their capacity.

International price trends

During the first quarter of 2013 we could not take note of significant changes in the commodity markets. The price of a barrel of Brent crude was 112 dollars on average, in contrast with the 110 dollar price of the previous quarter. The price of oil climbed to 118 USD/barrel in January, to decline again in February. While the price of ARA coal with next year delivery increased to 100 USD per ton during the first month of the year, it went through a constant decline for the rest of the period, sinking below 93 USD/ton at the end of the quarter.

The wholesale price of electricity continued to decline, while the price of natural gas did not change. The price of 2014 baseload power even touched a 40 EUR/MWh low during the first months of the year. One MWh of baseload power was traded for 42 Euros on average, 4.5 Euros less than the average of the previous quarter, and 10 Euros below the same period from last year. Similar trends are exhibited by the price of the

![Figure 1](source: EEX, EIA)

**Figure 1.** The price of 2014 ARA coal futures traded on EEX and the spot price of Brent Crude between January 2012 and March 2013

![Figure 2](source: EEX, ENDEX)

**Figure 2.** The price of 2014 futures electricity and natural gas between January 2012 and March 2013
The quarterly temperature and working day adjusted electricity use was the same as last year, 10.2 TWh in total. January power consumption matched the 2012 figure, while the February number was 4% below, and the March value was 4% above the electricity use of the same months of last year. This is explained by the fact that we compute the temperature adjusted electricity use to be in line with a multi-year average consumption. In 2012 the February temperature was considerably lower than the multi-year average, while the March figure exceeded it. In 2013, February was milder than the multi-year average, while March happened to be colder.

21% of domestic consumption was satisfied from import sources, and domestic peak product, with a decline of over 5 Euros compared to the previous quarter, and 12 Euros less than the price of the same quarter last year. The price of natural gas futures traded on the TTF exchange essentially did not move, quoted at around 26.5 Euros on average, one euro below the average of the previous quarter.

The price of emission allowances with December 2013 delivery continued to decline, all the way below 5 Euros. On a day in January, for example, the market closed below 3.5 EUR/t. Compared to the previous quarter the exchange traded volume of the credits grew by 40%. All this points to the growing difficulties of natural gas production, detailed in our article Gas fired power plants: edging lower.

**Overview of the domestic electricity market**

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generation was over 10% less than in the first quarter of 2012. The ratio of import is twice the figure from the first quarter of 2012, with essentially unchanged consumption. 55% of imported electricity arrived from Slovakia, and 31% from Ukraine. In addition, Serbian and Austrian import covered 7% and 3% of electricity use, while the rest, a few percent, was shared by Romanian and Croatian imports.

Of the monthly cross border capacity auctions, the price of capacity exceeded 1 Euro at the Slovakian, Austrian and Serbian border sections. Slovakian import capacity fetched 3-3.7 EUR/MWh, with the usual volumes available for reservation. Austrian import capacities, on the other hand, were not available in January and February. The price of the OPCOM baseload product heavily fell on regional exchanges, straight down to 30 EUR/MWh in March. By the end of the quarter the price of all four exchange traded baseload

![Figure 6. Results of monthly cross border capacity auctions in Hungary, Q1 2013](image)

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Capacities in the figure mean capacities offered for auction. Capacities were not sold fully in the period under review in the event of oversubscription at a specific price, because in such cases the system operator considers the next highest price as the auction price.

![Figure 7. Comparison of next day baseload power prices on EEX, OPCOM, OTE and HUPX between April 2012 and March 2013](image)

**Figure 7. Comparison of next day baseload power prices on EEX, OPCOM, OTE and HUPX between April 2012 and March 2013**

![Figure 8. Daily average of the balancing energy prices and the spot HUPX price, Q1 2013](image)

**Figure 8. Daily average of the balancing energy prices and the spot HUPX price, Q1 2013**
products dropped below 40 EUR/MWh. Interestingly, for the first time since 2011 the monthly average price of HUPX was lower than the price at the EEX.

The wholesale price of electricity is influenced by the costs of deviations from the schedule and the balancing energy prices as well. The system operator sets the settlement prices of daily upward and downward regulation based on its procurement costs of energy from the balancing market. The financial costs of balancing for the balance circles are determined by the balancing energy prices and the spot price of electricity in the settlement period. The higher the difference between the price of upward and downward regulation and the spot wholesale price, the more it costs to acquire the required amount from the balancing market. During the quarter the average price of positive and negative balancing energy was 18.25 and -7.35 HUF/kWh on average.

The price of the futures base-load product continued to fall on the exchanges of the region, the price of the baseload product with next year delivery stayed below 50 EUR/MWh on organized power markets. Czech and Slovakian electricity prices were half euro lower than the price of the German futures product. Compared to the previous quarter the HUPX premium over the German markets declined, but even in March the next year baseload electricity on the Hungarian power exchange cost 5.5 Euros more on average.

Overview of the gas market in Hungary

The mild weather of February and the late winter of March are
nicely illustrated by Figure 10. Consumption fell compared to the high gas use of February 2012, while demand for heating in March was somewhat higher than in 2012. On the whole, during the first quarter of the year 400 million m³ less gas was consumed than in 2012, and almost 700 million m³ less than in 2011.

On the Figure 10, the heating degree days (HDD) on the right axis 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 HDDs. By comparing the actual monthly HDD to the value from the previous year and the average HDD values 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.

Quarterly production ranged between 220 and 250 million m³, corresponding to the long term production figures of the quarter. The structure of consumption shifted to some extent: the quarterly share of Eastern import compared to total consumption increased from 14% in 2011 and 22% in 2012 to 26%. This growth came mainly at the expense of gas storage, and to a lower extent Western import: in 2011 gas storage facilities covered 43% of gas consumption, while only 36% in 2013.

During the quarter almost one and a half billion m³ of gas was withdrawn from domestic commercial storage facilities.

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**Figure 12.** The working gas storage capacity of commercial storage facilities and their stocks by month

**Figure 13.** Transmission at the Baumgarten entry point between April 2012 and March 2013, together with booked interruptible and non-interruptible capacities

**Figure 14.** Transmission at the Beregdaróc entry point between April 2012 and March 2013, together with total available capacity and booked non-interruptible capacity
As a result, by the end of the period 17% of their capacity was filled.

During the quarter 300 million m³ less gas arrived through Baumgarten than usual. Market participants reserved 65% of the capacity, and utilized 88% of this on average. In January they also made use of the non-interruptible capacities, but the utilization rate of reserved capacities dropped by half in February and March.

The mirror image of this development was observable for the Eastern direction: the ratio of reserved capacities did not change, but they were better utilized – 47% of the capacities were reserved, 43% of which was utilized. During the quarter slightly more than 1 billion m³ of gas arrived from the East.

The price of oil indexed import continued to stay at around 120 HUF/m³ during the first quarter. The price increase of March is due to exchange rate movements. The price of the import mix containing 70% exchange based and 30% oil indexed product was 22-25 HUF/m³ cheaper.
Overview of regional storage facilities and forecast for storage demand

We have already analysed the unilateral natural gas dependence of the countries of Central and Eastern Europe and the Balkan\(^1\) in a number of previous articles (e.g. Energy markets report 3/2012: TOP or TOPless beyond 2015?). These countries are characterised by the dominance of Russian import sources and decreasing domestic production. As much of the natural gas is used for heating purposes, their gas consumption is strongly seasonal: in case of Bulgaria, the Czech Republic, Hungary and Ukraine, over 70% of annual consumption takes place during the heating season. In the countries of the Balkan this ratio is below 60%, partly due to a milder climate (e.g. Croatia) and partly because of the under-development of the gas network serving households (Serbia, Bosnia).

In this region underground gas storage facilities serve two main purposes. First, there is a demand to mitigate the risk associated with the security of supply arising from gas dependency: the short disruption of transmission – for whatever reason – should not culminate in an emergency. Second, the increased demand of the seasonal peak winter periods should be possible to meet. In the past, when the networks were constructed, vertically integrated monopolies optimised the development of infrastructure on both sides of the border, and usually strove to ensure full utilisation of the transmission capacities. The importer tried to meet increased winter demand not by getting more gas out of the transmission line (“tugging the pipeline”), instead, during the summer it injected natural gas into gas storage facilities located as close to the consumers as possible, and withdrew the surplus during the winter. This practice originated from the technical and economic logic of optimally utilising the transmission infrastructure. Compared to this what kind of changes have the liberalisation of the energy market and market integration brought? How do we use the storage facilities of the region these days, and what kind of infrastructural or regulatory developments could make them more optimal? What is the storage need of the region, and what are the short term forecasts? We aim to provide short answers to these questions in our article, based on our analysis prepared for the Energy priority area of the Danube Region Strategy.\(^2\)

Having reviewed the inventory of gas storage facilities in Central and Eastern Europe and the countries of the Balkan, we can acknowledge that while for the EU as a whole the gas storage working gas capacity (the volume that can be stored in European facilities) makes up 18% of the 547 bcm of 2010 gas consumption, in our region even 40% of the 63 bcm annual consumption (2010) could be covered from gas storage facilities. Including Ukraine this ratio rises to 44%. In our region gas storage facilities were typically built on exhausted natural gas fields, in a technical sense the annual cycle of one injection and one withdrawal enables them to ensure mainly seasonal flexibility.\(^3\) Existing capacities, however, are not homogenously distributed, some of the countries have abundant storage capacity (Hungary, Austria, Slovakia, Czech Republic, Ukraine), while others do not have any facility at all (Slovenia, Bosnia and Herzegovina, Moldova).

Having inspected actual data from three countries with well developed infrastructure and significant household consumption (which translates into increased seasonality) covering the last three years\(^4\), we found that storage facilities supply 20-25% of annual consumption, and 35-40% of gas use in the heating season. Using the 25% figure as a conservative estimate, the 10.8 bcm of 2012 gas consumption of Hungary could be satisfied with 2700 mcm of working gas capacity of storage facilities, which is a little more than half of the current 4930 mcm of commercial working storage capacity. (In other words, if storage facilities were used at this ratio, then we would need close to 20 bcm of gas consumption in order to fully utilise the commercial storage capacities of Hungary).

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1 In this article the following countries are meant to belong to this region: Austria, Bosnia and Herzegovina, Bulgaria, Czech Republic, Croatia, Hungary, Moldova, Poland, Romania, Serbia, Slovakia, Slovenia, and Ukraine.

2 REKK: Natural Gas Storage Market Analysis in the Danube Region, March 2013

3 These facilities are not suitable for short run storage based arbitrage (injecting cheap gas during periods with low demand, and withdrawing when demand is high). Arbitrage is much more feasible in case of facilities built in a salt cavity or an aquifer.

4 In case of Hungary, Slovakia and the Czech Republic the analysis was based on daily consumption data published by the TSOs and actual gas flow data.
Figure 16 Capacity utilisation of sub-surface gas storage facilities in October 2012 in the countries of the Danube Region

Note: in case of Serbia we have not found utilisation data

Figure 16 seems to support this tendency. The capacity utilisation rate of Hungarian commercial storage facilities was about 60% in 2012. However, in the Austrian market we cannot observe the underutilisation of overdeveloped capacities. Considering that Austrian facilities also offer flexibility to the gas consumers of Slovenia, the estimated storage demand for Slovenian and Austrian consumption together is 2800 mcm of working gas capacity, or about 40% of the capacity of existing Austrian storage sites. Actual data from GSE, however, shows that these storage facilities are almost fully utilised. One explanation for this is that long term contracts are common in the Austrian storage market. Another reason is that one of the importers in Austria (Gazprom) has its own storage facilities, storing gas close to the Western European target markets: from here it can provide flexibility at a lower cost than through the pipeline. The third explanation is closely related to the previous one: increased demand for storage is associated with large volumes of transit flows: the competitive advantage of storing along a main avenue as opposed to a side street is easy to comprehend when the cost of transportation is non-negligible (especially including cross-border transactions).5

In our earlier article (Energy markets report 4/2012: Half empty or half full? Developments on the Hungarian natural gas storage market) we already discussed the decrease in the capacity utilisation of Hungarian gas storage facilities, and used declining demand for gas as the main explanation. Having recovered from recession, will increasing consumption reestablish the higher utilisation rate of storage facilities, as experienced in the middle of the last decade? To inspect this, with the gas market model of REKK (for an introduction please see Energy markets report 3/2012: How could gas become cheaper in Central and Eastern Europe?) we made a forecast for 2015, assuming a 21 bcm increase in regional gas demand, building on the gas use forecasts of the countries of the region. Assumptions on the development of cross-border infrastructure were based on the TYNDP6 (SK-HU, MV-RO, BG-SB and the completion of bi-directional developments), without allowing the entry of additional storage capacities.

Modelling results show that the 16,169 mcm utilisation of storage facilities, computed for the reference year of 2011, would decline by almost 2 bcm even at an increased demand of 21 bcm. This is explained mainly by the completion of new cross-border capacities: the flexibility market is supplied by more than just the storage facilities, transmission pipelines can also have a role, the use of which is shaped by market forces within the model. There is another reason as well: by connecting markets, the same cross-border capacities also facilitate competition among storage sites, thereby the construction of new pipelines leads to the rearrangement of stored volumes as well, for example from Slovakia to Hungary. Based on modelling results, for 2015 we can expect 9 bcm of unused storage capacity for the whole region7, located specifically in Austria, Hungary, Slovakia and Serbia, while the facilities of the other countries operate at full capacity. Based on this we can declare with conviction that there is no room for additional large storage

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5 We calculated the cost of different routes for a hypothetical stored product. The cost of the Ukraine – Hungarian storage – Austria (backhaul) route is 8.48 €/MWh, while the traditional route of Ukraine – Slovakia – Austria (storage) is only 8.15 €/MWh.

6 TYNDP: Ten Year Network Development Plan - gas: www.entsoe.eu

7 2012 GSE data shows 4 bcm of unused storage capacity in the region, a 5 bcm difference compared to modelled 2011 results. This difference is caused mainly by the long term reservations in the Austrian storage market: the competitive market model of REKK operates in 1 year cycles, and it is not capable of dealing with long term reservations or the strategic behaviour of participants. The modelled value for Austria shows how much of the Austrian facilities would be utilised under market conditions (2900 mcm in 2011).
facilities within the region, especially in the four listed countries. Having modelled the investment plans of regional storage sites, however, we found that construction of the Moldovan and Polish facilities is attractive for these countries.8

Analysing the role that storage facilities play in increased security of supply we learned that a 30% loss of January deliveries from Ukraine (equivalent to the situation during the crisis prompted by the 2009 Russian-Ukrainian gas dispute) would not generate a security of supply shock in the region under the 2015 scenario, as long as the countries comply with EU Regulation No. 994/2010 on the security of gas supply.9 Without that an emergency situation similar to the 2009 gas crisis could evolve.

Gas fired power plants: edging lower

High natural gas prices – relative to the price of electricity – have drastically reduced the profitability of natural gas based electricity generation in Europe for the last 1.5-2 years. The five largest European energy conglomerates (Enel, E.ON, EDF, GDF Suez, and RWE, often also called the Big Five) had to book about 8 billion Euro worth of losses on their assets in 2012, in a large part due to the weak performance of their CCGT fleet. An apparent example of the distress that gas fired plants are exposed to is the case of the Irsching power plant: E.ON was willing to forgo the closure of units 4 and 5, operating at a 60% efficiency, after – thanks to the active engagement of the regulator – this April it closed a deal with the system operator (Tennet) that the units in question receive an annual capacity fee to compensate for the frequently ordered load variations.

The trend in the profitability of fossil fuel based power plants is nicely captured by the margin indicators that show the difference between the producer price of electricity and the variable costs: the clean spark and the clean dark spread. The producer margin of the gas fired power plants operating in the German market – which already accounts for the price of carbon credits –, the so called „clean spark spread“ has been declining since 2009, sinking below zero in early 2012. Negative spread values signal that since the turn of the year the revenue of gas fired plants from selling baseload products does not any more cover current expenditures (fuel and carbon credit costs). The profitability of coal fired power plants, on the other hand, has been improving since 2010, the average value of the German clean dark spread has stayed within the 5-15 EUR/MWh range since the second half of 2011 (a fairly high number in view of the 40-50 EUR/MWh price of electricity).

Similar trends can be observed in the energy markets of other European countries as well. The profitability of gas based electricity generation notably declined in the Benelux countries, Spain and the United Kingdom, albeit to a lower extent than in the German market. The producer margin, nevertheless, to varying degrees, but narrowed everywhere, significantly reducing the capacity utilization of the gas fired power plant fleet. The utilization rate of gas fired plants in Germany decreased from 46% in 2011 to 32% in 2012, and it is expected to fall to 22% in 2013.

Figure 17 Profitability of coal and gas fired power plants

When calculating the spark and dark spread, the following parameters were assumed: the operating efficiency of natural gas fired power plants is 50%, their CO2 emission is 0.4 t/MWh. Coal fired plants are assumed to have 38% efficiency and emit 0.9-1 t/MWh of CO2. To calculate the spread, we divided the price of fuel by the rate of efficiency, then added the emission (t/MWh) multiplied by the price of CO2 allowances (EUR/MWh). This sum was subtracted from the wholesale spot baseload price.

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8 According to the results of the REKK model, social welfare improves with the completion of the infrastructure, compared to unchanged welfare without it. This positive value, however, does not mean that the project has a positive net present value from a financial perspective as well.

9 We modelled this with the discharge of stockpiled gas sufficient to supply households for a 30 day period, allowed only in case of a crisis.
The lost market share and decreased profitability of European gas based power plants for the last two years can be explained by three factors: oversupply of generating capacity, the relatively high natural gas price and the low price of CO₂ allowances.

While the demand for electricity in the major Western European markets has still not climbed back to pre-crisis levels, the supply side – thanks to the large power plant investments launched before 2008 – has been quietly expanding. As a result, today most of the Western European electricity markets are characterized by a significant excess supply of generating capacity. This oversupply and the status of conventional – primarily natural gas based – power plants is exacerbated by the large scale expansion of subsidized renewable electricity generation, further limiting the sales opportunities of conventional producers and lowering the ratio of peak and baseload prices.

On top of a shifting demand-supply ratio, since 2010 the competitiveness of natural gas fired units has been eroding at an accelerating rate driven by the adverse changes in both relative fuel prices and the price of carbon-dioxide allowances:

- In 2010 Western European spot market gas prices practically doubled: the 10-15 EUR/MWh price of early 2010 increased to around 25 EUR/MWh by the beginning of 2011, and it continues to linger within the 25-30 EUR/MWh range today. Following the July 2009 lows, within three years the price of long term contracts underwent a gradual increase of about 70%.
- CO₂ prices, decisive for the competitiveness of coal fired power stations, have been on a steep decline since the middle of 2011, credit prices dropped from 16 EUR/t to 8 EUR/t in half a year, and at present they are traded within the extremely low range of 3-5 EUR/t.
- In addition, in the middle of 2011 again, a major transition started in international coal markets: within a year the price of coal dropped from 125 USD/t to 90-100 USD/t, and it has been sitting on the low end of this range ever since. (The decline in coal prices is partly due to the rising American coal export as a result of the booming shale gas production in the US)

The above described developments radically rearranged the relative competitiveness of the two technologies, as a result of which during the last two years coal fired power plants were able to considerably increase their market share at the expense of gas fired plants. While the electricity generation of European gas fired power plants fell by almost 25% between 2010 and 2012, coal and lignite based power plants increased their production by 15%.

The transformation of European fuel and electricity markets have hit domestic natural gas based power plants disproportionately. The low efficiency of some of the power plant fleets, and the substantial premium of domestic natural gas prices compared to Western European spot market prices already limits their competitiveness. After the 2008 termination of the long term power purchase agreements (PPAs) these power plants suffered a significant loss of market share, further aggravated by the declining and stagnating demand during the recession. After 2010 the ordeal of domestic gas fired power plants was crowned by the import competition from cheap coal fired production as well as increased hydro-power generation in the Balkan region following a lot of precipitation, the exclusion of cogeneration from the purchase obligation regime, and the entry of virtual power plants into the market of system level services.

For the last two years the market loss of natural gas fired power plants was escorted by the gradual penetration of import: while their combined share within gross electricity consumption was practically unchanged, their relative weight considerably shifted. While in 2010 the production of domestic natural gas based power plants was more than twice the volume of net import, in 2012 net import almost
reached the size of gas based generation.

The above described developments were escorted by the shutdown of power plants and the suspension of generation. The inefficient, obsolete natural gas-fired units were stopped in 2012: the Tisza II power plant ceased production in March, while the F units of the Dunamenti Power Plant in December of last year. The difficulties, nonetheless, took their toll on the modern units as well: it is telling that during the last two years the average capacity utilization of even the highly efficient new CCN units (Gönyű and Dunamenti G3) did not exceed 30%. Citing adverse economic circumstances, the owner of the DKCE and the NYKCE decided to suspend production this summer. In order to avoid closure, the Dunamenti Power Plant decided on a 50% layoff, and even the temporary shutdown of the Gönyű Power Plant was in the news, even though this was later refuted by E.ON.

Natural gas based generation has a significant share within the future energy mix favored by Hungarian energy policy. This objective is reasonable only if gas becomes competitive again compared to other fuels used for electricity generation, and domestic natural gas prices descend to Western European levels (otherwise investments into gas fired generation will not take place in Hungary, but at our Northern and Western neighbors, where gas prices are more attractive).

The future price of natural gas in Hungary, governing the competitiveness of gas fired power plants, is a function of two factors:

- The first is the rate at which domestic natural gas prices converge to Western European natural gas prices. As a result of the dominance of Russian gas supply, Hungarian gas users have been paying a hefty premium over Western spot prices. Nevertheless, even in the short run there is a good chance for new developments that are favorable for Hungary. Regional model simulations of the gas markets of Central and Eastern European and South-East European countries indicate that with the bi-directional conversion of the pipelines connecting EU countries by 2014 and the targeted enlargement of international gas infrastructure a significant price reduction can be attained in these

- Another influential factor from the perspective of domestic natural gas prices is the level of Western European gas prices, driven by several variables. The future economic growth of the continent and its demand for natural gas, the medium term prospects of the global LNG market, the import needs of large Asian consumers (first of all, China), the pricing behavior of pipeline based exporters and the future potential of European shale gas extraction are all crucial from the perspective of natural gas prices in the key markets of Europe.

The market position of domestic natural gas fired power plants is not expected to drastically change in the short term. Based on the current expectations of fuel and electricity prices, the profitability indicator of the German CCGT power plants will most likely stay in negative territory for the next two years. Market developments, nevertheless, are unpredictable: just as the golden age of natural gas was envisaged by respectable institutions and analysts a few years ago, after 2015 market related and regulatory developments that make the construction and operation of natural gas fired power plants promising again, may very well take place.
Unilateral measures or EU coordination? The question of European capacity mechanisms

As it has recently become more and more evident, the profitability of gas fired power plants in Europe keeps declining (for more detail on this topic, please see the article in our current issue: Gas fired power plants: edging lower). Insufficient returns may easily result in the closure of existing plants, or mothballing until the market environment improves, while the volume of new investment into peak power plants may, in the short run, be less than the level required by system security. The inadequacy of profits that can be harvested during peak hours is often referred to as the problem of “missing money” by the technical literature, as a result of which the demand for the introduction of a financing mechanism has surfaced in a number of European countries, in order to support both the investment into peak power plants necessary from the view of system security, and the availability of existing power plant capacities. These mechanisms, nevertheless, may also bring about market distortions, affecting not only the markets of the countries operating the given mechanisms, they may also influence the energy markets of the neighbouring countries, potentially at odds with the integration of European energy markets. It should be noted, however, that the decreased competitiveness of gas fired plants and mothballing may also, to some extent, be considered as natural developments associated with economic recession. Therefore it is not clear if this is a temporary or a lasting problem, and whether supporting capacity development is necessary at all. Our article is dedicated to the question of capacity mechanisms, introducing their different variations, potential market distorting impacts, and the main international experience related to their operation.

What problems are capacity mechanisms supposed to solve?

By capacity mechanism we mean all support schemes which supplement traditional energy-only markets – where producers can make a profit primarily from energy sales – by also rewarding the available capacity of power plants. Importantly, producers already sell their available capacities as primary, secondary or tertiary system level reserves. Reserve markets, however, are destined to treat only one dimension of capacity problems: the flexible capacity need originating from the short run oscillation of electricity demand and the incidental outage of the largest generating unit of a country. When we inspect the problem related to flexible capacities, two more dimensions are also to be discussed, which are not necessarily handled by system reserves in a reassuring way.

- First, we can discuss the longer term problem that investments into capacity expansion and a country’s opportunities to import electricity should be able to meet future peak power demand. Notably, if this problem – provided such a problem exists at all – is mainly related to base-load plants, then their support through a capacity mechanism is not necessarily justified. If, however, we consider the argument that the capacities to be constructed should also be in harmony with the already adopted decarbonisation goals, then the development of a properly structured power plant portfolio can emerge as a problem that can be solved with capacity mechanisms.

- Second, we should not forget the supply side problem which is brought about by the fact that the short term fluctuations of solar and wind based generation are only moderately predictable and the temporary drops in production have to be substituted from readily accessible, traditional “back-up” capacities. The application of the capacity mechanisms is advisable mainly in relation to these problems. The latter two dimensions of the problem – the adequacy of long term investments, and the back-up capacity need – can be managed with capacity mechanisms in case the current, “energy-only” market does not work properly.

The types of capacity mechanisms

The capacity mechanisms can be assigned to five main categories: capacity payment, strategic reserve, capacity obligation, capacity auction and reliability option. Of these, the capacity fee based systems count as price driven, under which the official prices set by the regulator is to provide an incentive for new investments and the continued operation of existing capacities.
The other listed types are, on the other hand, volume driven, i.e. the regulator sets the needed capacity, but the price to be paid is determined by the market. Another important characteristic is the process behind the scheme: the systems based on obligation, auction or option contract represent a market mechanism, while the capacity fee and strategic reserve based systems are controlled by the authorities.

The procedures behind the five main types are described below:

1. **Capacity payment**: The regulator offers specific fees for either the installed or the available capacities. The fee may be fixed or it can be set based on a formula – the latter takes into account the proportion to which the needed capacity investments have already taken place. The set of eligible power plants is determined in advance, but in most cases already operating and planned capacities can both be eligible. The primary goal of the capacity payment is to provide incentives for new power plant investments – this, however, requires that newly built capacities are also eligible on a long enough time horizon, otherwise, in contrast with the intentions, the capacity payment will only achieve the continued operation of already existing capacities.

2. **Strategic reserve**: The regulator or the system operator makes a forecast about the expected maximum system load in the future – generally for the next three years –, and about how much capacity is expected to be available during the same period in the absence of capacity support. The prediction of the system load is usually based on the one-in-ten (or -twenty) year maximum load. If the expected peak load exceeds available capacities, then the difference is held in standby mode, separated from the market, as a strategic reserve that the system operator can deploy during peak hours. The procurement of the strategic reserve usually happens centrally through an auction or a public tender, and the reserve is generally provided by existing power plants which receive a fee in exchange for the reserve. The main goal of strategic reserves is ensuring security of supply for periods of peak load, and they are switched on only in special cases. Such a special case may be a price spike, more specifically those hours when the day-ahead day price of electricity exceeds a predetermined price level (the dispatch price) – the price spike is therefore an indicator for the system operator showing that prices rising further will not lead to a significant enough demand side adjustment, and limiting electricity consumption will soon be unavoidable. We should take notice that activating strategic reserves effectively puts a cap on day-ahead prices.

3. **a. Capacity market – capacity obligation**: The regulator or the system operator determines the future capacity need, then it obliges the traders and service providers delivering electricity to the final users to make a contract with the producers in order to reserve the needed capacity. As a key feature of the system, after having made the contracts, traders and service providers are allowed to trade their obligations with each other: the traded obligations create the capacity market. The capacity market generates an opportunity for producers to earn additional revenues on their capacities in addition to selling them as system reserves. The size of the individual obligations of traders and service providers are set so that the capacities contracted by them should be able to cover the peak load at their customers, and an additional capacity reserve (reserve margin). The trader is subject to a penalty payment if it has not secured sufficient capacities, while the producer is punished if it does not fulfill its capacity obligation.

3. **b. Capacity market – capacity auction**: The regulator or the system operator determines the future capacity need, after which the contracts to purchase the capacities are made centrally, through an auction, based on the forecasted demand. Both already operating and planned power plants can participate at the auction. This category of capacities is therefore quite similar to obligations, but there is also a difference: while in case of obligations the capacities are acquired bilaterally, for the capacity auction the needed capacities are secured through a centrally organised auction. Just as in the case of obligations, producers can be penalised in case of capacity auctions too, if they cannot deliver the contracted capacity when required.

3. **c. Capacity market – reliability option**: This type is also based on a central auction, and it is very similar to capacity auctions, except that in this case instead of a physical asset (a certain capacity size), a central body or the traders / distributors purchase call options – a financial instrument – from the producers to cover the capacity need. Based on the options contract the producer that issues the option is obliged to supply electricity on the request of the TSO when the spot price is above the strike price of the option. As a noteworthy point, a capacity option places a cap on the revenue of the producer, since the strike price of the option limits the spot electricity price if the option is exercised.
The danger of unintended consequences

While a casually developed mechanism may lead to severe market distortions both domestically and on a regional level, it is widely held that systems involving capacity payment and strategic reserves are more likely to distort the domestic market than market based solutions. A partial explanation for this is that capacity payment based mechanisms rely on central pricing, and once the prices are set, all of the investments into new capacities are left to market participants. Capacity payment based systems, therefore, do not guarantee that the necessary capacities are indeed available, that is, that the capacity payment achieves its goal. Consequently, in case of a capacity payment based system there is a risk of suboptimal capacities: a payment that is too low will lead to too little capacity, a payment that is too high will generate too much – expensively subsidised – capacity. Another question is whether capacity payments indeed provide an incentive for new investments. If, for example, only those planned power plants are eligible to participate at capacity auctions that are expected to come on-line within three years after the auction, it is not guaranteed that this time horizon is long enough for the auction to truly influence the investment decision. The capacity payment, therefore, is likely to keep only already generating, often obsolete capacities in operation.

An inherent feature of strategic reserves is that in case they are being activated, they limit spot prices, therefore they alone may reduce the profitability of peak power capacities as they do not allow spot prices to spike. As a result, potentially they can displace peak power investments, further aggravating the problem of missing generation. Exactly this is why it is essential that power plants providing strategic reserves should be started only rarely and in critical situations, minimising the peak price distorting impact of strategic reserves. Market based systems may produce similar impacts, but the problem in these cases is usually less severe, as long as they involve all power plants in the market.

We should also point out that all of the listed mechanisms are expected to increase the price of electricity charged to final consumers, since a subsidy scheme like this is typically financed through an item that is added to the invoice. In exchange, consumers receive an improved security of electricity supply, as the capacity mechanisms reduce the risk that consumption needs to be curbed.

Our analysis, nevertheless, does not imply that market based systems are inevitably more desirable: next we will consider how capacity markets (obligations, auctions, options) and capacity payment based systems may impact the internal energy market of the European Union.

Capacity mechanism and market integration: is there a common denominator?

If specific EU member states decide to introduce a given capacity mechanism, then we may anticipate that these systems will distort the internal energy market of the European Union and block the integration of the uniform internal energy market. From this perspective, the following may be the most important negative impacts of capacity mechanisms:

Impact on producer competition: Differences in mechanisms across countries – or their application in some countries, and complete absence in others – may artificially distort the competition from the producers of neighbouring countries and therefore affect their relative competitiveness. This impact is contrary to the competition policy related priorities within the process of the integration of EU energy markets. The risk of distorted competition is particularly striking in case of countries linked through market coupling, where a unilaterally applied capacity mechanism may displace the producers of neighbouring market(s) by potentially curtailing peak prices.

Long term external impact: Country-specific differences in mechanisms may have an impact on which countries are selected for new power plant investments. A capacity mechanism may, therefore, qualify as a targeted investment support in the market of a given country. In countries that support power plant investments to a lower extent, system security may deteriorate in the medium and long term. This effect may be somewhat alleviated by the participation of foreign power plants in the capacity market, or their eligibility for capacity payment. The participation of foreign plants, however, is unlikely: on the one hand, reserving the needed cross border capacities is costly for them, lowering their competitiveness, making participation financially unattractive (see below the issue of cross border capacities); while on the other, there may be political barriers for power plants to support the markets of neighbouring countries through this instrument.

Short term external impact: If foreign producers can participate in a capacity market, a particular
problem may arise as the foreign capacity offered in the capacity market may be missed from the market of the exporting country, which would jeopardize system security within the market of the foreign country even in the short run.

**Danger of regulatory competition:** The above described two impacts carry the risk of regulatory competition: particular member states may have an interest to aggressively support their system, outbidding each other - otherwise they may have to face serious challenges related to system security. The elemental interest of regulators in profitably operating power plants in their countries points to the same direction: since if this profitability is eroded by the capacity mechanism applied in the neighbouring country, then the affected producers will be inclined to pressure the regulator to introduce a similar mechanism - or another measure to compensate for the decline in competitiveness. Regulatory competition like this could highly distort the distribution of power plant investments across Europe, while also placing a substantial burden on the consumer who eventually pays for the capacity mechanisms.

**The issue of cross-border capacities:** Reserving foreign capacities implies that these capacities should be available with a high degree of certainty in order to be able to start them shortly after the system operator’s request – similarly to system reserves. This, however, demands that the corresponding cross border capacities are always reserved, which would reduce the cross border capacity available for day-ahead trading, reducing market competition and the degree to which prices converge across markets. This is clearly contrary to the intention to connect European day-ahead markets, while maintaining idle cross border capacities will definitely be in conflict with the European Network Code that is under development at the moment. From the above descriptions it is evident that unilaterally created capacity support systems may lead to serious trouble within the internal EU market, in some countries materially exacerbating the problems that they were created to solve. Therefore, if a country intends to introduce a capacity mechanism, it should be able to do this only after the regional and EU level impacts of the system have been considered. At the same time, whether it is possible to mitigate the potential damage arising from the application of capacity mechanisms – along the establishment of European or regional cooperation – is still questionable today.

**European review**

There are several European countries with operating capacity mechanisms. In Italy since 2004 low nominal capacity payments have been used to support already existing power plants: after 2017 the existing capacity payment mechanism would be replaced by a new options based system. Spain also applies a capacity payment based system, in which hydropower plants, and coal, gas and heating oil fired plants are all eligible for support, including already existing and newly built plants as well. The mechanism used in Portugal is similar to that of Spain, but it only covers newly built power plants. Since 2005 Ireland and Northern Ireland, operating a common electricity market, have also applied a capacity payment based system available to all domestic power plants. Sweden and Finland, on the other hand, maintain strategic reserves justified primarily by the weather dependent, highly volatile hydro generation and the related scarce winter capacities.

Recently several other European countries have given a thought to developing a capacity mechanism. At present, the United Kingdom has plans at an advanced stage: even though - according to the regulator - available capacities currently match demand, the growing supply of wind power, the expected expansion of inflexible nuclear generation (which may crowd out gas based plants from the merit order), and the forecasted closure of 20% of the presently available conventional capacities by 2020 raises concerns. As a response, the Department of Energy and Climate Change of Britain plans to launch a capacity market based on centralised auctions, making the support scheme available to both existing and future capacities. The first auction could take place in 2014, in order to secure the capacity need for 2015/2016.

Last year in Germany different views appeared on the necessity of capacity mechanisms. The consultation is carried on: the introduction of capacity auctions before 2020 has been discussed, but for now the continuation of the “energy-only” market seems more likely, just as the development of strategic reserves, though the latter at a lower probability. There is agreement, however, that in the absence of a capacity market the network will need to undergo adequate development, and more emphasis will have to be placed on demand side measures.

In France the establishment of a capacity mechanism is justified by the combination of increased renewable generation, and the closure of both
long term peak generating capacities and coal and oil fired power plant units. These plans, however, are quite dubious: the fortunes of the originally planned capacity obligation regime is uncertain and is not expected before 2016, while the draft legislation will probably be revised by the new French government.

In addition to the above listed countries, Belgium plans to introduce a mechanism based on strategic reserves and guaranteed returns offered to newly built CCGT power plants, while in Poland a capacity market-like solution with geographically differentiated support (nodal pricing) is contemplated, which is to be applied from 2014 at the earliest.

What about the near future?

The issue of capacity mechanisms is far from being settled, but the results of the public consultation organised by the European Commission, concluded in March already offer a number of important lessons. A prominent conclusion is that the participants of the consultation are divided concerning the real need for the introduction of capacity mechanisms, but there seems to be consent regarding a strong demand for general criteria and guidance from the European Union. Nevertheless, only about one-third of the consulted experts agree that the development of a uniform, EU level mechanism is desirable, most of those favouring capacity mechanisms would trust a solution that is differentiated by countries, but implemented under regional or European cooperation. We should also mention that a significant share of the experts do not support the introduction of capacity mechanisms of any kind.

Article 8 of Directive 2009/72/EC (“Tendering for new capacity”) at present provides a point of reference that allows the application of different capacity mechanisms for the member states. The only binding stipulation is that capacity tenders can only be issued if the security of supply is threatened – no detail, however, is devoted to explain cases when such a threat exists. Based on the already quoted industry consultation, in this July the European Commission plans to draft a guideline on the types of capacity mechanisms that qualify as state subsidy, and whether they are problematic from the perspective of market competition and the integration of European energy markets.

This guideline is expected to be the basis of the next phase – planned for the second half of this year – the goal of which is a coordinated EU level evaluation of capacity needs. We can assume that while the Commission does not have the authority to forbid or obstruct capacity mechanisms, it may still prescribe conditions to their application, or, when appropriate, reduce the leeway of member states to introduce measures unilaterally. At the same time, the Commission is likely to endorse measures that present an alternative to capacity mechanisms but are potentially less market distorting, such as investments into energy efficiency and the application of demand side management. By reducing both the total demand for electricity and peak hour load, these instruments could provide remedies for exactly those problems that member states are currently considering to treat by the adoption of capacity mechanisms.
Gas Market Integration in Central Europe

Excerpt of the workshop organized by the Regional Centre for Energy Research (REKK) in Budapest, Hungary, on the 4th of April 2013

Organized by the Regional Centre for Energy Policy Research (REKK) in Budapest, Hungary, in partnership with the Florence School of Regulation at the European University Institute and the Centre for European Policy Studies (CEPS), the workshop “Energy Market Integration in Central Europe: Drivers, Early Lessons and the Way Forward” was intended as the second chapter in a series of discussions on the “Schengenization” of EU Energy Policy, which was initiated by the Cliengendael International Energy Programme. Following an earlier meeting with a focus on the energy market integration experiences of Northwestern Europe, held in The Hague in October 2012, the Budapest-based workshop continued with a clear objective of discussing policy drivers and early lessons from integration initiatives in Central Eastern Europe (CEE). The four-chapter discussion continued with a third meeting in Florence in June, and will conclude in Brussels in October.

The EU’s aim of fully integrating national energy markets by 2014, and the urgent steps this target date necessitates, provided a starting point for the workshop’s discussions. In this overview, we are going to summarize the key messages of the workshop regarding European gas market integration.

The Polish V4 presidency: a Gas Target Model by 2017?

The first part of the workshop focused primarily on initiatives at the level of nation states. Discussing the priorities and accomplishments of the Polish presidency of the Visegrad Group (V4) countries, the presentations encompassed a wide range of political motives behind the integration of the CEE region. The objective of the current Polish presidency is to enhance cooperation in the region, with a particular focus on advancing the progress of the regional gas market integration by bringing forward regional interconnections and improving security of supply. Importantly, a forthcoming V4 Summit was held on June 16-17, 2013 where a roadmap to an integrated V4 gas market was presented. This roadmap will be followed by an analysis of the current state of the V4 markets by national regulators and an expert analysis of a regional Gas Target Model (GTM) which is intended to serve as the basis of future regional market integration.

At the workshop we have learnt that a viable GTM has to provide remedies for at least the following problems: the dominance of Russian long-term gas export contracts in the supply of regional countries; the limited physical interconnections among regional countries with the exception of the Czech Republic and Slovakia; the dominance of East-to-West gas flows; and the low level of security of supply, which manifested itself during the 2009 gas crisis. The GTM is envisioned to alleviate the existing problems by building on a number of opportunities: further supply source diversification via a possible new LNG terminal in Poland, and also possibly LNG gas from the Baltics and/or Greece, Turkey and even Italy; storage complementarity in the CEE region; new gas production from unconventional sources; the more and more competitive behaviour of companies selling Russian gas in CEE; and a more rapidly developing regional market.

It can be argued that there are a number of requirements the GTM must be aligned with: for example, each integrated market zone should be uncongested internally; should be based on common entry-exit tariffs which would define a virtual trading point; should have a market size of at least 20 billion cubic meters of gas per year; should have access to a minimum of three different supply sources; and should have a limited market power (i.e., HHI < 2000). A GTM should also use market tools for the integration, and must take into account market circumstances in its market design, and also existing cooperations.

A number of model alternatives are currently on the agenda. Integration in the form of a single cross-border V4 market zone, or a still demanding creation of a common trading region are the more ambitious options, while the integration could also take the form of multiple coupled markets. These are all in contrast to a “business-as-usual” case of independent connections to more liquid zones in Western Europe. Whatever will be the final form of integration, working connections among the V4 countries and their neighbours, e.g. virtual reverse flows should be established first,
after which the development or consolidation of the envisioned market zones should take place. The joint implementation of European Network Codes for capacity allocation, and laying down common criteria to consumer protection is also necessary before the decision on the final market design, which can take place around 2016-2017.

Integration is already happening: a trilateral effort by Austria, the Czech Republic and Slovakia

Regional gas market integration is already underway from a second direction: while the integration of the V4 gas markets is not expected before 2016, an effort by Austria, the Czech Republic and Slovakia to create a common trading region among the three countries is already underway. This integration would see one trading region with one virtual trading point and three separate balancing zones in each member states, and considers local integrations to be a more realistic alternative to creating one unified European system. The idea of the trading region leaves national markets untouched but would oblige every market participant to nominate at a common trading point. It was highlighted that the number and geographical scope of integrated markets (entry-exit zones) is a matter of costs and benefits: the AT-CZ-SK integration is no exception, and an important driving force of this effort is that it is estimated to bring about an estimated positive welfare gain of at least EUR 15 million for the three countries.

Visegrád and beyond: tasks for the Hungarian V4 presidency

Meanwhile, the forthcoming Hungarian V4 presidency has an overarching goal of advancing the development of a North-South energy corridor. Under Hungary’s presidency, a “V4+” dialogue is expected to extend the V4 cooperation by involving the region’s neighbours. At a later conference held in May in Warsaw1 it was revealed that Hungary is planning to set up pilot projects among V4 states and their neighbours in accordance with this extended dialogue: these projects would serve as a foundation for a region-wide implementation of European Network Codes, and will likely involve such initiatives as selling bundled capacity products under the cooperation of neighbouring TSOs.

1 Prospects for the creation of a regional gas market in Visegrád Group states, Warsaw, 2013. május 13

Abbreviations in the report:

- APX: Amsterdam Power Exchange
- ARA: Amsterdam-Rotterdam-Antwerpen
- CEGH: Central European Gas Hub
- EEX: European Energy Exchange
- ETS: Emission Trading Scheme
- EUA: European Union Allowance
- HAG: Hungary-Austria Gasline
- HDD: Heating Degree Day
- HUPX: Hungarian Power Exchange
- OPCOM: Operatorul Pieteii de Energie Electrica
- OTE: Operátor trhu s elektrinou
- PXE: Power Exchange Central Europe
- SEPS: Slovenská elektrizačná prenosová sústava
POSTGRADUATE COURSE: ENERGY ECONOMIST AND SPECIALIST, 2013

In September 2013 the Regional Centre for Energy Policy Research together with the Faculty of Business Administration of the Corvinus University of Budapest launches a postgraduate course to train energy economists/specialists. The course is available to professionals with a degree in economics, engineering, law and agricultural sciences.

The main goal of the Energy economist/specialist course is to provide practical, complex knowledge and analytic skills with a theoretical foundation to professionals with a vision to work in the energy sector. The course is open to those with a higher education degree recognised by the state. The energy economist course is available to graduates with a bachelor (formerly college) or masters (formerly university) degree in economics or business administration, while the energy specialist course is open to professionals with a bachelor or masters degree in engineering/science, law or agricultural sciences. The participants of the two semester program will have a chance to acquire comprehensive, methodologically sound knowledge about the EU and domestic legal and regulatory environment of competitive, liberalised electricity and gas markets, as well as the structure and operation of these markets. In addition to introductory courses in microeconomics and market structures, indispensable for the analysis of markets, participants receive a solid foundation in the theory and practice of regulation and domestic and EU competition law. Methodological subjects focus on sector specific data analysis, accounting, controlling, and investment analysis, essential for the management of companies in the field of energy. Within the course specialised lessons are devoted to the Hungarian and international experience related to the operation of electricity, natural gas and renewable markets, including models of liberalisation, energy trading systems and energy exchanges, the European greenhouse gas trading scheme and renewable energy support systems. Participants will also learn intensely about the Hungarian and international aspects of the security of energy supply, and the regulatory techniques with which the social problems faced by the energy sector can be managed.

The courses of the program are led by competent, internationally acclaimed professors of the University, also highly respected within the world of business. Practising corporate and regulatory experts are regularly invited to share their industry experience.
The ERRA Energy Investment & Regulation Conference offers a 2-day programme which has proved to be an excellent opportunity for a dialogue between the regulators and other stakeholders of the energy industry. The conference will be organised in Tallin, Estonia on 16–17 September, 2013.

The Sessions of the Investment Conference will attempt to address and initiate discussions on the following issues:

- **SESSION I:** energy markets in the baltic region: regional market development, investments and perspectives
- **SESSION II:** supporting competition in energy markets
- **SESSION III:** regulatory measures supporting investment (generation, network) during economic and financial crises
- **SESSION IV:** regulatory issues of emerging markets

The conference strives to provide the delegates with latest news in the energy industry and an outstanding occasion for exchange of ideas with high-level energy regulators of the ERRA region. The delegates use the Conference to engage in discussions about the necessary improvements for the development of energy markets and for energy regulation for electricity, gas and sustainable development of the industry. This year’s Conference is to feature a special session focusing on the development of the energy markets of the Baltic States.

Working languages of Conference are English and Russian.

Official website of the 2013 Conference is: [www.erranet.org/InvestmentConferences/2013](http://www.erranet.org/InvestmentConferences/2013)
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.

**Key activities of REKK:**

**Research**
- Geographically, our key research area is the Central Eastern European and South East European region:
  - regional electricity and gas price modelling
  - CO₂ allowance allocation and trade
  - supports for and markets of renewable energy sources
  - security of supply
  - market entry and trade barriers
  - supplier switching

**Consultancy services**
- price forecasts and country studies for the preparation of investment decisions
- consultancy service for large customers on shaping their energy strategy on the liberalised market
- consultancy service for regulatory authorities and energy supply companies on price regulation
- consultancy service for system operators on how to manage the new challenges

**Trainings**
- Our training programmes:
  - summer schools
  - courses for regulators
  - trainings and e-learning courses in the following topics:
    - price regulation
    - electricity markets
    - market monitoring
    - gas markets
  - occasional trainings for companies based on individual claims

Nowadays, due to market opening, energy markets cannot be analysed without taking into account regional environment. We monitor the market situation and developments of the countries of the Central Eastern and South East European region. We have built a regional electricity market model including 15 countries to forecast regional electricity prices.

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.

**Our reference partners:**

**Regulatory authorities and ministries**
- HEO (Hungarian Energy Office), GVH (Hungarian Competition Authority), KVVM (Ministry of Environment and Water), GKM (Ministry of Economy and Transport), FVM (Ministry of Agriculture and Rural Development)

**Energy companies and large customers**
- Mavir, E.ON, MOL, MVM, ELMŰ, Főgáz, Alcoa, DRV

**International organisations**
- DG TREN, USAID, ERRA, CEER, NARUC