Dear Reader!

In the current issue of our Hungarian Energy Market Report you may find several articles about international developments besides the trends in the Hungarian market.

As we have previously indicated, the EU selects infrastructure development projects which enjoy priority on the community level based on a development plan. The Energy Community has also started shortlisting the electricity and natural gas infrastructure projects of common interest in their own (mainly focused on the Balkans) region. REKK participated in the community-focused evaluation of the projects proposed, as a member of an international consortium. In our first article we present the proposed and selected projects of energy community interest, and evaluate their effects on the Hungarian electricity and natural gas markets.

Our second piece gives useful and rich supplement for the upcoming debate about nuclear power plant development: how do schedule and budget overruns or other construction risks affect costs based on international experiences. Although our article does not paint a positive picture, it is a worthwhile reading.

Then we present a summary of a study prepared for the Ministry of National Development about the primary energy consumption of Hungary. We estimated the energy use of the whole Hungarian economy and of some selected sectors. Our research projects considerable drop of consumption to 2020 both in final and primary energy consumption. We assess the primary reasons rooted in energy intensity, economic growth and source composition.

Finally we consider the increasing influence of the global LNG markets on Europe. The growth of gas demand in Europe is accompanied by the plunge in domestic production and expansion of international supply, so European LNG imports are facing a bright future. This fact is of great importance concerning European gas prices.

We hope you find our articles interesting and useful. Thanks to you, REKK –which is close to the 10 year anniversary of its foundation – will continue the independent analyses of the energy markets.

Péter Kaderják, director
Regional Centre for Energy Policy Research

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**TABLE OF CONTENTS**

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>INTRODUCTION</strong></td>
<td>2</td>
</tr>
<tr>
<td><strong>ENERGY MARKET DEVELOPMENTS</strong></td>
<td></td>
</tr>
<tr>
<td>International price trends</td>
<td>3</td>
</tr>
<tr>
<td>Overview of the electricity market in Hungary</td>
<td>3</td>
</tr>
<tr>
<td>Overview of the gas market in Hungary</td>
<td>6</td>
</tr>
<tr>
<td><strong>ENERGY MARKET ANALYSES</strong></td>
<td></td>
</tr>
<tr>
<td>Energy Infrastructure</td>
<td>9</td>
</tr>
<tr>
<td>Projects of Energy Community Interest</td>
<td></td>
</tr>
<tr>
<td>Nuclear power plant construction – missed deadlines, cost escalation, risks of implementation</td>
<td>12</td>
</tr>
<tr>
<td><strong>WORKING PAPERS</strong></td>
<td></td>
</tr>
<tr>
<td>Domestic primary energy use prognosis until 2020</td>
<td>16</td>
</tr>
<tr>
<td>Opportunities in a globalising market – European LNG imports until 2020</td>
<td>18</td>
</tr>
</tbody>
</table>

**Editor in chief:**
Gabriella Szajkó

**Authors:**
Antal Hum, Péter Kaderják, Lajos Kerekes, Péter Kotek, László Szabó

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REKK Energiaipari Tanácsadó Kft.
For further information about the publication please contact:
Péter Kotek
T: (+36 1) 482 7073
F: (+36 1) 482 7037
E: rekktanacsado@gmail.com
www.rekk.eu
ENERGY MARKET DEVELOPMENTS

Between the months of April and June nothing remarkable happened on regional markets. The price of crude oil and natural gas stood still, while the price of coal fell. Emission credits also changed hands at extremely low prices, further elevating the competitiveness of coal based generating capacities and degrading the outlook for gas based production.

Quarterly electricity consumption was in line with the usual seasonal pattern, but the share of import increased to reach one-third of total consumption. As a result of the high import ratio and the limited cross border capacities, next day Hungarian prices in June separated from those of other countries.

The injection period started in the gas markets. Storage facilities had been depleted to the exceptionally low level of 30%. Storage and consumption have both been mostly based on Russian gas.

International price trends

During the second quarter of 2013 commodity prices continued their decline. The price of Brent crude did not move much. While in April the price of oil fell even below 100 USD/barrel, it mainly stayed within the 100 and 105 USD price range during the quarter. The price of EEX traded ARA coal went through a slow slide, decreasing from 92 USD/ton in April to 85 USD/ton.

The price of futures electricity continued to descend on the German exchange, at the end of June baseload electricity was sold for 38 EUR/MWh, as opposed to the 42 EUR/MWh April price. Compared to the previous quarter, a unit of baseload product was available at 3 Euros less on average.

The price of the peak product decreased by 2 Euros, to 48 EUR/MWh by the end of June. The price of TTF gas stayed between 26 and 27 EUR/MWh, further eroding the competitiveness of natural gas based electricity production.

Emission allowances with December 2013 delivery barely fetched 3 EUR/MWh in April. The low prices on some days triggered extremely intense trading, with a volume of more than 80 million tons on an April day.

Overview of the domestic electricity market

The quarterly temperature and working day adjusted electricity use stood at 9.3 TWh.

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

Figure 2 The price of 2014 futures electricity and natural gas between March 2012 and June 2013
more or less the same as the consumption of the same period of 2012. The energy use of the individual months did not really deviate from the 2012 figures either, with April 1.9% higher, May about the same and June 1.7% lower than the monthly consumptions of 2012.

More than one-third of domestic consumption was supplied from abroad. During the same quarter of 2012 domestic electricity generation satisfied three-quarter of the consumption, this figure decreased to two-third.

At the monthly cross border capacity auctions the price of Austrian and Slovakian import exceeded 1 EUR/MWh. In May the Austrian import, while in June the Slovakian import was not accessible. Market participants substituted these unavailable border crossing capacities with the Croatian and Serbian directions, with the price of capacity being slightly raised by scarcity.

The price of next day baseload products on regional exchanges was in sync with the developments on the German exchange, HUPX being the lone exception in June. In April and May the Czech, Slovakian and Hungarian next day prices closely correlated: at 37 and 29 EUR/MWh in April and May, respectively, 1-3 Euros below the prices quoted on the German exchange. In this quarter the Romanian exchange proved to be the cheapest again, with next day electricity prices sinking below 25 EUR/MWh by the end of June. In June Hungarian prices broke away from Czech and Slovakian next day markets again, as the Hungarian baseload electricity was almost 7 EUR/MWh more expensive on average. On some days
the price of the HUPX traded baseload product increased to as much as 70 EUR/MWh. In addition to scarce cross border transmission capacities, this is also explained by the exodus of larger gas based producers, benefiting cheap hydro power production in the Balkan. Due to the relatively inflexible hydro power sources, as compared to gas based generation, the price of baseload power jumped on some days.

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...
ENERGY MARKET DEVELOPMENTS

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 20 and -6 HUF/kWh on average.

The futures price of baseload electricity with 2014 delivery on the German, Czech and Slovakian exchanges decreased from 40 EUR/MWh in the beginning of the quarter to 37 EUR/MWh by the last days of June. Compared to the markets of the region the baseload product on HUPX with next year delivery fetched a premium of 4 to 6 Euros.

Overview of the gas market in Hungary

Natural gas consumption during the second quarter was 100 mcm above the figure from last year. Gas consumption during the first half of the year usually makes up 54-56% of the annual gas use. Between January and June 5.8 bcm of natural gas was used in Hungary, suggesting total annual consumption between 10.3 and 10.8 bcm (As a comparison, based on the gas consumption of the first half of 2012 we had forecasted an annual figure of 11 bcm, while the final value happened to be 10.8 bcm.). We should note, however, that this relation may be distorted if household consumption gets a boost from the regulated compression utility bills.

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.

The 600 mcm of quarterly domestic production was 50 mcm higher than production in the second quarter of 2012, but 100 mcm below the figure from the second quarter of 2011. The majority of import arrived from the East, 58% of consumption and injection was supplied by the Beregdaróc pipeline.

The period of withdrawal came to an end during the quarter, and injection started. By the end of the winter commercial storage facilities held a total volume of 1 bcm. During the last days of July commercial storage sites were filled to 30% of their capacity. This is much less than the corresponding levels of 40% in 2012 and 50% in 2011.

During the quarter 830 mcm of gas was imported from the direction of Baumgarten and 1.13 bcm from the East. In the West 65% of the capacities had been reserved, 75% of which was utilised during the quarter. 42% of the total Eastern import capacity had been reserved, 51% of which was utilised, less than in the Western direction. Between
April and June the volume of imported gas was 10% less than in 2012, but the same as in 2011.

During the quarter the price of oil indexed gas stayed between 122 and 125 HUF/m³. The price of the import mix containing 70% TTF exchange based and 30% oil indexed product, applicable for universal service providers, fell by 4 HUF/m³ due to favourable market trends, from the 97 HUF/m³ price that characterised the first quarter, to 93 HUF/m³. As a result of the assumed decline of the price of Brent crude we expect that oil indexed and exchange based prices will start to converge.
ENERGY MARKET ANALYSES

Energy Infrastructure Projects of Energy Community Interest

As discussed in our previous analysis, the Balkan energy market developments have a significant influence on the processes of the Hungarian electricity and natural gas markets. For instance, due to our outstanding electricity network connections, during periods of restricted electricity supply the Hungarian electricity wholesale prices are boosted by the increasing wholesale electricity prices of the Balkan region. Furthermore, during rainy periods the availability of low-priced hydropower from the Balkan region helps restraining wholesale electricity prices in Hungary. Although such effects on the gas market are not yet typical due to bottlenecks in the infrastructure and the relatively low levels of market integration, the construction of the southern natural gas interconnections with Romania and Croatia, the enabling of reverse flows, the diversification of the Serbian transmission system, and the construction of the Southern Energy Corridor supported by the European Union may lead to significant changes.

This analysis examines the possible future effects that the planned individual electricity and natural gas development projects in the eight member states of the Energy Community Treaty can have on the Hungarian wholesale energy prices.

In one of our previous articles we described the selection process for common interest EU-level infrastructure development projects based on the trans-European energy infrastructure policy adopted earlier this year. On 14 October 2013, the European Commission reached an agreement to qualify 248 energy projects in this category. In recent months, a very similar process has taken place in the Energy Community that includes the Balkan region. This initiative does not concern the implementation of EU law; rather, it was connected to the common Energy Strategy of the Energy Community, accepted in July 2012.

The Energy Strategy recognises that more important units (e.g. power stations) of the electricity and oil infrastructure of the members of the Energy Community were built in the 1960s and 1970s, therefore the applied technologies are outdated, and their replacement is necessary. Meanwhile, the natural gas sector is underdeveloped, with no infrastructure developed in certain states (Albania, Kosovo, Montenegro). At the same time, the strategy foresees an increase in demand beyond the average levels in the EU. The necessity for infrastructure renewal, the satisfaction of the increasing demand, the implementation of the infrastructure necessary for the development of a regional energy market, and the integration of the growing renewable energy production requires significant investment from the sector participants. The strategy estimated the necessary investment costs based on three possible scenarios (current trends, minimal investment costs, sustainable growth) at 16, 35 and 60 billion Euros, respectively, for the period between 2012 and 2030 (not including Ukraine).

Projects of Energy Community Interests

Based on the above, the strategy proposed for the Energy Community the inspection and selection of mutual interest projects addressing electricity production and transmission, natural gas transmission and storage, and the oil industry infrastructure. The assessment and community focused evaluation of the projects was primarily aimed at informing private investors and financial institutions, in order to encourage investments. The Community Secretariat examined 100 project proposals, which included 43 power plants, 30 transmission plans, and 23 natural gas infrastructure and 4 oil infrastructure proposals. The estimated value of the proposed projects is 30 billion Euros. Figures 16 to 18 show the locations and types of the proposed projects.

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2 On 24 October 2013 the Energy Community Ministerial Council adopted the list of 35 “Projects of Energy Community Interest”. The list can be found at http://www.energy-community.org/portal/page/portal/ENC_HOME/AREAS_OF_WORK/Investments/PECIs/List_PECI
3 Albania, Bosnia-Herzegovina, Croatia, Macedonia, Kosovo, Moldova, Montenegro, Serbia, and Ukraine. From July 2013 Croatia has been a member of the EU and is no longer a member of the Energy Community.
6 The Energy Strategy of the Energy Community can be accessed at http://www.energy-community.org/pls/portal/docs/1810178.PDF
7 With Ukraine, the investment needed until 2030 in line with the scenarios is 29, 64 or 130 billion Euros.
REKK, as a member of an international consortium, recently participated in the community-focused evaluation of the above projects. As part of this research, we conducted a social cost-benefit analysis, using our own European regional electricity and natural gas models. We examined how the implementation of the individual projects would change the wholesale market prices throughout the expected project lifespans, in comparison to the estimates for 2012. We estimated the net social value of the projects based on the available information on investment costs and on our estimation of the cumulative social benefit changes, calculated from the consumer and producer surplus resulting from price fluctuation and the revenues that transmission companies acquired from cross-border capacity auctions. The result of this analysis gives an indication of, from a community perspective, which are the most promising electricity and natural gas infrastructure projects. We list these projects in Table 1 and 2 below.

Analysis by REKK

The present analysis is built upon the above cost-benefit analysis, and examines whether the Balkan region’s most promising electricity and natural gas infrastructure projects could significantly influence the Hungarian energy prices.8 To answer this question, we will build each of these projects into our electricity and regional natural gas market models.

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8 We are aware that a project “preference” – based on cost-benefit analysis – would lead to different outcomes depending on the particular socio-economic or business benefit approach that can undermine the effective implementation of a socially beneficial project. At the same time, the probability of realizing a project with high socio-economic benefit can be increased with less bureaucratic licensing procedure, and exceptional regulatory or governmental support.
for Europe, and will provide an estimate of the effects on cost, production, and trading pattern that can occur on the Hungarian market as a result of implementing each infrastructure item. The analysis is conducted separately for each individual project, without taking into account the rest of the projects.

We started the electricity market analysis – due to its regional importance – with a project that is already under construction and that is expected to go online in 2017. This is a 1000 MW Italy-Montenegro offshore interconnector, which once becomes operational will connect two regions which are prided significantly different. The interconnector will essentially present an absorbing effect in our region due to the high relative prices in Italy, and the base-load transfers directed from the Balkan to Italy will be dominant. The results of our modelling also indicate a significant influence on the prices in Hungary: in comparison to the previous state where no interconnector existed, the coal-based electricity production will increase by 4.6 %, the base-load prices will grow by 0.7 %, and our net import will decrease by 1.6 %.

When analysing the remaining electricity infrastructure projects – in accordance with the 10-year ENTSO-E network development plan currently in place and the expectations of the project company – we took the Italy-Montenegro interconnector as pre-existing (that is, unlike other projects we included this in the reference scenario of our model), and our analysis of the additional effects on the Hungarian electricity market was based on this (see Table 1).

It is clear that the two large-scale lignite based plant projects planned in Serbian would have the most significant impact on the Hungarian energy market by crowding out 4% of the Hungarian lignite based production and dampening the Hungarian wholesale prices by about 1%. At the same time, our net import would increase by one and a half percent. An additional notable result is that the development

We have shown values only in those cases where according to our estimate the project implementation would have a considerable influence on the processes of the Hungarian electricity market.

<table>
<thead>
<tr>
<th>Name of project</th>
<th>Description of project</th>
<th>Hungarian base load price change</th>
<th>Hungarian peak price change</th>
<th>Change in coal based electricity production</th>
<th>Change in net import</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nikola Tesla B3 Thermal</td>
<td>744 MW lignite</td>
<td>-1.2%</td>
<td>-1.1%</td>
<td>-3.9%</td>
<td>1.4%</td>
</tr>
<tr>
<td>Kolubara B Thermal</td>
<td>750 MW lignite</td>
<td>-1.2%</td>
<td>-1.1%</td>
<td>-4.0%</td>
<td>1.4%</td>
</tr>
<tr>
<td>Dubrovnik Hydro (II. Phase)</td>
<td>304 MW</td>
<td></td>
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<tr>
<td>Pancevo CHP</td>
<td>208 MW Natural Gas</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Skavica Hydro</td>
<td>350 MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>400 kV OHL SS Bitola (FYR of MK) - SS Elbasan (AL)</td>
<td>1.5%</td>
<td>1.5%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>400 kV OHL Tirana (AL) - Pristina (Kosovo*)</td>
<td>1.5%</td>
<td>1.5%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>400 kV OHL SS Resita (RO) – SS Pancevo (RS)</td>
<td>1.4%</td>
<td>1.4%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>400 kV OHL SS Kragujevac – SS Kraljevo (RS)</td>
<td>1.5%</td>
<td>1.5%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

We have shown values only in those cases where according to our estimate the project implementation would have a considerable influence on the processes of the Hungarian electricity market.

Table 1 The influence of electricity infrastructure projects with high socio-economic benefits on the Hungarian electricity market
of the electricity infrastructure of our southern neighbours, the strengthening of the Serbian network, and the integration of the network connections of the Southeast Balkan (Albania, Kosovo, Macedonia), which are currently isolated and lacking in sufficient power generation capacities, would generate surplus demand and pressure for power generation on the Hungarian electricity market.

Table 2 shows those natural gas projects in the Balkan region that produce significantly high socio-economic benefits.

As it can be seen, of the six projects with significant socio-economic benefits four projects are unlikely to have a direct individual influence on the processes of the Hungarian natural gas market. These include the TAP pipeline that prevailed against the Nabucco plan in the competition to deliver Azeri natural gas to Europe. Its distance from the Hungarian market, the insufficient development of the natural gas infrastructure in the southern regions, and the lack of interconnectors isolate Hungary from the pipeline’s indirect – and presumably positive – influence on the Italian and EU gas markets. Table 2 shows those natural gas projects in the Balkan region that produce significantly high socio-economic benefits.

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Nuclear power plant construction – missed deadlines, cost escalation, risks of implementation

The public view on nuclear energy has greatly improved for the last decade, and even the Fukushima accident did not notably disrupt this trend. Since the 2000’s the American and British energy policies have treated the incentives for new nuclear investments as a priority, citing both security of supply considerations, and climate protection goals. Most EU member states continue to accept the future use of nuclear energy, while some of the countries – including the Eastern European region – even have a clear preference for it. The number of actual power plant constructions, nevertheless, falls greatly behind targeted figures: most of the presently constructed plants are in China, India and South-Korea, while only three nuclear plants are being built in the United States, and two in the European Union – not counting the completion of the formerly abandoned Mohovce units.

Why do these planned investments fail? Nuclear investments are suspended or delayed not due to the Fukushima accident, but because investors still perceive nuclear power plant investments as too risky at current depressed coal and electricity prices. Below we provide a short review of the most serious risk factors that jeopardize the fulfilment of nuclear investments.

The etymology of missed deadlines

In the history of nuclear power plant investments delayed construction time is not an unfamiliar problem. In the United States 75% of the projects launched (i.e. the reactor units had already been ordered) in the 70’s have never been finished, and the average construction time of completed plants increased from 8.6 years in the previous decade to 14.1 years. Extremely delayed nuclear constructions, however, are not merely historical artefacts: the statistical figures of currently executed European nuclear investments are not at all better than those of their American predecessors. In comparison to the original plans, the Flamanville construction is delayed by 5 years, while the Olkiluoto site by 7 years.
The delay of constructions is in fact a symptom that can be traced back to regulatory/licensing and construction/technological problems/risks. The regulatory risk can be associated with decisions of the authorities hindering or impairing construction or commissioning, while construction risk stems from unexpected technological problems that arise during the extremely complex construction phase.

One of the typical ways for regulatory risks to appear is when the security requirements contained in regulations and permits are tightened after the investment decision has already been made and the construction is in progress, forcing the investor to develop and apply new technological solutions. These types of unexpected regulatory changes usually take place following a severe nuclear plant event or accident.

Regulatory change, however, is not necessarily needed to trigger an official intervention that is unforeseen by the investor. The supervisory authority may identify a number of misconducts when inspecting the construction site: in case technical solutions are found to be different from or substandard to the technological specifications within the construction permit, the construction may be interrupted, and the repair or replacement of the piece in question, or the repeated execution of a given phase may be prescribed to the developer. Since nuclear power plant investments have a much higher share of difficult to standardize, site-specific construction steps than other technologies, while the security and quality requirements are more serious and official inspections are more rigorous, the chances for such official intervention are also rather high.

Figure 19 Nuclear plant constructions between 1951 and 2011

An extreme example of the risks associated with the dual permitting system and the erosion of political and public support is the Shoreham power plant, built in the United States with a budget of 6 billion dollars. The power plant, completed by 1993 based on a valid construction permit and in compliance with regulations never started commercial operations as it was not granted an operating permit, since the regulators of Suffolk county and the governor of New York state were not convinced that the county could be evacuated in case of a state of emergency. The operating permit was refused to be issued partly due to the sharply falling political and public support of the project after the 1979 accident of the Long Island nuclear power plant: in June 1979 already 15,000 people protested in front of the power plant demanding the abolition of the construction.

The intervention of the supervisory authority is often triggered by the constructor itself as it amends the building/technical plans during the construction phase. These amendments are usually required by unexpected practical problems during the construction or the immaturity of the original technical designs. Permitting
complications arising from problems experienced by the constructor or amendments initiated by it should, in these instances, be viewed as building or technological risks.

Construction/technological problems mostly originate from the relative infrequency of nuclear power investments, explained by their large size, as a result of which obtaining the routine of building a given reactor type is more difficult and establishing the supply chain of nuclear equipment manufacturers, and other suppliers and subcontractors is slower than usual. Compared to other power plant technologies the share of difficult to standardize, site specific and other local regulation dependent building tasks is much higher (around 60%). These problems are even more pronounced for those current “commercially available” 3+ generation nuclear plant units where construction experience is still minimal.

The above power plant technologies, suffering from “teething troubles” - often in the early stages of the learning curve - are collectively referred to as FOAK (first of a kind), while NOAK (nth of a kind) is applied to those power plant types that have already accumulated significant construction experience, rely on mature, proven solutions and a well established supply chain, and are also well known to regulatory authorities and supervisory bodies. Currently sold FOAK nuclear technologies can be expected to achieve NOAK status only after several nuclear plants have been completed and commissioned on time, resulting in a much lower risk rating, and thus cheaper financing, which – as some experts claim – may decrease investment costs by one-third.

Cost escalation and investment recovery

The most important consequence of a prolonged construction time is the escalation of investment costs. Past experience with respect to cost overruns is just as unfavourable as in the field of missed construction deadlines. Nuclear plant investments started and completed in the United States between 1966 and 1977 faced cost overruns of 86% on average, but the present European experience is even worse: Areva expects the construction costs of the Finnish Olkiluoto and the French Flamanville power plants to reach EUR 8.2 billion, exceeding originally planned figures by 150%.

The dramatic cost overruns of delayed constructions can be explained by several factors. Solving construction problems, and complying with the requirements and quality expectations of the supervisory authority obviously require additional construction work or the replacement of important equipment. Depending on the pricing of the contract made with the constructor, not only the cost of additional pieces of work, but the cost of the unavoidable „idle time“ (availability) of the constructor may also fall on the investor.

The other source of cost escalation (apart from the use of additional materials and the execution of surplus tasks) is the rise of unit costs. Due to the length of the construction, years may pass between the order and delivery of specific equipments and construction materials, while a lot of materials are ordered only when a given construction phase has arrived. During this lengthy period the price of a number of raw materials (e.g. copper, steel, cement), building materials or equipment may surge, increasing the unit cost of the investment, even when the additional tasks are not considered.

The figure 20 depicts the European power plant investment index published by ISH CERA (EPCCI – European Power Capital Cost Index) for the period 2000 to 2012. During this period the cost of power plant construction (which includes the cost of the utilised labour, raw and building materials and equipment) increased almost twofold. As the figure nicely illustrates, in a period of three years the unit investment cost of power plant construction may increase by as much as 70%. The more gradual rise of the
The curve that excludes the costs of nuclear power plant construction indicates that the unit costs of nuclear power plant investments increase at a much higher pace than those of other technologies.

In addition to a rising investment cost, a prolonged construction may also crush the planned cash flow of the project. This is partly because the repayment of the loans that finance the investment needs to start prior to commissioning (IDC-Interest During Construction), before any revenue from electricity sales is received. The other reason for the impaired cash flow is that - in order to be able to fulfil the contracts on electricity sales signed and already in force prior to the commissioning of the plant - the owners of the power plant need to purchase electricity on the wholesale spot market (until their plant starts to produce for the market), even at prices above their own sales price, in order to forestall compensation payments.

On top of prolonged construction times and the escalation of investment costs, nuclear investments, of course, burdened by a number of additional risks: lower than planned capacity utilization or the – unexpected – shrinking of the lifetime of the plant (see the German nuclear power plant stop) may result in a serious loss of revenue, while the uncertainty surrounding the disposal of radioactive waste and the sudden technical difficulties during decommissioning may generate heavy surplus costs (reaching several hundred million dollars).

Still, the surge of investment costs may threaten the returns on nuclear projects more severely than any of the other risk factors in the more distant future. This is simply because the present value of any additional cost taking place during the investment phase can be an order of magnitude higher than the discounted value of a revenue loss or surplus cost decades from today. The present value of additional costs that take place in the 10th year of the investment, when operation starts, is barely half of the nominal value, while the present value of excess costs at the end of the lifetime of the plant is one-hundredth of the original nominal value.

As the above figure nicely illustrates, the return of an imaginary nuclear plant investment is most sensitive to the level of investment cost and the cost of capital. Changes in the cost of fuel and operation, the rate of capacity utilisation, lifetime or the cost of decommissioning, on the other hand, have a relatively minor impact on the return of the project.

Epilogue: what does the future hold?

Strong arguments support the use of nuclear energy: the electricity sector faces a serious challenge as climate change related commitments are translated into emissions reduction targets - a substantially growing demand needs to be satisfied with carbon neutral capacities. If nuclear energy is bypassed, these targets may turn out to be very difficult to achieve, the alternatives for baseload generation – coal and gas fired power plants – would be capable of meeting the emission targets only through the application of carbon capture and storage (CCS) technologies. The use of CCS, however, is presently still characterised by an investment cost risk similar to nuclear power investments, while environmental and health concerns related to the transportation and storage of carbon-dioxide make its application rather questionable.

The simultaneous fulfilment of climate protection and security of supply goals is probably not possible without regulatory incentives for carbon neutral investments. The US and UK regulatory reforms which were developed to lower the risk of nuclear investments, nevertheless, raise serious concerns with respect to the sustainability of the liberalised electricity market. The future of nuclear generation depends on the answer that the European electricity market regulation comes up with in order to solve the above dilemma.
Domestic primary energy use prognosis until 2020

REKK has made a primary energy use forecast for the Ministry of National Development as an input to the 2020 prognosis stipulated by the Energy Efficiency Directive (2012/27/EU) of the European Union.

The forecast was generated in two steps. First, we predicted the final energy use of the priority sectors of the Directive (industry, households, services and transport) using a variety of sector specific (households and services) and econometric (industry and transport) models. Next, we quantified the losses suffered by the energy transforming sectors. Figure 22 reviews the steps of the calculation.

Primary energy use is fundamentally driven by the assumed GDP path. The analysis was based on the GDP prognosis published by the European Commission, which, for the 2010-2020 period, has forecasted 0.9-1% of annual average growth for Hungary, and also indicates rather modest growth prospects for the whole of the European economy in general. This economic growth path has a critical role in non-heating energy use, since in both the industrial and the service sectors the added value and the energy use highly correlate. The GDP path within the current prognosis runs much lower than previous GDP forecasts, which had predicted annual growth of 2.5-3% until 2020, as opposed to the current figures of around 1%.

Sector estimates of final energy use

To forecast the final energy use of household buildings we utilised the building model of REKK. Modelling consists of the following steps:

1. modelling the autonomous change of the household building stock
2. setting the renovation rate and depth for given building types, as well as the fuel switch in some cases
3. determining the aggregated primary energy use for the given target year.

The household building stock is characterised by 15 building types, and we assumed an additional 4 types to incorporate future buildings into the model. Buildings are categorized based on their size (single or multi apartment houses), construction time and building material.

The service sector is meant to cover all of the public buildings and those buildings which are used by private enterprises in the service sector. The latter includes hotels, office buildings and retail establishments. The energy use of the service sector is calculated with a model based on the logic applied to make forecasts for household buildings.

In case of the industry and transportation sectors the change in energy use has been forecasted with econometric models. Unique models have been applied for five energy intensive branches within the industrial sector (chemical industry, iron and steel manufacturing, non-ferrous metal manufacturing, non-ferrous mineral manufacturing, pulp and paper industry).

Figure 22 Calculation of the primary energy use (based on 2010 data, TJ)

and for different modes of transport within the transportation sector (road transport, railways, aviation and shipping). For these we have made use of the estimation routines of multiple variable time series regression models. We applied explanatory variables for which independent predictions are either available or can be generated on the 2020 time horizon. These include GDP, sector specific added value variables, population and the price of crude oil.

**Estimation of primary energy use**

The calculation of final energy use was followed by the estimation of primary energy use. For this purpose, we made forecasts on the transformation losses of the energy transforming sectors (electricity and heat generation, crude oil refining and coke manufacturing), on the own consumption of these sectors (e.g. sectoral self consumption in case of the electricity sector) and on distribution losses.

We used the European electricity market model developed by REKK to forecast the primary energy use of the electricity sector, network losses and the energy mix consumed until 2020. The transformation loss of crude oil refining has been predicted with the use of an econometric model, while the losses incurred in other sectors have been forecasted with a ratio tied to final consumption.

Figure 23 summarises the simulated primary energy need within the electricity sector for each year until 2020. Apparently, the fuel input of nuclear generation does not change in this decade, since the potential new units of the Paks nuclear facility do not get to be built during this period, while the current units stay operational. The utilisation of coal fired plants declines as some of the generating units of the Vértes and Mátra power plants are closed. In case of renewables, our calculations were based on the figures of the National Renewable Energy Action Plan. The utilisation of gas fired plants continues to decline due to cheaper imports.

In short, fuel consumption decreases as a result of lower coal and natural gas based electricity generation, while some of the domestic production is replaced partly by newly established renewable capacities, and partly by rising electricity imports.

The analysis of the electricity sector shows that as a response to the assumed future trends (low economic growth, high gas prices, lower production costs of neighbouring countries) the sector will exhibit lower demand, an increasing import deficit and reduced gas consumption.
Summary

Figure 24 depicts the primary energy use pathway based on the above described method.

Our final energy use forecast for the 2010-2020 period indicates a decreasing tendency. We predicted a 6% decline of total final energy consumption, within which the energy use of households and the other sector (agriculture) falls to a larger extent, by about 10%. The energy use of the transport sector, on the other hand, is projected to start ascending from 2015, following the current decline. The 2020 energy consumption, however, will not reach the 2010 level in this sector either.

For the 2010-2020 period we project a notable, 9% decline for primary energy use as well. If we dissect the forces impacting the use of primary energy (change in population, income, and energy intensity), we can detect that in addition to the continued, but slowing improvement of energy intensity (energy use per unit of GDP), the forecasted lower growth of the economy also contributes to the lasting decrease of primary energy use.

To sum, we forecast a substantial decline of both our final energy use and our primary energy use for the period until 2020, which, on top of the existing declining trend in energy intensity, is also reinforced by the projected low European growth prospects. The current forecast expects lower primary energy use for 2020 than the predictions from two years ago (e.g. Economic Impact Assessment of the 2030 National Energy Strategy (2011)). In addition to the slower GDP track, this is mainly driven by the changes taking place within the electricity sector: the fallback of natural gas based electricity generation and the rise of electricity imports.

Opportunities in a globalising market – European LNG imports until 2020

The structure of European natural gas supplies is in transition these days: one of the key drivers of change is the dual goal of European countries to access cheaper natural gas at an improved security of supply. This, however, requires a level of import diversification that is not achievable with the overly constrained traditional inland sources. In addition to Russia, which traditionally has a large weight in European gas supply, only Norway and the Netherlands possess major gas reserves in the continent with the capability to supply piped gas to Western European countries – and even the ambitions of Azerbaijan fail to offer much relief. As depicted by Figure 25, European gas import was primarily pipeline based – and within that, it mainly originated from Russia – even in 2012: last year the LNG imports of Europe reached one-third of the volume of gas imported through pipelines. The role of LNG, nevertheless, is set to rise in parallel with an increasing European demand for gas, the expected decline of

Table 4 Factors driving primary energy use for two time periods

<table>
<thead>
<tr>
<th></th>
<th>Total consumption</th>
<th>Primary energy (TJ)</th>
<th>Population (thousand people)</th>
<th>GDP per capita (1000 EUR, 2000 basis)</th>
<th>Energy intensity (TJ/EUR, 2000 basis)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010/2000</td>
<td>101%</td>
<td>98%</td>
<td>124%</td>
<td>83%</td>
<td></td>
</tr>
<tr>
<td>2020/2010</td>
<td>90%</td>
<td>98%</td>
<td>107%</td>
<td>85%</td>
<td></td>
</tr>
</tbody>
</table>

Source: REKK calculation
European gas extraction\(^1\) and the expansion of non-conventional gas production in the US (Figure 25), as a consequence of which the LNG market will impact European gas prices to a higher and higher extent.

**LNG-trading: regional or world market?**

Natural gas trading has had regional characteristics since the beginning. At the moment this regionally segmented structure is evident mainly through the substantial price difference between regions. While the Henry Hub spot gas price, relevant for North America, has been fluctuating between 2 and 4 USD/MMBtu since shale gas production has suppressed domestic prices, the price at the European gas hub with most liquidity, the British National Balancing Point (NBP), keeps fluctuating at around 10 dollars. Asia is characterised by even higher prices: import prices often reach 15-17 dollars due to the steeply rising gas demand of the quickly growing economies of the continent and the increased Japanese gas demand triggered by the nuclear plant closures following the Fukushima accident.

The international trade of LNG continues to take place mainly under take-or-pay like contracts that are called SPAs (Sale and Purchase Agreement) in LNG terminology. Contracts in force today typically cover 15-20 years. The long duration is explained by the heavy investment need of the plants liquefying and regasifying natural gas - similarly to the investment requirements of constructing pipelines -, investors therefore demand the security stemming from long term commitments. Most of the nominal export capacity of newly built liquefaction terminals is typically reserved through SPAs before the final investment decision is made. Regions are apparently different not only in terms of prices, but also in the case of pricing mechanisms: while in Asia long term contracts are tied mainly to crude oil, in Europe they are linked to refined products and to a growing extent to the price of gas hubs\(^3\), while in North America price setting is usually hub based.

In addition, two new tendencies towards globalisation can also be observed:

- Firstly, the weight of spot trading is on the rise: in 2012 already one-quarter (59 million tons) of the traded value originated from short term and spot trades.\(^4\)
- Secondly, the "softening" of SPAs is also becoming more frequent: before departure, shipments reserved through long term contracts are redirected to markets characterised by higher prices (cargo diversion)\(^5\) and the re-export of already delivered gas to third countries is also common practice.\(^6\)

These two phenomena are sustained partly by the large price difference between the regions: sellers and buyers try to take advantage of the arbitrage opportunity created by the high prices of Asia, as a result of which in 2012 already 20

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\(^1\) In our article Russian extraction is not considered as European production, but as import through pipelines.

\(^2\) Million British thermal unit, approximately 1055.056 MJ

\(^3\) Gas hubs are physical or virtual nodes for natural gas trading.

\(^4\) It should be noted that under the LNG market terminology all contracts that cover less than a year are traditionally called spot trades, while short term contracts generally refer to a period of 1-5 years.

\(^5\) In commercial practice diversion can be initiated by the seller and the buyer alike: their agreement on diversion typically also includes profit sharing, in other words, both the seller and the buyer enjoy some of the benefits of redirecting the shipment to a market with a higher price.

\(^6\) A specific type of LNG re-export is reloading: LNG is delivered to the recipient terminal specified in the original contract, it is loaded to the storage tank before injecting it again into another carrier which transports it to a new market. This arrangement is available in case LNG has been contracted on a so-called DES (delivery ex-ship) parity, where injection into the storage facility also qualifies as delivery, thereby the parties do not violate the original SPA.
million tons of LNG – 10% of total worldwide exports – went from the Atlantic region to Asia, while Latin America also attracted substantial amounts of flexible LNG from the European market, and almost all of the LNG reserved in North America ended up in European and Asian markets.

**The LNG import opportunities of Europe today**

Europe, as an importer, is connected to an increasingly integrated LNG market, therefore its short and long term import opportunities depend both on the rival Asian importers and the new entrants of the export market, namely the United States and Australia.

At present most LNG is shipped to Europe from three countries (Figure 27): Qatar, Algeria and Nigeria. With respect to pricing, of the three large exporters so far Algeria has been extremely inflexible, and presumably it will continue to insist on oil-indexed contracts in the near future. The more flexible Qatar, however, may be an important partner to contracts the pricing of which is at least partly linked to European and/or American hubs, in particular to the British NBP or the Henry Hub (HH) in Louisiana. The role of Qatar should be specifically emphasized: for the last decade the Arabic country has achieved a dominant role among LNG exporters, and today it is the only large exporter that, based on its geographic location, can reallocate its shipments between America, Europe and Asia, being capable of spot deliveries to all three continents. In the near future, therefore, the profit maximising export strategy of Qatar will be a key factor determining the availability of LNG for Europe. LNG from the Bonny Island liquefaction plant of the third large supplier, Nigeria, arrives to Europe through Brent oil indexed long term contracts, but export from the planned Brass LNG terminal of the country may change this – the final investment decision on the Brass terminal may be made in 2014 at the earliest. During this time frame the rest of the current exporters are unlikely to increase their European supplies, the North African countries struggling with domestic political crises are expected to focus on the demand of their internal markets instead of expanding their export.

**New entrants**

We should be interested to know, therefore, which countries can be expected to contribute to the worldwide growth of LNG supply during the coming years, and for which of the new entrants and export-expanding countries it may be profitable to export to Europe.

The “shale gas revolution” taking place in the United States exerts pressure on the country to export a substantial part of the produced gas: until 2013 applications to construct liquefaction plans with a total capacity of 72 million tons/year have been submitted, equal to about 30% of the current worldwide export capacity. Two of the planned terminals, Sabine Pass in Louisiana and Freeport in Texas have already been granted construction permits and the investment decisions have been made, but at this time the exported volume and its timing is still very much uncertain. However, even if American export capacities are quickly created, it is a question if the NBP-Henry Hub price spread will be large enough and whether it may last long enough for LNG exports from the US to Europe to be profitable, including the costs of liquefaction and transport. The cost of liquefaction is about 3-3.5 USD/MMBtu presently (including the cost of transporting the gas from the site of extraction to the terminal), while shipping from the Eastern coast of the US to Europe costs about 1.25 USD/MMBtu. At the current NBP-Henry Hub price spread of about 6 dollars this implies that the American...
export could barely be profitable.\(^7\) In addition to the US, Canada may also be expected to become a notable exporter, but the non-conventional sources of Canada are located mainly on the Western coast of the country, convenient primarily for Asian exports.

Australia is already one of the biggest LNG exporters of the World with a capacity of about 25 million tons/year, but relying on the large non-conventional gas reserves of the country, an additional 62 million tons/year of terminal capacity is under construction - with the total value of these investments falling between 160 and 200 billion dollars. The investment cost of the Australian projects, nevertheless, keeps rising year after year, questioning not only the realisation of the projects, but also whether Australia will be in a position to profitably supply LNG to a European market that is both further away and is likely to stay considerably cheaper for the next few years than the Asian market. Australia may start to export its non-conventional natural gas reserves at around 2016-2017 at the earliest. In Africa not only Nigeria, but the Eastern-African Mozambique also has ambitious plans to export LNG, but its first terminal, with 10 million tons/year of capacity is likely to come online only in 2018, and it will primarily serve the Chinese and Indian markets.

### The future of European gas prices

By 2020 approximately 20 billion cubic meters worth of long term pipelined gas and LNG contract will expire in Europe, while - according to the analysis of Stream LNG, owned by Repsol and Gas Natural Fenosa\(^8\) - possibly as much as 70 billion cubic meters will need to be supplemented due to the expected decline of European production and the forecasted increase of demand.\(^9\) This creates a notable challenge for European countries, while also providing an opportunity for the continent to improve its gas purchase portfolio. Three aspects of European LNG import will have to be amended to ensure that the continent has access to cheaper gas at an improving security of supply.

- **More LNG:** A higher share of LNG within the total portfolio could help to reduce the dependency of European gas supply from Russia. Presently only the Spanish and Portuguese import relies on a higher share of LNG than pipelined sources. In addition, the UK, France and Greece covers at least 20% of their gas import need from liquefied gas (Figure 28 reviews the imported LNG volume of European countries). Of the current large suppliers of Europe only Nigeria can be expected to expand its export in the foreseeable future, therefore an increased import share of LNG requires access to new sources.

- **More diversified LNG:** Newly exporting countries could reduce the weight of politically unstable exporters within European LNG import. The need for this is well advocated by the examples of Egypt, Libya and Yemen, where domestic tension lead to the sizeable drop of LNG exports after 2011. The import from North-America and Australia, however, depends partly on their absolute level of profitability, and partly on the relative competitiveness of Asian and European markets.

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\(^7\) Once the cross-section of the Panama Canal will have been widened, shipping costs from the US Eastern coast to Asia will be at around 3 USD/MMBtu, more expensive than to Europe, but due to the higher Asian prices, which are frequently above 15 USD/MMBtu, exporting to Asia will still be substantially more profitable than to Europe.

\(^8\) [http://www.streamlng.com/servlet/ficheros/129730999423/323%5C870%5CSupplyingLNGtoEurope.pdf](http://www.streamlng.com/servlet/ficheros/129730999423/323%5C870%5CSupplyingLNGtoEurope.pdf)

\(^9\) It is worth noting that the forecasts of the additional gas demand of Europe widely vary. Other sources, such as a fresh GDF Suez analysis indicate a decline in demand by 2020: [http://www.gastechnology.org/Training/Documents/LNG17-proceedings/06_03-D-Bonhomme-Presentation.pdf](http://www.gastechnology.org/Training/Documents/LNG17-proceedings/06_03-D-Bonhomme-Presentation.pdf). Most analysts, however, agree that the gas demand of the continent will, for the next ten years, surpass the supply available under current conditions.
More flexible LNG: The expiry of old contracts may offer an opportunity for newly signed contracts to include more flexibility (e.g. shorter period lasting for 8-10 years at most, option for cargo diversion) and more favourable pricing (prices indexed to Henry Hub, NBP or other European gas hubs). At present European importers are apparently hesitant to engage in long term agreements, therefore a larger share of future LNG purchases may happen through short term or spot contracts. The flexibility and more advantageous pricing of contracts, however, also significantly depends on the volume of hub-indexed gas made available to the European market from North America and Australia, and the extent to which the competition generated by these countries contributes to an improved negotiating position for European importers when they deal with traditional suppliers like Qatar.

On top of the described uncertainties, the future of European LNG import is influenced by a number of other factors as well, such as how European shale gas production evolves (will Poland or some of the Western European countries be capable of large scale non-conventional production?), or Russia’s strategy for gas sales (will Gazprom aim to maximise its export revenues or maintain a minimum sales volume on the European market?). The development of European infrastructure – pipelined gas infrastructure, building LNG import terminals, more uniform internal market, more liquid gas hubs – also influences the degree to which Europe is able to integrate into the worldwide LNG market.