Dear Reader!

We are delighted to present to you the second issue of volume 4 of our Energy markets report. We sincerely hope that our readers have been satisfied with the earlier issues of the Report.

In addition to reviewing the last quarter of the electricity and gas markets, we publish four studies.

Despite weak domestic demand, for the last few months electricity prices in Hungary have significantly surpassed the German price level. In our first analysis we inspect if this can be explained by the below average hydro power generation of the Balkan countries.

To mitigate the adverse impacts of climate change, Hungary is about to prepare a Domestic Decarbonisation Roadmap. On this occasion we review the tools and development pathways envisaged by international studies for the decarbonisation of the European economy, equivalent to an 80% reduction of its greenhouse gas emissions.

In the third article we publish our most recent estimates for the domestic potential of biogas based energy generation.

Finally, in our last article we review if the electricity consumption of Hungary may, through the application of statistical-econometrical methods, be used to provide short term forecasts of GDP growth.

Péter Kaderják, director
ENERGY MARKET DEVELOPMENTS

During the first quarter of the year a number of exciting new developments took place in the energy markets. The price of Brent oil surpassed the price of futures ARA coal and climbed to a new 9 month high. In spite of this, the price for futures wholesale electricity and natural gas edged lower. The price of emission credits got stuck under €10, while the traded volume doubled. Domestic electricity consumption and the share of imports did not change compared to last year. The February weather substantially increased the price of cross border capacities, especially for the Austrian and Slovakian import and the Croatian and Serbian export. The next day price of electricity on the exchanges of the region was also influenced by the weather.

Even though new daily records were set for natural gas consumption in February, the total quarterly natural gas use stayed below the values from last year. With regard to source structure, the share of Russian import increased. In the gas storage market the turnover at the strategic storage facility of the MMBF decreased the utilisation of the E.ON storage facility. Due to multiple disruptions of the Russian supply in the neighbouring countries, our export to Croatia and Romania grew.

International price trends

During the first quarter of 2012 the price of Brent oil per barrel exceeded the price of coal per ton for a sustained period. During the previous quarter the typical average price of crude oil was around USD 110, which increased above USD 120 by February 2012. In January 2012 the EU ministers of foreign affairs agreed on an oil embargo to be imposed on Iran from July, as a response to which in February Tehran suspended its exports to a number of EU countries. The price of coal, on the other hand, stayed unchanged, the futures ARA coal with 2013 delivery was traded at an average price of 114 USD per ton, equivalent to the settlement price of the 2012 product from the previous quarter.

The price of 2013 futures products traded on the EEX electricity exchange declined by an average of 2 €/MWh: the baseload product was available within the 50-54 €/MWh range, with an average price of 52 €/MWh. The peak product moved back and forth between 62 and 66 €/MWh, a unit of peak load electricity for 2013 cost 64 €/MWh on average. The 2013 futures natural gas became

Figure 1. The price of 2013 ARA coal futures traded on EEX and the spot price of Brent Crude between January 2011 and March 2012

Figure 2. The price of 2013 futures electricity and natural gas between January 2011 and March 2012
Overview of the domestic electricity market

In the first quarter of 2012 domestic electricity consumption was 10 TWh, essentially the same as the figure from last year. Energy use in February was 2.5% below the February 2011 level, but other than that, the deviation for January and March was below 1%. Quarterly consumption was also the same as in 2010 and 2009.

10% of our electricity consumption was supplied from foreign sources, in harmony with the trends of the last few years.

At the Hungarian–Austrian border section capacities were reduced with 100 MW, which resulted in a price of around 2.5 HUF/kWh in January, and 1.5 HUF/kWh in February and March. A similar price trend was registered at the Slovakian–Hungarian border. The price of the Hungarian-Serbian capacities also notably increased during this period: due to the unfavourable weather Serbia, which has sizeable hydro
generating capacities, enhanced its import from all directions in order to fill its reservoirs (see our article The predictability of economic growth based on electricity consumption data).

The average monthly price of electricity with next day delivery, traded on the regional exchanges, slightly decreased in January compared to December, then the increased demand due to the low temperatures of February brought about exceptionally high prices, that on some days came close to, or even exceeded 100 €. Because of the February cold, buying a MWh of electricity in February was on average 15-17 € more expensive than in January. As the weather became milder in March, prices dropped below the January price level.

The highest and most volatile prices were recorded on HUPX: for the first two months of the year the price of baseload electricity was 17-20 €/MWh higher than the prices on the German and Czech exchanges, and the price of this product fluctuated between 26 and 145 €/MWh during the quarter. Since June 2011 the cheapest exchange of the region, OPCOM, became the second most expensive trading venue, the price of the baseload product traded here was 15 €/MWh higher in January and February than on the Czech and German exchanges. In these latter markets electricity was traded solidly at 40 €/MWh – aside from the 55 €/MWh price of February.

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
ENERGY MARKET DEVELOPMENTS

Figure 8. Daily average of balancing energy and spot prices, Q1 2012.

Figure 9. 2013 baseload futures prices in the countries of the region between January 2011 and March 2012.

Figure 10. Monthly natural gas consumption between April 2011 and March 2012 compared to the natural gas consumption in 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.

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. In January 2012 a new regulation was adopted on setting the settlement price of balancing energy.

As a result of the new regulation the price of positive balancing energy decreased to 26 HUF/kWh, while the price of negative balancing energy was -9.28 HUF/kWh.

The price of the 2013 baseload product in the Czech and Slovakian electricity markets was 50 €/MWh, while it was 1-2 €/MWh more expensive in the German, and 5 €/MWh more expensive in the Hungarian market. Within the exchanges of the region the price decline of January was followed by a surge in February, and a drop again in March.

Overview of the gas market in Hungary

January and March of 2012 were milder than either last year or the multi-year average, but in February an extended cold spell increased the gas consumption of Hungary as well as the region. Similarly to the last quarter of 2011, domestic gas consumption in February surpassed the figure from a year ago by 200 million m³, but for the quarter as a whole 300 million cubic meter less gas was needed than in the beginning of 2011.

The volume of domestic natural gas production did not change, but its composition did, with a higher share for MOL: previously other, small producers had generated slightly less than 10% (about 70 million
m³ quarterly) of the total domestic yield, while in the first quarter of 2012 they fed only 15 million m³, or 2% of the quarterly production into the natural gas transmission system. At the same time the production of MOL grew by 45 million m³. The consumption peak in February was satisfied from additional Russian supplies and domestic storage capacities – in February 380 million m³ of gas was imported from the East and 900 million m³ withdrawn from the commercial gas storage facilities. During the quarter Hungary exported 1.7 billion m³ of natural gas, the increase in export was due to the harsh February weather and interruptions in the Russian supply. Our export to Croatia and Romania multiplied.

Withdrawal during the quarter – like consumption – was 300 million m³ less than withdrawal in the first quarter of 2011. However, there was a notable change in the composition of withdrawal: during the quarter withdrawal from the commercial storage facility of the MMBF doubled to 500 million m³ of natural gas, while almost 600 million m³ less hydrocarbon was withdrawn from the facilities of the E.ON. In the beginning of the withdrawal period 1 billion m³ less gas was stored in the E.ON storage facilities than in the 2010-2011 winter period, while the commercial stocks of the strategic storage facility were 300 million m³ higher. This is due to a decree of the Ministry of National Development, adopted in April 2011, and its amendments, according to which the Minister...
re-classified part of the strategic natural gas reserve as commercial reserve, available to universal service providers and district heating companies. The two decrees together increased the volume of MMBF natural gas reserves that can be withdrawn by 385 million m³, and during January and February these reserves were sold to the beneficiaries.

From the direction of Baumgarten 1.2 billion m³ natural gas arrived, the same as in the first quarter of 2011. This is 300 million m³ more than the natural gas import through Beregdaróc, and makes up 57% of the import. 52% of the capacity of the Beregdaróc entry point was reserved, the gas flow was equal to 36% of the reserved capacity. Compared to the first quarter of 2011 the volume of imported natural gas increased by 300 million m³.

The price of the oil indexed import benchmark was 125 HUF/m³ during the quarter, with the January price of a cubic meter of natural gas being 10 HUF higher. This was explained by the high EUR and USD exchange rates. Traded volume significantly dropped on the benchmark CEGH spot exchange, less than one-tenth of the usual quarterly volume was traded in this quarter. To provide a perspective, below we also describe the Henry Hub price, which is illustrative of the gas market of the US, and stayed near 20 HUF/m³ during the quarter. The 50 HUF/m³ difference between the European spot price and the oil indexed gas price also seems to stabilise for the long run.

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* Weighted average of the oil indexed and the ENDEX TTF gas price on the power exchange, 60:40 weight until September 2011, 30:70 weight afterwards.

** The price difference between the oil indexed and CEGH for past prices, and the oil indexed and corresponding quarterly futures ENDEX TTF prices for future gas prices. The spread between the spot prices at the Dutch and Austrian exchanges has become very small recently. This is why the futures ENDEX gas prices are considered relevant for the Austrian market as well.

*** Cubic meter price of the Henry Hub wholesale gas price, exchanged at the medium exchange rate of the Central Bank of Hungary. The source of the forecast is the Short Term Energy Outlook.
ENERGY MARKET ANALYSES

The impact of the Balkan drought on the Hungarian wholesale electricity price

2011 was a particularly dry year all through Europe, and the countries of the Balkan were hit by the lack of precipitation even more than usual. The region went through the worst drought of the last 50 years, and the hydropower plants of the Balkan countries were also affected. In this article we inspect how the much less than usual hydropower generation in the Balkan in the second half of the year may have contributed to the detachment of the Hungarian electricity prices from the regional and German prices, starting in the third quarter of 2011.

The impact of the drought on the electricity generation of the Balkan

Precipitation for 2011 was 35% less in Croatia and Serbia, 30% less in Bulgaria, and 20% less in Romania and Slovenia than the average of the previous four years. This deficit started to accumulate from July, therefore the annual average values only partly express the true severity of the situation. The extreme weather alone would not have endangered the electricity markets of the Balkan and the surrounding countries. The share of hydropower plants in total electricity production is around 30-40% in a number of countries within the region, but there are countries – e.g. Albania – where almost all of the generation is hydro based.

The total installed capacity of the Balkan countries is 68 GW, of which 23 GW (34%) is provided by hydropower plants.

Table 1 describes the change of electricity generation in the Balkan countries as a result of the dry weather. Compared to the average values of the 2007-2010 period, production during the second half of the year fell substantially, by 20-40% in all examined countries, except for Bulgaria and Macedonia. Relative to the particularly rainy 2010, the decline is even more extraordinary – between 20% and 55% – and that already includes the production of the previously mentioned two countries.

As a result of the low hydro power generation, most countries were forced to import additional electricity, including the traditional electricity exporter Republika Sprska in Bosnia and Herzegovina. Referring to the critical conditions, the largest energy producer of Romania, the state owned Hidroelectrica substantially reduced the volume of electricity delivered to companies. Ordinarily Hidroelectrica generates 28-35% of electricity in Romania, but because of the drought this value dropped to 10-14% last year, and the loss of Romanian export further aggravated the Balkan situation.

Within the region only Bulgaria rode out the period without any major complication. While the hydro generation of the country dropped less than that of its neighbours, thanks to the record high generation of the Kozloduy nuclear power plant and the coal fired plants of the country, Bulgaria was able to further boost its electricity export.

<table>
<thead>
<tr>
<th>Country</th>
<th>Production, second half of 2010</th>
<th>Production, average of 2nd half-years, 2007-2010</th>
<th>Production, second half of 2011</th>
<th>Change compared to 2010 (%)</th>
<th>Change compared to the average of 2007-2010 (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina</td>
<td>3185</td>
<td>2407</td>
<td>1487</td>
<td>-53%</td>
<td>-38%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>2269</td>
<td>1533</td>
<td>1504</td>
<td>-34%</td>
<td>-2%</td>
</tr>
<tr>
<td>Greece</td>
<td>3519</td>
<td>2481</td>
<td>1927</td>
<td>-45%</td>
<td>-22%</td>
</tr>
<tr>
<td>Croatia</td>
<td>3810</td>
<td>2838</td>
<td>1618</td>
<td>-58%</td>
<td>-43%</td>
</tr>
<tr>
<td>Macedonia</td>
<td>816</td>
<td>563</td>
<td>619</td>
<td>-24%</td>
<td>10%</td>
</tr>
<tr>
<td>Romania</td>
<td>10611</td>
<td>8146</td>
<td>5402</td>
<td>-49%</td>
<td>-34%</td>
</tr>
<tr>
<td>Serbia</td>
<td>5587</td>
<td>4885</td>
<td>3522</td>
<td>-37%</td>
<td>-28%</td>
</tr>
<tr>
<td>Slovenia</td>
<td>2329</td>
<td>1915</td>
<td>1559</td>
<td>-33%</td>
<td>-19%</td>
</tr>
<tr>
<td>Total</td>
<td>32126</td>
<td>24768</td>
<td>17638</td>
<td>-45%</td>
<td>-29%</td>
</tr>
</tbody>
</table>

Source: ENTSO-E, REKK calculation

Table 1. Hydro power generation between July and December, GWh
Hungarian wholesale prices in 2011

As shown in Figure 16 above, until the summer of 2011 Hungarian wholesale electricity prices exhibited a strong correlation with the Czech-Slovakian-German prices.

From July 2011, nevertheless, the domestic (and the Romanian) prices started to break further and further away from the German price level, and this tendency became even more discernible at the end of the year: the average next day price for December was already 16€/MWh higher than in the Slovakian/Czech market, and 14€/MWh higher than in Germany. One of the possible explanations for the departure of the domestic wholesale price level from the German electricity prices may be the drought in the Balkan. Using the European electricity market model of REKK, next we examine if this argument holds, or the high electricity market prices and the detachment from the Western European price region are due to some other factor.

Modelling results

The European electricity market model developed by REKK simulates the electricity markets of 36 European countries. The equilibrium price of each country is computed based on the operating characteristics of almost 5,000 generating blocks in all these countries, paying attention to cross-border capacities and different demand equations. The model assumes perfect competition both in production and at the auctions of cross-border capacities.

Using the model we determined the prices that would have taken place in 2011 had hydro power plants operated with the average capacity utilisation of the previous years, and we also ran the model with the average capacity utilisation observed in the second half of 2011. Figure 17 shows the electricity wholesale prices at the multi-year average hydro power plant capacity utilisation (left hand figure) and at the utilisation rate in the second half of 2011 (right hand figure).

As the left figure shows, if in 2011 the hydro power plants in the Balkan region worked at average capacity utilisation, then – ceteris paribus – the electricity markets of the Balkan countries would have been a little bit cheaper than the

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Figure 16. Monthly average price of next day baseload power in Hungary and its neighbouring countries in 2010 and 2011 (€/MWh)

Figure 17. Baseload wholesale electricity prices at average (left side) and H2 2011 capacity utilisation of Balkan hydro power plants, €/MWh

1 The colours on the figures indicate price regions, within which the wholesale price of individual countries are more or less the same.
Hungarian-Slovakian region (except for Croatia, which is a “member” of the Hungarian-Slovakian price zone), that is, the Balkan countries would have exported electricity to the North. The Hungarian electricity prices in this case would not have significantly differed from the Slovakian or Czech prices, while they would have been 3-4 €/MWh below German prices.

If, however, the production of hydro power plants in the Balkan is low, then the price of electricity in the region will increase, and the Balkan price zone is extended to Croatia and Hungary as well: assuming 2011 precipitation this could trigger a price increase of a little more than 4 €/MWh. At the same time, prices in Slovakia and the Czech Republic also increase, but at a lower rate, thereby these countries “unite”, and their equilibrium price will be lower than in the Balkan, approaching the German prices from below. We modelled the electricity prices in the countries of the region as a function of different levels of hydro power generation in the Balkan, as displayed in Figure 18 below:

Apparently, in case of average utilisation, the prices in the Central and Eastern European and the South Eastern European regions are almost the same, and a substantially higher baseload price is observable only in Germany. As the production of the Balkan hydro power plants starts to decrease (i.e. we are moving to the right in the figure), the price in the Czech Republic and Slovakia slowly approaches the German price level, while prices in the Balkan countries and Hungary below a certain capacity utilisation rate (that would entail even more unfavourable precipitation than during the second half of 2011) increase to a much higher level than the German-Czech-Slovakian price level. Meanwhile, it is important to point out that if the generation at the Balkan hydro power plants did not decline to this threshold level, that is, they operated throughout the year at the capacity utilisation rate observed at the end of last year, then according to the modelling results the prices in Hungary and the Balkan would almost equal the German prices. By contrast, actual prices reveal that starting in the second half of 2011 (and also carrying on to the beginning of 2012) Hungarian wholesale prices were significantly higher than the German price level.

As a conclusion, generation at the Balkan hydro power plants has a significant impact on the Hungarian wholesale electricity price, but the low utilisation rates of hydro power plants at the end of last year only partially explain the substantial Hungarian-German price difference experienced during the second half of 2011 and the first quarter of 2012. These price differences may be driven by other factors, the exploration of which, however, is not the theme of our current analysis.

![Figure 18](image-url)
Visions of decarbonisation in Europe

Equipped with the knowledge of the emission reduction targets emerging from international negotiations and agreements on climate change, a number of examinations and studies have been conducted for the last few years to better understand the instruments and possible paths of development through which the European economy could be decarbonised—equivalent to cutting the emissions of greenhouse gases by 80%.

Based on studies on the decarbonisation of the European economy, below we review the emission reduction potential of different sectors, then we present the main instruments for decarbonisation and introduce a number of possible decarbonisation scenarios.

Sector level potential for emission reduction

The decarbonisation scenarios of various studies resulted in somewhat different sector level emission reduction targets, but in terms of the reduction potential of given sectors and the range of possible instruments for decarbonisation a number of common features stand out:

- Under the various decarbonisation regimes the biggest emission reduction burden clearly falls on the power sector: in case of electricity generation an emission reduction of 90-100% is claimed to be necessary, but also feasible by all studies. The limited CO₂ capturing ability (90% efficiency) of the Carbon Capture and Storage (CCS) technology is viewed as the only obstacle to complete decarbonisation of the sector. The main vehicles of emission reduction are the carbon-neutral generating technologies: nuclear electricity production, the use of renewables and the application of CCS.

- The household and service sectors, the emissions of which essentially stem from the energy use of heating and cooling the buildings, also have a very significant decarbonisation potential of over 85%. Two – more or less equivalent - pillars of sector level decarbonisation are the vigorous increase of energy efficiency and fuel switch. The energy use of buildings can be reduced primarily through more stringent energy efficiency standards for new buildings and stepping up the rate of renovation (focusing on heat insulation) for the existing stock of buildings. Fuel switch would involve the replacement of fossil fuel based heating systems, primarily with heat pumps operated with electricity.

- With regard to decarbonisation within the transport sector, different studies assume that 55-65% of emission reduction is feasible, which, on the face of it, seems quite modest. In fact, achieving emission reduction on this scale requires serious efforts: while the emissions of the power sector, or the household and service sector decreased considerably between 1990 and 2010, the emissions within the transport sector constantly increased since 1990. On a 2010 basis this results in an emission reduction target of well over 70%. The expected emission reduction within the sector can be split to two phases: until 2030 emission reductions are likely to be modest, for the most part driven by the increasing efficiency of gasoline and diesel engines. More significant decarbonisation of the sector is envisaged beyond 2030, with the penetration of Plug-in Hybrids Electric Vehicles (PHEV) and Electric Vehicles (EV) within passenger transport, and the use of 2nd and 3rd generation biofuels in freight transport and (to a lower extent) aviation.

- Different studies show fairly large variation of the viable level of decarbonisation within the industrial sector: emission reductions of 40% and 75-85% are presumed to be realistic by ECF and the Roadmap of the European Commission, respectively. The substantial difference is likely due to different assumptions on the dispersion of CCS within the industrial sector. Before 2030 decarbonisation of industrial production will be achieved primarily through improving energy efficiency, while after that through the use of CCS. The industrial application of CCS, however, faces strong economic headwinds: it is expected to be widely used in energy intensive / heavy industrial facilities only – including the cement and chemical industries; iron and steel manufacturing; and the oil and gas sectors - , its application at smaller facilities is unlikely to be economical even at higher CO₂ prices. The opportunities for fuel switch (e.g. electrification) within the sector are limited for technological reasons: most industrial heat demand cannot be satisfied from electricity due to the high temperature requirement.

- The decarbonisation potential of agriculture (which is responsible for about half of all non-CO₂ GHG emissions) is even more limited than that of the industrial sector: different studies believe that...
not more than 20-50% of emission reduction is reasonable. The timing of agricultural emission reduction is also the inverse of what is forecasted for the transport or the industrial sectors: most of the potential emission reduction is concentrated in the period before 2030. Decarbonisation in the next two decades can be achieved mainly through improved methods of animal husbandry and crop production – also strongly supported by current EU regulations. After 2030 agricultural production and related emissions will increase as a result of the growing global population and increasing worldwide demand for agricultural products, and efficiency gains will not be able to counterbalance this trend, therefore the pace at which emissions are reduced will substantially slow during the second half of the period.

Concerning the burden sharing of decarbonisation among the sectors, most studies view the electricity sector, and the household and service sectors as having the largest emission reduction potential. Options for emission reduction are somewhat more limited in case of the transport sector and industry (and also more segmented within the sectors), and they are more likely to be utilised in the second half of the 2010-2050 period. Within the transport sector, depending on the penetration of electric vehicles, passenger transport should have a bigger role; while within the industrial sector the energy intensive heavy industry is likely to be in focus, also depending on the development of the CCS technology. The emission reduction potential of agriculture and the other sectors is much more limited based on present knowledge.

**Instruments of decarbonisation**

Opportunities for sector level decarbonisation are based on the widespread use of a few key emission reduction tools: improving energy efficiency, use of CCS within the power sector and the industry, robust growth of renewable generation and the application of nuclear technology. The dynamic improvement of energy efficiency is highlighted as a vital tool for emission reduction under all scenarios: based on current estimates utilisation of the potential for the improvement of energy efficiency could deliver 30-40% of all emission reductions. To exploit this potential the 1.5% average annual improvement of energy intensity of the recent past needs to be increased to 2.5% during the coming decades, which requires a remarkable expansion of the regulatory efforts to date (an increase of 3-4 times).

The distinctive role of energy efficiency is primarily due to the fact that the instruments available for energy efficiency improvement are positioned early on on the GHG emission abatement curve: in other words, the savings generated by their application (mainly the cost reduction resulting from reduced energy consumption) exceed the costs of their implementation (the investment costs of purchasing and installing these instruments).

Instruments of energy efficiency, situated in the first part of the global abatement cost curve (carrying mostly negative values), are followed by emission reduction technologies (renewable generation, CCS and nuclear energy) that can be applied within the electricity sector at a relatively low, but net positive abatement cost – below 50 $/tCO₂ –, with quite large reduction potential. The steeply increasing last third of the curve comprises industrial fuel switch and CCS, as well as the use of biofuels within the transport sector.

**Strategies of decarbonisation**

Studies outlining potential scenarios of decarbonisation within the European economy, and particularly inside the electricity sector are mostly in agreement with regard to the spectrum of instruments that could be applied. Within this spectrum, however, different strategies of decarbonisation
can be constructed, depending on the additional weight put on an instrument (e.g. energy efficiency, renewables) or the lack of a given instrument (e.g. CCS, nuclear energy). Below we describe three major decarbonisation scenarios:

- **Balanced/diversified scenario**: it deploys all decarbonisation technologies – CCS, nuclear energy, renewables, energy efficiency improvement – and assumes a diversified/conservative fuel mix and a relatively modest renewable share (40-60%). Concerning the fuel mix this is a decidedly conservative scenario, in all other respects – growth of electricity demand, capacity enlargement, network development, share of renewables, price of electricity – it can be regarded as “average”.

- **Energy efficiency driven scenario**: it assumes a particularly robust improvement of energy efficiency and a significant (in excess of 40%) reduction of primary energy use. It is associated with a moderate increase of electricity demand, and consequently, a modest need for capacity expansion and network development, but it requires a lot of investments by the consumers (purchase of energy efficient appliances, reconstruction of buildings).

- **Renewable-heavy scenario**: It assumes an extremely high, 80% share of renewables, with an intensive development of peak power generation / storage, and very limited fossil fuel based and nuclear generation. This scenario requires outstanding capacity expansion and construction of reserve capacities, as well as network development, especially in case of transmission lines and cross border capacities.

The above scenarios provide a glance into the main alternatives, but they cannot depict the full diversity found in the decarbonisation strategies of the member states. The particular natural and infrastructural conditions, market structure, resource availability, energy policy considerations, the regulatory environment and the culture of the countries all make an influence on how the national decarbonisation strategies and regulatory instruments evolve. The two most distinct approaches are represented by the German and English strategies:

- In Germany nuclear generation is refused by both politicians and the population. The applicability of the CCS technology is also very much in doubt, mainly because of the strong resistance of the provinces which are potentially well supplied with storage capacity, due to perceived environmental risks. Renewable energy, on the other hand, has been traditionally well supported, the renewable industry has grown to be an indispensable economic actor with considerable lobbying power. All these factors contributed to the fact that the decarbonisation efforts of Germany focus on renewable energy and the improvement of energy efficiency: the German decarbonisation scenarios assume over 80% of renewable generation, close to 60% lower energy use (backed by an annual building reconstruction rate of 3.3%) and electricity consumption reduced by 10% (on a 2005 basis).

- By contrast, in the United Kingdom nuclear energy and CCS are central to the decarbonisation strategy, which can therefore be regarded as a more conservative and more diversified scenario. Supporting renewables and improving energy efficiency receive less attention in the studies. The explanation may be that the use of nuclear energy in the UK never faced the same public opposition as e.g. in Germany, while the application of CCS is considerably eased by the opportunities for storage along the English shoreline. Another important piece of the British strategy is a regulatory shift within the electricity sector from a liberal regulation, focusing on efficiency improvements toward a more interventionist policy that promotes investments. Furthermore, the technology driven opportunities for business development and job creation are often cited as important ingredients of the British CCS and nuclear strategies.

The above examples may well illustrate that while the concerned countries more or less agree on the national emission reduction targets and the sector level room for decarbonisation, there are fundamental differences in case of the applied instruments, the attitudes toward various technologies and the regulatory solutions.
Bottom-up estimation of the biogas potential of Hungary

At the end of 2011 REKK decided to bring into the focus of its research activities the bottom up modelling of the economic potential and the supply curve of the Hungarian biogas generation and utilisation, with a 2020 time horizon. We carried out a detailed sector level analysis of the three main sources of biogas production: landfills, wastewater treatment plants and biogas facilities within agriculture. Currently the prevailing form of biogas utilisation is combustion in CHP engines, and – in case of landfills and agricultural biogas plants – supplying the generated electricity to the grid in exchange for a feed-in-tariff (FIT). Utilisation of the generated heat is negligible in these two sectors. The technological energy need of municipal wastewater treatment plants, on the other hand, is substantial, therefore the generated heat and electricity is mainly used on site, with less energy supplied to the grid. Using publicly available information, biogas based CHP generation can be depicted as follows:

<table>
<thead>
<tr>
<th>Source</th>
<th>Installed capacity (MWe)</th>
<th>Number of plants</th>
</tr>
</thead>
<tbody>
<tr>
<td>Landfill</td>
<td>7.6</td>
<td>15</td>
</tr>
<tr>
<td>Sewage sludge</td>
<td>14.6</td>
<td>14</td>
</tr>
<tr>
<td>Agricultural</td>
<td>32.2</td>
<td>33</td>
</tr>
<tr>
<td>Total</td>
<td>54.4</td>
<td>62</td>
</tr>
</tbody>
</table>

Source: REKK own collection

Table 2. Installed capacity of biogas based CHP generating units in Hungary, December 2011, breakdown by source

In Hungary sewage sludge based biogas generation has the longest history: thanks to reconstruction projects there are biogas facilities at almost every wastewater treatment plant of the largest towns, or the investment is in progress as part of an already contracted bid. These projects have almost always been financed from EU funds.

A key feature of solid waste based biogas generation – besides the lack of fuel costs – is that of the three sectors this has the lowest unit investment cost requirement. Therefore this is the sector in which we can find examples of investments taking place without external support. The sector potential, nevertheless, is quite limited, as there are only a handful of large scale solid waste landfills and the average capacity of the biogas engines operated even at the largest sites is among the lowest within the three sectors. The biggest capacity increase of the last few years has taken place for agricultural biogas plants – which are less limited by size constraints or the number of projects –, the installed capacity of CHP engines in this sector grew by 16.5 MWe in 2010, thanks to the high percentage ratio of investment grants.

During the research the 2015 biogas based electricity generating potential has been estimated based on the currently planned investments, with use of concrete project data, while we determined the additional increase by 2020 considering existing trends and sector specific attributes (e.g. by detecting potential sites). Results show that by 2015 the current annual production of 380 GWh will increase by almost 80% to 669 GWh/year, and it will more than double to 1 TWh by 2020 (Figure 20). These future values amount to almost 1% (2015) and 2.5% (2020) of the year 2010 gross electricity consumption of Hungary. By the end of the inspected period agricultural biogas generation will provide over 50% of the total value. By 2020 biogas based electricity generation from landfills will exceed the production from sewage treatment plants. The former will rise from 14% to 25%, while the latter is expected to drop from the current 27% to 20%. Between 2011 and 2020 the average annual growth rate of total CHP based biogas utilisation is 11.5%.

In addition to estimating the economic potential, as part of the research we also constructed a cost model to specify the supply curve of different sources of biogas generation. For 2020 Figure 21 depicts the supply curve of biogas utilisation through CHP production in Hungary. For each sector the lowest cost is the short run cost of already existing plants (continuous line), while the dotted line represents the cost of future plants, including investment costs. A new plant is built only if the expected price (market price or FIT) is higher than the long run average cost of the plant.

The supply curve indicates the additional volume of the biogas based CHP engines that are expected to be dispatched at a given price. The first dotted line shows the costs of currently planned investments and upgrades based on the costs of the reference projects, while the second dotted line denotes the costs of previously planned, but – for the time being – postponed projects. In the figure we indicate the current average annual electricity
The following conclusions presume that the FIT is granted for the full lifetime of the project and the annual decline of the FIT set by the regulation is equal to the cost reductions originating from improved efficiency and accumulated experience.

- If there is no further investment support, around 620 GWh of annual biogas based CHP production can be realised by 2020.

**Policy conclusions**

**Investment support**

Waste and sewage sludge based biogas generation is limited since only a given amount of these raw materials is accessible. Extensive growth can only be based on the construction of agricultural biogas plants. These, however, are only viable if substantial investment grants are made available on top of the current operating support provided through feed-in-tariffs. According to the calculations of REKK with an additional 30% investment support for the biogas projects on wastewater treatment plants, all economically and technically feasible investments would likely be carried out. Agricultural plants in the design phase require another 20% of support, but the realisation of additional plants would be elicited only by a substantial investment support of up to 80%.

**Feed-in-tariff**

The current support scheme is going to change from January 2013, the future prices are not yet known. Under the present system the eligibility period for FIT is differentiated according to the source of the biogas: agricultural and sewage sludge generation is eligible for 15 years, while waste-based plants are eligible for 5 years only. In individual cases the eligibility period may be reduced, taking into account the investment grant received by the project.

Waste based facilities and already planned sewage sludge based biogas plants are economic and will be realised even under these conditions. If future investments are to be supported exclusively through FIT, then in order to promote future (not yet planned) sewage sludge based plants and
agricultural facilities, the feed-in-tariff ought to be raised by about one-third of the current tariff, to 43,159 HUF/MWh. This support regime, however, is not efficient, as it would significantly subsidise investments which would also take place without the increase in tariffs. As sewage sludge based biogas production does not have a fuel cost while agricultural biogas based generation has a significant one, it would be reasonable to differentiate between these two sectors.

Regarding the future support system, if the eligible time intervals for support are not differentiated among technologies, a possible option would be to continue with the current mixed support system (FIT + investment support) but with a more rational consideration of the unit costs of production and the cost structure (paying special attention to the ratio of fixed and variable costs within the unit cost).

**Biomethane production**

As a result of the current support system, the most common mode of biogas utilisation in Hungary is combustion in CHP engines, given that there is no feed-in-tariff for biomethane and the regulatory provisions for supplying biomethane to the network are also absent. Nevertheless, there is a Hungarian example for the production of biogas based CNG and its use as fuel in transport. Accordingly, we also assembled a scenario in which the available biogas is not combusted in the existing CHP engines, but rather, after additional purification it is injected into the natural gas network or sold as fuel. Our estimate for the Hungarian biomethane generating potential for 2020 is 300 million m³, equal to 2.5% of the approximately 12 billion m³ of domestic natural gas consumption, or 15% of the 2 billion m³ of domestic natural gas production.

**The predictability of economic growth based on electricity consumption data**

Using statistical-econometrical methods, we would like to determine the extent to which the electricity consumption of Hungary can be used for the short-term forecast of GDP growth. Our analysis is based partly on quarterly and partly on annual data: since 1998 quarterly data is available from ENTSO-E, while for the 1990-2010 period annual Eurostat data on net final consumption is used for the analysis.

Usually both Mavir and ENTSO-E publish the electricity consumption data for a given quarter before the Hungarian Statistical Office releases the Hungarian GDP figure for the same quarter. Therefore it is reasonable to ask if the electricity use of a given quarter may provide an indication on the rate of growth (or decline) of the national output during the same period. Our analysis was also prompted by the expectation that the electricity consumption of the economy moves in line with economic activity: when the economy grows, economic actors will use more energy.

First we explore the causal relationship between the volume of electricity use and quarterly GDP growth – to be exact: will a growing GDP result in higher electricity consumption of the economy? The use of quarterly – as opposed to annual – data is justified by the length of the time series, as a larger data set leads to more reliable estimates. There is strong seasonality in case of both electricity use and real GDP: in order to analyse their relation, first we need to adjust the data for seasonality. To do so we used real GDP figures from Eurostat, adjusted them for seasonality and the number of working days, and we also applied electricity consumption data from ENTSO-E – in this case we screened for the impact of seasonality and the number of working days with the TRAMO/SEATS method.

Inspecting the adjusted quarterly data we can see that between 1998 and 2008 both real GDP and electricity consumption displayed an increasing trend, during the 2008-2009 crisis they both fell, and from 2010 on both started to ascend again (Figure 22). The two time series therefore move together: we calculated that between 1998 and 2011 a 1% increase of electricity use was escorted by a GDP increase of 1.86% on average. However, in order to be able to declare that there is a causal relation between the two variables, we need to examine the relationship between the percentage change of electricity use and the percentage change of GDP. When we analysed the relationship between the percentage changes for the whole period of 1998 to 2011, we found a strong correlation between the two variables. Yet, as displayed by Figure 23, this relationship is much more evident in 2008-2009 than during the years before and after the 2008 crisis. When we repeated our analysis omitting the years 2008 and 2009 then the strong relationship was not any more detectable.

Working with annual data we noticed that the fluctuation of total electricity consumption is driven mainly by the variation in industrial
consumption. This is why we examined the relation of annual electricity use to both real GDP and industrial output. Although we found some co-movement between the analysed variables, we were unable to demonstrate a statistically significant causal relationship with either GDP or industrial output.

Using the correlation of the two time series we made an attempt at forecasting the change in quarterly GDP. Here we used the following approach: for each quarter of the 2005-2011 period we began with the last available real GDP figure, and tried to forecast the rate of GDP growth for the next quarter based on electricity use solely. To do this, using all available data until the quarter in question, first we estimated how much GDP growth would on average arise from a 1% increase in electricity use. For example, to forecast for the first period of our analysis, the first quarter of 2005, we used the 2.1% value estimated based on the period lasting until the fourth quarter of 2004. The results are illustrated in Figure 24. Apparently, the electricity use of the forecasted period accurately predicted the direction of GDP change for most quarters, but regularly overestimated its size. The underlying reason is that after 2005 a 1% increase of electricity consumption has been associated with substantially lower GDP growth than the value estimated for the whole period – but this information would not have been available for our forecasts, we only know it in retrospect.

We carried out a similar analysis using the annual GDP and electricity consumption figures of the 1996-2010 period. (In this case due to the low sample size...
we were not able to estimate the correlation between the GDP and the electricity use separately for each year, thus we used the 1.86% figure applicable for the whole period). The results are displayed in Figure 25: based on the annual consumption of electricity it is not possible to forecast the annual change in GDP with sufficient confidence. 

In our analysis we inspected if knowledge of electricity use may be helpful in predicting changes in GDP. Working with quarterly and annual data we found that knowing the volume of electricity consumption can – even under the best of circumstances – only slightly improve the short term forecast of GDP growth. During the period under study, the change of electricity use correctly predicted the direction of GDP change for most quarters, but it was not adequate to forecasting the size of this change. The poor predicting ability is partly due to the fact that while the correlation between GDP growth and electricity use had been quite stable until 2008, afterwards it considerably declined, eroding the soundness of the forecast. 

This is because during the years of the crisis the percentage decline of the electricity demand of households and the service sector was less than the drop in industrial electricity use, therefore the slump in economic performance was not followed by a similar decrease in the consumption of electricity. Separate examination of the electricity use of certain economic sectors and industrial branches could provide additional information on the relationship between electricity use and GDP, but such an analysis is beyond the scope of this article.