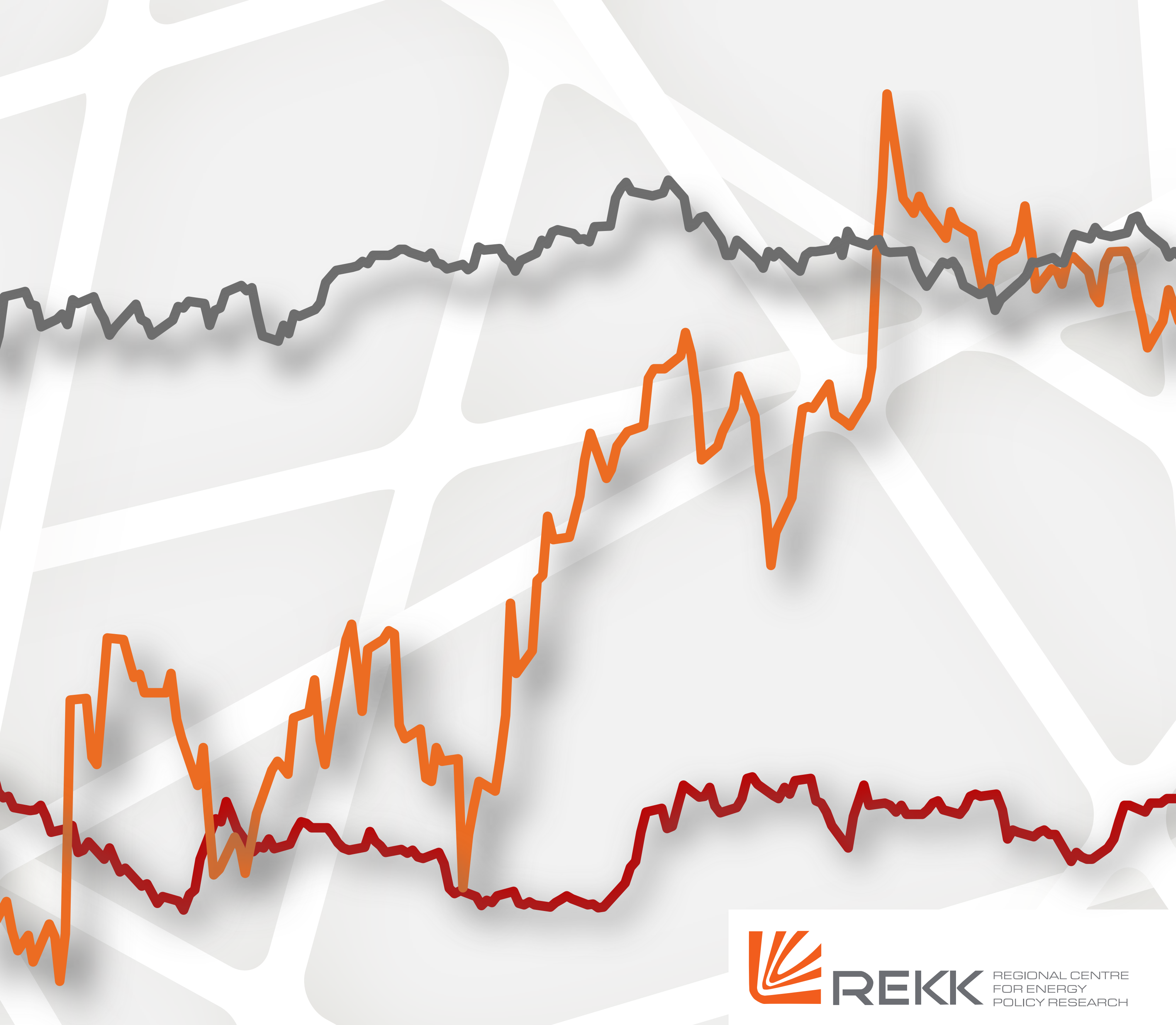

REKK
REGIONAL CENTRE FOR ENERGY POLICY RESEARCH

# HUNGARIAN ENERGY MARKET REPORT

## Q1 2016

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.

## Trainings

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Electricity market trainings

Market monitoring

Gas market trainings

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$CO_2$-allowance allocation and trade

Renewable energy support schemes and markets

Security of supply

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Supplier switching

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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

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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,

In addition to highlighting the prevailing trends of the energy markets, this current issue touches on the challenges of unintended electricity flows („loop flows"), options available for risk sharing associated with nuclear power plant investments, the amendment of the rules on capacity allocation within the natural gas sector, and the published strategies of the European Commission on the security of gas supply, storage and the import of liquefied natural gas.

The loop flows passing through the transmission networks of the Central European region have been causing considerable problems for system operators, on some border sections reducing the volume of capacity that can be allocated for commercial purposes. Urged by Poland - a country strongly exposed to loop flows - ACER initiated an inspection, and in its opinion published in September 2015 it called the respective authorities to terminate the common German-Austrian price zone and to introduce coordinated capacity allocation on the border section in question. The article looks at the escalation of loopholes over the last few years, from their origins to the problems they cause, and then offers potential solutions.

The second article describes the techniques applied to mitigate the market and financing risks of nuclear power plant investments, shared between investors, technology providers and the financing banks. After reviewing the different types of costs, the article examines the risk management and allocation techniques applied for presently ongoing power plant investment projects within Europe, namely Hinkley Point C in England and the Olkiluoto 3 and Hanhiviki I. projects in Finland. With this context the Paks 2 project is analyzed using currently available information.

The third article describes the amendments of the capacity allocation rules developed by ENTSOG and how they are applied to the Hungarian Network Code. It then evaluates the operation of the system and the RGB, the regional capacity reservation platform, launched with the active participation of the FGSZ.

In the final article, we discuss the strategic ideas of the European Commission published in February on the security of natural gas supply, storage and the import of LNG. This includes the proposed revision to Regulation 994 on the security of supply and the "natural gas package", introduced after a four-month consultation period, outlining the LNG and natural gas storage strategy of the Commission. These communications are summarized and evaluated according to their viability.

*Peter Kaderják, director*

## Contents




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# Energy market developments

***International energy markets saw a significant drop in prices in the last quarter of 2015, with at least a 10% drop in Brent, ARA, Henry Hub and TTF prices as well as German border prices of Russian LTC natural gas compared to the third quarter. Declining gas prices pushed clean spark spread into positive territory in October for the first time in years. There was a rise in domestic power production (3%) for the first time since 2010, but the output of some 30 TWh still lags behind peaks that approached 40 TWh before the crisis, while net imports hit record of 13.7 TWh. Domestic gas production continued to fall, nearly a 30% year-on-year decline in the third quarter was followed by another 18% decline in the fourth quarter. By REKK estimations, the official natural gas price of universal service lagged significantly behind the average purchase price, which had narrowed in the second and third quarters.***

## International price trends

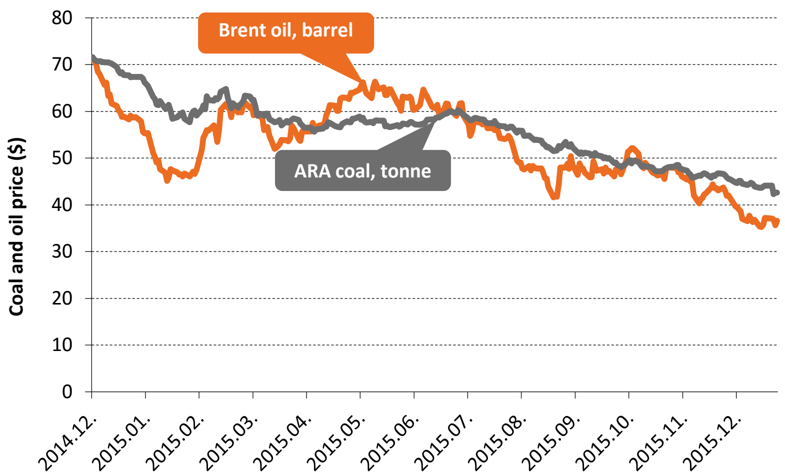
The end of 2015 saw an accelerating drop in international oil prices due to the global oversupply, attributable to non-conventional production and changes in OPEC's price protection policy: following a 6% decline in the third quarter, average Brent price fell 13% to 43.6 USD in the fourth quarter (Figure 1). The December average price of 38 USD was 10 USD below January, followed by a temporary increase. The quarterly average ARA price fell 14% to 46.5 USD/ton, which is similar to the previous period's decline. The fall in coal prices is due to the Chinese economic downturn and the effect of the more intensive competition triggered by gas and renewables.

Henry Hub prices sat at under 2 USD/MMBtu in December, which matched the April 2012 low. The EUR/MWh quarterly average price lagged behind the July-September average by more than 10% (Figure 2). Meanwhile, the U.S. Energy Information Administration (EIA) anticipates that the incremental domestic and export gas demand should exceed incremental supply this year, which will lead to significant price increase by the end of 2017. While this year EIA expects lower than 3 USD/MMBtu Henry Hub prices, it anticipates higher Henry Hub prices in 2017. In the EIA outlook, gas production should grow only by 0.7% following last year's 5.7% rise. Standard & Poor's has not changed its gas price assumptions and expects a 2.75 USD/MMBtu average price for 2017, as it sees a shift in the country's gas production profile towards the lower-cost shale gas formations (North Eastern).

While there were not any significant changes in Japanese spot LNG prices in the fourth quarter of last year, the quarterly average TTF spot price was down 15% from the third quarter to under 16 EUR/MWh by December while Russion LNG German border prices declined by 10%, thus the gap between the TTF and the German border prices has widened. However, since crude oil prices have a direct effect on the latter due to its link to oil prices, a significant drop in prices will arrive with some delay.

The transformation of global LNG market might be accelerated by the new LNG strategy of the Japanese government, which aims to develop liquidity in the local market with the creation of an LNG hub. It is triggered by the demand from traders that will enter the market as Japanese LNG demand settles at lower levels. With nuclear power plant restarts – following Sendai 1, also the 2nd reactor of the plant started production in October, which may be followed by another 10 reactors by next spring – Osaka Gas anticipates that the Japanese LNG demand could drop to 70 million tons from the current 90 million t/a in the next 10 years. Meanwhile, Eclipse Energy forecasts that the annual contracted amount might reach 82-88 million tons between 2017 and 2020. Similarly, South Korea's LNG imports are falling: last year's 33.6 million tons lost 10% compared to 2014, and the competent ministry of the country expects further decline in the following 15 years.

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




Source: EEX, IEA

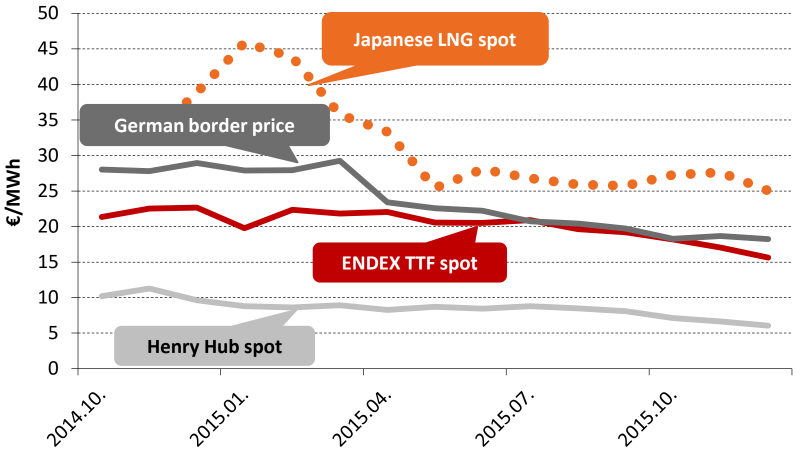
Due to the decreasing Asian demand, Europe will be an important market for LNG in the short to medium term. Last year, the Belgian Zeebrugge-terminal received LNG equivalent to 3.6 bcm natural gas, which exceeds the amount in 2014 by nearly 30%. The amount of LNG transported to Asia dropped nearly 40%, and the amount of gas traded on TTF grew by 28% (to 17800 TWh). As for liquidity, TTF was far ahead of NBP according to churn rate, which was rated 42 at TTF and 20 at NBP in 2015. In general, markets over 10-15 are considered liquid; this index was only 5 at Baumgarten CEGH in 2015.

As for TTF price outlook, in addition to growing LNG supply and falling oil prices, a mild winter could also dampen prices in the short run. The mild winter left Dutch storage inventories somewhat saturated at 77.2% (10.1 bcm) at the beginning of January, which projects a very weak injection demand for the summer. However, any significant fallback in Dutch gas production would have the opposite effect on prices. The production of the largest field in Groningen plummeted one third to 28 bcm, and the government decided on a production cap of 27 bcm for the 2015/16 gas year.

The fall in the three monthly average of German EEX year-ahead baseload prices slightly accelerated in the fourth quarter, and sank to under 29 EUR/MWh (Figure 3). Similarly, peakload prices dropped to 34 EUR/MWh by the end of the period under review. In the EUA market, prices have been steadily rising: the three-month average of futures allowances grew from 8 EUR/ton to 8.4 EUR/ton by the last quarter. Several times prices exceeded 8.5 EUR for the first time since November 2012, triggered by an expectation of declining supply in allowances.

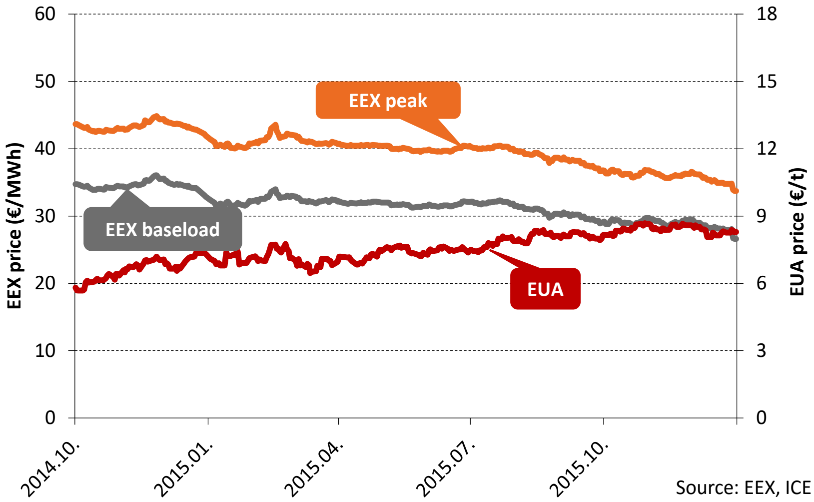
With decreasing gas prices, the clean spark spread temporarily reached positive territory in October (Figure 4). However, since coal prices were also dropping and allowances prices remained relatively low despite their slight rise, the competitive edge of coal-fired power plants remained significant. In

**Figure 2 Prices on select international gas markets from October 2014 to December 2015**



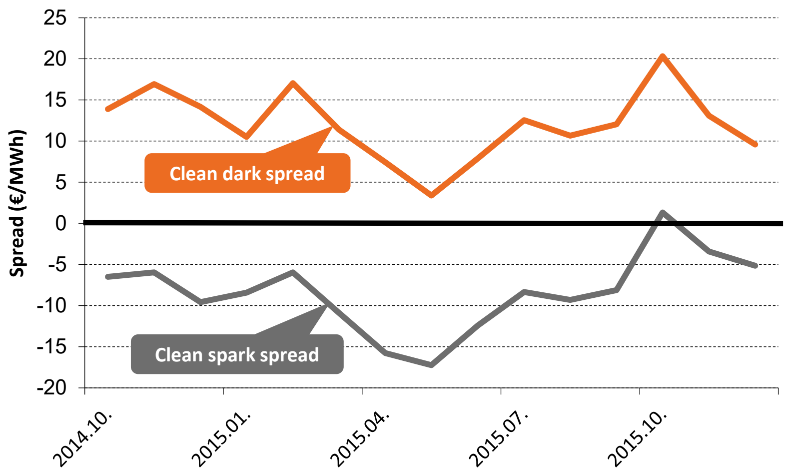

Source: Statistical Office of Japan, EIA, Gaspool, IMF

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




Source: EEX, ICE

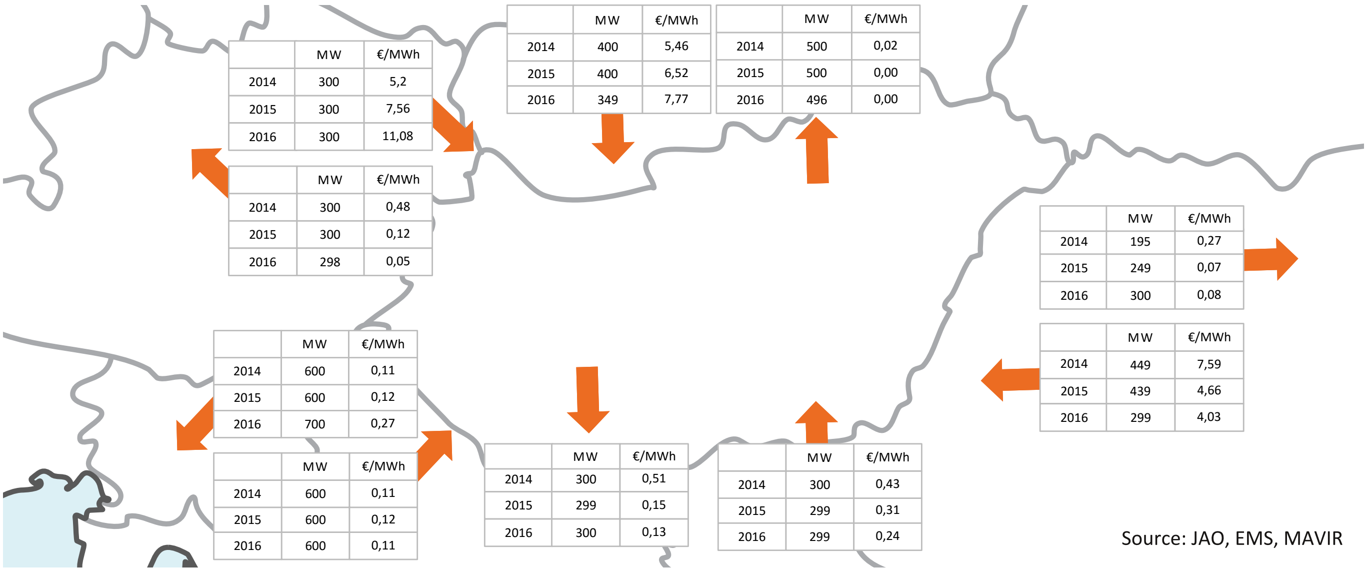
**Figure 4 Clean spark spread (gas fired power plants) and clean dark spread (coal fired power plants) on German market from October 2015 to December 2015**




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

*Both indicators show the difference between electricity prices on exchanges and the cost ofelectricity 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 ofcoal-fired ones.*

**Figure 5 Results of monthly cross-border capacity auctions in Hungary, 2014-2016**




| | MW | €/MWh |
|---|---|---|
| 2014 | 300 | 5,2 |
| 2015 | 300 | 7,56 |
| 2016 | 300 | 11,08 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 300 | 0,48 |
| 2015 | 300 | 0,12 |
| 2016 | 298 | 0,05 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 400 | 5,46 |
| 2015 | 400 | 6,52 |
| 2016 | 349 | 7,77 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 500 | 0,02 |
| 2015 | 500 | 0,00 |
| 2016 | 496 | 0,00 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 195 | 0,27 |
| 2015 | 249 | 0,07 |
| 2016 | 300 | 0,08 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 449 | 7,59 |
| 2015 | 439 | 4,66 |
| 2016 | 299 | 4,03 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 600 | 0,11 |
| 2015 | 600 | 0,12 |
| 2016 | 700 | 0,27 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 600 | 0,11 |
| 2015 | 600 | 0,12 |
| 2016 | 600 | 0,11 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 300 | 0,51 |
| 2015 | 299 | 0,15 |
| 2016 | 300 | 0,13 |

| | MW | €/MWh |
|---|---|---|
| 2014 | 300 | 0,43 |
| 2015 | 299 | 0,31 |
| 2016 | 299 | 0,24 |

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

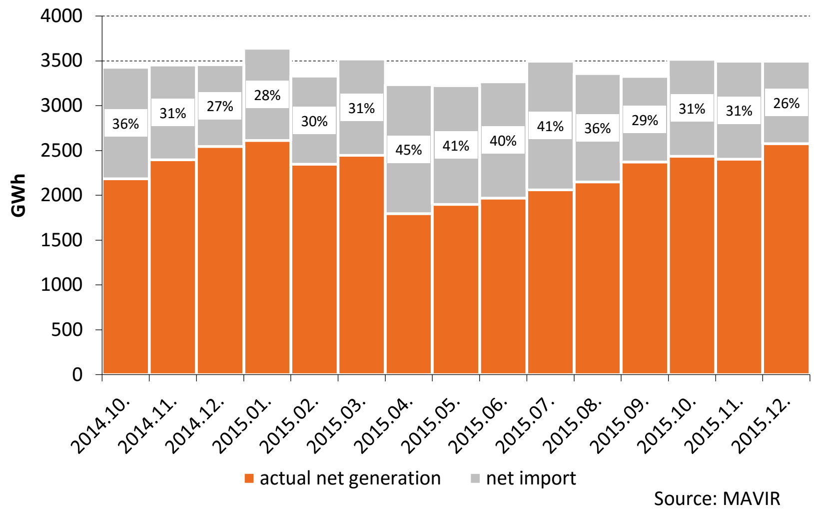
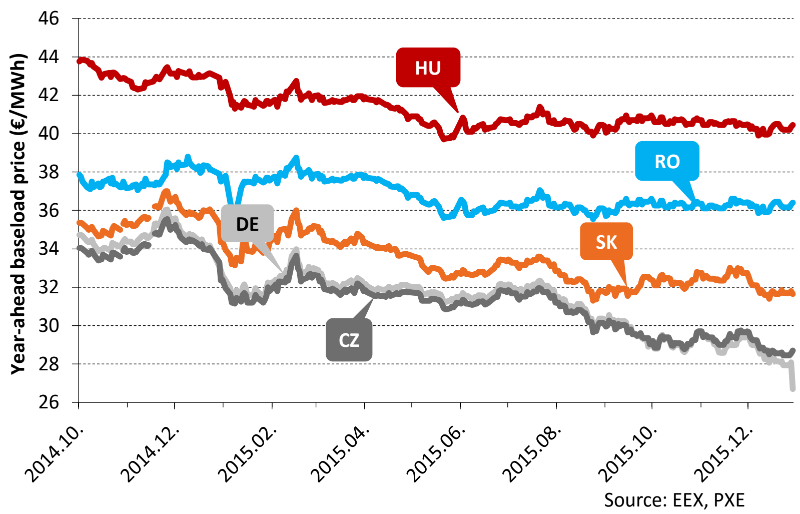



**Figure 7 Year-ahead baseload futures prices in given countries of the region, between October 2014 and December 2015**




addition, the clean spark spread returned to negative in November and December due to the declining electricity prices.

The prospects of German gas-fired power plants are not promising in the long run due to the rapid extension of renewables. The country's power production broke a record by rising to 647.1 TWh with renewable based production, which grew by 31.6 TWh and reached 30% share in overall power production. Wind power plants took the lead amongst renewables, with a growth rate of 50% and a production of 86 TWh. Peak output was achieved in November (10.6 TWh), and then in December (11.5 TWh); December was the first time that wind energy was the primary electricity source in Germany. Consequently, the spot market witnessed negative hourly power prices several times. The significant growth in German electricity export (from 35.57 TWh in 2014 to 50.16 in 2015 is also due to the peak wind energy production. Considerable part of exports went to Austria due to the common/single price zone and, in addition, less than half of the effective flows to Austria were scheduled in 2015. Non-scheduled flows are also problematic on a regional level (See Article 'Gripped by loops' on page 11.). The German wind energy capacity grew from 39.2 GW in 2014 to 45 GW in 2015.

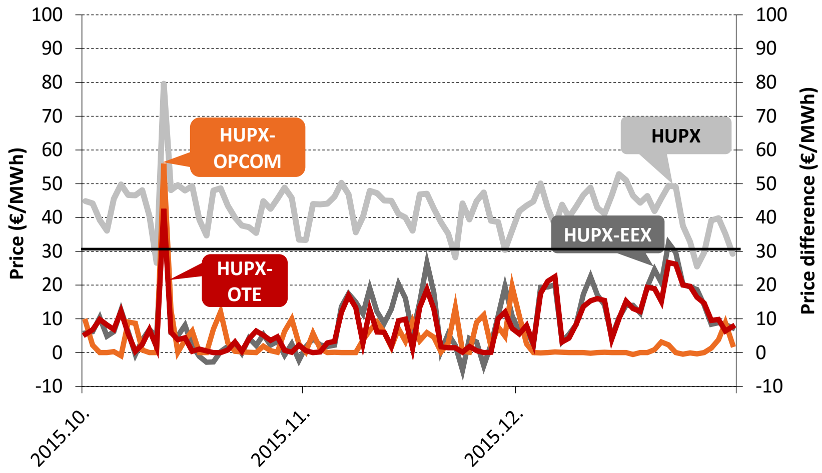
## Overview of domestic power market

There was a considerable rise in the price of 2016 annual Austrian baseload import capacity, reflecting an interconnection capacity fee of 11 EUR/MWh (more than double the 2014 price) that exceeds the price of the Slovakian interconnection by nearly 50% (Figure 5). Although to a lesser extent, the capacity fee of Slovakian import grew as well, approaching 8 EUR. In addition, the size of the auctioned capacity decreased (by more than 10%) from 2014. Meanwhile, although the size of the auctioned Romanian capacity declined, the prices dropped, and thus the capacity needed to export 1 MWh from Romania cost 4 EUR and from all other directions only a few eurocents consistent with previous months.

Domestic electricity consumption was relatively stable in the last quarter of 2015 at around 3500 GWh (Figure 6). This is more or less consistent with the past year's consumption, exceeding it by only 2%. However, the quarterly production grew by 4% relative to the same period of 2014, leading to a small decline in the import share from 31% to 29%. Although the growing production and declining import share are norml for winter seasons, the 26% in December 2015 was an especially low import share, the lowest since March 2013. Considering the whole year, net imports broke a record at 13.7 TWh by exceeding 2014 net imports by 2.2%. For the first time since 2010, domestic power production grew in 2015 (by 3%), and even though it hovers around 30 TWh it still lags well behind the prices approaching 40 TWh before the crisis.

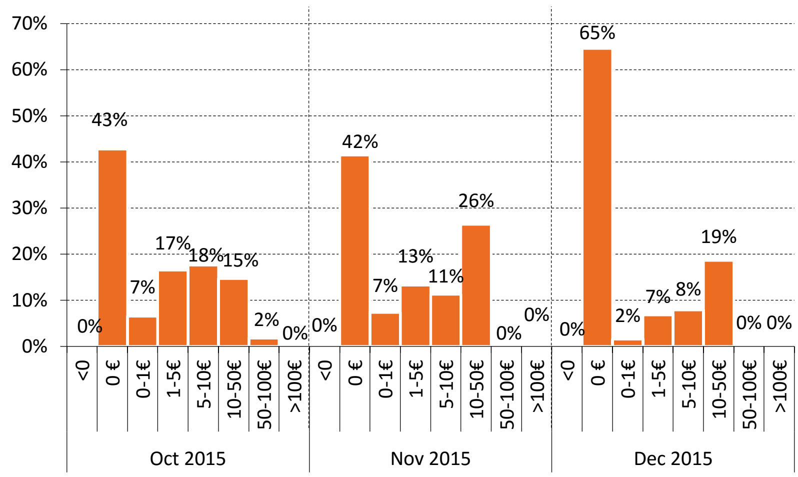
In the fourth quarter of 2015, the spread between HUPX and EEX futures grew on year-ahead markets (Figure 7). In September, the HUPX-EEX spread reached its highest point in 4.5 years at 11 EUR/MWh, while the spread peaked at 12 EUR in December with HUPX futures exceeding 40 EUR/MWh. While the quarterly averages of HUPX and OPCOM futures remained unchanged, EEX dropped below the previous quarter's averages by 7%, the Czech exchange by 5% and the Slovakian one by 1%.

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



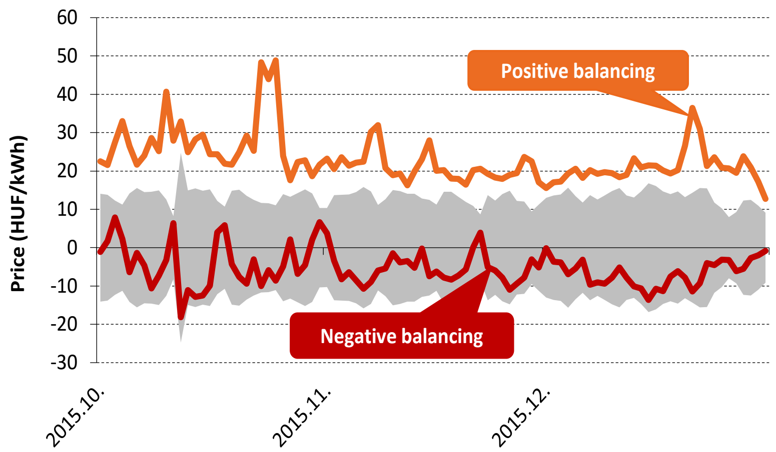

Source: EEX, OPCOM, OTE, HUPX

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




Source: REKK calculation based on OTE data

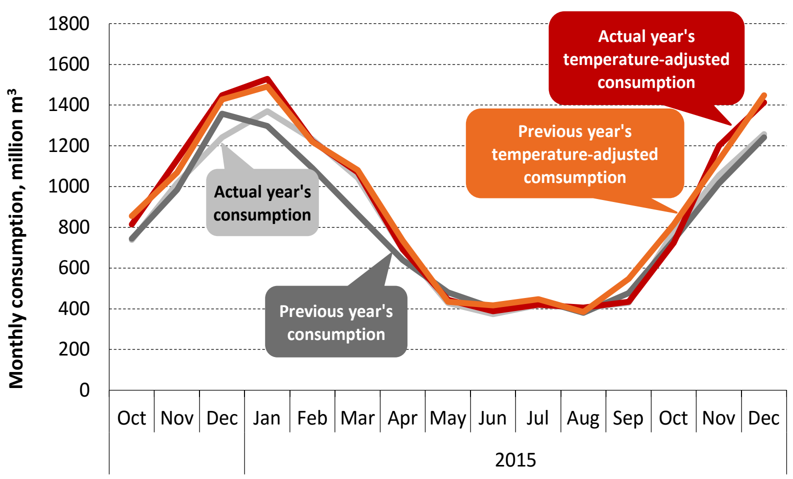
**Figure 10 Daily average of balancing prices and spot HUPX prices Q4 2015**




Source: MAVIR, HUPX

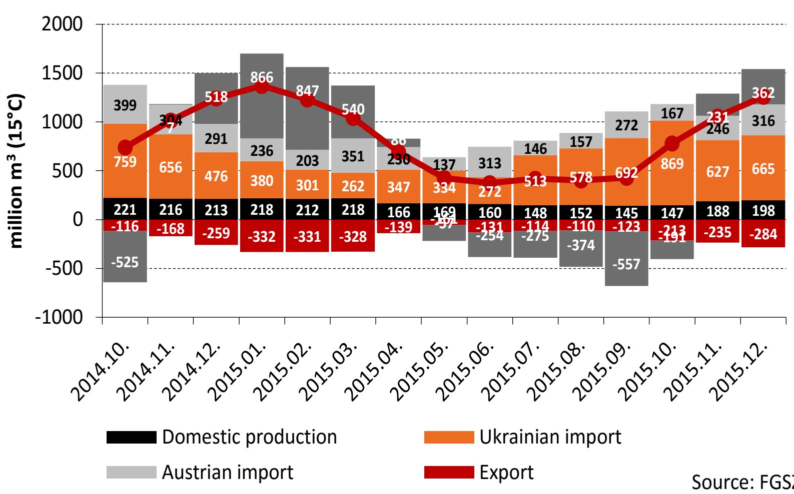
*Note: The upper edge of the grey range in the figure is determined by the next day price of HUPX, while the lower edge is the opposite of the same price. According to the Trading Rules of MAVIR the price of positive balancing power is limited to the next day price on HUPX, while the negative balancing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

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




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

**Figure 12 Source structure of Hungarian gas market by month between October 2014 and December 2015**




Source: FGSZ

Meanwhile, the HUPX-EEX spread narrowed on day-ahead markets from 15 EUR/MWh in the third quarter to 9.5 EUR/MWh in the fourth quarter (Figure 8). The fourth quarter also witnessed a small drop also in the HUPX/Czech and HUPX/OPCOM spread. The downward price pressure exerted by mild wheather conditions and the ample hydro production in the Balkans helped compensate the outage caused by the one-month long maintenance works at a block of Paks nuclear power plant. Relative to 2015, there were practically no changes in day-ahead prices compared to 2014, even so the HUPX-EEX spread rose by nearly 16%. The amount of electricity traded on HUPX increased considerably by 31% to 21.4 TWh due to the market coupling with Romania in 2014 and to the new 5 HUPX members.

Figure 9 illustrates the frequency and size of spreads under HU-SK market coupling. In December, the alignment of HUPX and Slovakian prices was very weak: HUPX prices exceeded Slovakian prices by more than 5 EUR in 75% of the hours, and by 10 EUR in more than 50% of the hours. At the same time a strong alignment between HUPX and Romanian prices surfaced in the fourth quarter, with no difference in 88% 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 try to manage foreseeable deficits and surpluses through exchange based transactions – in other words, covering the expected deficit and surplus by balancing the energy market would not otherwise be desirable. 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 fourth quarter, the average price of positive balancing exceeded 23 HUF, similar to the second quarter average and less than the third quarter average approaching 29 HUF (Figure 10).

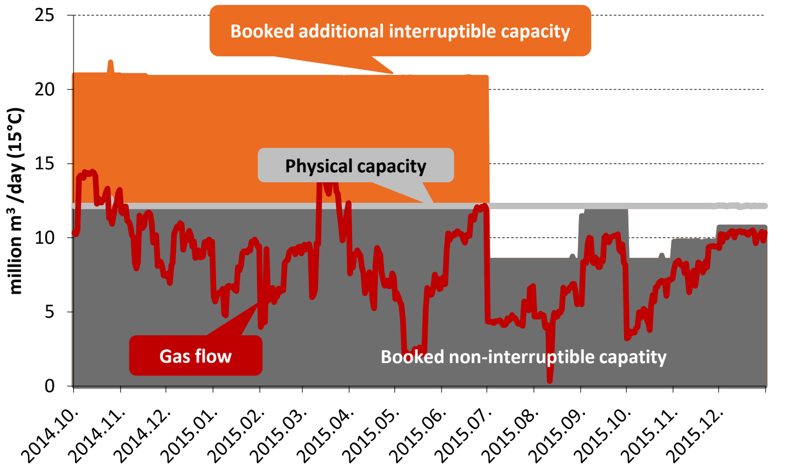
## Overview of domestic gas market

Although fourth quarter gas consumption was 3% greater than 2014, it was a result of the colder winter than the previous year (although it was still milder than an average winter). The temperature adjusted consumption showed a 2% decline year-to-year (Figure 11).

Domestic gas production continued to decline. After a nearly 30% drop year-to-year in the third quarter, it fell by another 18% in the fourth quarter (Figure 12). Thus, while domestic sources covered 22% of consumption in the last quarter of 2014, it accounted for only 17% in the last quarter of 2015. As with the third quarter, Eastern imports grew (by 14%), while imports from Austria declined (by 27%) year-to-year because of the maturation of the Ukrainian crisis and improving competitiveness of the oil linked gas. There was also a considerable 35% drop in exports and flexibility was covered by growing net withdrawal of storage. While injection and withdrawal were leveled out in the last quarter of 2014 due to the very mild October, net withrawal in the fourth quarter of 2015 exceeded 400 million cubic meters.

Due to the low level of imports from Austria, the average interconnection capacity utilization of the Mosonmagyaróvár entry point accounted for 65% between October and December 2015, while it was 89% in the last quarter of 2014, with transporters utilizing only 81% of the contracted and non-interruptible capacities without any interruptible capacities contracted (Figure 13). At the same time, the utilization of the Beregdaróc interconnection point (of far greater capacity than Mosonmagyaróvár entry point) rose from 36% to 42% compared to the previous year. (Figure 14). While transporters contracted a daily average of 18.4 mcm of non-interruptible import capacity at Beregdaróc entry point the previous year, it totalled 26.5 million in 2015. There was no usage of the new Slovakian-Hungarian interconnection commissioned last July either during the third or the fourth quarter, since the Baumgarten hub from Mosonmagyaróvár was cheaper.

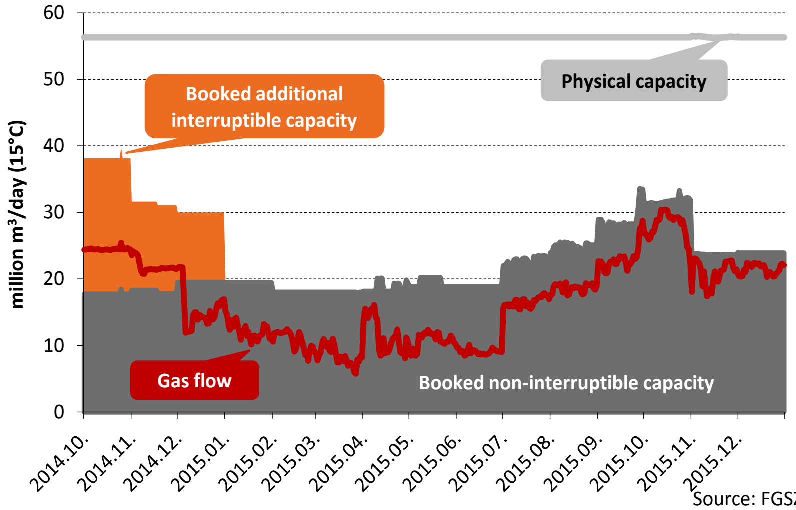
**Figure 13 Transmission at the Mosonmagyaróvár (Austrian border) entry point between October 2014 and December 2015 together with booked interruptible and non-interruptible capacities**




Source: FGSZ

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

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



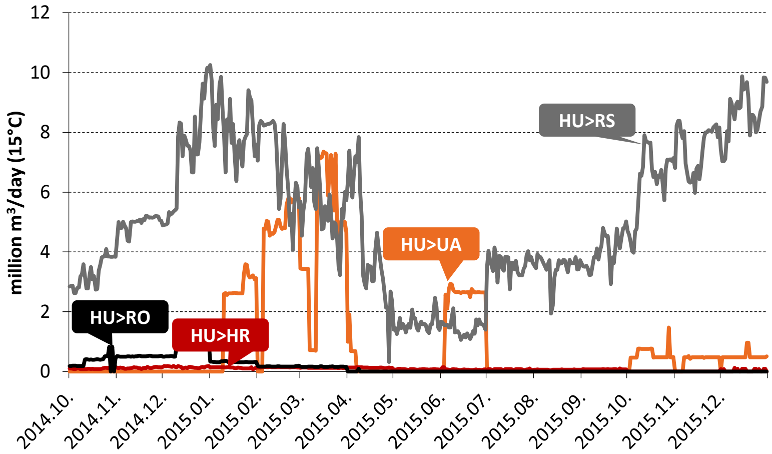

Source: FGSZ

*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*

While Hungary did not export any gas to Ukraine in last quarter of 2014, 44.3 mcm were exported in the fourth quarter of 2015, which accounted for 6% of Hungary's total export. The remaining 94% was exported to Serbia, marking growth of 45% on a yearly basis (Figure 15). FGSZ Ltd. would support growth in Serbian exports in the post-2020 period by offering non-interruptible capacity of 6.1 bcm annually with upgraded infrastructure. Although this joint project between Hungary and Serbia was not a PCI (Project of Common Interest) in 2015, they can apply again in 2017. The joint project is in anticipation of the possibility that Ukraine's role transitting Russian gas to the West would end with the North Stream extension, forcing the two countries to largely depend on rerouted Western imports. However, Russia seems less inclined to cut Ukrainian transit from 2019 as it warned before and Gazprom stated that the quantity to be transported along the Ukrainian trunk system „will depend on customers".

Ukraine expanded its interconnection capacities to increase Slovakian import capacity from 41 mcm to 54 million, and will be able to import up to 1 bcm of gas from Romania annually beginning this year. Kiev also hopes that new interconnection facilitates will increase import capacity from Poland to 8 bcm annually. Ukraine made tremendous strides in diversification of its imports in 2015: its European imports doubled to 10.3 bcm including 9.7 billion from Slovakia, 0.5 billion from Hungary and 0.1 billion from Poland. At the same time, Russian imports plummeted from 14.5 to 6.1 bcm. Overall the country's yearly natural gas consumption fell by more than 20% (to 33.8 bcm).

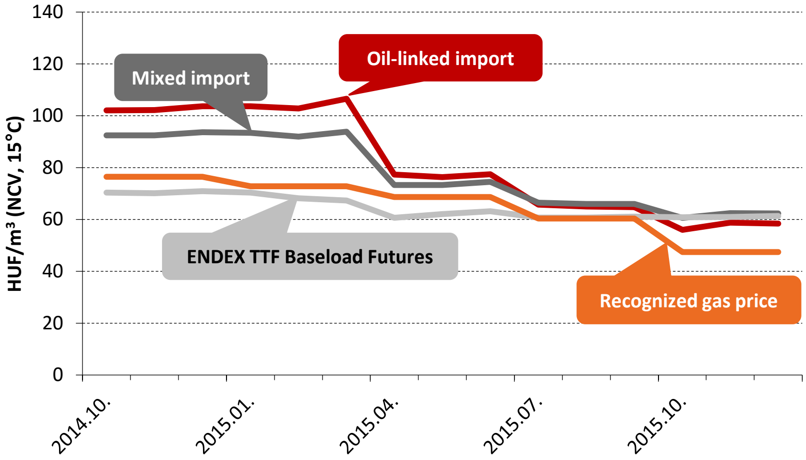
**Figure 15 Hungary's natural gas exports to Ukraine, Romania and Serbia from October 2014 to December 2015**




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 October 2014 and December 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 ofthe 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 ofthe rates set by decree.*

In REKK's estimation, the recognised natural gas price of universal service lagged significantly behind the assumed average purchase price consistent with previous periods (Figure 16). The assumed average purchase price consists of the weighted average of oil-indexed price (60%), and spot price (40%) at market exchange rates. Meanwhile, the recognised Hungarian domestic gas price has a predefined weighted average of 25% oil indexation and 75% spot (only if it is under oil-indexed price), and an exchange rate assumption (260 HUF/USD and 300 HUF/EUR last quarter 2015) that underestimates importers' costs.

# Gripped by loops

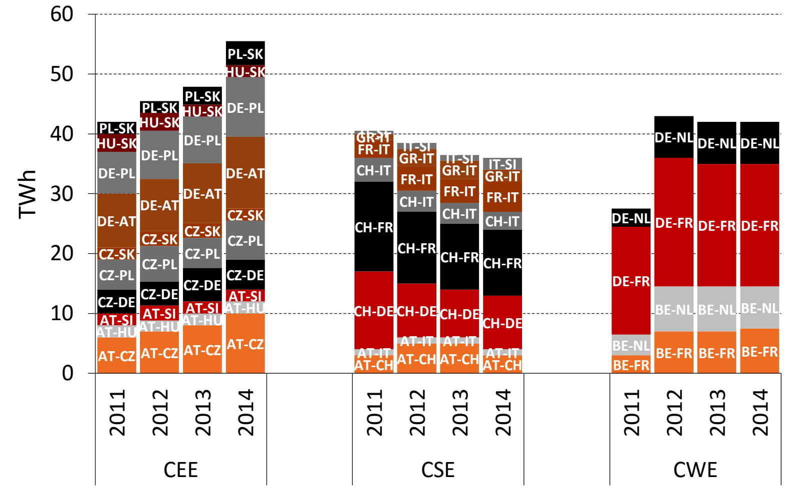
***The simmering discontent of countries suffering from unintended physical flows through their electricity interconnections and within their internal network reached a tipping point for Poland in December 2014. At this time, Polish energy regulator (URE) made a formal request for ACER to form an opinion on the compliance of the current methods of allocation of cross-border transmission capacities in the CEE region with the provisions of Regulation 714/2009. ACER issued its legally non-binding opinion on this matter in September 2015, requesting the regulators and TSOs in the CEE region to come up with a timeframe for implementing coordinated capacity allocation at the German-Austrian border. ACER supports URE's claim that the absence of cross-border capacity allocation for commercial transactions at the DE-AT border results in significant power flows across the transmission system of neighbouring countries, notably the German-Polish, German-Czech and Czech-Austrian border resulting in structural congestion that threatens network security and crowds out commercial trade. As a consequence, the DE-AT border must be defined as structurally congested and – following the provisions of the Regulation – needs to be the subject of a transparent and non-discriminatory capacity allocation procedure, i.e. the splitting of the German-Austrian single price zone. The Austrian regulator, E-Control, challenged ACER over the proposed market-splitting of the German-Austrian single electricity price zone before the European Court of Justice and filed an appeal with ACER's Board of Appeal. However, only appeals directed against individual ACER decisions or measures having legal effects can be admitted by the Board of Appeal. Since ACER's request for the implementation of a capacity allocation procedure did not qualify for a binding measure with direct legal effects, ACER has dismissed the appeal as inadmissible.***

## What are loop flows?

The European wholesale electricity market is structured into bidding/price zones that usually correspond with the territory of countries, even though some countries are split into several zones (Italy or Sweden). Within a zone commercial transactions can be made regardless of the physical realities of the network, i.e. any consumer can buy electricity from any producer. This assumption facilitates trade within the zone, however at the borders TSOs have to limit cross-border capacity using ex-ante capacity allocation mechanisms to manage congestion.

The result of these capacity allocation procedures are the pattern of scheduled flows at each border prepared by the relevant TSOs. However, physical electricity flows do not necessarily follow contractual paths embodied in scheduled flows as the former follows physical rules within the transmission system, while the latter is the result of market decisions. The reasons for the existence and growth of these unscheduled flows (UFs - the difference between physical and scheduled flows) is that the network development does not necessarily follow the changes in the topology of generation and load capacity development that drive commercial transactions. In addition, the timeframe of the former is usually much longer than the increase of traded electricity volumes.

**Figure 17 Sum of hourly absolute UFs per border in the three European regions (2011-2014, TWh)**




The following figure shows the volume of unscheduled flows in Europe: the volume of unscheduled flows have increased in recent years in the CEE and CWE regions, with the sharp increase in the CEE region attributed to the DE-AT, DE-PL and AT-CZ directions.

## Why is it a problem?

Unscheduled flows pose various challenges for TSOs. The first problem is that unscheduled flows may threaten the security of network operation. It is generally measured with the occurrence of N-1 violations in the electricity system. In the CEE region, both the occurrence and duration of this type of security threat was recognized by ENTSO-E already in 2012 when it alerted

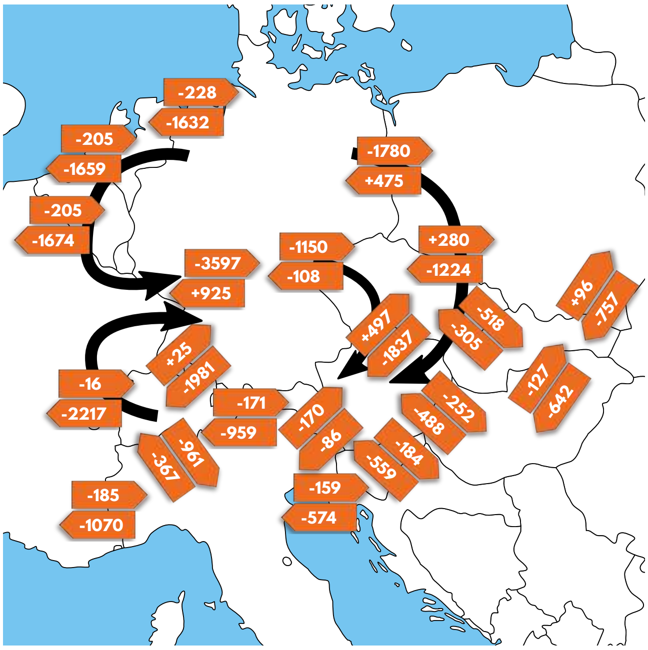
[1] *Opinion of ACER No. 09/2015*
[2] *T-63/16 - E-Control v ACER*
[3] *Unscheduled flows can originate either from trade within a bidding zone (loop flow) which are partly realised through other zones, or trade across bidding zones (unscheduled transit flows). Loop flow is an often used general term denoting all flows that are not linked to commercial transactions (i.e. unscheduled flows).*

the European Commission: "the security risks observed today are the culmination of the deterioration of the overall system that can be observed by the gradual limitation of the NTCs between these countries over the recent years." In order to ensure secure grid operation, TSOs have to apply remedial actions such as re-dispatching, countertrading and curtailment and absorb associated costs partly due to such electricity flows that are external to their scope of action.

The second problem associated with unintended flows – also derived from the above mentioned system security aspect – is the loss of NTC available for commercial transactions. In theory, UFs can even increase NTC (depending on volumes and directions) however in practice it is always reduced due to the uncertainty of UFs and the associated forecasting errors resulting in conservative estimates. In the calculation of transfer capacities available for cross border trading TSOs not only calculate the level of UFs but must also factor the uncertainty and the related reliability margins (RMs). The capacity losses are especially considerable on the DE-PL, DE-CZ and CZ-AT borders and on the DE-NL, NL-BE, BE-FR and FR-DE borders. These two electricity loops (East and West of Germany) both start in North Germany and end in South Germany. Another loop can be observed on the CH-FR, DE-CH and FR-DE borders (see 2. Figure). Limited import volumes due to loop flows of electricity from the Netherlands to Belgium, coupled with the reduced Belgian generation (due to nuclear capacity outages) and insufficient reserve capacity pushed average day-ahead prices up to 189 EUR/MWh September 22, and to 208 EUR/MWh October 16 2015, triggering price spikes in intraday and balancing markets. Physical inflows were dominant at the NL-BE border, but there were hardly any commercial transaction in this direction (commercial import was registered mainly from France).

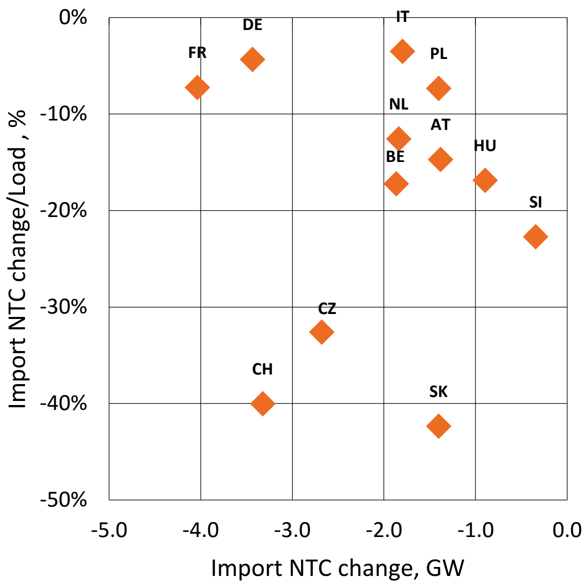
It is interesting to examine which European countries are the most affected by NTC reduction due to UFs. The following figure shows the import NTC reduction due to UFs in absolute terms and compared to the average load. In Slovakia, Czech Republic and Switzerland the import possibilities decrease by 35-45% compared to the average load. In Hungary the decrease is considerable in relative terms; however, the absolute value is not so high (below 1000 MW).

**Figure 18 Average cross-border capacity loss/gain due to unscheduled flows (MW)**




The reduction of NTC available for electricity trade results in lower traded volumes, hence loss of welfare and distorted price signals. The welfare loss can be estimated by the non-traded volumes multiplied with the price difference between the zones, and it is quite significant: according to the ACER calculation in 2014 the total welfare loss in Europe was almost 1000 mEUR. Almost 20% of this total welfare loss is related to the PL-DE border. The high level of UFs in the SK-HU border caused a 40 mEUR welfare loss in 2014, mainly due to the large price spread between these countries.

**Figure 19 Import NTC decrease due to UFs in Europe in absolute terms (horizontal axis) and compared to the average load (vertical axis) in 2014**




4 This criteria means that the outage of any transmission network element does not result in the overload of another element, i.e. the remaining network can manage the consequences of the failed capacity.
5 Reliability margins are estimated and the realised UFs for the same hour observed in the past.
6 Platts, Issue 723, April 11 2016 and CREG Study (F)160324-CDC-1520 on the price spikes observed on the Belgian day-ahead spot exchange Belpex on 22 September and 16 October 2015 (24 March 2016)

## The CEE loop

As discussed above, the CEE loop stretching from North to South Germany is the largest in absolute terms and has been increasing most dynamically over the last few years. The increase of UFs is triggered by the massive rollout of wind capacities in North Germany that – due to the insufficient network capacity inside Germany – are transported to the major load centre, i.e. South Germany, mainly via routes outside Germany. This argument is supported by a strong and statistically significant correlation both between wind production in North Germany and UFs on the DE-PL border, and the DE-AT exchanges (scheduled flows) and the UFs on the DE-PL border.

North-South congestion was aggravated after the closure of 8 nuclear reactors, 5 of them located in southern part of the country. According to Annegret Groebel from Bundesnetzagentur (the German regulator) "The historically singular simultaneous shutdown brings the transmission grids to the edge of their resilience." Structural congestion within the German network is manifested in the application of congestion-related re-dispatching: between 2013 and 2015 German TSOs activated re-dispatch in 80% of the days of the sample. Furthermore, transmission network development within Germany lags behind the planning. Out of the 22 transmission projects identified by the energy network expansion law (ENLAG) in 2009 seven were completed by 2015 and only another five are likely to be commissioned by 2020. The federal transmission system need act (BBPIG) of 2015 identifies 43 projects including 3 HVDC lines connecting North and South Germany scheduled for operation between 2019 and 2022. The execution of these "corridors", however, is delayed by strong NIMBY resistance from local citizens and the fact that in the meantime the preference for underground cabling (mainly pushed by Bavaria) became a legally binding decision in July 2015. This means that the planned system development over the past few years has to be completely reimagined, likely resulting in massive delays.

The structural congestion of the DE-AT border is illustrated by the fact that in 2011 nearly 100% of flows were scheduled and by 2015 this dropped to less than 50%.

## Remedies

We can divide the measures that can relieve the pressure on the network caused by unscheduled flows into two groups: readily available measures and those measures which will be available only in the medium or long-term. Each measure is assessed according to the following criteria: i) impact on available commercially available cross-border capacity levels; ii) categorized as an internal action or requiring cooperation between TSOs; iii) determining if there is cost sharing between TSOs; and iv) impact on wholesale electricity price (Table 1).

Topology measures are defined as internal actions whereby the TSO can improve the ability of the grid to accommodate physical flows. A special topology measure is the use of physical Phase Shifter Transformers (PSTs) which help to increase the commercially available cross-border capacities. Installing PSTs is the most immediate and common way for countries affected by loop flows to address the issue. It offers a quick fix but diverted flows are likely to create problems elsewhere on the grid.

**Table 1 Main characteristics of the different measures that can be used to relieve pressure on congested network elements**

| | | | Impact on commercial available cross-border trading | Internal/cross country | Cost sharing between the TSOs | Price effect |
|---|---|---|---|---|---|---|
| Readily available measures | Topology measures | | - | Internal | no | no |
| | Using currently operating Physical Phase shifters | | ↑ | Cross-country | no | yes |
| | Redispatch | | - | Internal | possible | no |
| | Counter-trading | | - | Cross-country | yes | yes |
| | Virtual phase-shifters | | ↑ | Cross-country | yes | yes |
| | NTC limitation | Ex-ante | ↓ | Cross-country | n.a. | yes |
| | | Ex-post | ↓ | Cross-country | n.a. | yes |
| Future measures | Regulatory | Determine new bidding zone(s) | ↑ | Cross-country | n.a. | yes |
| | | Flow-based allocation | ↑ | Cross-country | n.a. | yes |
| | Infrastructural | Commissioning new Physical Phase Shifters | ↑ | Cross-country | no | yes |
| | | New grid elements | ↑ | Cross-country | possible | yes |

[7] ACER Opinion and Thema: Loop-flows – Final advice (2013)

8 The regulation of Germany energy markets and its European dimension, presentation by Dr. Annegret Groebel, Head of Dep. of Bundesnetzagentur, Bruegel Institute,June 28, 2012

[9] ACER Opinion

10 Platts, Issue 721,(March 14, 2016)

Re-dispatch is the most common way to handle physical congestion problems within price zones. In this case, the TSO instructs a producer to increase its production in order to relieve the physical pressure on one part of the grid. At the same time, another producer in a different location has to decrease its production. Total production remains the same but the topology of production changes resulting in different – and from a congestion point of view more favourable – physical flow patterns within the country. TSOs may compensate producers for the adverse effect of such operations. Redispatch is usually executed within a bidding zone but in some cases TSOs can agree on a bi- or multilateral agreement on cross-border re-dispatch.

Counter-trading is a special case of re-dispatch when the TSO initiates a commercial cross-border transaction in the opposite direction of the main commercial trade flow. It helps to decrease the net commercial inflow to a country and hence relieve congestion but at the same time it impacts electricity wholesale prices. A virtual phase-shifter agreement (vPSTs) is a coordinated cross-border re-dispatch contract between two (or more) TSOs. ENTSO-E claims that mitigating measures currently employed by the CEE TSOs (re-dispatch and planned network extensions) provide an effective remedy to UFs. But the vPST agreement concluded between the German and Polish TSOs (50 Hertz and PSE) aimed at ensuring a minimum of 500 MW available cross-border DE-PL capacity failed as NTC value remained zero.

The last of the presently available and most commonly used measure is NTC limitation that can be either ex-ante or ex-post. Ex ante NTC limitation means the inclusion of UFs (plus the related uncertainty – RM) in the calculation of NTC available for allocation among electricity traders. Ex-post NTC limitation is when the TSOs curtail day-ahead allocated capacity after the day-ahead firmness deadline and makes a compensation payment either equal to the day-ahead price differential between the two affected countries or the original price of transmission rights plus a small premium. Both of these measures decrease the commercial available capacity and impact wholesale electricity prices.

Future or medium/long-term measures can be split into regulatory and infrastructure measures. One potential regulatory action is the introduction of new bidding zone delimitations and the flow-based allocation of cross-border capacity rights. A potential separation of single national bidding zones, e.g. DE-AT market split, or splitting Germany into separate price zones would make the now hidden internal congestion within the single zone explicit. This decision is likely to have a very dramatic impact on wholesale electricity prices, estimated to result in 6-7 EUR/MWh price increase in Austria; however implementation – if so decided – is expected to take 3 years. The DE-AT market is one of the largest and most liquid electricity trading zone in Europe. The Austrian regulator, E-Control, claims that restricting trade at a border to alleviate grid problems elsewhere conflicts with EU competition law.

Splitting Germany into separate bidding zones would be most welcomed by the surrounding countries but domestically it is controversial. It would likely result in quite low wholesale electricity prices in the Northern part of the country, while South Germany could experience a significant price increase. The average price spread between North and South Germany after splitting zones is estimated in the range of 2-11 EUR/MWh, further pressured by the total phase-out of nuclear power in 2022 which will deprive the southern region of a considerable volume of baseload power. However, the price spread would give a strong impetus to the network development needed to relieve congestion and help the surrounding borders presently most affected by UFs to increase their available transfer capacity for commercial purposes.

Another regulatory option is the introduction of flow-based capacity auctions. Under this regime, in the allocation of transfer capacities on a given border the TSOs take into account the physical flow effect of all the commercial transactions. However, the flow-based auction is only effective if new bidding zone(s) are established. Without the proper delineation of bidding zones flow-based allocation doesn't make much difference: Belgium is part of the flow-based market coupling but still suffers from the adverse effects of loop flows sometimes resulting in large price spikes.

Medium to long-term measures relate to infrastructure investments. The easiest, but probably the most expensive way to handle the loop flow problem, is to build new grid elements including new physical phase shifters. The Bundesnetzagentur estimates the investment needs of the German networks including offshore wind farm connections and modernization of distribution networks at 30 to 50 billion EUR until 2020.

*[11] Trepper and Bucksteeg (2013): An integrated approach to model redispatch and to assess potential benefits from market splitting in Germany, EWL Working Paper 19/2013 and Frontier Economics (2014): If Germany was split into several bidding areas, would they go for a system price? (presentation)*

## Conclusions

The question of how to deal with loop flows creates political tension among European countries and some of the measures clearly do not align neatly with the effort to create a single electricity market in Europe. Austria is firmly against the splitting of the DE-AT price zone, evident from the new director of E-Control who stated unambiguously that "(we) actively support the German-Austrian price zone". According to estimates of Verbund CEO, Austria gains 300 mEUR from the single price zone in part because of the flexible nature of its production profile that includes significant hydro capacities. This sum is comparable to the CEE welfare losses, estimated by ACER to be about 469 mEUR in 2013. The price attached to cross-border infrastructure use would reduce the profitability of its producers.

Germany is a less determined supporter of the single price zone as the volume and consequently the cost of the necessary re-dispatch is increasing. The German TSO has to book 6.7 GW reserve capacity and a quarter of this volume would be sufficient in case of separate price zones. The export possibilities of the Czech Republic are seriously constrained by the CEE loop flows. Phase shifters on the DE-CZ border due to start operation at the end of 2016 is expected to block electricity generated by wind farms in north Germany from flowing into the Czech Republic. The CZ-SK-HU-RO coupled market is not likely to join Western European unless the CEZ anticipates some guarantees that its export capacities are freed from the current level of loop flows.

The final solution should strike a balance between the requirements of free electricity trade, a financeable network expansion and the application of mitigating measures with equitable cost allocation based on the cooperation of involved countries and stakeholders.

*12 "The regulation of Germany energy markets and its European dimension", Dr. Annegret Groebel (Head of Dep. of Bundesnetzagentur) előadása, Bruegel Institute, June 28, 2012*
*13 Platts, Issue 724, April 25 2016*

# REKK among the top think tanks of the world

REKK has been ranked in the University of Pennsylvania's 'Global Go To Think Tank Index' and is the only research institute in the region to make the list of 'Top Energy and Resource Policy Think Tanks.'

The ranking was performed in a three-round process. Based on the nominations of more than 5000 journalists and research centres, think tanks receiving more than ten nominations were included in the next step of the process. More than 6800 think tanks were ranked by the panel of 5000 in an online questionnaire. The research institutes ranked highest were then reviewed by a panel of 900 experts across various categories.

REKK was ranked 48 on the global 'Top Energy and Resource Policy Think Tanks' list.

# Competition and Regulation 2015

The Hungarian Academy of Sciences has published an English-language digest of the yearbook Competition and Regulation. Three studies authored by REKK experts were selected for the volume.

András Kiss: *The Effect of the Regional Integration of Electricity Markets on the Market Power of Power Plants*

László Paizs: *Incentive Problems in the Hungarian Energy-Balancing Mechanism*

Péter Kaderják - András Kiss - László Paizs - Adrienn Selei - Pálma Szolnoki - Borbála Tóth: *Natural Gas Market Integration in the Danube Region: The Role of Infrastructure Development*

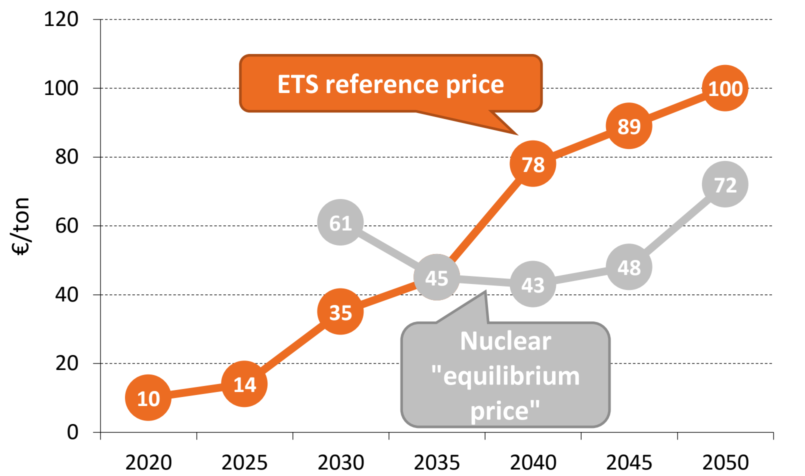
The papers are avalailable at the website of the Hungarian Academy of Sciences (www.econ.core.hu)

# Managing the market and financing risks of ongoing and planned nuclear investments in Europe

***In recent months three anticipated documents were published, each drawing the attention of investors in new electricity generating facilities in Europe. On 4 April the European Commission revealed a detailed analysis titled the "Nuclear Illustrative Programme", providing an overview of the full vertical chain of nuclear technology - from mining through power plants to waste management - and covering the main economic features of new potential nuclear investments[1,2]. The Commission's state aid sector inquiry into electricity capacity mechanisms was then published on 13 April[3]. Lastly, the February publication of the International Energy Agency (IEA), "Re-powering Markets"[4] is also informative. Its subtitle aptly reflects the opinion of the agency on the most critical challenges of the forthcoming period: "Market design and regulation during the transition to low-carbon power systems".***

The analysis of the IEA explicitly articulates the challenges faced by planned power plant projects. Due to the declining trend of wholesale prices the expected revenue from the market in itself is not sufficient to finance the creation of new capacities of low carbon intensity. Moreover, the proliferation of renewable energy, by far the lowest marginal cost producers, continues to add downward pressure on wholesale prices. The 450 PPM scenario that limits the global temperature rise to 2°C includes the rollout of 731 GW of supplemental renewable capacity in Europe by 2040, which will reduce the expected sales potential of traditional power plants. The expansion of renewables also requires increased flexibility from the other producers on the grid. As more solar and wind based power is connected to the network, there will be lower demand for traditional baseload products. The IEA expects total EU gas-based capacity to reach approximately 315 GW by 2040 (adding 128 GW of is new capacity), but these plants will operate far less frequently than today, with an average capacity utilisation rate of 12%.

**Figure 20 Minimum $CO_2$ prices predicted to be necessary for nuclear power plant investments to break even in a competitive market**




*Source: REKK based on EC 2013 and 2016 data*

Down the road, nuclear plants will need to adapt to a market that poses an increasing number of challenges. As baseload producers they have to compete in a continuously narrowing market segment without clear-cut advantages over traditional fossil fuel baseload capacities. From the perspective of greenhouse gas emission abatement, nuclear energy generation is indisputably more attractive than coal based production, but the market does not fully reward this advantage. According to an analysis commissioned by the European Commission, none of the modelled pre-2030 scenarios resulted in an equilibrium $CO_2$ price at which new nuclear investments would break even in a competitive market. Modelling analysis shows that after 2030 a $CO_2$ allowance price of 43 to 72 EUR/ton is required for nuclear investments to competitively break even, while the current EUA price of 5-6 EUR/ton is not expected to exceed the 30 EUR/ton level even in 2030.

Under these unfavourable conditions the replacement of European nuclear power plants (with an average age of 30 years) continues to be marred in uncertainty. The current nuclear fleet operates across 14 countries with a total capacity of 120 GW, but this figure is expected to drop to 95-105 GW by 2050. It remains a substantial level, but implies that the share of nuclear energy will drop from the current level of 27% to 17-21% of European electricity generation.

The recent experiences for European nuclear investments do little to reduce business uncertainty. For the last decade only two projects were launched within the EU, one in France (Flamanville) and one in Finland (Olkiluoto), both based on the EPR 1600 reactor unit developed by Areva. The originally

[1] *European Commission (2016): Nuclear Illustrative Programme. COM(2016) final. Brussels, 4.4.2016.*
[2] *European Commission (2016): Commission staff working document. SWD(2016) 102 final. Brussels, 4.4.2016.*
[3] *European Commission (2016): Interim Report of the Sector Inquiry on Capacity Mechanisms. Draft (HU), Brussels, 13.4.2016.*
[4] *International Energy Agency (2016): Re-powering markets. OECD/IEA, Paris.*

planned budget of the two projects - both of them initiated in 2004 - stood at EUR 3 billion, with planned start-up dates of 2009 and 2010. According to the most recent available information Flamanville is expected to start operation by 2018 at the earliest, marking a delay of 8 years, with total costs expected to reach EUR 10.5 billion, more than three times the original budget . The Olikuluoto-3 power plant of Finland is in a similar predicament. To safeguard investment costs, the Finnish TVO signed a turnkey contract with the constructor Areva-Siemens consortium. The magnitude of cost overruns is similar to the French case, possibly exceeding EUR 8.5 billion, while the construction may be ready by the end of 2018 under the best case scenario. The dispute between the contracting parties has now reached the International Arbitration Court in Stockholm, where the Areva-Siemens consortium sued TVO for EUR 3.52 billion, while in its counterclaim the latter seeks compensation of EUR 2.6 billion from the developers.

While the recent history of nuclear projects is certainly not a success story, a number of EU member states have still decided to launch nuclear investments or plan to do so in the near future. Our analysis reviews the risk sharing models through which the developers of newly launched European projects attempt to make the disorderly market and financing environment more predictable. Our assessment covers the risk sharing solutions applied in the case of the planned UK (Hinkley Point C) and the newer Finnish (Fennovoima consortium, Pyhäjoki) power plants, comparing them to the publicly disclosed measures applied within the Paks-2 project.

Of the risks associated with nuclear power plant projects we evaluate the management of four types of risk: demand, investment, operation and financing. Of course, when designing a nuclear project a broader spectrum of crucial risk factors (such as safety, acceptance by society, waste management) need to be inspected, but their detailed analysis falls beyond the scope of the current analysis.

## Controlling sales risks

Due to volatile demand and the long term uncertainty surrounding electricity prices one of the most important guarantees for nuclear facilities that have a useful lifetime of 50-60 years is the creation of stable and guaranteed prices. To mitigate sales related risks, two models have recently surfaced. The first is the strike price applied in case of Hinkley Point, which sets the price for a fixed period of time (92.5 GBP/MWh for 35 years). If the market price does not reach this level, then the revenue of the power plant is supplemented by British energy consumers through a special tariff to ensure targeted revenues. Likewise, if the market price exceeds the strike price, the additional revenue is transferred by the power plant to a designated fund. It is easy to identify the similarity between the strike price model and the feed-in mechanism that has been widely applied to promote the penetration of renewable energy.

Finland chose a different method, the so called "Mankala model" to mitigate the market risk of the power plant. Under this scheme the owners of the power plant have the right to purchase the generated electricity from the power plant at a price equal to direct production costs. Since the marginal cost of nuclear generation is low, this solution can ensure the long term operation of the plant. This may still not be sufficient to fully cover investment costs, but it is not expected with each owner financing its share of the investment at its own cost of capital. In this case the primary goal of the owners is to gain access to electricity at a predictable price, meaning they are prepared to face the related financing costs and risks.

For Paks, similar risk sharing arrangements are not associated. According to the Hungarian government they are not needed because the project is expected to be profitable on a purely competitive basis. Citing the long term price forecast of KPMG the government claims that regional market prices will continue to ensure a return for the plant operator that would be acceptable for a private investor. From the perspective of risk sharing, it would be interesting to see if the government advisors that took part in project preparation assumed any financial liability for a scenario in which the market prices received by the power plant turn out to be less attractive then the prices they forecasted. However this cannot be determined because the government documents have been classified as strictly confidential.

## Reducing investment risks

The risks associated with the investment period are substantial for nuclear facilities given that in Europe on average 7.8 years pass between the launch of the construction and the start of operation. The two main risk components of the investment period are cost overruns and delays. Past nuclear projects exhibited numerous such examples, and therefore potential investors need to mitigate both types of risks.

[5] *Reuters, 2015.09.03 http://uk.reuters.com/article/edf-nuclear-flamanville-idUKL5N1190M820150903*
[6] *http://www.world-nuclear.org/information-library/country-profiles/countries-a-f/finland.aspx*
[7] *European Commission: State aid SA.38454 (2015/C) page 13.*

**Table 2 The incremental financing cost of the construction period in comparison with the overnight construction cost**

| Construction time | WACC 4% | 5% | 7% | 10% | 13% |
|---|---|---|---|---|---|
| **5 years** | +8% | +10% | +14% | +21% | +28% |
| **7 years** | +11% | +14% | +20% | +29% | +39% |
| **10 years** | +19% | +25% | +37% | +57% | +80% |

European Commission (2016): Commission staff working document. SWD(2016) 102 final. Brussels, 4.4.2016.

The impact of cost overruns are amplified by additional financing costs that arise from the delays. The term "overnight construction cost" is frequently cited in the nuclear industry (typically this data is published by the developers), neglecting the financing costs of the investment period. Thus the Commission's April 2016 analysis quantifies the following potential incremental cost as a function of the cost of capital:

The delay of a project may dramatically diminish its business prospects. In order to mitigate potential cost overruns and delays, the procurers of nuclear projects stipulate alternative contractual guarantees within the contracts.

The Hinkley Point C project places the investment risks squarely with private investors; the risks associated with design, construction and operation are all borne by the investors. For the power plant developed by the Fennovoima consortium the investment risk is also carried by the private investors, but it is not as straight forward owing to the involvement of a number of Finnish industrial and energy corporations among the project owners; the ownership of the "classic" technological partner (Rosatom) is limited to 34%. This also means that for each euro of excess cost, the developer Rosatom as a project owner must finance at least 34 euro-cents. The importance of this fact was emphasised by the director of the Hanhiviki I. project with the following statement: "Our Finnish shareholders are looking for a partner that owns part of the [Hanhikivi] nuclear power plant because we believe that owner security creates much more motivation to finish the project on time and to budget." According to the developers of the Hanhiviki project the ownership risk carried by the professional partner ensures that during the construction period events similar to the catastrophic Olkiluoto project can be avoided.

In the case of Paks a project company fully owned by the Hungarian government is expected to execute the investment, and the risks of the construction period are supposed to be mitigated by the turnkey contract. As the documents are classified, the details are not available, but it is worth keeping in mind that the Olkiluoto 3 carries a similar contract. Unfortunately, the guarantees laid down in the construction agreement alone are not sufficient to preclude fierce disputes among the partners with respect to cost overruns. In comparison with the two other nuclear projects, it is clear that the Hungarian structure leaves considerably more risk on the side of the procurer.

## Mitigating operational and financing costs

In the case of Hinkley Point the operational risks, similar to the financing risks, are borne by the private investor. With the Hanhiviki project the risk is shared among the corporations that own the project. And for Paks the state owned operating company takes on the obligation of managing operational risks.

The EDF-Areva consortium is obliged to provide financing for Hinkley Point, ensuring the initial financial resources necessary to implement the project in addition to any subsequent financial needs. This risk is shared among the consortium partners of the Finnish project (the shareholders of the project) in proportion to their stake in the project. In Hungary 80% of the initial financing, up to 10 billion euros, is provided by Russia through an intergovernmental credit agreement. According to the contract the repayment of the loan starts after the start-up of the new generating units, but not later than 15 March 2026. Coverage of any additional financing requirement is not discussed within the contract. A degree of risk sharing is also inferred here, shifting the risk from the project company towards domestic tax payers, as opposed to placing it on a private investor. According to the intergovernmental credit agreement the Hungarian government essentially guarantees the repayment of the loan, regardless of whether the original investment goal has been achieved.

*8 The overnight construction cost includes all of the investment costs connected to the development, the costs of project preparation and execution and the related costs borne by the owners, except for the financing costs falling on the period between the investment decision and start-up.*

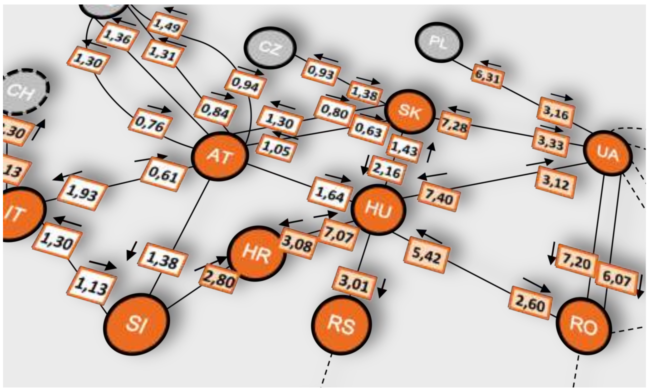
*9 Looking for a domestic analogy, this financial structure is in many ways similar to the business model of the concession highways (especially highway M6) built in Hungary for the last decade, in which case the private investor is granted an availability fee for the contractual period when the facility is operational. As such, the revenue of the private partner is guaranteed, but in case of cost overruns or delays the related incremental costs cannot be passed to the project owner.*

*10 Summary of the World Nuclear News from the WNA sector experts panel discussion, 18 September 2015.*

## Summary

Albeit with a declining share, nuclear technology will continue to be an important segment of European electricity generation for decades to come. Credible sources, however, overwhelmingly claim that under current market conditions - burdened with regulatory interventions - these facilities are not viable on a purely market basis, requiring a detailed review of potential risk sharing between consumers, operators of the facility, and developers. The April 2016 analysis of the European Commission presents two possible techniques to resolve the issue: the strike price method and the “cooperative” solution, the Mankala model. It is likely not coincidental that the financing structure devised for Paks-2 has not been included among the risk sharing models recommended by the Commission.


# The preconditions for market integration compatible gas transmission tariffs in the CESEC region




Access tariffs to cross-border infrastructure are important features of the natural gas market integration “software”. Distorted access tariffs can lead to the underutilization of both existing and newly built infrastructure.

This paper addresses the relationship between cross-border gas transmission tariffs (mostly entry-exit tariffs) and regional cross-border gas trading between CESEC countries. First it identifies the present outlier (above average) tariffs in the region that are most likely to distort efficient cross-border trading. Next the paper offers potential explanations for tariffs being outliers. With market simulation tools it assesses the impact of a number of tariff reform scenarios – each addressing outlier tariffs – on market integration, the utilization of existing and a selected set of priority new CESEC infrastructure and on regional social welfare.

The study can be downloaded from the European Commission's website

# Capacity allocation developments in the gas market - facts and opinions

***The European Network of Transmission System Operators plays a major role in creating uniform European markets for both electricity (ENTSOE) and gas (ENTSOG). Since its foundation in 2011 ACER (Agency for the Cooperation of Energy Regulators) has provided substantial assistance in accordance with its mandate to facilitate the cooperation of energy market regulators. The initial conceptualization of the framework guidelines and network codes for sub-themes started with the collaboration of the above organisations following regulations 714/2009/EC and 715/2009/EC of the European Parliament and the European Council. This article will first describe the most important changes (adopted 1 October 2015 for the most part) in connection with the above regulations and then elaborate as to their impact on the Hungarian transmission system, specifically with regard to capacity sales in the gas market.***

Since the summer of 2015 two transmission system operators have a licence to operate in Hungary: the Földgázszállító Zrt. (FGSZ) and the Magyar Gáz Tranzit Zrt. (MGT). While the latter is solely responsible for the operation of the Slovakian-Hungarian cross-border gas interconnector and the corresponding network segment in Hungary (about 92 km between Vecsés and Balassagyarmat), FGSZ coordinates the transmission of the remainder of the domestic network (totalling some 6000 km) and the adjoining cross-border connectors. As the preeminent system operator it is responsible for developing the Network Code of the natural gas system.

Based on the guidance of the above regulations, gas market related work has commenced in the following areas:

- Congestion management procedures (CMP) (definition of the general principles of CMP, e.g. use-it-or-lose-it1 principle, mechanism of oversubscription and repurchase, etc.)

- Capacity Allocation Mechanisms (CAM) (detailed rules for auctions)

- Balancing (BAL) (detailed guidance for balancing and nominating rules)

- Interoperability of networks (regulation primarily on data publication and on the standardisation of commercial and technical codes for different markets)

- Harmonised Transmission Tariff Structures (TAR) (regulation targeting cost reflecting tariffs, and the standardisation and increased transparency of tariff systems)

The applied standards for the CMP have been obligatory since October 2013. Most of these, such as the use-it-or-lose-it principle and the oversubscription-repurchase mechanism, were incorporated into the Network Code of the Hungarian system operator from the beginning with the introduction of the capacity auctions in connection with the CAM NC. However, some areas of their incorporation have become much more complex, requiring automation and the elaboration of additional rules, and their description would fall beyond the scope of the current analysis.

The national application of the CAM and BAL rules has been obligatory since the autumn of 2015, with deadlines of 1 October and 1 November respectively. Meanwhile the deadline for the introduction of the rules on the cooperation of networks is expected in May 2016 and the final network code on tariff setting (TAR) has not yet been approved.

In Hungary, the CAM NC that came into force on 1 October 2015 resulted in significant changes for FGSZ and system users alike. It had been revised during the preceding summer before the changes were granted final approval by the Hungarian Energy and Public Utility Regulatory Authority (HEPURA).

The most important amendments resulting from the CAM NC can be assigned to one of two categories: on the one hand they aim at the standardisation of the products offered at the capacity auctions as well as the auction algorithms, on the other hand they require the “bundled” auction of the entry and exit points of two countries in the vent of cross-border capacity trade („bundled capacity product”). Essentially, the capacity belonging to the exit point of the exporting country and the entry point of the recipient country does not have to be reserved separately, and instead the right to transfer at a given location can be acquired together.

*1 use-it-or-lose-it: when a market participant has been awarded the right to a given capacity, but it does not want to use (all of) the capacity, then the unused capacity has to be offered again to the rest of the participants; mechanism of oversubscription and repurchase: a system that provides incentives to offer surplus capacities in excess of the non-interruptible physical capacity, and all the rules for the repurchase of the capacities allocated this way.*

While EU regulations prescribed the application of the respective rules only for cross-border intersection points, HEPURA, upon a system review and development of new rules for the auction platform, decided to apply the same rules for domestic network nodes as well[2].Thus the described changes affect all transfer points within the Hungarian transmission system.

Some of the changes aimed at standardisation are related to basic units and measurements. According to the new rules, energy that used to be measured in 15/15 °C reference temperature, on a NCV (net calorific value) basis and expressed in MJ, now must be expressed in 25/0 °C reference temperature, based on a GCV (gross calorific value) calculation, in kWh or kWh/day. Therefore the unit used for products offered on capacity auctions has also changed to kWh/h[3]. Furthermore, beginning in 2015 the start of the gas year shifts from July to 1 October. In 2015 this change was bridged with an interim period: the 2015/2016 annual products (for the period starting on 1 October) were made available in May 2015 (non-interruptible) and June 2015 (interruptible). Special rules were applied for the interim period (July to October) of this year: the capacities secured during the annual auction were also offered by FGSZ to the winners for the months of July, August and September, in exchange for fees that were based on the prices from the auctions. Short term product sales, however, continued without any change until 1 October 2015.

The other part of standardisation affects the time horizon of the products. Under the new framework, annual, quarterly, monthly, daily and intraday products are offered. The first two products are auctioned once a year, while short-term auctions are carried out in a rolling fashion, always a specific number of days before the referred period. FGSZ is obliged to retain at least 10% of the capacities for auctions with a time horizon of less than one year, reflecting an important intention of the regulation to increase the weight of shorter term auctions.

The way that products are sold also changed (already introduced at the end of last year), most notably the requirement that all products are to be sold through auctions. In the case of the annual, quarterly and monthly auctions the applied process is always the so called „Ascending clock" algorithm, a volume auction with predetermined price steps, in which the starting (minimum) price is the "reserve price" set by the regulator[4]. The auction method applied for daily and intraday auctions is the so called "Uniform price" algorithm, whereby participants may submit up to 10 price-volume pair bids for the given capacity product and the price may not be lower than the respective tariff[5].

An important precondition to the applicability of the above described rules is the existence of proper IT infrastructure through which different auction algorithms can be executed. The so called „Regional Booking Platform" (RBP) was created to ensure this, and the first capacity auctions were held at the end of last year. Since then six TSOs (Slovakian Eustream, Croatian Plinacro, Romanian Transgaz, Bulgarian Bulgartransgaz and Hungarian FGSZ and Magyar Gáz Tranzit Zrt) and more than 50 system users have joined the platform that consists of 7 interconnectors and 318 domestic network nodes.

In Europe at present there are three capacity trading platforms: PRISMA, GSA Platform and RBP. PRISMA was founded in 2013 and has emerged as the most important platform with its membership of 37 TSOs from 16 countries (mainly from Western Europe), offering the option of trading for over 1500 network nodes. The Polish GSA is an IT platform which was developed by the system operator, similar to the RBP. Following its launch in 2013, the Czech and Slovakian TSOs have also joined, and in total 26 nodes are available for trading.

After long deliberation, FGSZ decided not to join an existing system, but to develop its own auction platform. This required substantial development efforts, while also ensuring more freedom and independence in terms of pricing and the business model. The platform use fee of RBP is generally between those of its two competitors (PRISMA being the most expensive), but significantly depends on the actual service used. Some argue for the need to develop a uniform trading platform for the whole of Europe, while others believe that the existence of three (differing) platforms is especially advantageous, since the competition forces continuous development and high quality services.

For cross-border interconnectors the system operators of the two countries need to agree on an adjoining platform so that the capacity products can be sold as a bundle. At some border nodes negotiations have yet to be concluded, mainly on the edges of areas covered by the different platforms (e.g. AT-HU and DE-PL borders). In three out of the seven cross-border intersections of the RBP system it is possible

*2 The changes do not extend to the auction calendar and the products are only partly affected (e.g. the scheduling of quarterly auctions is revised). The auction algorithms and the allocation through auctions, however, are amended.*

*3 To be precise, depending on the time horizon of the auctions, the unit is kWh/h/year, kWh/h/quarter, etc.*

*4 Along constantly increasing prices the participants of the auction bid the volume that they are willing to reserve at the price of the given round. The auction ends when the total volume sought to be reserved at a specific price first falls below the offered capacity.*

*5 Then bids are placed in an increasing order of price, the volumes summed, determining the price above which the sum of volumes would already exceed the offered capacity. The price of the last accepted offer will be the settlement price based on which the fees are calculated.*

to auction bundled products (SK-HU, HR-HU and RO-HU), while on the other four borders (with Austria, Serbia and in two locations with Ukraine) there are still on-going negotiations to join the systems on both sides, where for now FGSZ offers capacities on the RBP platform only on its "own" side. For the time being there is no obligation to sell bundled products at border sections that are not within the European Union. The accession of the countries of the Energy Community, however, will be on the agenda soon, which should ensure further growth of the two smaller platforms.

As mentioned before, the interconnector capacities need to be auctioned as a bundled product from October. The CAM NC specifically addresses the treatment of existing contracts for bundled auctions, stating that they need to "be converted to bundled" within 5 years up to the lower of the two capacities purchased in either directions. The remaining excess capacity (in one direction) can continue to be used unbundled. The Network Code separately specifies that the above described auction rules do not apply to the sale of capacity yet to be built, as long as it is constructed under an "open-season" or similar procedure approved by the Regulator before construction. The preparation and need assessment for Hungary's open-season procedure planned for this year has already started. According to the plans, the sale of new capacities related to the extension on the Romanian-Hungarian border may be partially linked to the Hungarian-Austrian cross-border capacity.

The Network Code also specifies that the FGSZ may suspend or cancel auctions that have been pre-announced in the auction calendar only if the appropriate type of capacity is not available for the period in question due to technical or commercial reasons.

Since January 2015 the sale of the monthly, non-interruptible products on the Hungarian-Romanian border has already been announced as a bundled pilot project. Altogether 22 auctions have been completed. According to data available on the auction platform, further bundled auctions were held on the annual, monthly, daily and intraday timeframe on the Croatian-Hungarian border (at Drávaszerdahely with 113 closed auctions) and the Slovakian-Hungarian border (at Balassagyarmat with 227 and almost 3600 mostly intraday closed auctions for interruptible and non-interruptible products, respectively). Up to this point only small shares of capacity have been reserved via completed auctions, implying that the above auctions were closed mostly without success; no capacities were reserved in the Romanian or Slovakian direction (interruptible or non-interruptible), and on the Croatian border only the 2016 annual auction was successful. According to market participants the application of the „use-it-or-lose-it" principle has not made trading more difficult than with the non-bundled purchase of capacities, it only poses an administrative burden.

The changes made in October are indicative of an even more competitive operation of the gas market. The higher share of short term auctions should, in theory, result in even more market liquidity, while the introduction of bundled capacity auctions are meant to make the sale of capacities more transparent and advance the cooperation of system operators.

We thought it would be interesting to inspect how market participants view the accomplishment of these theoretical goals in everyday practice. Can increased transparency and liquidity indeed be noticed, and do they recognise any change in prices or the accessibility of capacities? One of the unquestionably important changes is that capacities can be reserved much more quickly (the lead time that formerly may have taken up to a few months has decreased to a few days thanks to modern information technology), therefore the system contributes to improved predictability. Market participants also maintain that the increased weight of short term capacities makes it easier for traders to acquire precise amounts of capacity; short term products, however, are more expensive, and therefore it does not always make sense to use this option. A good indication for this is the large share of unsuccessful (mostly short term) auctions.

It is important to note that the prices are not primarily driven by the auction based allocation, since in most cases capacities can be reserved at the initial prices announced by the HEPURA decree. In other words, the price of short term products is higher than the price of long term products not because of high demand, but due to the regulation, as the Authority intends to apply this tariff structure to ensure that system use is as uniform as possible.

Yet the disappearance of bottlenecks is hardly the result of the changes related to the allocation mechanism, rather it is much more likely related to the general decline in gas demand and the decrease of gas prices due to the fall of the price of oil. Another important factor is the elimination of the former regulation on preferential access to capacities on the Austrian-Hungarian border.

The introduction of the auction calendar was definitely a popular measure among system users, resulting in increased transparency. According to the interviewed experts, however, there is still room for improvement in the field of secondary capacity trading.

# The Commission's vision for LNG, storage and security: Complete the market

***In February of this year, following a four month consultation period in 2015, the European Commission released a package of communications that include a concrete proposal for the revision of security of supply Regulation 994 and the outline of a strategy for LNG and storage[1]. Together they are aimed at improving natural gas security of supply and competitiveness with the reinforcement of regional solidarity and integration. The term strategy is somewhat misleading with respect to the LNG and storage communications, as the Commission provides more of a suggestive assessment highlighting challenges and potential. Similar to its outlook on security of supply, it prescribes market-based solutions that are dependent on the full implementation of the Third Energy Package. In Central and Southeast Europe (CSEE) the Commission must oversee more market development for these solutions to be feasible, particularly with respect to infrastructure. Here it defers to processes underway, the Central and South-Eastern Gas Connectivity (CESEC) initiative identifying critical projects that are supported with the Connecting Europe Facility (CEF) and cross-border cost allocation (CBCA) overseen by the Agency for the Cooperation of Energy Regulators (ACER). Meanwhile, the security of supply revision seeks to institutionalize shared emergency planning and response measures. As logical as the Commission's observations and intentions are regarding the improvement of security of supply, the recommendations are quite ambitious and unlikely to be implemented as currently envisioned.***

## LNG and storage strategy

In its recently published strategy for LNG and gas storage, the European Commission[2] has forecasted a 50% expansion in global LNG supply over the next few years. Although this holds the promise of lower prices and enhanced gas supply security, the current infrastructure of regasification terminals is not optimally distributed across the EU - most functioning LNG terminals are in Western Europe, while the CSEE region still lags behind. The goal of the strategy is therefore to help the integration of the poorly interconnected regions. As the Commission points out, the six priority projects identified by the Central East South Europe Gas Connectivity group (CESEC), for example, have the potential to contribute to LNG access for all countries in the region along two main corridors from the Krk terminal towards the east and from Greece to the north. Increasing gas-to gas competition, coupled with the effects of falling oil prices on oil-indexed contracts, is expected to result in cheaper gas in parts of Europe where a sufficient degree of infrastructure is in place.

The Commission evaluated the impact of selected gas infrastructure projects of common interest (including those of the CESEC region) on possible LNG penetration in a situation where LNG and domestic production were the only available supply sources to cover total demand on an average winter day - essentially modelling a Russian supply cut. It found that if a cooperative approach is taken – i.e. Member States with LNG capacity exceeding national gas demand share the surplus with neighbouring countries using sufficient interconnection capacity – new infrastructure could significantly increase LNG-uptake in the region. In the case of Hungary, for example, the 'LNG Supply index', calculated as the percentage of national gas demand covered by available LNG capacity, would more than double from 11.2% to 26%.

Along with building the necessary infrastructure, the Commission reiterates the importance of completing the internal gas market to enable price signals while improving cooperation with third parties to promote free, liquid and transparent global LNG markets. In the context of CESEC in particular, the Commission „invited the National Regulatory Authorities to propose an ambitious roadmap of regulatory solutions by mid-2016 which will support the CESEC process", that is streamlining efforts to facilitate cross-border and trans-European projects that diversify gas supplies to the region and implementing harmonised rules.

As far as storage is concerned, the Commission notes that obstacles to cross-border availability of stored gas between Member States and unfavourable market conditions are hampering prospective storage investment and leading to falling capacity usage that puts existing facilities at risk of closure. The strategy aims to ensure that storage facilities survive in an environment where their security-of-supply-value is generally not recognized by the market. The profits of storage operations are under pressure because of the declining spread between summer and winter prices, which could jeopardise not only planned future investments but also existing levels of storage capacity. Although current EU-wide storage capacity appears sufficient, physical and regulatory cross-border issues still need to be addressed to improve its wider regional availability.

*1 Heating and cooling is not covered in this paper*

*2 Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on an EU strategy for liquified natural gas and gas storage (COM(2016) 49), and the accompanying Commission staff working document (SWD(2016) 23)*

In particular, transmission tariffs to and from storage should better reflect costs so as to ensure a level playing-field between competing flexibility instruments. According to the Commission, this issue should be addressed in the work that is underway to harmonize EU-wide network codes. However this effort met another obstacle last October, when the board of the Agency for the Cooperation of Energy Regulators (ACER), made up of the EU's 28 energy regulators, failed to agree upon a common view. At the time the Commission said it would continue to pursue a binding code without an ACER agreement, with the next step gaining approval from an EU committee of national government officials.

The strategy also recommends that regulators should allow and encourage storage operators to develop and provide new innovative services that are freely tradable on secondary markets and across borders. If the capacity allocation mechanism allows operators to book storage and transmission capacity at interconnection points simultaneously (bundling) with a sufficient time horizon in advance of their needs, this could contribute for optimising the regional use of storage.

Furthermore, the market does not fully reward the security-of-supply benefits of gas stored for crisis situations. This is because the benefits accrue to a broad range of stakeholders other than the company bearing the costs of storage, the storage operator. Suppliers, households and the public and private sectors all benefit in the event of major supply disruption.

Therefore, some of the benefits of gas storage, notably its insurance value, may be considered a public good that is not fully reflected in the market value associated with its financing. Some Member States address this by using strategic reserves and storage obligations, but this must be done carefully to avoid unnecessary costs to the gas system that would reduce the overall competitiveness of gas vis-à-vis other fuels. These policies should be subject to strict conditions set out in detail in regional risk assessments, preventive action plans and emergency plans, as proposed under Regulation 994.

The Commission's 'LNG and storage strategy' is more of an assessment, which provides valuable insight but lacks concrete proposals. It falls back on the usual prescription of completing the internal market as laid out in the Third Energy Package by building the necessary infrastructure to enable sufficient cross-border trade and harmonizing network codes and tariffs. Even though the document highlights risks to gas storage and recognizes current shortcomings of the usual, market-oriented approach of the EU, it remains to be seen if national governments implement change based on the Commission's evaluation.

## Incentivizing infrastructure

Beginning with last year's Energy Union package, the Commission's focus on the performance of European natural gas markets has not been entirely well received. Critics of the Energy Union alluded to its disproportionate focus on natural gas markets and the subsequent LNG and storage strategy continued with this philosophy. Those that view natural gas as an obstacle rather than a bridge to a carbon-free future based on renewable energy sources do not endorse additional financial commitments that lock-in a transitional role for the fossil fuel. While security of supply proposals are largely costless organizational measures relying on collective actions for efficiency gains, ensuring access to LNG in the CSEE region requires such financial commitments. At the same time Europe's financial and political commitment to the Trans Adriatic Pipeline (TAP), securing the delivery of 10 bcm of Caspian gas to Europe from 2020 (an inconsequential amount relative to total demand) should send a signal to anyone doubting the fundamental long-term position of gas.

The gas industry is also wary of long-term investments that run the risk of becoming stranded assets in a low demand/low growth environment. It highlights the importance of a thorough CBA assessment for individual, competing and clustered projects that identifies those projects contributing the greatest positive social NPV.

Of course the gas industry was seeking more guarantees from the demand side to improve the fuel's overall competitive position in generation (e.g. capacity markets for gas generation as a complementary back-up for renewables, raising emissions costs to marginalize coal usage). It was critical of the Energy Union for what it considered a one dimensional track of security and diversification (supply side) that ignored the core concern of fledgling European consumption and the future position of natural gas as a transitional fuel. Eurogas, the industry lobby, went as far as labelling the Commission's strategy as contradictory.

This comes following an unprecedented period of upheaval in European gas markets when the industry is particularly sensitive. Incumbent gas utilities have been battered in recent years unable to compete with cheap coal buoyed by a soft emissions trading scheme and zero marginal cost renewables that have shaved peak prices and shifted the entire merit order curve. At the same time, energy efficiency continues to drive down overall consumption already depressed from weak economic growth. And while the Commission is working to facilitate secure and competitive natural gas by urging expensive infrastructure projects for the ultimate benefit of consumers, it continues to revise down its official 2030 demand forecast year after year. For the industry, there are no guarantees if or when demand will recover to pre-crisis levels or beyond given current trends.

Uncertainty is part of the inherent risk factor affecting the viability of natural gas projects, and utilization relies on persistent consumption levels. While prospects for growth are weak, gas certainly is not going away either. The infrastructure that the Commission is promoting for the Energy Union and its LNG strategy is designed to integrate markets where the price spread is great enough to justify the investment through transmission fees and consumer surplus. Infrastructures that are not economically viable at the project level but generate an aggregate positive social NPV in a wider region can be assisted with direct financial support from European loan facilities and/or cost sharing based on the monetization of positive spillover effects (CBCA). In the end, the CBA and multi-criteria analysis will be critical to positive final investment decisions under current demand conditions.

## Revision of Regulation 994

The package of documents released for the revision of EC Regulation 994 touts the solidarity principle and emphasizes the need for enhanced regional coordination/cooperation to plan for and overcome potential supply disruptions of varying magnitudes. The other notable provision is for the Commission to have immediate and regular access to gas supply contracts to i) help assess and coordinate an emergency or ii) in duly justified circumstances. The revision is one of 15 action points listed to achieve the goal of the Energy Union, and follows the main conclusion of the October 2014 stress test asserting that increased cooperation and coordination can substantially mitigate the impact of a disruption.

It was just last year that the Commission completed its country level opinions on the preventive action plans and emergency action plans submitted by Members States in accordance with Regulation 994. Member States were for the most part only required to consider national criteria (joint/regional considerations were encouraged but not mandatory) and yet in every case the Commission concluded that some elements of the Plans did not comply with the provisions of the regulation. To varying degrees they all failed to meet the Commission's interpretation of the criteria in some fashion. Additionally, the comment section of the opinions routinely advised Member States to cooperate with other relevant Member States in the development of preparatory and mitigating measures, including analysis of potential effects of measures adopted by neighboring countries. However, this was optional and countries deferred, electing to keep exclusively national platforms without even slight consideration of neighboring countries (besides UK and Ireland).

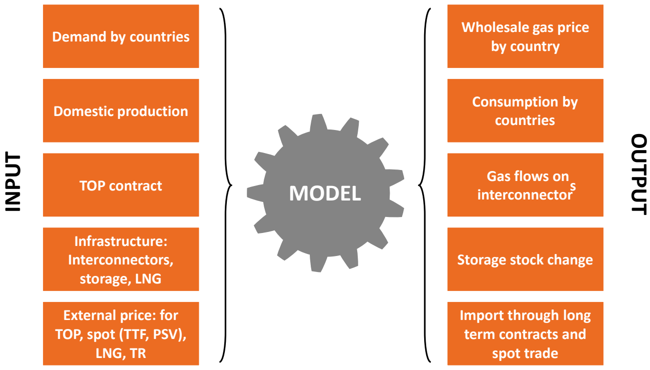
Despite Member States' inability to meet national criteria of Regulation 994 and unwillingness to embrace the recommended cooperative spirit for their own national benefit, the Commission detailed mandatory cooperation and imposed deadlines in its revision proposal: Article 6 stipulates that competent authorities of each region will agree on a cooperation mechanism to conduct risk assessment by 1 September 2018; Article 7 states that competent authorities of each region shall establish joint preventive action plans (PAPs) and emergency plans (EPs) including risks of purely national dimension in accordance with templates in Annex V by 1 March 2019.

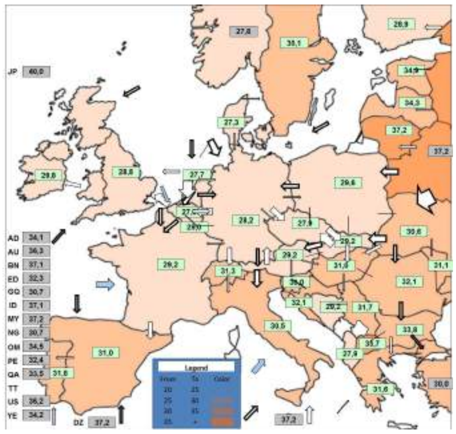
There is no question that the regional approach to risk assessments (RAs), PAPs, and EPs is more efficient than the national approach and, subsequently, that shared market-based measures offer the optimal, least cost solutions to security of supply scenarios - as the Commission points out several times. Perhaps then, the ambition to go beyond the national confines of the original regulation in order to build momentum toward the regional endgame is not only beneficial but necessary to pressure otherwise insubordinate Member States. Or it could also be too far of a leap at too early a stage. If Member States are still absorbing relatively fresh evaluations of their shortcomings to the original regulation, expectations that these countries will now work together to establish much more complex regional plans – within a set timeframe – could be unreasonable.

Already Bloomberg News reported on April 8 that Austria, Belgium, France, Germany and Italy were all against ceding more powers over security of supply to EU authorities, according to a document that it had obtained, specifically mentioning requirements for closer regional cooperation among member states and more oversight of contracts with external suppliers. Belgium in particular opposes the proposed regional geographic zoning found in Annex 1 of the revision, preferring it to be based on a risk analysis. It remains to be seen how the European Council, European Parliament and individual Member States will react to the revision proposal, but there will likely be lack of consensus in its current form.

# EUROPEAN GAS MARKET MODEL (EGMM)

***EGMM is the natural gas market model of REKK developed since 2010 modelling 35 countries***



## ASSUMPTIONS

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

## USAGE

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

## RESULTS

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

## REFERENCES

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

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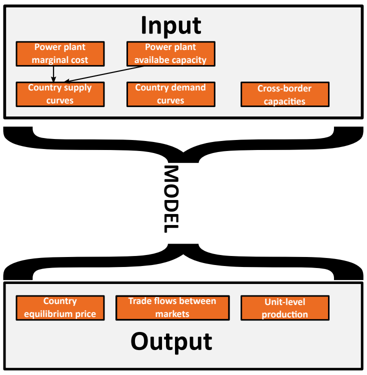
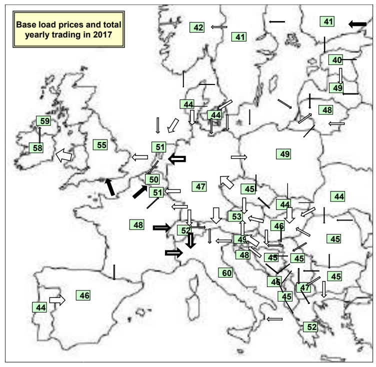
# EUROPEAN ELECTRICITY MARKET MODEL (EEMM)

***EEMM is the electricity market model of REKK developed since 2006 modelling 35 countries***




## ASSUMPTIONS

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

## USAGE

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

## RESULTS

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

## REFERENCES

- Ranking of Project of Common Interest (PECI) projects
- Evaluating the TYNDP of ENTSO-E
- Assessing the effects of the German nuclear decommissioning
- Analysing the connection between Balcans and Hungarian power price
- Forecasting prices for Easterns and 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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