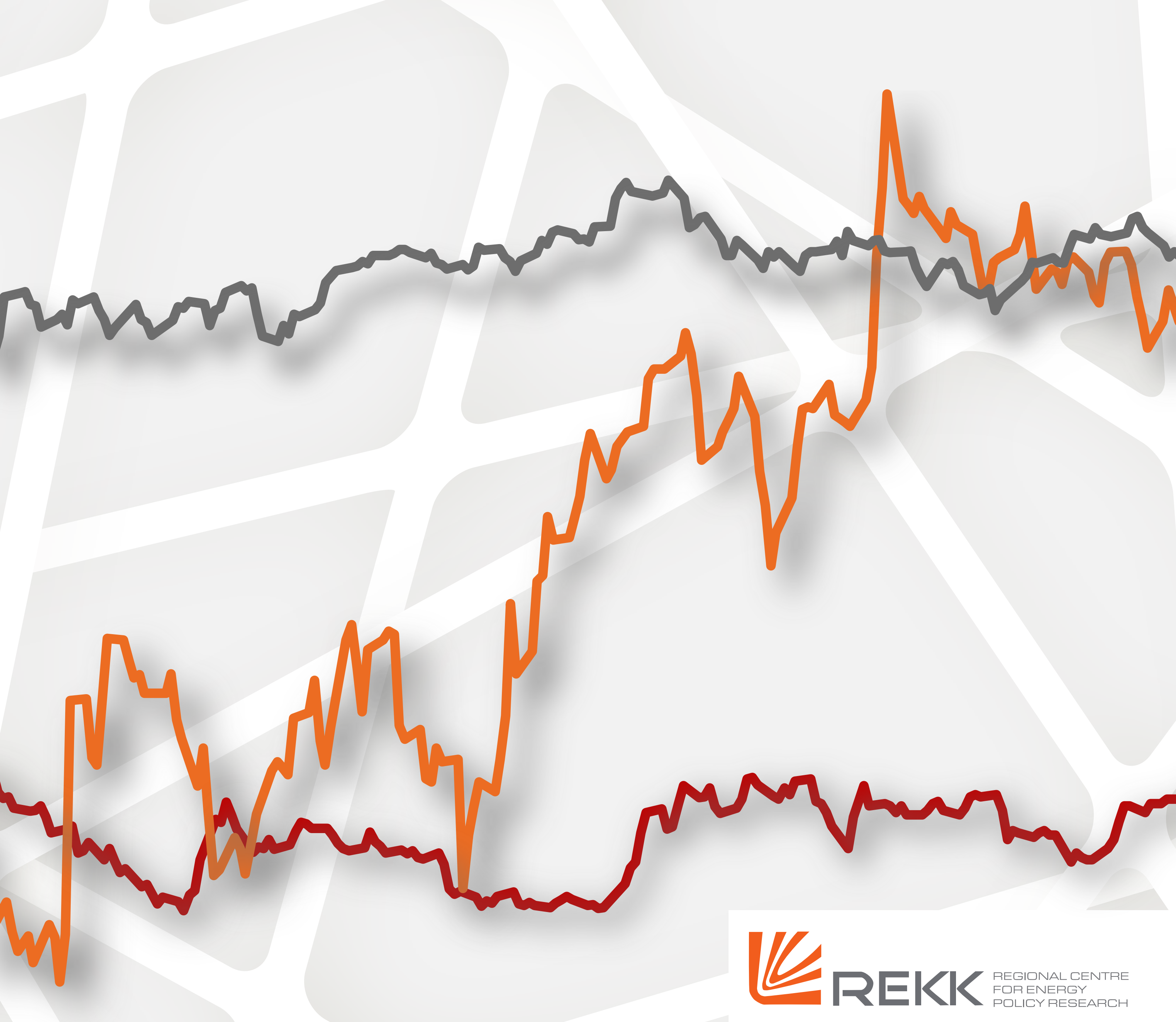

REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

HUNGARIAN ENERGY MARKET REPORT

Q4 2015

REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

The aim of the Regional Centre for Energy Policy Research (REKK) is to provide professional analysis and advice on networked energy markets that are both commercially and environmentally sustainable. We have performed comprehensive research, consulting and teaching activities on the fields of electricity, gas and carbon-dioxide markets since 2004. Our analyses range from the impact assessments of regulatory measures to the preparation of individual companies' investment decisions.

Training programs

- Energy market economist post-graduate training
- ERRA summer schools
- Regulatory trainings
- Price regulation
- Electricity market trainings
- Market monitoring
- Gas market trainings
- Tailored trainings upon request

Research

Geographically, our key research area is the Central Eastern European and South East European region:

- Regional electricity and natural gas modelling
- CO_2-allowance allocation and trade
- Renewable energy support schemes and markets
- Security of supply
- Market entry and trade barriers
- Supplier switching

Consultancy

- Pride forecasts and country studies to support investment decisions
- Consultancy service for large customers on shaping their energy strategy on the liberalised market
- Consultancy service for regulatory authorities and energy supply companies on price regulation
- Consultancy service for system operators on how to manage the new challanges
- Preparing economic assessment for strategic documents

Nowadays, due to market opening, energy markets cannot be analysed without taking into account regional environment. We monitor the market situation and developments of the countries of the Central Eastern and South East European region. We have built a regional electricity market model including all countries of the EU to forecast regional electricity prices. In 2012, we have developed a regional gas market model for the Danube Region countries, which was expanded to a model covering Europe.

The experts of REKK with their energy regulatory experience and academic background can supply scientific solutions taking also into account the specialities of the given markets.

Dear Reader,

This report reviews recent energy market trends according to our usual structure, provides a summary on the prospects of Hungarian renewable energy production, examines the probable future of the European nuclear sector, analyses the impacts of American LNG exports to Europe and introduces concerns on the possible enlargement of Nord Stream.

A professional debate began on the concept of the new renewable energy support scheme (METÁR) at the beginning of the year. This concept will be the basis for the legal provision supposedly effective in April according to the competent Ministry. Fulfilling the renewable share targets set in the National Renewable Energy Action Plan (NREAP) appears to be a great challenge even with the new support scheme. With regard to biofuels, significant district heat reforms and the introduction of a brown premium would be highly important in addition to the increased blending ratio and the efficient utilization of EU resources in order to fulfil the overall target of 14.65%. The first article gives a brief overview on the last 10 years' developments in this field and examines the conditions required to comply with the renewable targets.

The second article tries to answer the question of whether the European nuclear sector has any future in strong political headwinds following Fukushima and in spite of the serious deficiencies of ongoing nuclear power plant projects in Europe. Following the overview of the bitter experiences of the past years, we examine recent processes in countries that are flagships of nuclear industry including USA, Japan, Great Britain, China and Russia, and the possible impacts of these processes on the European nuclear sector. Although the future of nuclear power plants is not cloudless, it is far from as dark as it seems in Continental Europe.

The third article analyses the impact of transforming LNG markets on the European natural gas market. In 2015, a number of global market developments indicated that the typical dynamics of LNG markets are about to experience profound and lasting changes. The age of high Asian prices and the nearly insatiable demand of far eastern markets is in a decline. Now with the demand from previously attractive markets decreasing, the excess gas has been absorbed by Europe. The article examines the effects of possible LNG exports from the US on the European natural gas markets under the current economic conditions.

The last article scrutinises the controversial megaproject of the natural gas transmission pipeline, which would connect Russia and Germany with double the current capacity of Nord Stream, which amounts to 55 bcm. This project underlines Russia's intent to ultimately deprive Ukraine of its transit role and to make its European transports independent from regular Ukrainian conflicts. However, the project, which is strongly supported by Germany, is not favoured by many other countries: seven EU member states requested Brussels to intervene. The approval of the project may face serious obstacles. This article reveals the reasons behind the conflict, and gives an introduction on the possible disadvantages and security supply risks which could arise for the countries of Central and South Eastern Europe.

Péter Kaderják, director

Contents

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Energy market developments

After a momentary upswing, third quarter Brent oil prices fell again to levels matching those at the beginning of the year while the German border price of Russian LTC natural gas sank closer to the TTF price. The global LNG market remains mirred in an oversupply phase, and this is expected to continue in the near term as Japan's nuclear power plant restarts displace gas consumption in electricity generation. Declining gas prices helped to improve the clean spark spread in Europe, but the overall profitability of coal was unchanged. Hungarian domestic power generation in July-September was nearly the same year-to-year, thus the slight increase in consumption resulted in a rising import share. The decline in year-ahead baseload futures was much lower on the Hungarian electricity market than on other power exchanges in the region, and the gap between day-head market prices also grew substantially. In the third quarter, domestic gas production declined by 30% compared to the same period last year, thus accounting for 36% compared to last year's 48% of consumption. Reduced fears of disruption over the Ukrainian crisis and impoving competitiveness of oil-linked gas led to an increase of 20% in Eastern imports while imports from Austria fell by 56%. With the suspendion of gas transits from Ukraine through Hungary, domestic exports are down 40% from last year, 98% of which went towards Serbia.

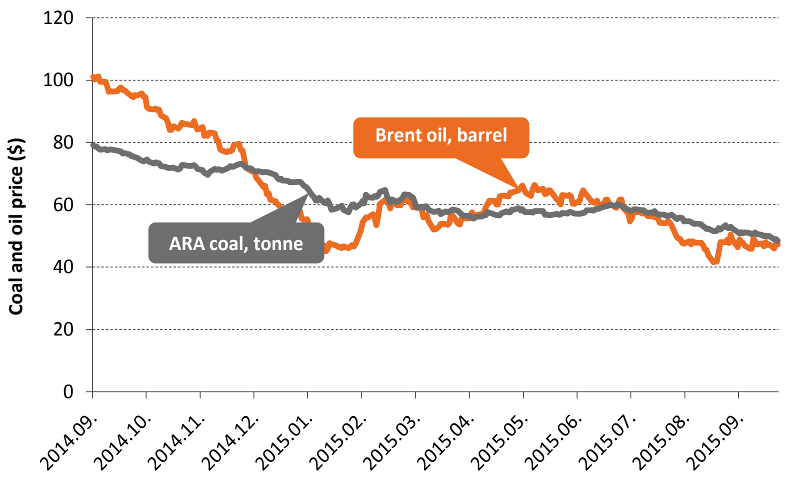
International price trends

Following an upswing in the second quarter, the global oil market was pared again between July and September: the quarterly average Brent price sank from 61.7 USD to 50.3 USD (Figure 1). This is the lowest figure in several years, and what's more, the price in September (47.6 USD) matched the 2015 January low. Meanwhile, there was not any signficant change in the coal market as quarterly average ARA prices have been declining for the past three years. This quarter saw a further 6% decline, while the drop in prices amounted to 13% between June and September.

In the third quarter, there were not any significant changes in Henry Hub prices either (Figure 2). The average price of $2.76 MMBtu is practically equal to the 2015 yearly average indicated in Standard & Poor's latest report. Compared to its previous outlooks, Standard & Poor's anticipates a slower price increase of $3 MMBtu in 2016, 3.25 in 2017 and 3.5 in 2018. The rate of decline in TTF spot gas prices accelerated slightly following the second quarter's 1.5% decline, with prices falling another 5% to rest at under 20 EUR/MWh. The fall in oil prices in the last quarter of 2014 was transmitted through Russian LTC German border prices in the second quarter of 2015 with the price falling 20% and another 11% in the third quarter. In September, German border prices were lower than 20 EUR/MWh and essentially converged with the TTF price.

Since the EUR average price of spot LNG transported to Japan nearly halved between March 2014 and June 2015, it stabilized between July and September. As with the previous periods, the main reason behind the global LNG market oversupply was weak Japanese demand. The forecast of the Institute of Energy Economics, Japan (IEEJ) says that the Japanese LNG import should decline 1.1% by the financial year ending in March 2016, and another 5.4% by March 2017. The estimation is based on the nuclear restart assumptions following block 1 of 890 MW Sendai Nuclear Power Plant in August, with four more blocks activated by the following spring, and a total of 13 restarted reactors operating in two years' time. Sendai 1 was the first of the 43 reactors that was restarted since the Fukusima accident. Declining LNG demand in Japan is also a consequence of the spectacular growth in renewable capacities, accelerated by a generous obligatory feed-in system that the IEEJ estimates will lead to the construction of 63 GW of renewable capacity by the end of the financial year 2016.

Figure 1 **Prices of year-ahead EEX ARA coal and Brent crude oil futures from September 2014 to September 2015**



Source: EEX, IEA

Notably in third quarter the German electricity market also declined, with the quarterly average of EEX year-ahead baseload futures down by 1 EUR/MWh to under 31 EUR/MWh (Figure 3). Year-ahead peak futures also fell to 37

EUR/MWh by the end of the quarter. In the EUA market, prices have been steadily rising for two years. By the end of the third quarter futures allowances oscillated around 8 EUR/ton, which reflects a 0.5-Euro rise within three months.

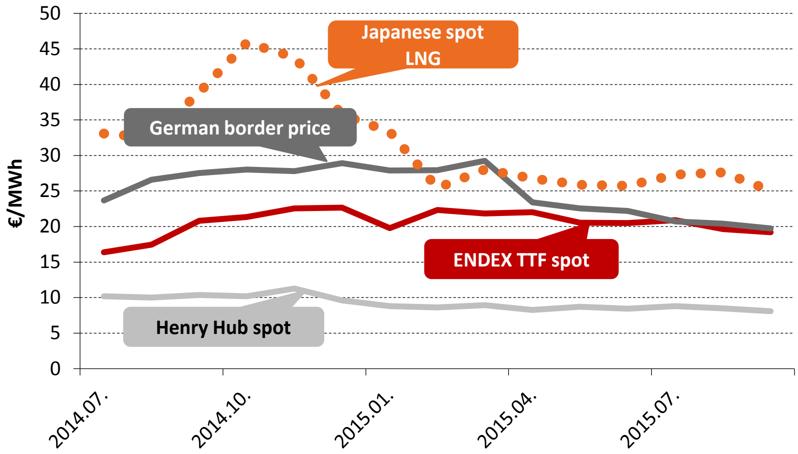
The clean spark spread has improved dramatically over the past three years. Although it has been well into the negative, the quarterly average for the generation of 1 MWh electricity resulted in only an 8.6 EUR loss for gas-fired power plants compared to the average loss of 15 EUR in the previous quarter (Figure 4). However, the additional decline in coal prices continued to bolster the profitability of coal-fired power plants, and the gap between the clean spark and the clean dark spread remained unchanged, leaving coal-based production at a competitive advantage.

In Germany, wind generation is taking the lead among renewable energy sources. While growth in solar energy capacities has slowed over the past 3 years and reached its lowest point since 2007, onshore wind capacities grew by 4-4.5 GW to as much as 42 GW in the second half of 2015 according to VDMA Power Systems reports. This rapid upswing can be explained by the reduced support for engines commissioned after 1 January 2016 and a change to the regulation that cancelled support if market prices are lower than 0 for more than 6 hours, the solar industry was incentivized. In July, the German wind and solar energy output broke a historical record at 11 TWh.

Overview of domestic power market

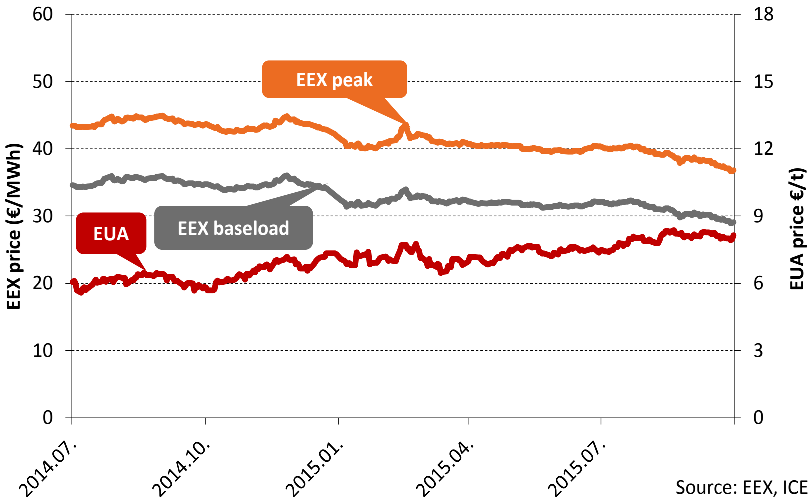
Since system operators did not offer any import capacities on the Austrian-Hungarian border in July, auctioned interconnection prices exceeded 13 EUR/MWh and 9 EUR/MWh in August and September (Figure 5). Compared to the previous quarter, import capacities were relatively expensive on the Slovakian-Hungarian interconnection as well, reaching 6.5-9 EUR/MWh. Meanwhile

Figure 2 **Prices on select international gas markets from July 2014 to September 2015**



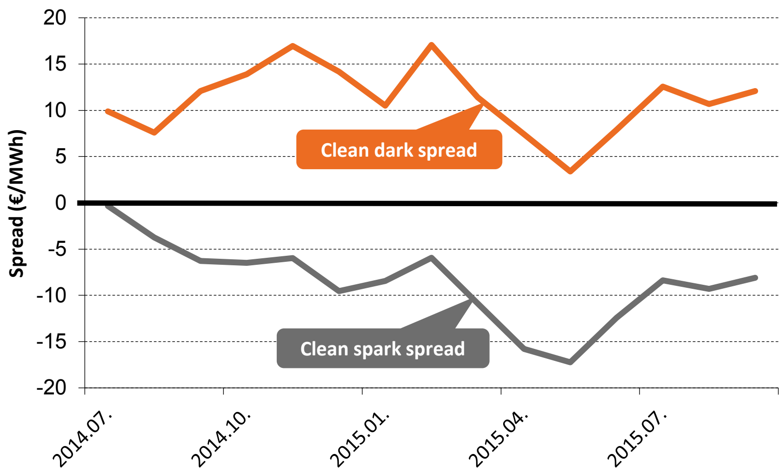
Source: Statistical Office of Japan, EIA, Gaspool, IMF

Figure 3 **Prices of EEX year-ahead futures and CO_2 allowances (EUA) with December delivery from July 2014 to September 2015**



Source: EEX, ICE

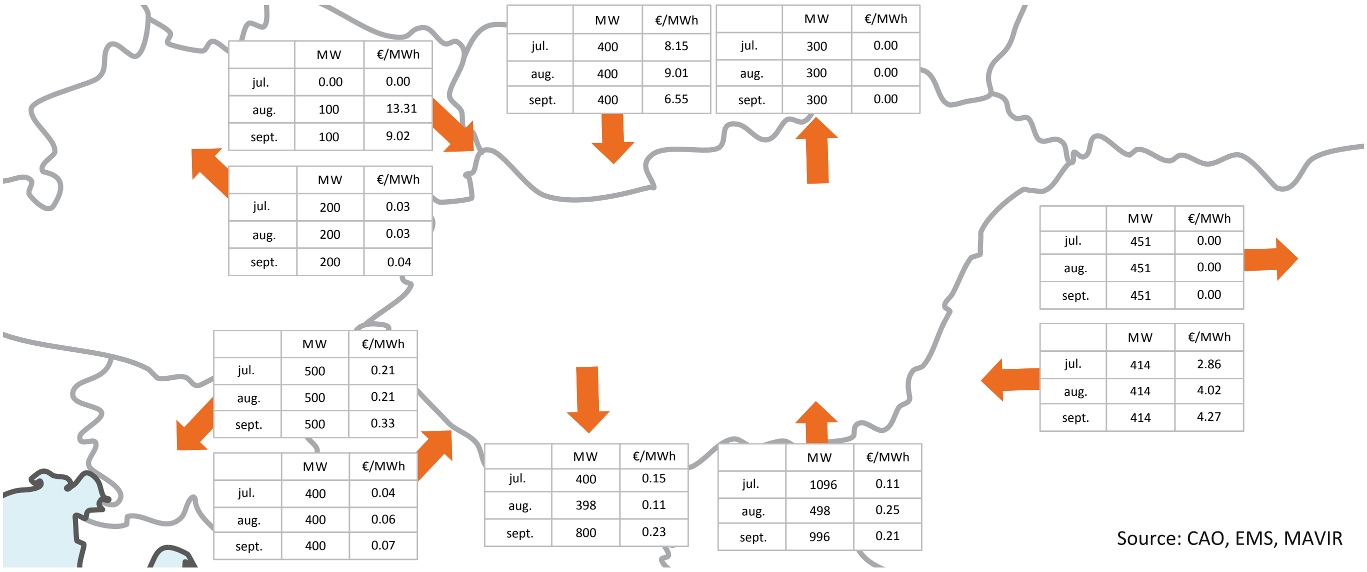
Figure 4 **Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from July 2015 to September 2015**



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

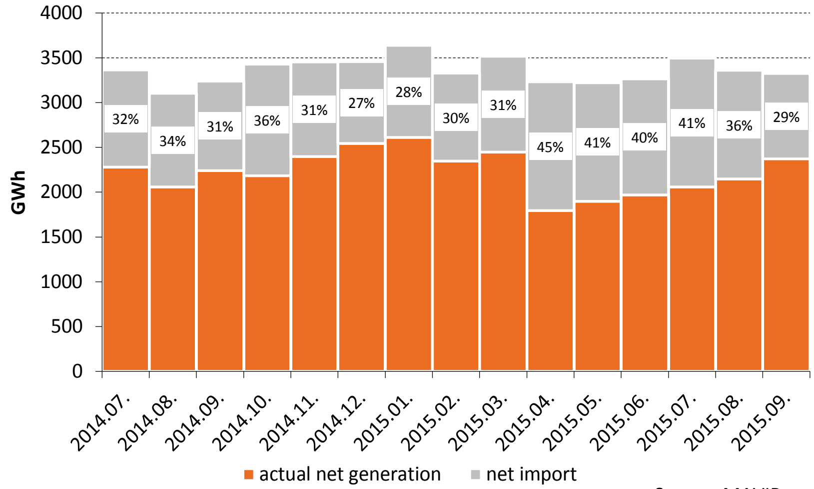
Both indicators show the difference between electricity prices on exchanges and the cost of electricity generation, where the cost of production is added up by the cost of gas (spark spread) or coal (dark spread) needed for generating 1 MWh of electricity and the additional cost of CO_2 emission allowances. Calculations are based on spot baseload power prices on the German EEX exchange, Dutch TTF spot prices and ARA coal prices. The Figure shows the monthly averages of these two indicators calculated with day-head market prices, assuming 50% energy efficiency in the case of gas-fired power plants and 38% in the case of coal-fired ones.

Figure 5 **Results of monthly cross-border capacity auctions in Hungary, Q3 2015**



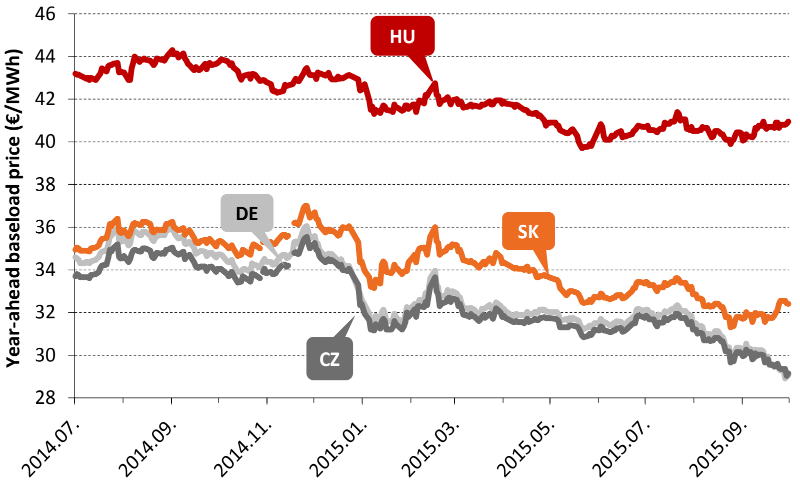
Source: CAO, EMS, MAVIR

Figure 6 **Net electricity production of Hungary's power plants, and monthly net electricity import of Hungary between July 2014 and September 2015**



Source: MAVIR

Figure 7 **Year-ahead baseload futures prices in given countries of the region, between July 2014 and September 2015**



Source: EEX, HUPX, OTE

the capacity needed to export 1 MWh from Romania cost only 3-4 EUR/MWh, and from all other directions only a few eurocents, consistent with previous months.

Domestic electricity consumption rose by 5% on a quarterly basis along with a 16% rise in power production, leading to a decline in the import share from 42% to 35% (Figure 6). This value slightly exceeds the 32% import share of the same period year-on-year as a result of the increased consumption.

The spread between HUPX and EEX futures converged some but still was close to 9 EUR/MWh. The cheapest baseload futures in the region were on the Czech exchange, 9.3 EUR/MWh below HUPX, while the HUPX-Slovakian spread was nearly 8 EUR on a quarterly average. The persistent spread between Hungarian and German prices decreased some on day-ahead markets, with HUPX futures averaging only 4.2 EUR/MWh higher than EEX in the second quarter compared to 7.7 EUR/MWh in the first quarter.

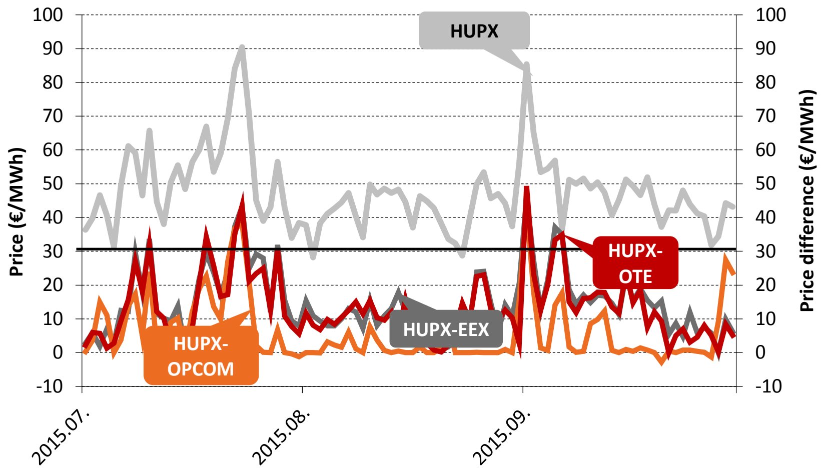
Year-ahead baseload futures continued to decrease across regional exchanges, but to a lesser degree in Hungary than the others (Figure 7). While the averages of German, Czech and Slovakian futures in the third quarter dropped below the previous quarter's averages by nearly 1 EUR/MWh, the decline in HUPX accounted for only 10 eurocent/MWh. In September the HUPX-EEX spread reached its highest point in 4.5 years at 11 EUR/MWh.

The spread also grew significantly on day-ahead markets: the HUPX-EEX spread went from 4.2 EUR/MWh in the second quarter to nearly 15 EUR/MWh in the third quarter (Figure 8). For a day in July 2015, the day-ahead baseload price on HUPX exceeded 90 EUR/MWh, which was a two-year record. The price spike can be attributed to extreme temperatures, water shortage levels in the Balkans, power plant outages at Matra and Paks power plants, and inconnection congestion. A peak price the first day of September was caused by simultaneous import restrictions from Slovakia and congestion at the Austrian border.

Figure 9 illustrates the frequency and size of spreads under HU-SK market coupling. Compared to June, when the difference between HUPX and Slovakian prices was less than 1 EUR/MWh in 60% of the hours, it was only 39% in September when the alignment of HUPX and Slovakian prices was the strongest. Similarly, June was the month in which HUPX prices were most closely aligned with the Romanian and Czech prices. While a difference of more than 10 EUR/MWh occured in only 12% of the hours, this frequency was over 40% in each month between July and September. At the same time a strong alignment between HUPX and Romanian prices surfaced in August, recording no difference in 83% of the hours and a difference of less than 1 EUR/MWh in another 2% of the hours.

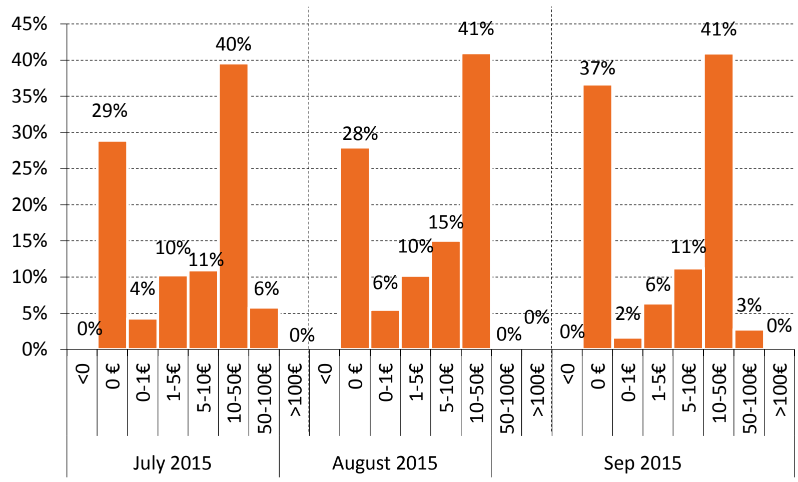
The wholesale price is affected by the costs incurred from the deviation of energy prices from normal schedule and balancing. The system operator determines the accounted unit price of upward and downward regulation based on the energy tariffs of the capacities used for balancing. The order for using these capacities is established based on the energy tariffs offered on the day-ahead regulated market. The system charges for balancing energy has been developed by MAVIR so that it provides incentives for market participants to manage foreseeable deficits and surpluses through exchange based mechanisms, otherwise covering the expected deficit and surplus by balancing the energy market would not be incentivized

Figure 8 **Comparison of day-ahead baselaod prices on the EEX, OPCOM, OTE and HUPX exchanges between July and September 2015**



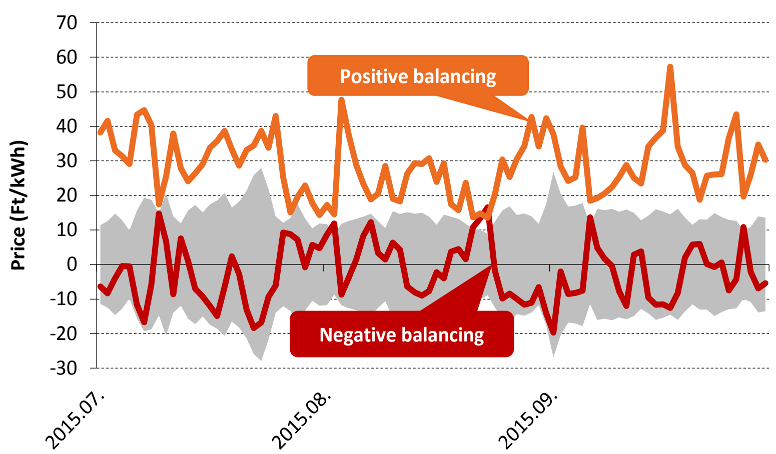
Source: EEX, OPCOM, OTE, HUPX

Figure 9 **Frequency of various levels of price difference between the Hungarian and the Slovakian exchanges between July and September 2015**



Source: REKK calculation based on OTE data

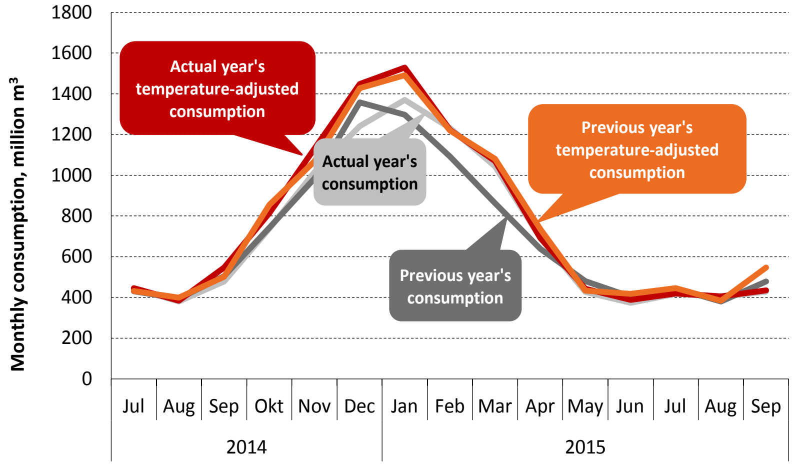
Figure 10 **Daily average of balancing prices and spot HUPX prices, Q3 2015**



Source: MAVIR, HUPX

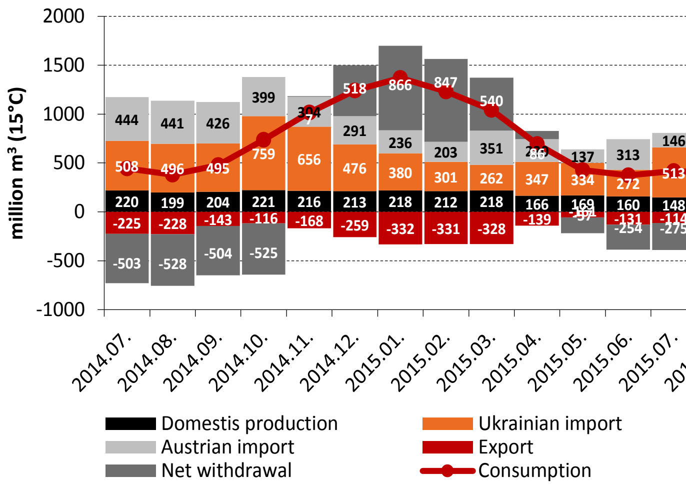
Note: the upper treshold of the gray area denotes the HUPX day ahead price, while the lower treshold indicates the HUPX price multiplied by -1. According to the Commercial Code of Mavir, this is the upper and lower minimun of balancing energy price.

Figure 11 **Raw and temperature-adjusted monthly gas consumption between July 2014 and September 2015 compared with the respective data in the previous year**



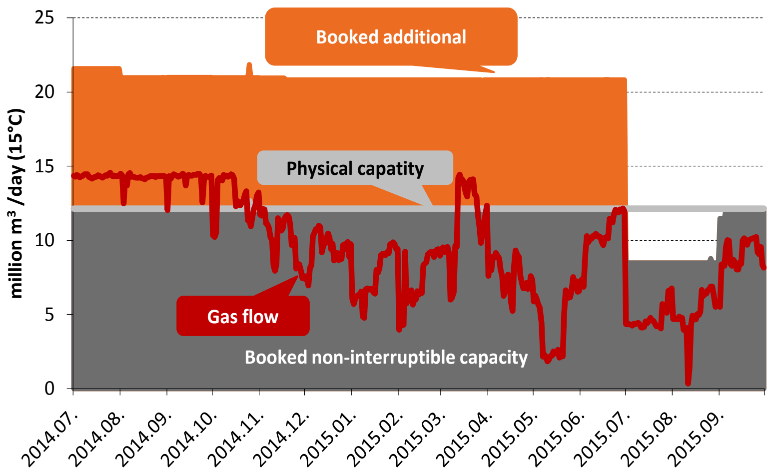
Source: FGSZ, European Climate Assessment & Dataset, and REKK calsulations

Figure 12 **Source structure of Hungarian gas market by month between July 2014 and September 2015**



Source: FGSZ

Figure 13 **Transmission at the Mosonmagyaróvár (Austrian border) entry point between July 2014 and September 2015 together with booked interruptible and non-interruptible capacities**



Source: FGSZ

Note: the illustrated physical capacity in the value provided by the FGSZ

on its own. For this purpose, the price of upward balancing energy cannot be lower than the HUPX price for the same period, while the system operator does not pay more for downward balancing energy than the price at the exchange. In the third quarter, the average price of positive balancing approached 29 HUF/kWh compared to the average of the previous period, which was 23.8 HUF/kWh, and the period from January to March that reached 19.3 HUF/kWh. (Figure 10).

Overview of domestic gas market

While year-on-year summer gas consumption remained almost unchanged, it dropped by 50 mcm in September 2015 compared to the previous year. Since September temperatures were actually lower, the temperature adjusted consumption showed a decline of 113 mcm in consumption (Figure 11).

Domestic gas production declined by nearly 30% year-to-year in the third quarter, covering only 36% of consumption compared to 48% (Figure 12). Eastern imports grew by nearly 20%, likely because of the normalization of the Ukrainian crisis and improving competitiveness of the oil linked gas, while net injection lagged behind 2014 levels by more than 20%. This coincided with a significant drop in spot priced imports from Austria, amounting to 56% on a yearly basis. There was also a considerable 42% drop in exports.

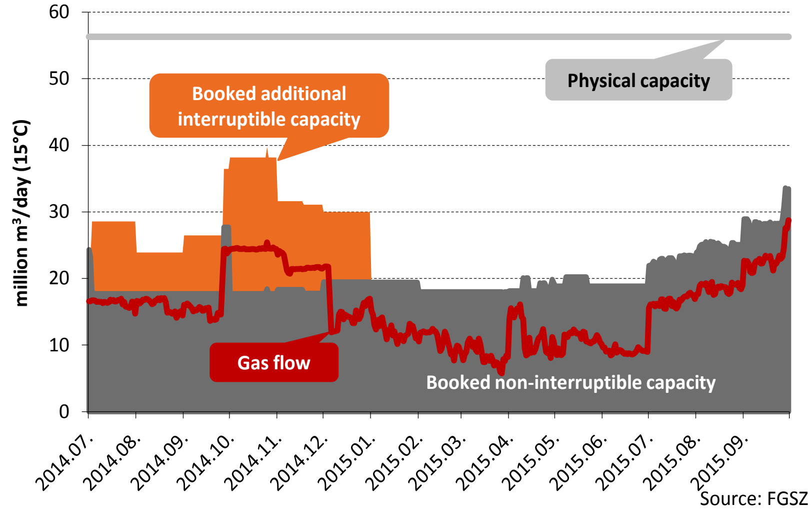
The changes in import composition can be seen in gas flow data at Mosonmagyaróvár and Beregdaróc entry points (Figures 13 and 14). While the interconnection capacity utilization of the Mosonmagyaróvár entry point almost always exceeded the technical capacity in the third quarter of the previous year, the average utilization reached only 51% in the third quarter of 2015, and only 63% of the contracted and non-interruptible capacities were utilized. At the same time, the quarterly average utilization of the interconnection capacity from Ukraine rose from 29% to 34% compared to the previous year. While transporters contracted a daily average of

18.3 mcm of non-interruptible import capacity at Beregdaróc entry point the previous year, it totalled 25.5 million in 2015.

Ukraine suspended Hungarian gas imports from 1 July and at the same time increased imports from Slovakia based on agreements concluded with German traders. The Slovakian-Hungarian interconnector launched commercial operation on 1 July with annual firm transmission capacity of 4.5 bcm from Slovakia to Hungary and interruptible capacity of 1.8 bcm bidirectional. However, there was no usage of this new pipeline during the third quarter, and according to information available this was exclusively due to market dynamics whereby imports were cheaper from Ukraine and Austria. Hungary did not export any gas to Romania in the second or third quarters, and exports to Croatia declined by more than 20% from the second quarter. However, Serbia imported 55% more gas from Hungary, accounting for 98% of total Hungarian exports (Figure 15). In the previous year, due to the intensification of the Russia-Ukraine crisis, more than half of the 70% higher total Hungarian export was transported to Ukraine.

The drop in oil prices at the end of 2014 were transmitted through to oil-linked import prices in the second quarter, leading to a fall in oil linked price from what was a flat 100 HUF/cubic meter to less than 80 HUF/cubic meter. It continued to decline between July and September with the quarterly average down to 65 HUF/cubic meter (Figure 16). Hungarian domestic gas prices have a predefined weighted average of 75% spot and 25% oil-indexation and an exchange rate assumption that is not fully reflective of the narrowing oil-linked and market prices elswhere in Europe. For this reason the regulated price was 5 HUF lower (60 HUF/cubic meter) than the quarterly average.

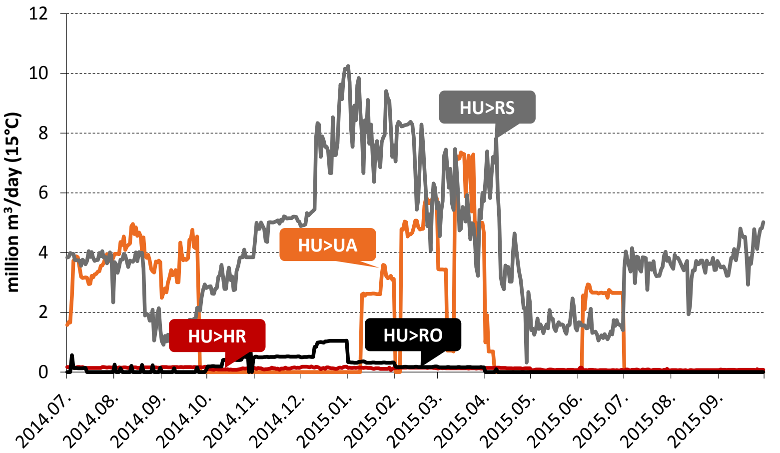
Figure 14 **Transmission at the Beregdaróc (Ukrainian border) entry point between July 2014 and September 2015, together with booked interruptible and non-interruptible capacities**



Source: FGSZ

Note: The illustrated physical capatity is the figure provided by the FGSZ. The data also contains the transit gas flow arriving from Ukraine, directed to Serbia and Bosnia

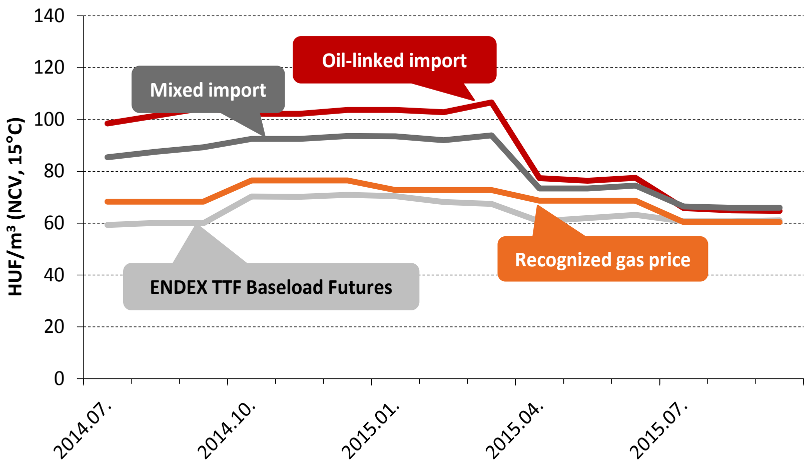
Figure 15 **Hungary's natural gas exports to Ukraine, Romania and Serbia from July 2014 to September 2015**



Source: FGSZ

Note: FGSZ publishes the transit gas flows that exit on the HU>RS (Kiskundorozsma) point and are directed to Serbia and Bosnia

Figure 16 **Recognised natural gas selling price of universal service providers and factors of the gas price formula between July 2014 and September 2015**



Source: REKK calculations based on EIA and ENDEX data

Note: The 'recognized natural gas price' is the REKK estimation of the quarterly MEKH figure of the accepted weighted natural gas price, which relates to the universal service provision, and is based on the decreed gas price formula and the decreed EUR and USD foreign exchange rates, using publicly available information. The estimation does not take into account the effect of the storage gas featured in the gas price formula. The 'mixed import' was calculated with a similar estimation, but in this case foreign exchange market rates were used instead of the rates set by decree.

Domestic renewable energy generation: 2020 targets and perspectives

According to Directive 2009/28/EC (hereafter: Directive), the share of energy generated from renewable sources in Hungary has to increase from what is currently about 10% of the total gross energy consumption of year 2020 to at least 13%. At the same time the National Renewable Energy Action Plan of Hungary (NREAP) boosted this target to 14.65%. However, it is the obligatory 13% target of the Directive that is important. If the renewable ratio exceeds this level, then Hungary can sell the difference to another EU member state through a statistical transfer. If, however, Hungary fails to reach the targeted renewable ratio, it will have to purchase the deficit from a country in surplus, which could cost more than domestic renewable production.On top of the 13% renewable ratio, the Directive requires that by 2020 each member state should secure at least 10% of the energy consumption of its transport sector from renewable sources (biofuels and renewable based electricity). No additional sector specific obligatory target is set by the Directive, meaning the separate heat and electricity targets of the NREAP should only be viewed as guidance.

Analysis of the renewable energy consumption

The last decade has witnessed substantial growth in domestic renewable energy use. While in 2003 total consumption barely reached 33 PJ, it grew to 65 PJ by 2013. The share of renewables increased at an even higher rate primarily due to a declining gross final energy use, approaching 10% by 2013. The NREAP forecasted a renewable ratio of 7.5% by 2013, which was unexpectedly surpassed by the realized values. Nevertheless, the seemingly positive picture should be tempered for two reasons. First, the declining gross final energy consumption in the last few years significantly contributed to the increasing share of renewables. Second, the NREAP anticipated large scale growth of renewable energy consumption in the second half of the decade, thus the targeted renewable energy use was easier to reach during the first few years of the 2010s.

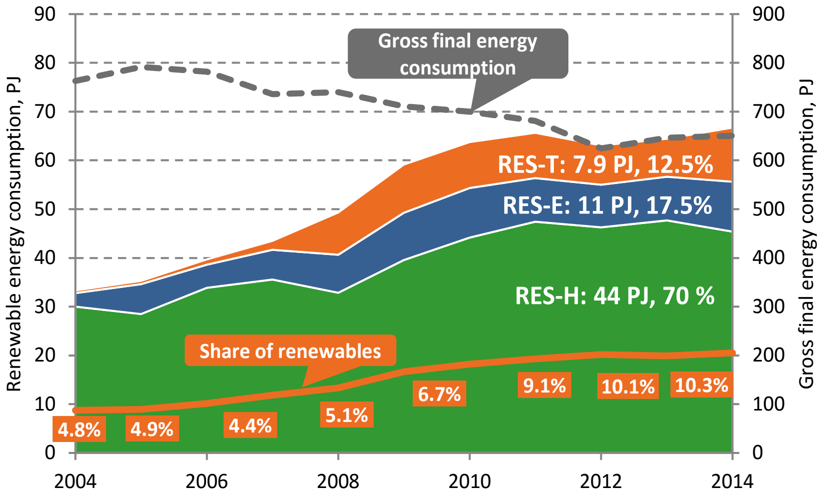
The growth of renewable energy use took place mainly within the heating and cooling sector, while renewable energy use within the transport and electricity sectors has stagnated or declined since 2009. The growth in this sector - especially between 2008 and 2010 - was fueled by increasing household use of firewood. This was not advanced by a conscious energy policy, rather it was driven by stagnate/declining incomes, as the lowest income households substituted for natural gas based heating partially or completely with the use of firewood where possible.

In 2014 the cooling-heating sector was responsible for 70% of renewable production, while the electricity sector contributed 17.5% and transport 12.5%. Upon further inspection of the fuel mix of renewable consumption, the use of biomass - and within that firewood - clearly dominates. In transport the use of bioethanol and biodiesel reigned, while within electricity and heat production biomass combustion has been crucial.

The level of expected gross final energy consumption

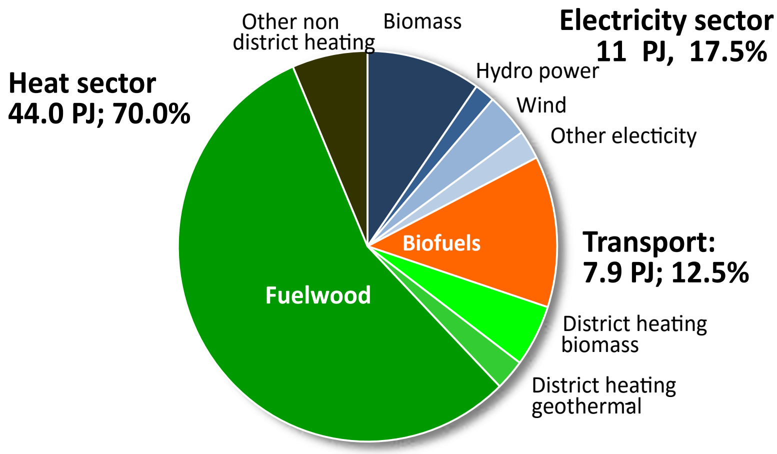
Since renewable targets were set as a percentage, the expected level of gross final energy consumption plays a key role in their achievement. In addition to the final consumption of industry, transport, households, and the commercial, service and agricultural sectors, this measure also includes the self-consumption of electricity generation, and the network and distribution losses of district heating and electricity supply. Government Decree 1160/2015 contains the expected 2020 and 2030 consumption data in a sector breakdown under different scenarios. Based on these figures the 2020 gross final energy consumption is expected to be 627.8 PJ, 13% or 14.65% of which must be supplied from renewable sources, depending on whether the EU or natio-

Figure 17 **Renewable energy consumption between 2004 and 2014**



nal targeted is adopted. At present the gross final energy consumption is 653 PJ, hence the 2020 forecast of the Government implies a 4% reduction compared to current use. Considering recent trends, this assumption seems to be reasonable. Based on this level of energy consumption, renewable energy use will have to grow by 25-40% during the coming years to be able to meet the targeted level of 81.6 and 91.9 PJ of renewable energy consumption by 2020.

Figure 18 **The composition of renewable energy use in a sector breakdown, 2014**



Transport goals

According to the Directive, by 2020 each member state has to reach a renewable rate of at least 10% compared to the gross final energy use of the transport sector. Based on the forecast of the government decree, the energy use of transportation will be 147 PJ by 2020. In accordance with the listed items in the Directive this figure would be amended down to 143.7 PJ, and 10% of this has to be supplied from renewable energy sources. Renewable energy consumption is composed of a number of elements, currently the most important of which are first generation bioethanol and biodiesel. However, in line with the October 2015 amendment of the Directive, the inclusion rate of first generation biofuels - that, to some extent, compete with food production - cannot exceed 7%. Second generation biofuels, considered more environmentally sustainable, are recorded with a double weight, i.e. the use of 1 GJ of second generation biofuel accounts for 2 GJ of renewable use. The third significant source of renewable energy consumption in this sector is the renewable share of electricity use. The Directive allows the multiplication of the electricity use of the transportation sector with the average renewable share of the EU or domestic electricity consumption. Moreover, renewable electricity used in road and rail transport can be increased with a multiplier of 5 and 2.5, respectively when the fulfilment of transport targets are calculated.

Assuming that Hungary takes advantage of the maximum inclusion rate of 7% applicable for first generation biofuel use, consumption of 10.3 PJ of this renewable source can be predicted, as long as the transport sector's forecasted energy consumption figures are accurate. Consequently, relying solely on the requirement of the obligatory inclusion rate, most of the 14.4 PJ target for the transport sector can be met.

The table below summarizes the 2020 use of various renewable sources within the transport sector.

Based on the above table, the 10% target set for the transportation sector seems to be easily within reach (it may even be exceeded). This, however, does not reduce the burden of meeting the overall renewable target: due to the peculiar accounting rules of the Directive, the renewable consumption recorded for the transport sector (16.4 PJ expected for 2020) is not the same as the value calculated for the overall renewable compliance, since the transport related multipliers for electricity consumption cannot be applied for the latter. Therefore in the calculation of the 13% and 14.65% renewable target the lower renewable figures of the transport sector (13.4 PJ in the second column of the table) need to be used.

Heat and electricity sector

From the perspective of renewable use, the heat sector can be divided into two large components: 1) individual heating primarily based on biomass, and 2) renewable based energy generation for district heating purposes. In the absence of regulatory interventions and additional support, it is assumed that significant changes in either sub-sector will not occur and renewable heat consumption for 2020 will remain the same as 2013 (48.1 PJ).

For the 2020 hydro and wind capacities of the power sector it is assumed that, in the absence of wind ca-

Table 1 **Expected 2020 renewable energy use within the transport sector, TJ**

	Can be used towards the transport related goals	Can be used towards overall renewable goals
First generation biofuel	10 290	10 290
Renewable share of the electricity use of road transport	1 002	200
Renewable share of the electricity use of rail transport	3 663	1 465
Second generation biofuel	1 491	1 491
Total	**16 447**	**13 447**

pacity auctions, they will not exceed their current values. With respect to PV, installed capacity is expected to rise to 500 MW by 2020 since the current net metering provides adequate incentives for investments. Meanwhile, a substantial decline is expected in biomass and biogas based electricity production given current conditions. If the brown premium that promotes the continued operation of the power plants in question is not introduced, the plants will either have to shut down or return to coal combustion following the termination of the purchase obligation regime

It can be concluded that without the introduction of a support mechanism or regulatory intervention a substantial amount of additional renewable energy consumption - 12.7 or 23.1 PJ - is needed to meet the targets. Within the heat and power sector the regulatory instruments through which these goals can be achieved are listed below:

a. EU investment support
b. Introduction of a brown premium
c. District heating regulatory reform
d. Electricity market auctions

Our calculations show that HUF 100 billion is available to support investments in the field of renewable energy during the 2014-2020 EU financing cycle. Based on our estimates - and relying on past experience - if used in an optimal way, these funds are sufficient to promote investments to 8 PJ of renewable capacity. Furthermore, another approximately 4 PJ of renewable production could be retained if the brown premium is introduced. The latter implies primarily mixed coal and biomass based power plants, and to a lesser extent biogas based electricity generation. The brown premium, nevertheless, is only capable of keeping existing capacities in the system temporarily: these capacities are not likely to operate beyond 2030.

The implementation of renewable district heating projects is hindered by a number of factors, the most important of which is that in the absence of a precise, legally enforced price setting methodology determining district heating prices each year, they are unpredictable for the long run. Moreover, the existence of a profit cap does not reward the risk taking of investors and their efforts to improve efficiency. A low cost regulatory reform of the district heating market alone would ensure significant renewable based district heating generation - about 2 PJ in our estimate - mostly from biomass and to a lower extent geothermal generation.

In short, the 13% renewable target prescribed by the Directive could, in principle, be achieved without the introduction of a new renewable electricity support scheme. However, in order to meet the 14.65% target set by the NREAP, 9 PJ of additional renewable energy use would have to be activated through operating subsidies provided to green electricity generation. This figure is equivalent to 120 MW of wind capacity, 430 MW of combined biomass based generation or 2300 MW of PV capacities.

In the end, meeting the 2020 renewable target of 13% is not out of question, but it will require substantial effort, including an increased inclusion rate for biofuels, the efficient use of EU investment grants, a major reform of district heating regulation, and the introduction of a brown premium. If any of these is not accomplished, then the operation of renewable electricity capacities through the new electricity support scheme becomes inevitable. The 14.65% target poses an even bigger challenge. Under this scenario considerable new renewable capacities will have to be built within the electricity sector, and this is clearly unrealistic without an appropriate support scheme.

Table 2 **The targeted renewable energy use and the volume to be acquired through the new electricity support scheme, TJ**

	13% target	14.65% target
Gross final energy consumption	627 817	627 817
Required renewable energy consumption	81 616	91 975
Transport sector renewable energy consumption	13 448	13 448
Electricity sector renewable energy consumption without subsidies	7 314	7 314
Heat sector renewable energy consumption without subsidies	48 115	48 115
Investment support	8 206	8 206
District heating regulatory reform	1 890	1 890
Brown premium	3 965	3 965
Volume to be acquired through the new electricity support scheme	-1 322	9 037

Future of nuclear energy

Nuclear power production is one of the most contradictory segments of Europe's energy policy. On the one hand, it is regarded as the solution to security of supply concerns as one of the most efficient tools of climate protection, while it is also seen as the bearer of unforecastable environmental and financial risks, on the other. There are countries that support nuclear power plant construction with extensive regulatory reforms and financing, while others impose special taxes on nuclear power plants, moratoria on new investments or force their closure. These contradictory effects may equally lead to a renaissance of nuclear power plant construction or to the total disqualification of the technology. Although we cannot predict the future trends, we can take into account the previous years' experience and analyse possible scenarios as to the direction of European nuclear power plant production.

Nuclear energy production has a distinguished priority in the agenda of several international organisations focusing on energy markets and climate protection. The Paris Climate Conference gave another boost for the fight against climate change: the biggest GHG emitters pursued efforts to reduce GHGs and to decarbonise electricity production. Nonetheless, critics say that conference participants did not provide any guarantees toward this end. Yet, experience shows that altough proposals from international climate conferences are mostly refused, some measures are eventually adapted by the given countries.

Based on the calculations of the International Energy Agency (IEA), in order to be able to limit global warming to less than 2 °C, OECD countries need to replace their ageing nuclear capacities, while developing countries need to strongly extend their nuclear capacities. Relevant studies on the decarbonisation of European power production (including the IEA forecast) anticipate that by 2040 European nuclear power plant capacity will not be far behind current levels. It assumes the construction of 25 to 65 GW of new capacities, primarily targeting the replacement of retiring reactors, in the coming 25 years in addition to the lifetime extensions currently underway.

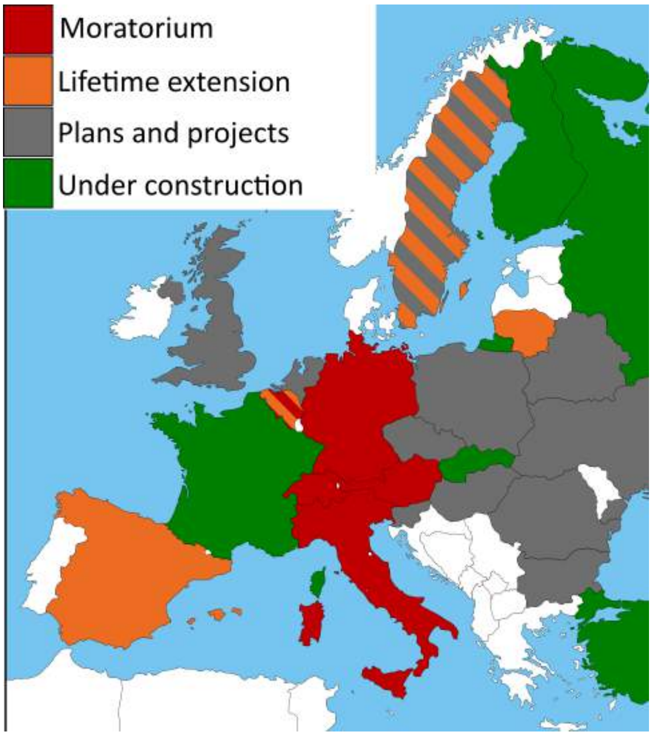
Painful present

In light of the bitter experiences of the last decade of European nuclear power plant projects, IEA expectations might seem overly optimistic, to put it mildly. The ongoing Finnish and French projects based on the third generation 1600 MW reactors of the French Areva (EPR) cope with deadline and cost overruns never before witnessed. The total cost of EDF's project in Flamanville, France increased from 3.3 billion EUR to 10.5 billion EUR according to the latest estimations, while construction will take at least 11 years instead of the originally planned 5 years. And yet, the French difficulties are not unique: the EPR block under construction in Olkilouto, Finnland cannot be regarded as a success story either with its cost overlay reaching 5 billion EUR and a 9-year delay. Areva was the flagship of the French nuclear energy industry, inventing and producing nuclear reactors, and is now practically bankrupt: the government and the EDF will soon administer a rescue package worth several-billion EUR.

In addition to severe financial problems incurred in the course of construction, fundamental technical concerns were also raised against the EPR blocks. In spring 2015, ASN, the French nuclear authority, detected and identified „very serious" defects on the pressure vessel built in the Flamanville power plant. The carbon content of the forged steel exceeded the maximum value allowed at given points, which could weaken the mechanical toughness of the pressure vessel which will be under considerable duress due to extreme heat, pressure and radiation. A few months later malfunctioning safety relief valves were detected which, in a critical situation, could lead to „grave consequences". Steve Thomas, a frequently cited British energy policy expert, simply called EPR an „unbuildable" design.

Although the above problems were of concern, they cannot be considered extraordinary. The fragility of new constructions, the initial teething problems and the lack of construction experiences, certainly cause deficiencies. For instance, the technical documentation of Areva was not complete when the construction of the Olkiluoto power plant started in 2005, and therefore the continuation of the construction was subject to the submission of the missing documents and their assessment and approval by the Finnish nuclear authority. In addition to the subsequent licensing delays, there were difficulties in the practical construction phase as well. Apart from a few special exceptions, no new nuclear power plants have been commissioned in Europe since 1989, and thus there is a pervasive lack of experiences in construction of third generation reactors - not only in Europe but also worldwide. This is similarly acknowledged by the American consortium (Westinghouse and Shaw Group) that was contracted for the construction of the 3-4 blocks of Vogtle power plant in the U.S., which proceeded to make an agreement with the state-owned Chinese nuclear company SNPTC to send ex-

Figure 19 **Nuclear policies in Europe**



perienced engineers (recently constructing the AP1000 blocks in China). Taking into account these conditions, unexpected difficulties might well be expected at the end of the day.

In addition to the abovementioned factors affecting third generation power plants, the European nuclear sector also faces another unusual problem: early closures due to loss-making operation. First Vattenfal, then E.ON announced the early closure of several of their reactors in Sweden, and will not seek out license renewal. Operators do not want to endure continuing losses associated with the increasing costs of ageing power plants, the special taxes imposed on nuclear power plants and low electricity prices.

A number of experts agree that loss-making nuclear power plants prove that the nuclear industry is not competitive in electricity markets. However, regulatory intervention is responsible for the upswing in renewable generation which has caused depressed electricity prices. In addition, low carbon prices favouring fossil-based power generation, are the result of regulatory preferences. And finally, the regulator determines the tax level for nuclear energy production and the standard of operational security, both of which can entail much higher costs depending on the preferences of the regulator. Unquestionably, the support scheme of renewables, the regulation of emissions allowance trade, climate change measures and the regulation on state aid all have significant influence on the competitiveness of nuclear energy production. In addition to the regulatory environment, another important factor is the potential of nuclear technology development.

All in all, two important questions must be answered to predict the future of nuclear energy production. The first question is whether there is any chance that the commitment to decarbonisation in European and national regulations will overcome the concerns about nuclear power plants. The second question is whether experience accumulated in the ongoing nuclear power plant buildout are sufficient to considerably reduce the risk premium of nuclear projects and rein in skyrocketing investment costs.

Light at the end of the tunnel

The regulatory environment of nuclear energy production is determined by politics. However, the social and political opinion on nuclear technology is very unstable. Premature promises made in the course of election battles often face supply security, budgetary and social-political constraints and business lobbying. Promises about the closure of nuclear power plants and sabre rattling can gain favor in an election campaign but the loss of tax revenues and capacities as well as the requirement to keep energy prices low generally force governments to quietly withdraw.

Nuclear accidents, however, may at any time destroy this fragile status quo. Moratoria imposed on nuclear power plant constructions by several EU member states after the Chernobyl accident were gradually dissolved in the noughties with respect to climate protection and security of supply arguments. Great Britain and Italy announced an intensive investment program. In Switzerland, the proposal for the phase-out of nuclear power plants was retracted by referendum, while Belgium and Germany have hinted at lifetime extensions. However, the Fukushima accident suddenly broke this trend of public acceptance, and several member states reintroduced moratoria.

Many (particularly green organisations rejecting nuclear energy „ex officio") thought that Fukushima was the fatal blow against the awakening nuclear industry. The accident caused only a temporary halt in the majority of countries that are traditionally for nuclear power and have significant nuclear fleet and/or serious nuclear background industry.

Japan is an example of economic realities in time overtaking the social and political storms immediately following the accidents as the nuclear-free energy policy announced after the accident was extremely short-lived. The rising natural gas imports following the shutdown of 54 reactors and the loss of nearly 300 TWh nuclear electricity production caused a ballooning trade deficit and convinced political decision makers. Nuclear energy production has even officially regained its strategic role in energy hardly 4 years after the accident. Two blocks of the Sendai power plant relaunched in summer 2015 after complying with the more stringent security requirements, which the remaining reactors will also have to meet.

Fukushima did not cause a similar reaction in the United States. The support scheme established at the beginning of the noughties and the resulting investment activities continued smoothly with the construction of 4 of 5 nuclear reactors that started two years after the accident. In America, nuclear investments are encouraged by the regulation of design certification, combined licensing, tax relief, loan guarantees and regulatory risk insurance. The Nuclear Regulatory Commission (NRC) has approved the application of more than 80 reactors for lifetime extension since 2000 for up to at least 60 years. And it is anticipated that this is not the upper limit, with the NRC now considering the conditions of lifetime extension of up to 80 years.

However, the American model is very difficult to apply in Europe. As a result of mostly liberalized retail markets, it is impossible to incur initial construction costs with low consumer prices while state aid to nuclear technologies is somewhat tolerated but far from preferred in Europe.

This is well illustrated by the case of the United Kingdom. The commitment of the British energy policy to the decarbonisation of electricity production and to nuclear power plant investments has been increasing since 2006. In addition to the deep and comprehensive regulatory reform of the UK electricity market (so called EMR), the rules of licensing of nuclear power plant investments have been modified and a significant state support system has been developed. In the framework of the British nuclear program, new nuclear power plant capacities of as much as 20 GW (one and a half times more than the current capacity size) are to be established until 2030. The frontrunner of these projects is the Hinkley Point project consisting of two EPR blocks accounting for 3.2 GW. The project is led by the French EDF in cooperation with the Chinese CGN and strongly supported by the British government. The budget of the project is massive, amounting to 24.5 billion £.

The key pillars of the investment are the CfD contract signed for 35 years, by virtue of which the actual selling price of double the current market price, i.e. to 90-93 £/MWh will be committed to by a state-owned company established for this purpose, and the loan guarantee provided by the Treasury for approximately 17 million £ debt. The European Commission approved the massive state aid after a lengthy inquiry following some bargaining with the British government. However, the decision did not put an end to legal uncertainty, since Austria, which has no interest in the project, challenged the decision at the European Court.

Concerns about nuclear projects are illustrated by the fact that the final investment decision could not be made even in a highly committed regulatory environment providing significant state aids. It is almost impossible to find investors, and the British Prime Minister could convince the Chinese party to participate in the project only by promising other concessions unrelated to the project (eg. authorizing the Chinese to design and build a nuclear power plant in Bradwell), which raised doubts about the viability of the British nuclear strategy not only in the media but also in state administration.

Japanese, American and British efforts to support the technology's advancement are not unique, and these investments are not even outstanding: China itself, suffering from the air pollution of coal-fired power plants and the resulting severe health problems, is about to extend its capacities by more than the capacities of the above countries put together. Currently, China has 29 reactors under construction, and wants to reach 200 GW by 2030 (double the American nuclear power plant capacity). Although Chinese state owned companies are eager to develop and test their own „home-made" reactors, from among the companies involved in several of the nuclear power plants under construction (excluding the Japanese boiling water reactors) almost all big vendors are represented: Westinghouse with its AP1000, Areva with EPR and Rosatom with VVER-1000 (AES-91).

Russia is a veteran of nuclear technology, also committed to gradually increasing the share of nuclear energy production, and the exports of its companies have good records in designing and producing Russian reactors. The strategy of selling service packages, which include not only planning, construction but also financing, and reprocessing of spent fuels seems to be successful. More than one third of the 70 reactors under construction throughout the world are built by Rosatom and the order book of the foreign projects exceeded $100 billion by the end of 2015. The increased construction experience, particularly when Finnish and Hungarian construction will have started, may easily make the top reactor of Rosatom, the VVER-1200 (AES-2006) as well as VVER-TOI, a technological alternative accepted in the close future by the European market.

...and what then?

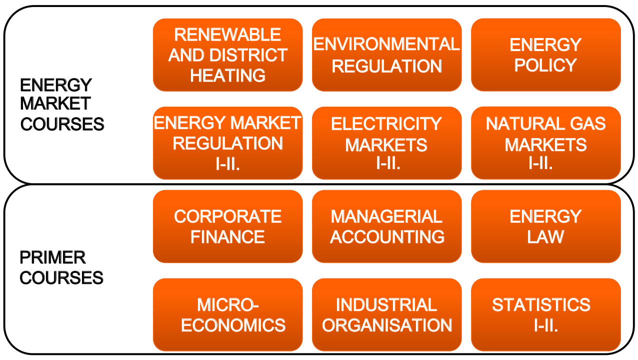
What does it all mean for nuclear investments in a sceptical Europe? The importance of ongoing investments is that they might be able to shift nuclear technology on the learning curve. If nuclear power plant investments survive the fragile transition between FOAK and NOAK technologies, it would result in the dramatic drop of investment costs. The very high risk premium on the nuclear projects would be reduced by the construction experiences, which would allow for several new projects.

Cost reduction would significantly mitigate the aversion to the technology and the resulting political risks. While the memories of the Fukushima accident are fading, stricter climate protection measures and rising security of supply concerns are gaining political recognition and the competitiveness of nuclear energy is improving.

Although the future of nuclear power plants is not cloudless, it is far from as dark as it seems in Continental Europe. Construction deficiencies are real but will not last forever, and security concerns can be managed. This might be the reason why mature democracies and market economies are not afraid of supporting the technology.

Postgraduate course at the Corvinus University of Budapest: Energy economist and specialist

For the seventh time in a row the Regional Centre for Energy Policy Research together with the Faculty of Business Administration of the Corvinus University of Budapest offers a postgraduate course in which graduates with a first degree in economics can obtain a specialist economist degree, while graduates from other fields can receive a specialist diploma.



The participants of the two semester higher education program will have a chance to acquire comprehensive, methodologically sound knowledge about the EU and domestic legal and regulatory environment of competitive, liberalised electricity and gas markets, as well as the structure and operation of these markets.

The course will provide novel knowledge that can be easily applied in everyday work, targeting primarily the employees and medium level managers of corporations within the energy sector (permit holders) and senior executives from other sectors. Getting to know the peculiarities of regulated industries will translate into a better understanding of the corporate strategy and streamlined daily decision making. The laguage of the course is Hungarian.

Rethinking LNG markets – the effect of LNG supply surge in Europe

In 2015, a number of global market developments indicated that the typical dynamics of LNG markets observed in the 2011-2014 period are about to experience profound and lasting changes. The age of high Asian prices and the nearly insatiable demand of far eastern markets is in its decline. Typically, the lion's share of LNG cargoes were delivered to the Pacific basin, more specifically to Japan, South Korea, and in a lesser extent to China and Taiwan. Following the Fukushima disaster, Japan replaced its missing nuclear generation with fossil fuels, and paid an extremely high premium for gas obtained on the spot market. However, 2015 brought the winds of change: two units of the Sendai NPP came back online and more nuclear capacities are to follow. Besides this phenomenon, Japanese companies have contracted the future Australian natural gas production to allow favourable prices compared to their existing oil-indexed long-term contracts and spot deliveries. Slowing economic development in the East-Asian region coupled with the LNG supply surge of 2015 resulted in depressed price levels in Asia. Demand became tighter in the previously lucrative markets, and the surplus gas volumes started to trickle down to Europe.

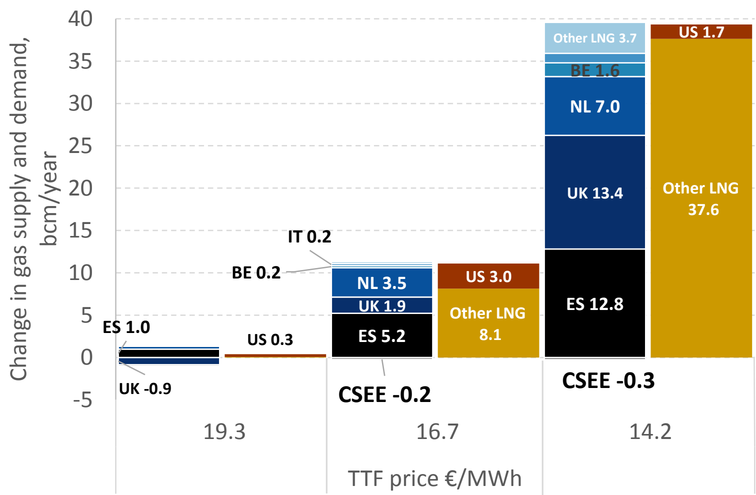
In our analysis we assessed the effect of the US LNG liquefaction terminals on the European markets. First two trains of the most developed project, the Sabine Pass terminal, are to be commissioned in Q1 2016, with the third and fourth trains following in 2016-2017 and 5-6 trains subsequently in 2018. Each train possesses a liquefaction capacity of 4.5 Mtpa (approximately 6 bcm/a). Capacities of the terminal were fully booked on 20-year long term contracts. Roughly one third of the terminal's capacities were contracted by Asian companies and the remaining two thirds by European-based energy trading firms. The volumes contracted by energy trading companies are not linked to specific regasification terminals and they will thus react to regional price signals promptly, allowing for the tighter integration of global gas markets. As opposed to the nearly ubiquitous oil-indexed price formula, traders agreed upon a Henry Hub-based price. The gas price is set by a two-part formula, a volumetric part financing the molecule and liquefaction cost, another part funding the fixed cost of investment and operation of the terminal. Sabine Pass contracts were concluded with a 115% Henry Hub price and a 2.5-3 $/MMBtu fixed component. Transport and regasification costs are borne by the buyer. In 2015, this was considered a favourably priced contract, having a 3-4 EUR/MWh saving to TTF and a 5-6 EUR/MWh to the oil indexed benchmark German border price.

What does the cheap gas allow? Demand response of gas fired power plants

Lower natural gas prices may bring gas fired units back to the merit order and electricity generation. Since 2013, gas-based power generation on the wholesale markets has not been a lucrative business, as electricity sales do not even cover the variable cost of production (See figure 4 as an illustration). The reason for this on the one hand is that natural gas is relatively expensive compared to other fossil fuels, perpetuated by the failure of CO_2 quota prices to penalize the higher polluting coal-based generation. At the same time, dwindling European electricity demand does not allow the gas-fired producers located at the end of the merit order to compete with the other sources. In the past years, gas-fired power generation has been replaced by renewables and coal: in 2010, gas-fired units supplied 23% of European demand, while in 2014 this fell to 13%.

To determine how the new gas sources will reshape this downward trend, the demand response of gas-fired power generation was simulated with the European Electricity Market Model (EEMM). Two-third of European gas-fired units are located in four countries: Italy, UK, the Netherlands and Spain, and consequently we expect the biggest demand adjustment in these markets. Setting the TTF reference gas price at 20.5 EUR/MWh, we considered the gas demand at three lower price levels.

Figure 20 **Demand response of European gas-fired power plants**



A meagre 1.2 EUR reduction in price would cause only a negligible change in gas demand of 400 mcm, allowing for the operation of some Spanish and UK units. If a more substantial drop to 16.5 EUR/MWh is observed, then the power sector would react with a 10 bcm/a demand growth, still concentrated in Spanish, UK and Dutch markets. This demand corresponds to the 2012 gas consumption of the power generating sector in Europe. Were the TTF price to drop to 14.4 EUR/MWh, gas demand would increase by 40 bcm/a. (See figure 20). The US LNG exports are not able to cause such a high price effect on their own.

A surge in gas consumption will be encouraged by regulatory actions as well. In the UK, coal fired power stations must switch to biomass firing or apply CCS by 2023, otherwise they will be required to shut down. In the Netherlands, by 2017 coal fired power plants can operate only if their efficiency surpasses 40%. Belgium is planning to decommission its nuclear fleet of 6000 MW by 2025, and aims to replace the capacities with coal and gas fired units. Thanks to this artificial tightening of electricity supply, gas fired units may return to the generation mix.

To allow for a substantial drop in TTF gas prices, huge amounts of LNG are needed. The next part of our article considers the potential of the LNG supp and shows whether it can facilitate the “great return” of gas-fired power plants.

The effect of increased LNG supply on the European gas prices

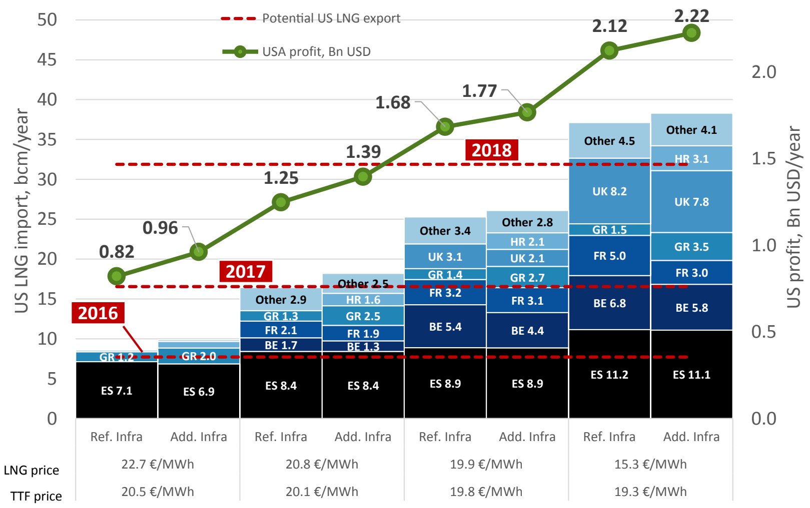
Price effects of the LNG arriving to European markets depend on the price at which the new entrants sell their product and the markets they reach. LNG capacity surge is modelled in three scenarios: the first representing the commissioning of the first two trains, the second scenario covers trains three and four, while the third scenario considers trains five and six. We assume that gas is sold on a spot basis in Europe. For the ease of representation, we omit strategic response of incumbents (Russia and Qatar) to higher LNG imports (but we will discuss at the end of the article).

Modelling shows that the first two Sabine Pass trains will be sold at Spanish and Italian markets. Although the effect of these volumes is marginal on the TTF market, it may allow for the gas fired units to restart at local markets. Capacity of the third and fourth trains primarily impacts the Spanish market, but at this point it can appear in Belgian and French consumption as well. This volume of supply will affect TTF prices as well: although small, a 0.3-0.4 EUR/MWh effect may be detected. Still, European gas prices do not drop to such a level that provides economic rationale for Hungarian gas fired producers to return to the wholesale markets.

Current infrastructure allows for the marketing of LNG in Western European markets. Due to lack of sources and interconnections, the Central and South-eastern European region suffers from high wholesale gas prices. LNG sales in these markets may yield much higher marginal profits, but current infrastructure makes it impossible to markets of these landlocked countries. Therefore we simulated how additional infrastructure development may change the current situation. These new projects were the CESEC priorities: Croatian LNG terminal and capacity expansion on the Croatia-Hungary interconnector, and new interconnectors at the Greek-Bulgarian and Bulgarian-Serbian border

The main findings of the modelling are summarized in Figure 21. New gas source was introduced to the European markets at four price scenarios: 22.7, 20.8, 19.9 and 19.3 EUR/MWh. In certain markets, LNG may be sold at higher prices, but this is the lowest at which the US exporter is willing to sell. For each price scenario, two infrastructure scenarios were matched, one without CESEC priority projects and one with. On Figure 21, the left axis shows the US LNG volumes shipped to Europe by destination market, while the right axis represents the profit of the exporter. For calculating profits, we assumed a marginal cost of 5 $/mmbtu. It is possible that the first two trains of Sabine Pass may be marketed at TTF+3 EUR/MWh, with trains 3 and 4 sold at TTF+0.5, and trains 5 and 6 even below TTF parity. Generally, CESEC infrastructure development factors in a 5% gain in profits if LNG is priced at the TTF price and a 10-15% gain on a TTF+ basis.

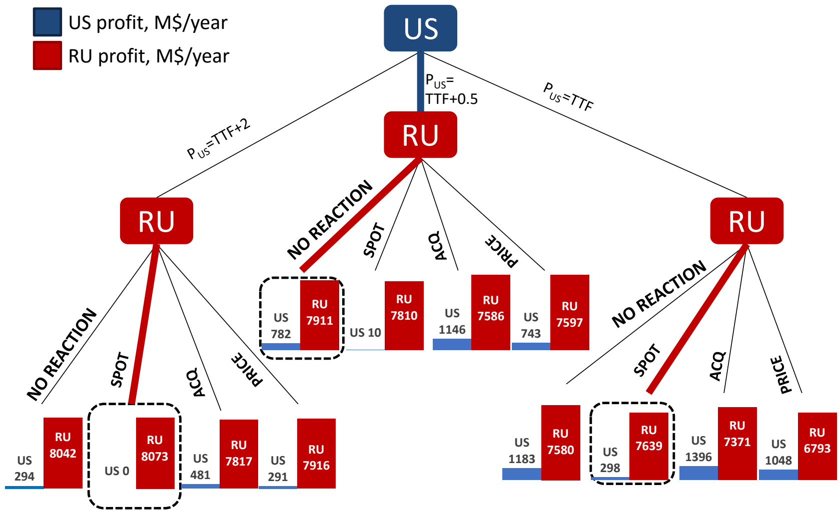
Figure 21 **Destination markets of US LNG and the profit of US LNG exporter**



However, there is still the issue of how the incumbent players Russia and Qatar will react to a new contender in the European markets.

To model Russia's reaction, we formulated a sequential game, in which the Russian player reacts to the US LNG volumes entering the European market. Both players aim to maximise their profits. The choice of the US player is to price its LNG at TTF+3, TTF+0.5 or at TTF. Russia may react by deciding not to interfere, since the LNG will not change the European market fundamentally (no reaction). The second possible reaction of Russia is to defend its market share as much as possible, by selling just below the LNG price (spot). The third strategy covers the curtailment of long term contract ACQ-s, to generate scarcity of supply and raise prices in the market, thus allowing for lower volumes sold but ideally at a higher profit (ACQ). The fourth strategy refers to the renegotiation of existing LTCs, if LNG arrives to a specific market (price). For each pair of strategies, profit for Russia and the US was calculated. The solution of the extensive game was arrived at by backward induction, first determining the best response of the Russian player to each decision of the US player (which holds the highest profit). Then the US player chooses the outcome yielding the highest profits.

Figure 22 **Modelling the strategic response of Russia**



At TTF Parity and TTF+2 prices, the Russian player maximises profits by selling spot gas. However, if the US player chooses to sell at TTF+0.5, the Russian player is better off not responding. Thus the US should enter at TTF+0.5 price. It must be noted that this is only true if the Russian player is maximising its annual profits – if it thinks it is more rational in the long run to crowd out alternative sources of supply, then the cost of this action is merely the profit difference of „no response" and „spot pricing".

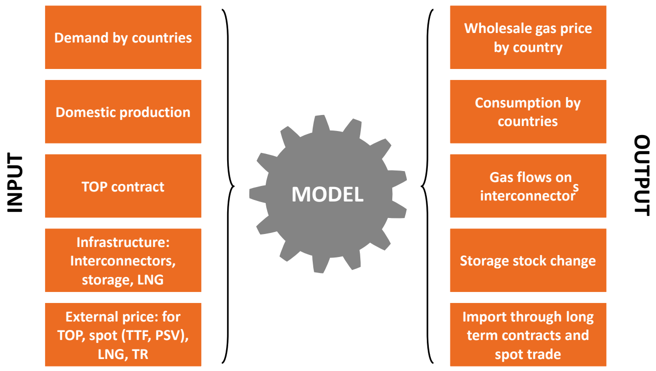
The reaction of Qatar is modelled similarly. Qatar may disregard the US LNG or price below to keep up its market share. If Qatar responds by such a pricing strategy, European spot demand surges by 40% compared to the reference case. Additional LNG is consumed mostly by terminals located in the Mediterranean, half of this new demand will be covered by Qatar and the other half by the US. However, the strategic options of Qatar are more limited than Russia: its LNG terminals are locked into long-term contracts and only 10% is free for strategic market manipulating behaviour. Considering this as a capacity constraints, Qatari cargoes are not able to stop the US LNG from Europe: demand would increase by 7%, mostly covered by the US.

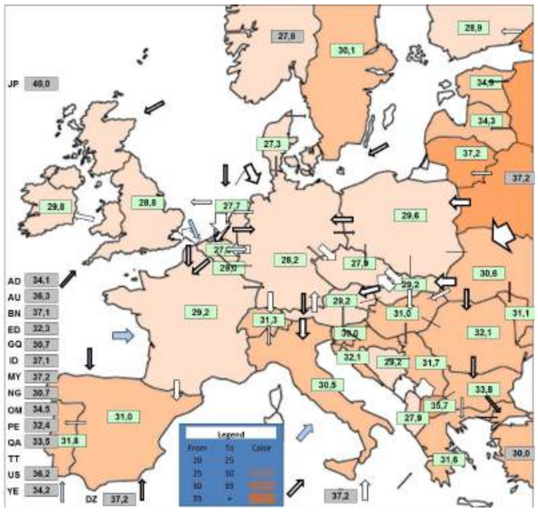
Summary

We demonstrated that only a significant 5 EUR/MWh drop in gas prices allows for the demand response in the power sector to rebound to 2012 consumption levels. Such a price reaction may not be ensured by US LNG supplies. Nevertheless, US LNG is an extremely competitively priced gas product, which can still be marketed under conditions of depressed European demand. Even if no LTCs were present, capacity of the first two trains of Sabine Pass would be possible to monetize at TTF+3, while train 3 and 4 can sell at TTF+0.5. A new entrant may not appear without causing a reaction from the incumbent market suppliers, therefore we evaluated the possible steps of Russia and Qatar. If the Russian player optimises in the short run, it may choose not to keep up its market share by selling spot volumes but instead tolerating some US competition in Europe. Qatar, because it is bound by LTCs, has insufficient capacity to crowd out the US LNG from the European markets.

EUROPEAN GAS MARKET MODEL (EGMM)

EGMM is the natural gas market model of REKK developed since 2010 modelling 36 countries.





ASSUMPTIONS

- Perfect competitive market
- Modelling period of one year (12 months)
- LTC and spot trade in the modelled countries, pipeline and LNG suppliers
- Physical constraints are interconnection capacities
- Trade constraints: TOP obligation
- Model includes domestic proiduction and storages
- Model calculates with transmission nd storage fees

USAGE

- Provides benchmark prices for the region
- Facilitates the better understanding of the connection between prices and fundaments. Eg. LTC market changes or storage changes.
- Price forecasts
- Allows analysing the effects of public policy interventions
- Analysing trade constraints
- Assessing effects of interconnector capacity expansion
- Security of supply scenarion analysis

RESULTS

- Gas flows and congestion on interconnectors
- Equilibrium prices for all countries
- Source composition
- Storage levels, LTC flows and spot trade
- Welfare indices

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Effects of the Ukrainian gas crisis
- Welfare effects of infrastructure investments (TAP)
- Regional security of supply scenarios and N-1 assessments
- National Energy Strategy 2030
- Regional storage market demand forecast

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Nord Stream 2: Downgrading Europe's Security of Supply Where it Matters

Nord Stream 2 is the latest Russian incarnation intended to bypass Ukraine and bring Russian gas directly to Europe's borders. It would double the existing Nord Stream capacity to 110 bcm/year with two additional strings between Russia and Germany under the Baltic Sea. In spite of a recently signed shareholders agreement between Russian gas giant Gazprom and five European firms and unflinching German support, Nord Stream 2 remains subject to considerable legal and regulatory oversight at the discretion of the European Commission.

The Nord Stream 2 consortium is led by Gazprom (50 percent share) with the remainder divided evenly between Shell, OMV, BASF/Wintershall, Engie and E.ON (10 percent each). Considering the established strength of the Third Energy Package and the recent launch of the Energy Union, Nord Stream 2 and its commercial backers will face stiff regulatory oversight from Brussels in addition to vocal opposition from Member States that feel slighted by South Stream's demise and threatened by implications of Nord Stream 2 for their own energy security — these are legitimate concerns that will be expounded upon below. The entire College of Commissioners will respond to the letter signed by seven EU countries requesting the Nord Stream 2 pipeline to be stopped, although there is no timeline. For now, the Commission is waiting for more precise details from Gazprom officials concerning the routing, environmental impact, public procurement and steps that will be taken to ensure conformity with EU law. In recent interviews Maros Sefcovic has repeated that the Commission's opinion will ultimately reflect the principles laid out in its state of the Energy Union report and depend on Gazprom's intentions for Ukraine transit post-2019.

The primary motives of the project's promoters are narrow self-interests. The companies see commercial opportunity for profit. Germany benefits directly, improving its supply security and becoming Russia's primary gas transit state to the rest of Europe. Russia significantly weakens Ukraine's relevance/leverage as a transit country, eliminates its exposure to third-country transit risk, and continues to splinter European solidarity.

Such a platform is entirely contrary to the well-articulated aims of the European Commission and its nascent Energy Union proposal, which is why the promoters make two broad claims to justify the pipeline's construction: that it will improve Europe's security of supply and generate commercial gains. The former claim simply does not match the Commission's concept of European supply security. On the latter claim, it is the companies involved that will profit. Rather than generate a tangible net gain in social welfare, it is a redistribution of benefits as demonstrated by the REKK's modeling.

The same geopolitical rationale that fueled Russia's ambition for South Stream is the driving force behind Nord Stream 2. Russia is determined to end its dependence on Ukraine as the main transit route to Europe so as not to affect its reliability as a supplier. Although volumes of gas transiting through Ukraine have steadily declined over the past few years (offset by increased Nord Stream 1 utilization), it will require the realization of at least one of these grand proposals—South Stream, Turkish Stream, or Nord Stream 2—to effectively make the Ukraine transit system secondary. Each is at best shrouded in tremendous uncertainty; South Stream was abandoned by Russia and despite Bulgaria's wishful thinking it remains dead in the water while Turkish Stream was originally envisioned as a 53 bcm project comprising four strings but now experts agree there will be two at most with only one dedicated to European markets. Turkish Stream has been beset by lengthy negotiations over the price discount sought by Turkey for future contracted Russian volumes that remains unresolved and exasperated by geopolitical tensions over Syria that culminated in the downing of a Russian fighter plane. Now Nord Stream 2 has momentum as Russia's du jour pipe dream, but EU regulatory obstacles alluded to above will have to be addressed for its approval from Brussels.

Russia's effort to consolidate support for these projects over the past decade has created rifts between some EU member states and Brussels. This is a complimentary strategic benefit for Moscow and one that slows the progress of the EU's energy policy initiatives, particularly in the realm of internal infrastructure that would erode Gazprom's current monopoly in certain markets.

Even as Russia attempts to diversify its export routes to Europe, the European Commission continues to emphasize the importance of source diversification for the improvement of Europe's security of supply, which is why it supports the Southern Corridor and various LNG projects.

Since 2009, the Commission helped guide the most vulnerable Central and Southeast European (CSEE) countries toward major gains in security of supply through efficient and manageable small-scale infrastructure investments. Binding regulations mandate reverse-flow obligations (although exemptions are granted) as a cornerstone of integration between historically isolated domestic markets. Most importantly, this enabled Western-sourced gas to enter pipelines that previously operated in one single-source direction—from Russia westward. Consequently, security of supply-driven bidirectional investments (e.g., Germany-Poland, Czech Republic-Slovakia, Slovakia-Ukraine among the most important) led to a degree of price convergence between cheaper spot priced Western European markets and more expensive, typically oil-indexed long-term contract-based Central and Eastern European (CEE) wholesale markets.

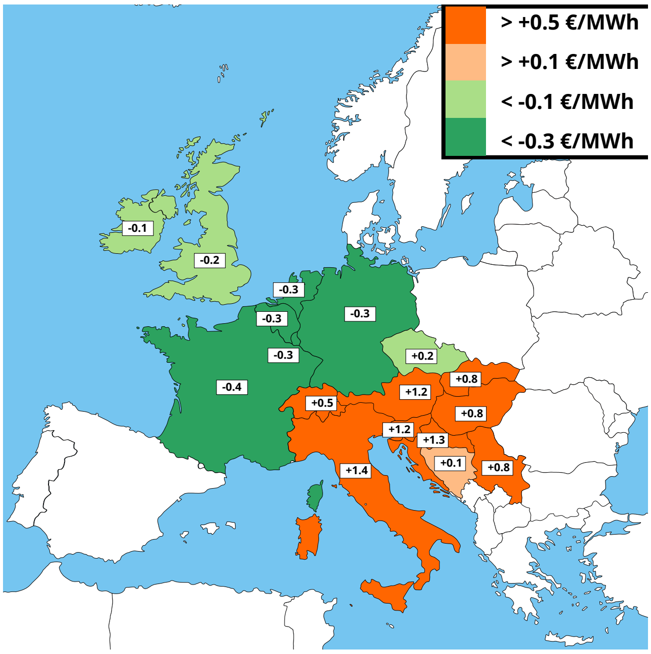
REKK modeling and the European Commission's stress test have confirmed that a one-month supply disruption along the Ukraine route now, in 2015, would be much more manageable than it was in 2009 because of these upgrades. Yet the CSEE region remains vulnerable in a supply disruption scenario, particularly Ukraine, the Balkans, and to a lesser extent Hungary, despite its reasonable interconnectivity with bordering countries.

Nevertheless, the Nord Stream 2 project does not aim to secure supply for countries of this region and, in fact, undermines it. The target markets of the project — Germany, France, Austria, and Italy — are not in need of any further safeguards against a short supply disruption, while the most significant impact would be a deterioration of Ukraine's security of supply. A disruption or supply cut affecting the CSEE region would no longer be able to be mitigated by market-based shipments with a portion of the reverse-flow capacity committed to Russia's long-term contract obligations formerly delivered through Ukraine. Nord Stream 2 not only subtracts from Ukraine's transit earnings and ability to maintain its transmission system, it also makes Ukraine more vulnerable to a Russian supply disruption that would otherwise be offset by Western wholesale markets as it has been since 2014, primarily through Slovakian reverse flow.

Because Russia's "new" supply source would be used to displace an existing route, it would have to make use of west to east flows via Germany, the Czech Republic, and Austria to reach customers in Slovakia and Hungary. In this manner, Nord Stream 2 intervenes with the design and purpose of post-2009 infrastructure investments, diminishing security of supply value and restricting market development.

REKK modeling assessed the commercial benefits of the project using a gas market simulation with target markets (Germany, France, Austria, Italy) fully supp-

Figure 23 **Yearly average gas wholesale market price change due to rerouting of Russian long-term contracts to Nord Stream 2 (change in €/MWh)**



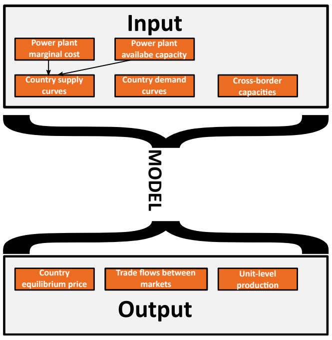
lied by Russia's long-term contract obligations through Nord Stream 2 and smaller markets in CEE (Czech Republic, Slovakia, Slovenia, Hungary) fully or partially supplied according to available transmission capacity. The result is a drop in wholesale prices in the target countries and a small price increase in CEE and the Balkans.

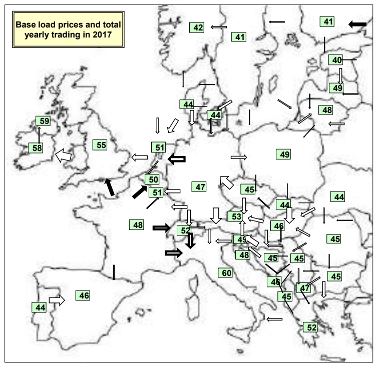
Taking into account consumers, producers, long-term contract holders, transmission service operators, and storage service operators, the aggregate social welfare effect in the European Union is virtually zero, but the benefits are not evenly distributed among countries and market players. Not surprisingly, Germany, France, Italy, and Switzerland would benefit the most while Slovakia and Poland would lose transit revenues. In the end, the price gap between Western and Southeastern Europe widens.

This does not seem to be a time that Brussels will shy away from its principles on the issue of energy security. A revision of the Gas Security of Supply Regulation and the release of a second list of projects of common interest are intended to improve the position of less-developed and integrated markets in the CSEE region that remain largely dependent on a single source for their energy needs. It is, therefore, ironic that in the Nord Stream 2 scenario EU-funded infrastructure intended to strengthen the CSEE's resilience would instead facilitate the rerouting of Russia's long-term obligations and weaken the region.

EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

EEMM is the electricity market model of REKK developed since 2006 modelling 36 countries





ASSUMPTIONS

- Perfect competitive market
- The model calculates the marginal cost of nearly 5000 power plant units and the unique merit order for each country
- 12 unique technologies
- Includes future power plant developments
- Takes 85 interconnectors into account
- Models 90 reference hours for each year. By appropriate weighting of the reference hours, the model calculates the price of standard products (base and peak)

USAGE

- Provides competitive price signal for the modelled region
- Facilitates the better understanding of the connection between prices and fundaments. We can analyse the effect of fuels prices, interconnector shortages, etc. on price
- Gives price forecast up to 2030: utilizing a database of planned decommissionings and commissionings
- Allows analysing the effects of public policy interventions
- Trade constraints
- Assessment of interconnector capacity building

RESULTS

- Base and peakload power prices in the modelled countries
- Fuels mix
- Power plant generation on unit level
- Import and export flows
- Cross-border capacity prices

REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Evaluating the TYNDP of ENTSO-E
- Assessing the effects of the German nuclear decommissioning
- Analysing the connection between Balcans and Hungarian power price
- Forecasting prices for Easterns and Southeast-European countries
- National Energy Strategy 2030
- Assessment of CHP investment
- Forecasting power plant gas demand
- Forecasting power sector CO_2 emmissions

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